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ATTACHMENT A

Public Utilities Code Section 399.20,
as amended by Senate Bill 1122 (Rubio), Stats. 2102, ch.612

399.20. (a) It is the policy of this state and the intent of the Legislature to encourage electrical generation from eligible renewable energy resources.
(b) As used in this section, "electric generation facility" means an electric generation facility located within the service territory of, and developed to sell electricity to, an electrical corporation that meets all of the following criteria:
(1) Has an effective capacity of not more than three megawatts.
(2) Is interconnected and operates in parallel with the electrical transmission and distribution grid.
(3) Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers.
(4) Is an eligible renewable energy resource.
(c) Every electrical corporation shall file with the commission a standard tariff for electricity purchased from an electric generation facility. The commission may modify or adjust the requirements of this section for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.
(d) (1) The tariff shall provide for payment for every kilowatthour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to paragraph (2) and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.
(2) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with an electric generation facility, in consideration of the following:
(A) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission.
(B) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
(C) The value of different electricity products including baseload, peaking, and as-available electricity.

(3) The commission may adjust the payment rate to reflect the value of every kilowatthour of electricity generated on a time-of-delivery basis.
(4) The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.
(e) An electrical corporation shall provide expedited interconnection procedures to an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit, if the electrical corporation determines that the electric generation facility will not adversely affect the distribution grid. The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit.
(f) (1) An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts cumulative rated generation capacity served under this section and Section 387.6. The proportionate share shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand.
(2) By June 1, 2013, the commission shall, in addition to the 750 megawatts identified in paragraph (1), direct the electrical corporations to collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013. The commission shall, for each electrical corporation, allocate shares of the additional 250 megawatts based on the ratio of each electrical corporation's peak demand compared to the total statewide peak demand. In implementing this paragraph, the commission shall do all of the following:
(A) Allocate the 250 megawatts identified in this paragraph among the electrical corporations based on the following categories:
(i) For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, 110 megawatts.
(ii) For dairy and other agricultural bioenergy, 90 megawatts.
(iii) For bioenergy using byproducts of sustainable forest management, 50 megawatts. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.
(B) Direct the electrical corporations to develop standard contract terms and conditions that reflect the operational characteristics of the projects, and to provide a streamlined contracting process.

(C) Coordinate, to the maximum extent feasible, any incentive or subsidy programs for bioenergy with the agencies listed in subparagraph (A) of paragraph (3) in order to provide maximum benefits to ratepayers and to ensure that incentives are used to reduce contract prices.
(D) The commission shall encourage gas and electrical corporations to develop and offer programs and services to facilitate development of in-state biogas for a broad range of purposes.
(3) (A) The commission, in consultation with the State Energy Resources Conservation and Development Commission, the State Air Resources Board, the Department of Forestry and Fire Protection, the Department of Food and Agriculture, and the Department of Resources Recycling and Recovery, may review the allocations of the 250 additional megawatts identified in paragraph (2) to determine if those allocations are appropriate.
(B) If the commission finds that the allocations of the 250 additional megawatts identified in paragraph (2) are not appropriate, the commission may reallocate the 250 megawatts among the categories established in subparagraph (A) of paragraph (2).
(4) For the purposes of this subdivision, "bioenergy" means biogas and biomass.
(g) The electrical corporation may make the terms of the tariff available to owners and operators of an electric generation facility in the form of a standard contract subject to commission approval.
(h) Every kilowatthour of electricity purchased from an electric generation facility shall count toward meeting the electrical corporation's renewables portfolio standard annual procurement targets for purposes of paragraph (1) of subdivision (b) of Section 399.15.
(i) The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380.
(j) (1) The commission shall establish performance standards for any electric generation facility that has a capacity greater than one megawatt to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability.
(2) The commission may reduce the three megawatt capacity limitation of paragraph (1) of subdivision (b) if the commission finds that a reduced capacity limitation is necessary to maintain system reliability within that electrical corporation's service territory.
(k) (1) Any owner or operator of an electric generation facility that received ratepayer-funded incentives in accordance with Section 379.6 of this code, or with Section 25782 of the Public Resources Code, and participated in a net metering program pursuant to Sections 2827, 2827.9, and 2827.10 of this code prior to January 1, 2010, shall be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section.
(2) In establishing the tariffs or standard contracts pursuant to this section, the commission shall consider ratepayer-funded incentive payments previously received by

the generation facility pursuant to Section 379.6 of this code or Section 25782 of the Public Resources Code. The commission shall require reimbursement of any funds received from these incentive programs to an electric generation facility, in order for that facility to be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section, unless the commission determines ratepayers have received sufficient value from the incentives provided to the facility based on how long the project has been in operation and the amount of renewable electricity previously generated by the facility.
(3) A customer that receives service under a tariff or contract approved by the commission pursuant to this section is not eligible to participate in any net metering program.
(l) An owner or operator of an electric generation facility electing to receive service under a tariff or contract approved by the commission shall continue to receive service under the tariff or contract until either of the following occurs:
(1) The owner or operator of an electric generation facility no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract.
(2) The period of service established by the commission pursuant to subdivision (d) is completed.
(m) Within 10 days of receipt of a request for a tariff pursuant to this section from an owner or operator of an electric generation facility, the electrical corporation that receives the request shall post a copy of the request on its Internet Web site. The information posted on the Internet Web site shall include the name of the city in which the facility is located, but information that is proprietary and confidential, including, but not limited to, address information beyond the name of the city in which the facility is located, shall be redacted.
(n) An electrical corporation may deny a tariff request pursuant to this section if the electrical corporation makes any of the following findings:
(1) The electric generation facility does not meet the requirements of this section.
(2) The transmission or distribution grid that would serve as the point of interconnection is inadequate.
(3) The electric generation facility does not meet all applicable state and local laws and building standards and utility interconnection requirements.
(4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.
(o) Upon receiving a notice of denial from an electrical corporation, the owner or operator of the electric generation facility denied a tariff pursuant to this section shall have the right to appeal that decision to the commission.
(p) In order to ensure the safety and reliability of electric generation facilities, the owner of an electric generation facility receiving a tariff pursuant to this section shall provide

an inspection and maintenance report to the electrical corporation at least once every other year. The inspection and maintenance report shall be prepared at the owner's or operator's expense by a California-licensed contractor who is not the owner or operator of the electric generation facility. A California-licensed electrician shall perform the inspection of the electrical portion of the generation facility.

(q) The contract between the electric generation facility receiving the tariff and the electrical corporation shall contain provisions that ensure that construction of the electric generating facility complies with all applicable state and local laws and building standards, and utility interconnection requirements.

(r) (1) All construction and installation of facilities of the electrical corporation, including at the point of the output meter or at the transmission or distribution grid, shall be performed only by that electrical corporation.

(2) All interconnection facilities installed on the electrical corporation's side of the transfer point for electricity between the electrical corporation and the electrical conductors of the electric generation facility shall be owned, operated, and maintained only by the electrical corporation. The ownership, installation, operation, reading, and testing of revenue metering equipment for electric generating facilities shall only be performed by the electrical corporation.

END OF ATTACHMENT A

ATTACHMENT B
Staff Proposal

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1. Staff Proposal on Implementation of SB 1122

Executive Summary

The following proposal from Energy Division staff (staff) makes recommendations to implement Senate Bill (SB) 1122 (Rubio), Stats. 2012, ch. 612. This section provides an executive summary of the recommendations contained within the staff proposal:

- **Interaction with the Feed-in Tariff (FIT):**
  Bioenergy projects eligible for a FIT contract pursuant to SB 1122 may not seek a contract pursuant to the baseload, peaking, or as-available categories of the FIT.
- **Allocation by Share of Peak Demand:**
  - **Pacific Gas & Electric (PG&E):** 110.78 MW
  - **Southern California Edison (SCE):** 114.53 MW
  - **San Diego Gas & Electric (SDG&E):** 24.68 MW
- **"Commence Operation":**
  Eligibility pursuant to SB 1122 should be limited to new facilities whose initial commercial operation date, as defined by the California Energy Commission (CEC), is on or after June 1, 2013.
- **Bioenergy Category Definitions:**
  - **Category 1:**
    Fuel type:
    - Biogas

    Resource:
    - Biogas from wastewater treatment plants, as defined by Water Code.
    - Municipal organic waste diversion definition adapted from Integrated Waste Management Board regulations.
    - Biogas from "food manufacturing" activities as enumerated in Title 311 of the North American Industry Classification System (NAICS).
    - Biogas from the anaerobic digestion of multiple feedstocks, provided less than 50% of the biogas is derived from dairy cattle manure.

- **Category 2:**
  Fuel type:
  - Biogas or Biomass

  Resource:
  - Biogas generated primarily (80% or more) from the anaerobic digestion of dairy cattle manure.
  - Biogas or biomass that is generated by a customer on the same premises where the customer produces agricultural or horticultural products.
- **Category 3:**
  Fuel Type:
  - Biogas or Biomass

  Resource:
  - Forest byproducts derived from (i) fire threat reduction, (ii) fire safe clearance activities, (iii) infrastructure clearance projects, or (iv) other sustainable forest management activities certified and approved by the California Department of Forestry and Fire Protection (CAL FIRE) or another appropriate state or federal agency.

- **Bioenergy Category Allocation:**

Utility	Category 1:	Category 2:	Category 3:	Share of Statewide Peak Demand
PG&E	30.5	33.5	47	**110.78**
SCE	55.5	56.5	2.5	**114.53**
SDG&E	24	0	0.5	**24.68**
SB 1122 Procurement Targets:	**110**	**90**	**50**	

- **SB 1122 Eligibility for Multi-fuel Facilities:**
  A bioenergy project signing a FIT contract pursuant to SB 1122 must source 80% or more of its feedstock from the SB 1122 category pursuant to which it signed its contract.

- **<u>Determination of Bioenergy Category:</u>**
  A bioenergy project seeking a FIT contract pursuant to SB 1122 must demonstrate at the time of application for the FIT that its facility will utilize the appropriate fuel type and resource for the SB 1122 category pursuant to which it seeks a contract.
- **<u>Maintenance of Bioenergy Category:</u>**
  The FIT contract should be modified to require an annual report by bioenergy projects seeking a FIT contract pursuant to SB 1122 to the contracting utility that includes an auditable record that demonstrates its utilization of SB 1122-eligible fuel sources for its facility.
- **<u>FIT Pricing Mechanism (ReMAT):</u>**
  - **Pricing Structure:**
    Establish a single statewide renewable market adjusting tariff (ReMAT) pricing mechanism to set one statewide FIT payment rate for each SB 1122 category.
  - **Starting ReMAT Price for SB 1122 Eligible Projects:**
    $124.66/MWh (pre-time of delivery (TOD) adjustment)
- **<u>FIT Viability Screens:</u>**
  No changes proposed to the existing FIT viability screens.
- **<u>"Strategically Located":</u>**
  No changes proposed to the existing definition of "strategically located" adopted for the FIT.

1.1. Purpose of the Staff Proposal

The purpose of this proposal is to present a comprehensive outline for implementation of SB 1122.

In April 2013, Energy Division staff released a draft consultant study prepared by Black & Veatch titled, *Small-Scale Bioenergy: Resource Potential, Costs, and FIT Implementation Assessment.* Parties to R.11-05-005 and other participants in the bioenergy industry provided informal comments on the draft study and participated in a workshop in May 2013 to provide feedback to refine and improve the study. The revised, final version of that study is attached.[1] It has been used by staff to inform this proposal and is referenced throughout.

1.2. SB 1122 Background

SB 1122 amended Pub. Util. Code § 399.20,[2] adding §§ 399.20(f)(2)-(4) to mandate a 250 megawatt (MW) increase in the size of the FIT to be set-aside for generation from bioenergy projects. The Commission must allocate the 250 MW among the state's three large investor-owned utilities, or IOUs (PG&E, SCE, and SDG&E), based on the ratio of each utility's peak demand relative to total statewide peak demand.[3]

The Commission must allocate these 250 MW further based on the following categories of bioenergy:

(i) **For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion**, 110 megawatts.

(ii) **For dairy and other agricultural bioenergy**, 90 megawatts.

(iii) **For bioenergy using byproducts of sustainable forest management**, 50 megawatts. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest

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[1] Attachment 1 contains the final consultant study, Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment (October 31, 2013). The final study is also available on the Commission's web site, at http://www.cpuc.ca.gov/assets/CPUCBioEnergyReport_103113.htm.

[2] All further references to sections are to the Public Utilities Code unless otherwise specified.

[3] § 399.20(f)(2)(A).

> management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.[4]

Section 399.20(f)(3) also gives the Commission the authority, in consultation with several other state agencies (the State Energy Resources Conservation and Development Commission,[5] the State Air Resources Board, the Department of Forestry and Fire Protection, the Department of Food and Agriculture, and the Department of Resources Recycling and Recovery), to review and modify the allocation of megawatts among the three bioenergy categories above if it determines such a modification is appropriate.

1.3. FIT History

SB 1122 is codified within § 399.20, which authorizes the FIT as part of the renewables portfolio standard (RPS) program. Assembly Bill (AB) 1969 (Yee), Stats. 2006, ch. 731, created § 399.20, authorizing tariffs and standard contracts for the purchase of eligible renewable generation from public water and wastewater facilities that are 1.5 MW or smaller.

In Decision (D.) 07-07-027, the Commission ordered each regulated electric utility to submit tariff provisions implementing § 399.20. D.07-07-027 also authorized additional tariffs beyond those required for AB 1969 to customers *other than* public water and wastewater customers in PG&E and SCE service territories. Resolution (Res.) E-4137 approved the final tariffs and standard contracts and set the effective date of the tariffs as February 14, 2008.

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[4] § 399.20(f)(2)(A)(i)-(iii).

[5] This agency is commonly known as the CEC.

SB 380 (Kehoe), Stats. 2008, ch. 544, amended § 399.20 to create one tariff that would apply to all utility customers. SB 32 (Negrete McLeod), Stats. 2009, ch. 328, further amended § 399.20, increasing the eligible project size to 3 MW. SB 2 of the 2011-2012 First Extraordinary Session (Simitian), Stats. 2011, ch. 1, amended § 399.20 by deleting a reference to § 399.15 and replacing the reference with the language that had been used in that code section addressing the "market price of electricity." The Commission implemented these statutory changes through D.12-05-035, D.13-01-041, and D.13-05-034. The revised tariffs for the FIT became effective in July 2013.

The IOUs began accepting program participation requests (PPRs) from eligible FIT projects in October 2013, with the first award of contracts beginning in November 2013.

1.4. Overview of the FIT Pricing Mechanism (ReMAT)

In 2013, the Commission replaced the original pricing mechanism for the FIT (which used the market price referent, or MPR,[6] to set the price) with the renewable market adjusting tariff (ReMAT).[7] The ReMAT is a market-based pricing mechanism that will automatically adjust the offered FIT payment rate every two months based on market demand at the previously offered rate. The

[6] The MPR was adopted by the Commission in D.04-06-015 to reflect the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine (CCGT). The Commission last updated the MPR values in 2011 via Res. E-4442.

[7] Authorized by SB 380, SB 32, and SB 2 (1X), and implemented by D.12-05-035, D.13-01-041, and D.13-05-034.

ReMAT pricing mechanism operates independently to determine the market price for each of three product types: peaking, as-available, and baseload.[8] The ReMAT mechanism sets the market price separately for each utility, for each of these three product types. For a detailed overview of the ReMAT pricing mechanism, see Appendix B: Overview of the ReMAT Pricing Mechanism.

Viability Requirements

All eligible renewable energy resources sized up to 3 MW can participate in the FIT, subject to a demonstration that the project has met several viability criteria.

These viability criteria are:[9]

- **Bid Fee:** Generator must pay a $2/kW fee to submit a program participation request (PPR).
- **Interconnection:** Generator must have a System Impact Study, Phase I Study, or have passed the Fast Track screens or Supplemental Review in order to participate.
- **Site Control:** Generator must attest to 100% site control, as demonstrated through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon execution of a FIT contract.
- **Developer Experience:** Generator must attest that at least one member of its development team has (a) completed at least one

[8] Section 399.20(d)(2)(C) provides:

> The commission shall establish a methodology to determine the market price of electricity . . . in consideration of the following . . . the value of different electricity products including baseload, peaking, and as-available electricity.

[9] D.12-05-035, at 69-71 (as modified by D.13-05-034, removing the Seller Concentration requirement, and clarifying the developer experience requirement).

project of similar technology and capacity, or (b) has begun construction of at least one similar project.

- **Online Date:** Generator must demonstrate that it can achieve commercial operation within 24 months of executing a FIT contract, subject to one 6-month extension on account of regulatory delay beyond the generator's control.

Strategically Located

Section 399.20(b)(3) requires that FIT projects be "strategically located." The Commission defined this term in its implementation of the FIT based on the estimated transmission network upgrades required for a project to interconnect.

To meet this requirement of the FIT, a generator must plan to interconnect on the distribution system, as opposed to the transmission system, and its interconnection study must estimate $300,000 or less of transmission system network upgrades at the time of FIT contract execution.[10] In the event that a new interconnection study estimating transmission system network upgrades greater than $300,000 is provided *after* the generator executes its FIT contract, the generator has the option to buy-down the excess to avoid becoming ineligible for the FIT and having its contract terminated.[11]

1.5. Guiding Principles of Staff Proposal

Energy Division staff articulates the following guiding principles to guide this staff proposal on implementation of SB 1122:

1. Establish a bioenergy feed-in tariff based on quantifiable utility avoided costs that will stimulate market demand;

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[10] D.12-05-035, at 56-59.

[11] D.13-05-034, at 29.

2. Contain costs and ensure maximum value to the ratepayer and the utility;
3. Ensure administrative ease and lower transaction costs for the buyer, seller, and regulator;
4. Efficiently use existing transmission and distribution infrastructure;
5. Establish project viability criteria to increase the probability of successful projects within the program.

1.6. SB 1122 Implementation Elements

1.6.1. Interaction with the FIT

The FIT is available to all eligible renewable energy resources sized up to 3 MW. By definition, the small-scale bioenergy projects targeted by SB 1122 must be certified eligible renewable energy resources by the CEC[12] and thus are eligible to participate in the FIT. Energy Division staff expects that most projects that would be eligible to seek a FIT contract pursuant to SB 1122, as outlined in this proposal, would also be eligible to participate in the baseload category of the FIT. Staff makes this assumption because the majority of existing large-scale RPS projects operating in California that utilize bioenergy feedstocks have generation output profiles consistent with the FIT's baseload category.

This creates a potential market power concern, however, where projects seeking a FIT contract pursuant to SB 1122 would have an opportunity not available to other market segments to choose between the ReMAT price offered to baseload generators and a potentially different ReMAT price offered to projects eligible under SB 1122. This would necessarily distort the FIT market and result in a ReMAT price that is not truly representative of a given market

[12] Section 399.25(a).

segment. For this reason, Energy Division staff recommends that projects which are eligible to seek a FIT contract pursuant to SB 1122 may not seek a contract pursuant to the baseload, peaking, or as-available categories of the FIT.

<u>Staff Proposal:</u>

Projects which are eligible to seek a FIT contract pursuant to SB 1122 may not seek a contract pursuant to the baseload, peaking, or as-available categories of the FIT.

1.6.2. Allocation by Share of Peak Demand

The Commission must allocate SB 1122's 250 MW procurement requirement to the three large IOUs based on the ratio of each utility's peak demand to statewide peak demand. This is the same ratio that is applied by § 399.20(f)(1) to the FIT, already implemented by the Commission in D.07-07-027,[13] and replicated in D.12-05-035,[14] to establish utility specific procurement targets for the FIT by comparing each utility's coincident peak demand to the total system statewide peak demand.

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[13] D.07-07-027 at 9.

[14] D.12-05-035 at 77-79, and Conclusion of Law 39.

Staff proposal:

SB 1122's 250 MW procurement requirement should be allocated across the three large IOUs by share of statewide peak demand, as follows:

- **PG&E:** 110.78 MW
- **SCE:** 114.53 MW
- **SDG&E:** 24.68 MW

1.6.3. "Commence Operation"

Section 399.20(f)(2) requires that the Commission limit eligibility for projects seeking a FIT contract pursuant to SB 1122 to projects that "commence operation on or after June 1, 2013." Staff relies on the CEC's *RPS Eligibility Guidebook* (7th Edition, April 2013) for guidance on how to implement this provision of SB 1122. While the CEC does not explicitly define the term "commence operation," it does provide the following related definition:

> **Commercial operation date (COD):** the date on which an electrical generation facility ceases to generate electricity for testing purposes and first generates electricity solely for the purpose of consumption by the facility or any customer or for sale to any procuring retail seller or POU; also referred to as commenced operation date in WREGIS.[15]

Staff recommends using the CEC's definition of "commercial operation date" to determine whether a project is eligible to seek a FIT contract pursuant to SB 1122. That is, to be eligible for a FIT contract pursuant to SB 1122, a project

[15] CEC, *RPS Eligibility Guidebook* (7th Edition, April 2013) at 17. Available online at: http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-SF.pdf.

must first generate electricity on or after June 1, 2013 solely for the purpose of consumption by the facility or any customer or for sale to any procuring retail seller or publicly-owned utility (POU).

Staff Proposal:

The requirement in Section 399.20(f)(2) that projects must "commence operation on or after June 1, 2013" should be interpreted to limit eligibility for SB 1122 to new facilities whose initial commercial operation date, as defined by the CEC's *RPS Eligibility Guidebook* (7th Edition, April 2013), is on or after June 1, 2013.

1.6.4. SB 1122 Eligibility for Multi-fuel Facilities

Some bioenergy generation facilities may utilize multiple feedstocks, either by economic choice or by operational necessity. This is not a bar to eligibility under SB 1122, so long as the generation facility is RPS-eligible and 100% of its fuel is RPS-eligible. To address the use of multiple feedstocks, staff proposes that, for a project to qualify for a contract pursuant to SB 1122, at least 80% of the project's fuel on an annual basis must be sourced from the same SB 1122 category pursuant to which it received its contract. Staff further recommends that the relative contribution of a fuel to a generator's overall generation, for purposes of determining eligibility for SB 1122 only, should be determined using the CEC's methodology for measuring the renewable generation from multi-fuel facilities.[16]

Staff Proposal:

[16] *RPS Eligibility Guidebook* at 42-45.

Any bioenergy project securing a contract pursuant to SB 1122 must source 100% of its fuel from RPS-eligible sources and at least 80% of its fuel on an annual basis from bioenergy resources that fall within the SB 1122 category pursuant to which the project obtained its contract. To determine the utilization rate of a particular fuel, projects should use the CEC's methodology for measuring the renewable generation from multi-fuel facilities.

1.6.5. Bioenergy Category Definitions

Note that any project seeking a FIT contract pursuant to SB 1122 must (1) obtain certification from the CEC as an eligible renewable energy resource [17] and (2) register as a "qualifying facility" (QF) pursuant to the Public Utility Regulatory Policies Act (PURPA).[18] Projects seeking a FIT contract pursuant to SB 1122 will be a subset of bioenergy facilities that qualify as eligible renewable energy resources. The purpose of this section is to present analysis on the basis of which it can be determined in which bioenergy category of SB 1122 a specific RPS-eligible bioenergy facility is eligible to submit a PPR.

Category 1: Biogas from Wastewater Treatment, Municipal Organic Waste Diversion, Food Processing, and Codigestion.

Fuel type definition:

[17] Section 399.25(a).

[18] PURPA is codified in scattered sections of 16 U.S.C., including, § 796, § 824a-3 and §§ 2601, et seq.

For a generator to qualify under this category, the generator is required to derive its biogas from wastewater treatment, municipal organic waste diversion, food processing, or codigestion.

The Commission should adopt the same definition of "biogas" for purposes of SB1122 eligibility that has been adopted by the CEC:

> **Biogas:** includes digester gas, landfill gas, and any gas derived from an eligible biomass feedstock.[19]

Staff notes, however, that not all biogas that may qualify as an eligible renewable energy resource pursuant to the CEC definition would also be eligible to seek a FIT contract pursuant to SB 1122, as addressed below in this section with respect to detailed resource definitions for each of the three bioenergy categories of SB 1122.

Resource definition:

Within the biogas technologies certified by the CEC as eligible renewable energy resources, staff proposes definitions for the following terms found in SB 1122: wastewater treatment, municipal organic waste diversion, food processing, and codigestion.

- **Wastewater treatment**

For purposes of determining eligibility for a FIT contract pursuant to SB 1122, staff proposes that the phrase "biogas from wastewater treatment"

[19] *RPS Eligibility Guidebook*, Glossary of Terms at 116.

refers specifically to biogas generated at wastewater treatment plants. The Water Code defines "wastewater treatment plant."[20]

Staff proposes that for a project to be eligible for a FIT contract pursuant to SB 1122 because it utilizes "biogas from wastewater treatment," that facility must utilize biogas generated from a wastewater treatment plant, as defined by the Water Code.

- **Municipal Organic Waste Diversion**

Other than in § 399.20, the term "municipal organic waste diversion" is not found in California statute. Title 14 of the California Code of Regulations (CCR), however, includes a chapter which includes the "Planning Guidelines and Procedures for Preparing and Revising Countywide Integrated Waste Management Plans."[21]

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[20] Water Code § 13625(b) provides:

> Wastewater treatment plant' means any of the following:
>
> (1) Any facility owned by a state, local, or federal agency and used in the treatment or reclamation of sewage or industrial wastes.
>
> (2) Any privately owned facility used in the treatment or reclamation of sewage or industrial wastes, and regulated by the Public Utilities Commission pursuant to Sections 216 and 230.6 of, and Chapter 4 (commencing with Section 701) of Part 1 of Division 1 of, the Public Utilities Code.
>
> (3) Any privately owned facility used primarily in the treatment or reclamation of sewage for which the state board or a regional board has issued waste discharge requirements.

[21] 14 CCR § 18720.

That chapter of the CCR contains definitions for the following related terms: municipal solid waste,[22] organic waste,[23] and waste diversion.[24]

Staff recommends merging these three definitions to define the term "municipal organic waste diversion" as used in § 399.20(f)(2)(a)(i). Staff proposes the following three-part definition:

> <u>Biogas from Municipal Organic Waste Diversion:</u>
> Biogas that is generated from:
>
> (1) A diversion of organic solid wastes, in accordance with all applicable federal, state and local requirements, from disposal at solid waste landfills or transformation facilities; and,
>
> (2) Where the organic solid wastes originated from living organisms and their metabolic waste products which

[22] 14 CCR § 18720(a)(40) provides: 'Municipal solid waste' or 'MSW' means all solid wastes generated by residential, commercial, and industrial sources, and all solid waste generated at construction and demolition sites, at food-processing facilities, and at treatment works for water and waste water, which are collected and transported under the authorization of a jurisdiction or are self-hauled. Municipal solid waste does not include agricultural crop residues (SIC Codes 071 through 0724, 0751), animal manures (SIC Code 0751), mining waste and fuel extraction waste (SIC Codes 101 through 1499), forestry wastes (SIC Codes 081 through 0851, 2411, and 2421), and ash from industrial boilers, furnaces and incinerators.

[23] 14 CCR § 18720(a)(47) provides:

> 'Organic waste' means solid wastes originated from living organisms and their metabolic waste products, and from petroleum, which contain naturally produced organic compounds, and which are biologically decomposable by microbial and fungal action into the constituent compounds of water, carbon dioxide, and other simpler organic compounds.

[24] 14 CCR § 18720(a)(80) provides:

> 'Waste diversion' means to divert solid waste, in accordance with all applicable federal, state and local requirements, from disposal at solid waste landfills or transformation facilities through source reduction, recycling or composting.

contain naturally produced organic compounds, and which are biologically decomposable by microbial and fungal action into the constituent compounds of water, carbon dioxide, and other simpler organic compounds; and,

(3) Where the organic solid wastes were generated by residential, commercial, and industrial sources, or were generated at construction and demolition sites, at food-processing facilities, or at treatment works for water and waste water, and which were collected and transported under the authorization of a jurisdiction or were self-hauled.

Staff proposes that all three criteria outlined in the above definition must be present in order for the feedstock to qualify for the "municipal organic waste diversion" category pursuant to SB 1122.

- **Food Processing**

A definition of the term "food processing" is not found in California statute. Staff seeks, however, to clearly delineate whether a feedstock qualifies as "food processing" (Category 1) or as "other agricultural bioenergy" (Category 2) because of the relatedness of the source material for the two subcategories and the fact that SB 1122's bioenergy categories have distinct capacity targets.

Generally, staff interprets the term "food processing" to refer to the waste, residues, or by-products of processing or other manufacturing that transforms raw agricultural ingredients into food. On the other hand, as described below in the section addressing Category 2 resource definitions, staff interprets the term "other agricultural bioenergy" to refer to energy generated by the customer on the same premises where the customer produces agricultural or horticultural products.

Staff proposes relying on the North American Industry Classification System (NAICS) to define the term "food processing" for purposes of determining whether a project is eligible to sign a FIT contract pursuant to Category 1 of SB 1122. Title 311 of NAICS enumerates and defines economic activities classified as being within the "food manufacturing" industries.[25]

Staff proposes the following definition of "food processing":

> Biogas from Food Processing:
> Biogas that is generated from the "food manufacturing" activities enumerated and defined in Title 311 of the North American Industry Classification System (NAICS).

- **Codigestion**

Other than in § 399.20, the term "codigestion" is not found in California statute. Staff seeks, however, to clearly delineate whether a feedstock qualifies as "codigestion" (Category 1) or as "dairy" (Category 2) because of the possible relatedness of the source material for the two subcategories and the fact that SB 1122's bioenergy categories have distinct capacity targets.

Generally, staff interprets the term "codigestion" to refer to the anaerobic digestion of multiple biodegradable substrates or feedstocks. As the staff proposal will address below, staff interprets the term "dairy" to refer specifically to the anaerobic digestion of dairy cattle manure. The definition of "codigestion," therefore, must distinguish between biogas generated from the anaerobic digestion of dairy cattle manure (Category 2) and the anaerobic digestion of multiple biodegradable substrates or feedstocks (Category 1). For this reason, staff proposes that, for a facility to qualify under Category 1 as "codigestion,"

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[25] Title 311, "Food Manufacturing," encompassing §§ 3111-311999, can be found online at http://www.census.gov/cgi-.bin/sssd/naics/naicsrch?chart_code=31&search=2012%20NAICS%20Search.

dairy cattle manure must constitute less than 50% of the fuel source for the facility, determined using the CEC's methodology for determining the relative contribution of fuels for multi-fuel facilities, as discussed above in Section 1.6.4 of this staff proposal. Generators that primarily utilize biogas generated from dairy cattle manure may be eligible to participate in the program pursuant to Category 2 of SB 1122, as discussed in the following subsection of this proposal.

For purposes of determining whether a project qualifies as "codigestion" pursuant to Category 1 of SB 1122, staff recommends the following definition:

> <u>Biogas from Codigestion:</u>
> Biogas that is generated from the anaerobic digestion of multiple biodegradable substrates or feedstocks, provided that dairy cattle manure constitutes less than 50% of the facility's fuel source.

Staff Proposal:

Fuel Type: Biogas only

Resource Definitions:

Wastewater treatment:

Biogas that is generated from a wastewater treatment plant as defined by the Water Code.

Municipal organic waste diversion:

Biogas that is generated from:

(1) A diversion of organic solid wastes, in accordance with all applicable federal, state and local requirements, from disposal at solid waste landfills or transformation facilities; and,
(2) Where the organic solid wastes originated from living organisms and their metabolic waste products which contain naturally produced organic compounds, and which are biologically decomposable by microbial and fungal action into the constituent compounds of water, carbon dioxide, and other simpler organic compounds; and,
(3) Where the organic solid wastes were generated by residential, commercial, and industrial sources, or were generated at construction and demolition sites, at food-processing facilities, or at treatment works for water and waste water, and which were collected and transported under the authorization of a jurisdiction or were self-hauled.

Food processing:

Biogas that is generated from the activities described as “food manufacturing” in Title 311 of the North American Industry Classification System (NAICS).

Codigestion:

Biogas that is generated from the anaerobic digestion of multiple biodegradable substrates or feedstocks, provided that dairy cattle manure constitutes less than 50% of the facility's fuel source.

Category 2: Dairy and Other Agricultural Bioenergy

Fuel type definition:

Category 2 is available to generators that utilize both biogas and biomass. Staff recommended above that the CEC's definition of "biogas" be used for determining eligibility for SB 1122. Similarly, the CEC defines "biomass" in the following way:

> **Biomass:** any organic material not derived from fossil fuels.[26]

Further, the CEC also characterizes "eligible biomass fuel."[27] The resources eligible for Category 2 of SB 1122 will be a subset of the fuels included in the CEC's definitions of "biomass" and "biogas".

Resource definition:

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[26] *RPS Eligibility Guidebook*, Glossary of Terms at 116.

[27] *RPS Eligibility Guidebook* at 9:

> Eligible biomass fuel. Includes, but is not limited to, agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, biosolids, sludge derived from organic matter, wood and wood waste from timbering operations, and any materials eligible for "biomass conversion" as defined in Public Resources Code Section 40106.

- **Dairy**

For purposes of determining SB 1122 eligibility, staff proposes that the term "dairy" refers specifically to biogas generated from the anaerobic digestion of dairy cattle manure. As noted above for the definition of "codigestion," however, staff seeks to clearly delineate between projects which are eligible for Category 2 as "dairy" and projects eligible for Category 1 using "codigestion" because of the possible relatedness of the source material for the two subcategories and the fact that SB 1122's bioenergy categories have distinct capacity targets. Consistent with the definition of "codigestion" proposed above, staff proposes the following definition for "dairy":

> <u>Bioenergy from Dairy:</u>
> Biogas that is generated primarily from the anaerobic digestion of dairy cattle manure, provided that dairy cattle manure constitutes at least 80% of the facility's fuel source.

- **Other agricultural bioenergy**

Other than in § 399.20, the term "other agricultural bioenergy" is not found in California statute. The Commission, however, recently adopted a settlement agreement that addresses, among other things, what constitutes "Agricultural Power Service" for rate design purposes. In D.13-03-031, the Commission approved a settlement agreement that provided the following:

> <u>Agricultural Power Service:</u>
> Agricultural Power Service is the electric energy and service used by a customer on the same Premises where the customer produces agricultural or horticultural products, including poultry and livestock. Notwithstanding the foregoing, Agricultural Power Service also applies to electric usage for: (1) packing houses that pack only whole fruits or whole vegetables, and associated cold

storage on the same Premises as the packing houses; (2) cotton gins; and (3) nut hulling and shelling operations.[28]

Staff proposes using this characterization as the basis for defining the term "other agricultural bioenergy" for purposes of SB 1122 implementation.[29]

Staff Proposal:

Fuel Type: Biogas or Biomass

Resource:

Dairy:
Biogas that is generated primarily from the anaerobic digestion of dairy cattle manure, provided that dairy cattle manure constitutes at least 80% of the facility's fuel source.

Other agricultural bioenergy:
Biomass or biogas that is generated by a customer on the same premises where the customer produces agricultural or horticultural products, including poultry or livestock, as well as biomass or biogas that is generated on the premises by: (1) packing houses that pack only whole fruits or whole vegetables, and associated cold storage on the same premises as the packing houses; (2) cotton gins; and (3) nut hulling and shelling operations.

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[28] D.13-03-031, Attachment E, Section 4(a)(1): Definition of Agricultural Power Service.

[29] Although the adopted Settlement Agreement is not precedential, as provided in Rule 12.5 of the Commission's Rules of Practice and Procedure, staff concludes that this characterization may be useful for purposes of implementing SB 1122.

Category 3: Bioenergy Using Byproducts of Sustainable Forest Management

Fuel type definition:

Category 3 is available to generators that utilize both biogas and biomass.

Resource definition:

- **Bioenergy using byproducts of sustainable forest management**

Other than in § 399.20, the term "sustainable forest management" is not found in California statute. Nor has CAL FIRE adopted a formal definition of the term. Energy Division staff has engaged in informal consultation with staff at CAL FIRE in order to obtain information about sustainable forest management to be included in this staff proposal.[30] Based on these staff-to-staff communications, Energy Division staff makes the following proposal to define "sustainable forest management" for purposes of implementing SB 1122:

> A generator seeking a contract pursuant to Category 3 of SB 1122 must ensure that the bioenergy feedstock for its project is sourced from one or more of the following:
>
> i. **Fire Threat Reduction** – bioenergy feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate state, local or federal agency.
>
> ii. **Fire Safe Clearance Activities –** bioenergy feedstock originating from fuel reduction activities conducted to comply with Pub. Res. Code Sections 4290 and 4291. This would include bioenergy feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) 150' Fuel Reduction Exemption.

[30] The proposal herein is that of Energy Division staff. It has not been prepared by, and does not necessarily reflect the views of, CAL FIRE staff.

iii. **Infrastructure Clearance Projects –** bioenergy feedstock originating from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure, including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CCR 1104.1(b)-(g).

iv. **Other Sustainable Forest Management –** bioenergy feedstock certified and approved as being derived from "sustainable forest management" by CAL FIRE or another appropriate state or federal agency.

<u>Staff Proposal:</u>

Fuel Type: Biogas or Biomass.

Resource:

A generator seeking a contract pursuant to Category 3 of SB 1122 must ensure that the bioenergy feedstock for its project is sourced from one or more of the following:

i. **Fire Threat Reduction** – bioenergy feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate state, local or federal agency.

ii. **Fire Safe Clearance Activities –** bioenergy feedstock originating from fuel reduction activities conducted to comply with PRC Sections 4290 and 4291. This would include bioenergy feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) 150' Fuel Reduction Exemption.

iii. **Infrastructure Clearance Projects –** bioenergy feedstock originating from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure, including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CCR 1104.1(b)-(g).

iv. **Other Sustainable Forest Management –** bioenergy feedstock certified and approved as being derived from "sustainable forest management" by CAL FIRE or another appropriate state or federal agency.

1.6.6. Bioenergy Category Allocation

SB 1122 requires that the Commission allocate the capacity targets for the three bioenergy categories among the three large IOUs.[31] To assist with this effort, staff asked engineering firm Black & Veatch to develop a resource potential assessment by utility service territory for the bioenergy resources that are expected to be utilized by facilities eligible to seek a FIT contract pursuant to SB 1122.

Black & Veatch's summary findings on resource potential by utility service territory are shown below in Table 3-1 from the consultant study:[32]

Table 1-1 Utility Resource Potential, MW

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	TOTAL POTENTIAL	SB 1122 TARGET
PG&E	101	340	478	919	111
SCE	115	118	16	249	114
SDG&E	26	3	3	32	25
Total	**241**	**461**	497	1200	250

[31] § 399.20(f)(2)(A).

[32] Attachment 1, *Small-Scale* Bioenergy, at 3-8.

SB 1122 Target	110	90	50	250	

On the basis of the resource potential identified by Black & Veatch, staff has concluded that the bioenergy resources expected to be utilized by SB 1122-eligible projects are unevenly distributed across the service territories of California's three large IOUs. This creates challenges in allocating the SB 1122 bioenergy category capacity targets based on each utility's share of peak demand.

Black & Veatch developed an option for allocating the statute's category capacity targets based on each utility's share of peak demand. To develop this option, Black & Veatch first allocated the 50 MW target for Category 3 based on the basis of the volume of forest materials, as identified by CAL FIRE, located in fire threat treatment areas (FTAA), as required by § 399.20(f)(2)(A)(iii). For the other two categories, Black & Veatch allocated the capacity targets based on each utility's share of peak demand. Black & Veatch also provided estimated costs, both in average $/MWh of generation purchased and $MM/year of total net expenditure by each utility, for this type of allocation approach to estimate expected costs.[33]

Black & Veatch's allocation option driven by each utility's share of demand is shown below in Table 5-2 from the consultant study:[34]

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[33] Section 4 of the Black & Veatch report provides levelized cost of generation estimates for projects that Black & Veatch anticipates could seek a contract pursuant to SB 1122. *Small-Scale Bioenergy* at 4-6.

[34] *Small-Scale Bioenergy* at 5-10.

Table 1-2 Utility Resource Targets and Projected Costs, Proportional by Load

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	35 *(101)*	29 *(340)*	47 *(478)*	127-195	111-171
SCE	62 *(115)*	50 *(118)*	2.5 *(16)*	126-194	113-174
SDG&E	13 *(26)*	11 *(3)*	0.5 *(3)*	140-200	28-40
Procurement Totals	110	90	50	--	252-385

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This allocation method would fulfill the statute's requirement that each utility procure capacity equal to its share of statewide peak demand, while maintaining the capacity targets for each of the SB 1122 bioenergy categories. Staff notes, however, that this allocation would result in the practical concern of SDG&E having an 11 MW target for Category 2, despite Black & Veatch having only identified 3 MW of Category 2 resource potential in its service territory. Given the limited resource potential in SDG&E's service territory, this allocation may result in SDG&E having an unattainable procurement target, resulting in an inability of the IOUs to procure the 90 MW of dairy and other agricultural bioenergy that the statute targets.

To address this situation, staff requested that Black & Veatch generate a slightly modified allocation that takes into account identified resource potential, but then modifies the allocation to eliminate SDG&E's procurement target for Category 2. This proposal maintains the statute's requirement that each utility procure its proportion of statewide peak demand, and that each of the three SB 1122 categories are targeted at the capacity levels required by statute. Black & Veatch then optimized the allocation of the remaining capacity to create the most equitable estimated costs (on a $/MWh basis of procured energy) across all three utilities.

The resulting allocation proposes first to allocate 50 MW of forest bioenergy to the three IOUs solely on the basis of the volume of forest material located in fire threat treatment areas per IOU service territory, as identified by CAL FIRE. Black & Veatch then eliminates SDG&E's procurement target for Category 2 for the reason described above and allocates the remainder of SDG&E's capacity target based on its share of statewide peak demand (24 MW) to Category 1. This results in needing to allocate the remaining capacity targets between PG&E and SCE for Categories 1 and 2, such that the overall target for each utility is consistent with the requirement that each utility procure its share of statewide peak demand and that the overall target for each bioenergy category equals the capacity target set out in the statute. To make this remaining allocation to PG&E and SCE for Categories 1 and 2, Black & Veatch used its estimated blended cost range ($/MWh) for each category to optimize the expected estimated costs per unit of energy generated by PG&E and SCE. The result of this cost optimization is displayed below.

Black & Veatch presents this hybrid allocation option in Table 5-4 of its study,[35] and staff recommends it here for the implementation of SB 1122 because of the balance it provides between identified resource potential and estimated blended costs, while maintaining the statutory capacity targets.

Staff Proposal:

Energy Division staff proposes adopting the following allocation of the SB 1122 capacity targets by IOU:

Utility	**Category 1:** Wastewater, food processing, municipal organic waste diversion, codigestion	**Category 2:** Dairy and other agricultural bioenergy	**Category 3:** Byproducts of sustainable forest management	Share of Statewide Peak Demand
PG&E	30.5	33.5	47	**110.78**
SCE	55.5	56.5	2.5	**114.53**
SDG&E	24	0	0.5	**24.68**
SB 1122 Procurement Targets:	**110**	**90**	**50**	

1.6.7. Determination of Bioenergy Category

Staff expects that the offered tariff rate for each of the three SB 1122 bioenergy categories may vary (see section 1.6.9 below for staff's proposal on SB 1122 pricing), making it important to the maintenance of a fair and competitive market that only generators eligible for a particular bioenergy category are securing contracts at the tariff rate offered for that category.

The determination of the appropriate bioenergy category should be made by the utilities as part of the process for a facility to submit its program

[35] Attachment 1, *Small-Scale Bioenergy* at 5-12.

participation request (PPR) form to participate in the program. Staff proposes that a one-time determination at the time the generator submits its PPR to the utility is sufficient to qualify the generator for a particular SB 1122 category and its associated tariff payment rate.

Staff Proposal:

The utilities should make a one-time determination of the SB 1122 category (Category 1, 2, or 3) for which a project qualifies at the time that the project submits its program participation request form to participate in the FIT. As part of this one-time determination, generators seeking a contract pursuant to a particular bioenergy category pursuant to SB 1122 should be required to demonstrate:

(1) That the fuel type the generator intends to use (biogas or biomass) is consistent with the definition of what qualifies for eligibility pursuant to that bioenergy category within SB 1122; and

(2) That the resource the generator intends to use is consistent with the definition of what qualifies for that bioenergy category within SB 1122.

1.6.8. Maintenance of Bioenergy Category Determination

Staff also recognizes the importance of monitoring whether a project that secures a project pursuant to SB 1122 maintains its bioenergy category determination over the term of its contract. To prevent a generator from fuel-switching from a resource that would be eligible for one SB 1122 category to another category, staff proposes a mechanism by which the utilities should monitor whether a facility maintains its bioenergy category determination. For example, a generator that secures a contract pursuant to Category 3 (bioenergy from byproducts of sustainable forest management) should not be permitted to switch its feedstock to some type of agricultural bioenergy (a resource that would be eligible under Category 2) during the term of its contract. Otherwise, in the view of staff, the statute's requirement that the utilities procure specific capacities from each of three bioenergy categories would be rendered meaningless.

Similar to the one-time determination of bioenergy category discussed in the previous section, staff proposes that this ongoing monitoring of a facility's maintenance of bioenergy category be handled by the utilities. Whereas the one-time determination of bioenergy category to participate in the program is best handled through the PPR, staff recommends that the existing FIT contract terms be modified to require the utilities to monitor whether projects securing contracts pursuant to SB 1122 have maintained their bioenergy category determination.

Staff Proposal:

In order to monitor the maintenance of bioenergy category determination, the joint utility FIT contract should be modified to require an annual report from generators in which the generator provides the contracting utility with an auditable accounting of their feedstock sources over the previous twelve month period. The generators should be required to quantify the percentage of their feedstock input attributable to particular resources.

1.6.9. FIT Program: Pricing Mechanism (ReMAT)

The purpose of this section is to propose a pricing structure that will establish the FIT payment rate for projects securing a contract pursuant to SB 1122, in addition to considering potential modifications to other elements of the ReMAT mechanism.

A detailed overview of the ReMAT pricing mechanism can be found in Attachment 2 to the Staff Proposal.

Pricing Structure

For the FIT, the Commission created separate ReMAT mechanisms to establish separate FIT payment rates, in each of the three utility service territories, for projects with the following three generation profiles: baseload, peaking, and as-available.[36] The resulting nine ReMAT mechanisms respond independently to differentiated market segments, setting a unique FIT payment rate for each.

Table A, below, provides a visual overview of how the ReMAT is structured:

Table A: Overview of Pricing Structure for the SB 32 FIT

		Investor-Owned Utility		
		PG&E	**SCE**	**SDG&E**
Generation Profile	**Baseload**	Separate ReMAT Mechanism	Separate ReMAT Mechanism	Separate ReMAT Mechanism
	Peaking	Separate ReMAT Mechanism	Separate ReMAT Mechanism	Separate ReMAT Mechanism
	As-available	Separate ReMAT Mechanism	Separate ReMAT Mechanism	Separate ReMAT Mechanism

[36] D.12-05-035 at 38-48.

This structure was designed to allow for a differentiation of price among various FIT market segments and among IOU service territories. To better ensure that the ReMAT mechanism responds to true market conditions—rather than to the economic circumstances of one or two unrepresentative projects—the Commission requires that 5 eligible projects, from different developers, be participating in the program for a particular generation type, for a particular utility, before the price will adjust. If fewer than 5 projects are participating, the price will remain unchanged.[37]

In the context of SB 1122 implementation, several parties raised the concern, both at the workshop held to review the draft consultant study and in informal feedback provided to staff, that it would be difficult to attract 5 eligible projects per SB 1122 bioenergy category, per IOU, given the infancy of the small-scale bioenergy market. These parties expressed concern that this would prevent the ReMAT mechanism from truly reacting to the economics of the industry, and may result in few projects being developed pursuant to SB 1122.

As an alternative to relaxing the requirement that 5 eligible projects be registered for the program before the price may adjust to market conditions, staff instead proposes a modified pricing structure for the SB 1122 tariff. Staff proposes that a single statewide ReMAT pricing pool be created for each of the three bioenergy categories in SB 1122, rather than deploying a separate ReMAT mechanism for each SB 1122 bioenergy category, in each IOU service territory.

Table B, below, provides a visual overview of staff's proposal for the ReMAT pricing structure to implement SB 1122:

[37] D.12-05-035 at 45.

Table B: Energy Division Staff's Proposed Pricing Structure for SB 1122

		Investor-Owned Utility		
		PG&E	SCE	SDG&E
Generation Profile	Baseload	Separate ReMAT Mechanism	Separate ReMAT Mechanism	Separate ReMAT Mechanism
	Peaking	Separate ReMAT Mechanism	Separate ReMAT Mechanism	Separate ReMAT Mechanism
	As-available	Separate ReMAT Mechanism	Separate ReMAT Mechanism	Separate ReMAT Mechanism
SB 1122 Bioenergy Category	(1) Wastewater, food processing, organic waste, codigestion	Separate ReMAT Mechanism to set one statewide Category 1 price		
	(2) Dairy and other agricultural bioenergy	Separate ReMAT Mechanism to set one statewide Category 2 price		
	(3) Byproducts of sustainable forest management	Separate ReMAT Mechanism to set one statewide Category 3 price		

Staff proposes this pricing structure to achieve several objectives. First, this pricing structure would allow for a differentiation of price among the three bioenergy categories enumerated by SB 1122 to encourage the development of projects in each category, consistent with the statute. Second, the deployment of a single ReMAT mechanism to set a statewide price per bioenergy category would address the potential challenge that the nascent small-scale bioenergy market might face if there were nine separate ReMAT mechanisms, one per bioenergy category, per utility. Third, this structure promotes greater market competition in each bioenergy category across the state.

Staff recognizes, however, that this type of pricing structure would require a greater level of coordination among the three utilities than currently exists for the FIT Program. Staff proposes that the pricing mechanism would work as follows:

(1) **Capacity targets per SB 1122 category.** Each IOU will maintain its own capacity targets per SB 1122 category, as proposed above in section 1.6.6.

(2) **ReMAT Queue per SB 1122 category.** A bioenergy project seeking a contract pursuant to SB 1122 will submit a program participation request to participate in the FIT program with a specific utility (corresponding to the utility service territory in which the project intends to locate). Execution of a FIT contract by a bioenergy project would draw down the SB 1122 category capacity target for that utility.

(3) **Statewide ReMAT "Pricing Pool."** Only for purposes of determining whether or not the ReMAT mechanism should adjust the offered payment rate, the three IOUs should coordinate. If the conditions for a ReMAT price adjustment, as defined by D.12-05-035 and D.13-05-034, are met by considering the *cumulative participation* of the market per SB 1122 category across the three IOUs, then the price will adjust. The result is that the bioenergy market will set one statewide price per SB 1122 category based on demand for FIT contracts across utility service territory.

<u>Staff Proposal:</u>

The pricing structure for SB 1122 should utilize a single ReMAT pricing mechanism for each bioenergy category to set a statewide price for each category. Implementation of this pricing structure should include the following elements:

(1) Individual projects will submit PPRs directly to a single utility (the utility in whose service territory the project intends to locate).

(2) Each IOU will maintain its own ReMAT Queue per bioenergy category, consistent with the capacity targets proposed in section 1.6.6. of this proposal.

(3) Execution of a FIT contract by a bioenergy project will result in the

capacity of that project being attributed to the SB 1122 capacity target for the utility with which the project signs its contract.

(4) The IOUs will jointly administer a statewide "price pool" for each of the three SB 1122 bioenergy categories to establish a single, statewide FIT payment rate for each of the categories. The conditions for a price adjustment that were adopted by D.12-05-035 and D.13-05-034 will remain the same for SB 1122, with the exception that the conditions will be evaluated by considering the *cumulative participation* per SB 1122 category across the three IOUs.

SB 1122 Starting Price

According to the Assembly Floor Analysis of SB 1122, the bill's author proposed the bill to "promote diversity in resource technologies" which the author believed would be lacking with the existing FIT program, as implemented by the Commission.[38] The author also argued that, "[w]ithout differentiating small renewable biomass and biogas projects from other renewable distributed generation, opportunities for methane pollution reduction and clean energy generation will not be realized."

To achieve this legislative objective, the FIT payment rate offered to projects seeking contracts pursuant to SB 1122 must be sufficient to stimulate their development. Given that small-scale bioenergy facilities have been, and remain, eligible for the FIT, staff interprets the adoption of SB 1122 as an acknowledgement that small-scale bioenergy projects will likely cost more to develop than other renewable distributed generation.

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[38] Assembly Floor Analysis, August 24, 2012, "Author's Statement." Available online: http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_1101-1150/sb_1122_cfa_20120824_204842_asm_floor.html.

Several parties have suggested to staff, and the Black & Veatch study confirms, that the cost of small-scale bioenergy projects is likely to exceed that of other similar-sized new RPS projects, such as solar photovoltaic (PV) projects.

Additionally, as shown by Energy Division's RPS Project Status Table,[39] more than 80% of the capacity that secured a contract through the first three RAM auctions[40] was from solar PV projects. It is reasonable, as a result, to select a different ReMAT starting price for SB 1122 that better reflects recent market data for bioenergy projects, rather than using the $89.23/MWh starting price utilized thus far for the FIT program.

For these reasons, staff proposes the following starting price to be used for all three SB 1122 bioenergy categories:

- **ReMAT Starting Price**: $124.66/MWh (pre-TOD).

Staff developed the proposed new ReMAT starting price for SB 1122 bioenergy projects of $124.66/MWh by calculating the weighted average post-TOD bid price of all conforming bids into the first three RAM auctions from bioenergy projects. This price reflects the most recent RPS market data available to the Commission for bioenergy projects nearest in size to those mandated for procurement through SB 1122.

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[39] Available online: http://www.cpuc.ca.gov/NR/rdonlyres/86F3CDEA-32F1-4343-97EA-777965714123/0/RPS_Project_Status_Table_2013_July.xls.

[40] The Renewable Auction Mechanism (RAM) was approved by the Commission in D.10-12-048 as a pilot program for the procurement of utility-scale renewable resources up to 20 MW in size. The RAM was initially authorized as a 1,000 MW program to be procured by the three IOUs in four auctions held over two years. The first RAM auction closed in November 2011 and the fourth RAM auction, for which data is not yet available, closed in June 2013.

Staff does not recommend making any additional changes to the ReMAT pricing mechanism. The requirement that five eligible projects be participating in the ReMAT queue before the price can adjust, for instance, is still relevant for SB 1122 as it ensures that the ReMAT mechanism only adjusts the price in response to true market conditions, rather than in response to one or two unrepresentative projects.

Staff Proposal:

The ReMAT mechanism as applied to SB 1122 should remain unchanged from what has been previously adopted by the Commission for the FIT program, with one exception. The ReMAT starting price should be set at $124.66/MWh (pre-TOD) for all three SB 1122 bioenergy categories to better reflect the most recent market data available to the Commission from bioenergy projects in this size range.

1.6.10. FIT Program: Viability Screens

In the development of the FIT, the Commission adopted several viability screens that a project must meet before it is eligible to participate in the program.[41] The viability screens that a generator must meet in order to participate in the FIT are reviewed above in Section 1.4 of the staff proposal.

While several parties have recommended to staff that these viability screens be modified to accommodate the small-scale bioenergy market, staff does

[41] D.12-05-035, at 69-71 (as modified by D.13-05-034, removing the Seller Concentration requirement, and clarifying the developer experience requirement).

not propose to do so. The Commission found in D.12-05-035, which established these viability screens for the FIT, that:

> Increasing the viability of contracts executed pursuant to the FiT Program will allow for more efficient management of the limited program capacity and benefit the market by reducing speculative contracts.[42]

For these same reasons, staff declines to propose modifying the viability screens for projects seeking a FIT contract pursuant to SB 1122.

Staff Proposal:

The viability screens for participation of projects eligible under SB 1122 should remain the same as those previously adopted by the Commission for the FIT.

1.6.11. FIT Program: "Strategically Located"

As described in Section 1.4 of the staff proposal above, § 399.20(b)(3) requires that projects be "strategically located." The Commission defined this term by requiring that a FIT project must have no more than $300,000 of transmission network upgrades estimated at the time of FIT contract execution. [43]

Staff does not recommend modifying this definition.

[42] D.12-05-035, Finding of Fact 28.

[43] D.12-05-035, Ordering Paragraph 8.

<u>Staff Proposal:</u>

The Commission's definition of "strategically located" for determining eligibility for SB 1122 should remain the same as the definition previously adopted by the Commission in D.12-05-035.

ATTACHMENT 1

Black & Veatch Consultant Study:
Small-Scale Bioenergy: Resource potential, Costs, and Feed-in Tariff Implementation Assessment
(October 31, 2013)

FINAL CONSULTANT REPORT

SMALL-SCALE BIOENERGY: RESOURCE POTENTIAL, COSTS, AND FEED-IN TARIFF IMPLEMENTATION ASSESSMENT

PREPARED FOR

California Public Utilities Commission

31 OCTOBER 2013

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Legal Notice

1.0 Executive Summary

KEY FINDINGS

- **Lack of a Robust Existing Market May Delay Project Starts.** Few SB 1122 eligible projects have passed the ReMAT (Renewable Market Adjusting-Tariff) eligibility screens (only seven are estimated to be in the interconnection queues of the utilities). As a result, it appears that a very limited number of small-scale bioenergy generators could take advantage of the market-based pricing mechanism recently adopted by the CPUC for the feed-in tariff program. Given these factors, there may be a delay of three years or more from tariff implementation to project completions. Modifications to the ReMAT mechanism or eligibility rules may accelerate this schedule by more quickly leading to a higher tariff, but the time required for development, permitting, and interconnection must also accelerate.
- **Disproportionate Resource Availability.** Approximately 1,200 MW of SB 1122 eligible resources are available in the utility service territories, five times what is required by the statute. However, these resources are located disproportionate to load, with PG&E having more than 75 percent and SDG&E less than three percent. This may create compliance issues for SDG&E, since SB 1122's procurement requirements are based on load. As a consequence of this disproportionate resource availability, allocating the statutory capacity targets across utilities will be challenging.
- **Potential for High Costs to Meet Statutory Targets.** The cost of generation can vary considerably among bioenergy technologies, but is likely to average $130 to 200/MWh for a blended rate. This would be higher than recent costs seen in the Renewable Auction Mechanism (RAM) and large scale renewable solicitations. Incentives, strategic placement of projects, and coproduct values may help to lower the cost. This price reflects delivered cost to the utility, but does not reflect the full range of potential value that small scale bioenergy brings to the state.
- **Modification of the Statute May Reduce Costs and Improve Equity.** Removal of the Section 399.20 statutory requirement that feed-in tariff projects must be located in the service territory of the procuring utility and modification of the utility procurement requirements to better reflect resource availability (rather than by share of peak load, as currently in statute) may lower costs to ratepayers, be more equitable between utilities, reduce market manipulation, and be less administratively burdensome.
- **Feedstock Classification.** Clarification is needed for what classifies as "sustainable forest management material" pursuant to SB 1122. Separately, clarification is also needed for how to classify projects seeking to use multiple feedstock types, and how to verify that a generator continues utilizing the same feedstock for which it signed a contract.

1.1 SCOPE OF WORK

Senate Bill (SB) 1122 directed the California Public Utilities Commission (CPUC) to establish a standard tariff for at least 250 megawatts (MW) of bioenergy projects with nameplate capacities of 3 MW or smaller in three feedstock categories:

- **Category 1:** Biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion (110 MW)
- **Category 2:** Dairy and other agricultural bioenergy (90 MW)
- **Category 3:** Bioenergy from the byproducts of sustainable forest management (50 MW)

The statute requires that the tariff only be available to projects that "commence operations" on or after 1 June 2013. The three large investor-owned utilities (IOUs) – Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric – in California must comply with procurement targets based on their proportionate share of statewide peak demand. The CPUC and other state agencies have the flexibility to determine if the allocation of the 250 MW by resource is appropriate or if it should be modified.

As part of its continuing work with the CPUC on renewable distributed generation (DG), Black & Veatch was retained by the CPUC to assist with implementation of SB 1122. The intent of this analysis is to determine the likely availability of resources and projected cost of electricity for projects eligible for the SB 1122 tariff. Potential feed-in tariff implementation issues are also considered.

Future areas of evaluation may include identifying and quantifying the full range of benefits and costs from the use of distributed bioenergy. These may include items such as avoided capacity, energy, transmission and distribution costs, as well as reduced GHG emissions, line losses, and load impacts relative to a base scenario. Additional impacts specific to bioenergy, such as criteria pollutant changes, reduction in open burning, reduced high intensity forest fire threat, landfill diversion, CHP benefits, and methane capture may also merit further analysis. The potential costs and benefits are not addressed in this study.

1.2 APPROACH AND METHODOLOGY

Estimates were made for the magnitude of the resources available for SB 1122 compliance. Technical availability using economic breakpoints[1] in both dry tons per year and equivalent MW of power generation were estimated for the following resources:

[1] "Technical availability" refers to material deemed possible for collection and use in a bioenergy facility, taking into account environmental concerns, topography and collection efficiencies, material needed for soil fertility and erosion control, and other factors. Economic factors such as facility size, alternative uses, and exclusion of poor quality resource were also taken into account in the assessment.

- **Category 1**
  - Biogas from Wastewater Treatment Plant (WWTP) biosolids digestion
  - Biogas from "municipal organic waste diversion, food processing, and codigestion" was quantified through assessments of digestion potential for food waste, leaves and grass, and FOG[2]
- **Category 2**
  - Biogas from dairy cattle manure digestion
  - Biopower from the gasification of agricultural residues
- **Category 3**
  - Biopower from the gasification of sustainable forest management byproducts

Publicly available, peer reviewed datasets were the basis for the majority of the resource assessments. The goal was to capture the magnitude of the resources available and allocation by utility service territory. This assessment is not intended to reflect all potential resources that could be used for SB 1122 compliance.

To estimate the energy generation potential, assumptions for feedstock quality and operational performance of commercially available anaerobic digestion and biomass gasification units coupled with internal combustion (IC) engines were used.[3] Estimates were then created for the levelized cost of electricity (LCOE) needed to support SB 1122 projects based on low, medium, and high capital and operating cost assumptions. These assumptions were entered into a financial pro forma to estimate the LCOE. The intent of the LCOE estimates are to bracket the range of likely SB 1122 project costs, and are not intended to reflect any particular project. LCOEs will vary considerably based on site specific development requirements, feedstock costs, coproduct values, and available incentives.

1.3 RESULTS

1.3.1 Resource Potential

Table 1-1 provides an estimate of SB 1122 potential by resource and within each utility service territory.

[2] Separation of high and low solids organic wastes was required due to wording in SB 1122 and differences in how each material would be converted to power. Wetter, low solids materials (up to roughly 40 percent solids) are suitable for biogas production through anaerobic digestion, while high solids material would be combusted or gasified. Leaves and grass are assumed to be part of the municipal organic waste diversion for biogas allocation, while drier, high solids food waste such as nut shells are categorized as agricultural bioenergy.

[3] While a range of technologies could be used to convert these resources to power, the most commercially available, lowest cost technologies that could feasibly be permitted in California were chosen.

Table 1-1 Utility Resource Potential, MW

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	TOTAL POTENTIAL	SB 1122 TARGET
PG&E	101	340	478	919	**111**
SCE	115	118	16	249	**114**
SDG&E	26	3	3	32	**25**
Total Potential	**241**	**461**	**497**	1200	**250**
SB 1122 Target	**110**	**90**	**50**	**250**	

From a resource perspective, this estimate indicates that there is roughly five times more total material available to meet SB 1122 requirements when compared to the requirements of the statute. Forest (Category 3) and dairy/agricultural residues (Category 2) each have nearly 500 MW of potential with biogas from Category 1 materials roughly half this amount. Forest material is most abundant in Northern California and lower than other statewide assessments due to the exclusion of material from shrubland. While shrub biomass is an eligible resource and in significant fire threat areas, cost, resource collection issues, and potential technical challenges in utilizing this material have led to it rarely being used. This analysis is intended to capture the current magnitude of the resources available by applying reasonable discounts and economic factors to the gross statewide potential. Changes in waste and land management practices,[4] resource competition, industry regulations, market economics, recovery efficiencies, and policy shifts could all impact these estimates.

If only material in each utility's service territory is used to meet SB 1122 requirements, PG&E would have by far the most feedstock availability. PG&E will need to procure approximately 111 MW to meet its SB 1122 procurement requirement based on its share of statewide peak demand; roughly eight times this level of feedstock is estimated to be available in its service territory. SCE is estimated to have roughly twice as much feedstock available relative to its SB 1122 procurement requirement (114 MW), while SDG&E is estimated to have barely enough feedstock to meet its requirement (25 MW).

Using load shape data at IOU substations developed as part of the renewable DG technical potential analysis being performed at the CPUC, over 11,000 MW of low-cost interconnection potential is estimated to exist throughout the IOU service territories. However, many types of bioenergy resources are located in rural areas, which may not have as much transmission availability as urban areas with more robust grids. This was evident through an analysis of the available transmission

[4] Including both federal and state land management practices.

capacity without upgrades in each country relative to the demand for new project interconnections. Southern California shows high transmission potential but more demand than availability capacity in most counties, while Northern California has less transmission potential but also lower new project demand. Developers should consult the on-line interconnection maps available from each IOU to provide initial indications for the level of transmission available at a specific site. The ability of some bioenergy projects, namely those using forest or agricultural feedstocks, to move to more strategic interconnection locations may help mitigate some of the transmission issues, but this may result in higher fuel costs for the generator if it needs to haul its feedstock a greater distance.

1.3.2 Cost of Generation

Estimates of the LCOEs for each of the feedstock types can be seen in Table 1-2 and Figure 1-1. A proxy project size is used for each feedstock based on what was considered reasonable for development. No financial incentives and limited coproduct values are assumed in the economic model. It is assumed that forest and agricultural residue projects pay for feedstock (average $30/dry ton for agricultural residues and $45/dry ton for forest material) while new Category 1 digester projects receive a tipping fee (average $20/dry ton). Unique factors that could greatly influence the project cost are also listed.

Table 1-2 SB 1122 LCOE Summary by Feedstock Type, $/MWh

RESOURCE AND SIZE	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE	UNIQUE COST FACTORS
Category 1				
Existing Digestion (3 MW)	51	63	76	Gas cleaning and infrastructure requirements
New Digestion (3 MW)	88	155	219	Tipping fee, coproduct value, digester type
Category 2				
Dairy Cattle Manure (1 MW)	218	288	346	Solids disposal costs, fertilizer value, AB32 credits, codigestion, digester type
Agricultural Residues (3 MW)	138	204	258	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Category 3				
Forest Material (3 MW)	148	219	281	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Generic project estimates not taking into account incentives or coproduct values/disposal costs				

Figure 1-1 shows the above data graphically, with comparisons to the range of costs recently seen for projects with executed PPAs from recent Renewable Auction Mechanism (RAM) and large-scale renewable solicitations. Without incentives or value for the coproducts, the required LCOE for most SB 1122 compliant projects will be higher. However, if SB 1122 projects are able to take advantage of some of the currently available incentives and/or obtain value for their coproducts, the LCOEs for some resources may become more comparable to the range of prices recently seen in other solicitations. However, given the lack of an existing market for small-scale bioenergy generators and the range of unique incentive scenarios possible in the state, analysis of the true value that a combination of incentives and coproduct values may deliver can only be performed on a project specific basis. More detail on incentives is provided in the Appendix.

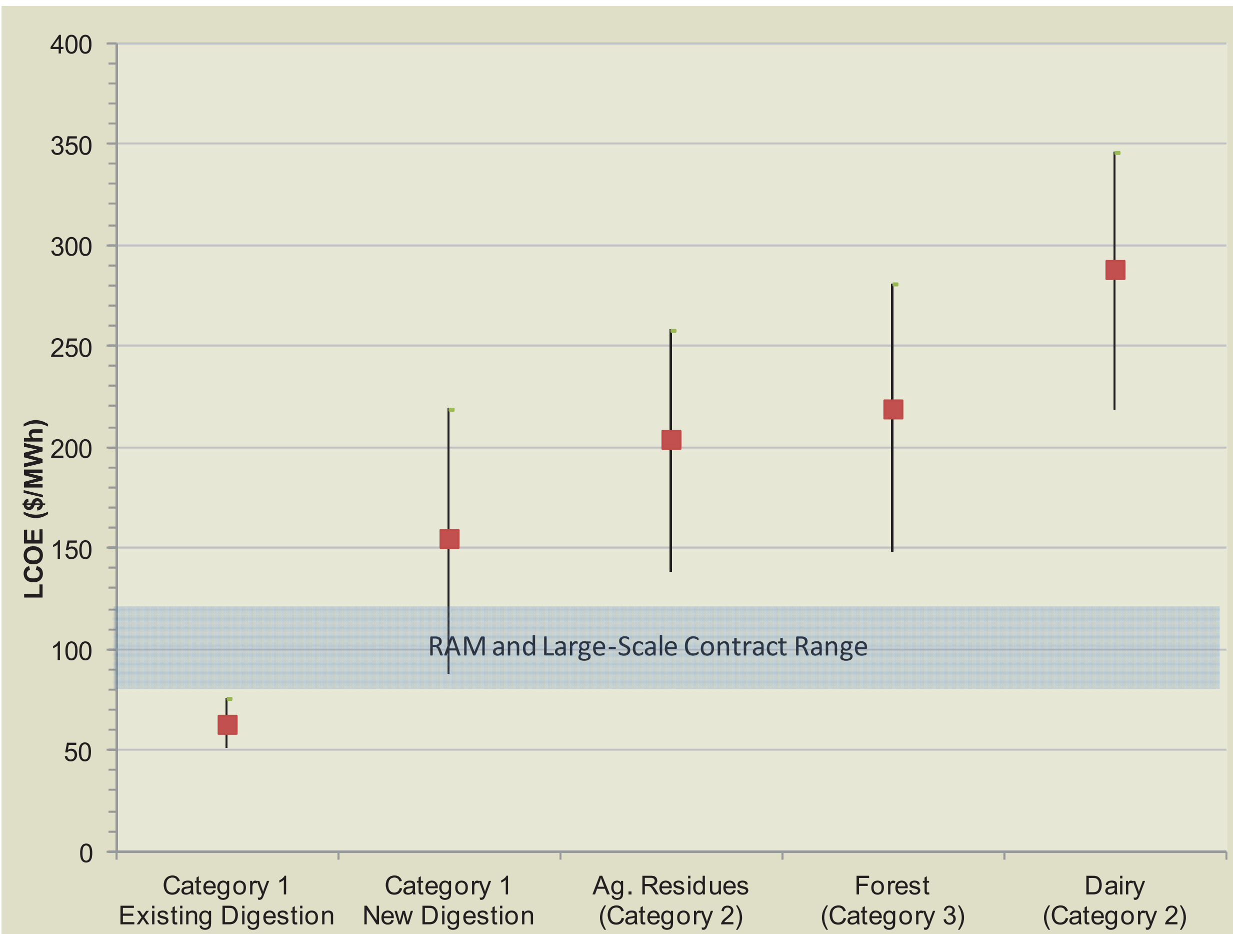


Figure 1-1 SB 1122 LCOE Range, No Incentives

SB 1122 eligible projects that can receive a fee for their feedstock (such as food waste digestion) or that have a readily available resource (WWTPs with existing digesters) will have the lowest LCOEs. However, the availability of SB 1122 eligible Category 1 biogas available from existing digesters is very small (roughly 4 MW). The lower gas yield and lack of a tipping fee for dairy manure digestion relative to most Category 1 digesters leads to a higher LCOE. Unlike food waste digestion projects, dairy manure digesters are eligible for AB 32 greenhouse gas offset credits from installation of the digester and destruction of methane (wholly separate from the REC, not reflected in the graphic above), which may add an additional revenue stream in the future.

Forest and agricultural residue projects may also be able to obtain revenue through the marketing of coproducts such as heat and biochar. These projects are sensitive to changes in feedstock price. If feedstock was free, LCOEs would drop by 15 to 20 percent; conversely, if the feedstock cost in the base case rises by $10 per dry ton, this would increase the LCOE by roughly $10/MWh.

1.3.3 Implementation Challenges

A range of technical and procedural issues may need to be addressed to implement the SB 1122 tariff. While the use of certain types of anaerobic digestion technology and IC engines for power generation is proven for many feedstocks in this size range, other types of technologies are less proven, namely "dry" digestion (up to roughly 40 percent solids) and small scale biomass gasification. There is likely to be an operational learning curve until greater experience is gained on these units in California.

SB 1122 was codified within §399.20 of the Public Utilities Code, the code section which authorizes California's renewable FIT program The CPUC recently adopted significant changes to the FIT program[5], most notably creating the ReMAT to set payment rates for FIT projects. The ReMAT is a market-based pricing mechanism designed to allow a competitive market by adjusting the offered tariff payment rate based on the level of demand. Given the lack of an existing market for small-scale bioenergy generators in California, several aspects of the ReMAT pricing mechanism should be noted in the context of SB 1122:

- **Development Experience:** Meeting this screen will depend on how the definition of "similar technology/project" is applied. More anaerobic digestion project developers would be able to meet this criterion relative to developers wanting to use small scale biomass gasification.
- **Tariff Level and Ramp Rate:** Under the ReMAT pricing mechanism, the tariff rate is initially set at $89.23/MWh. The tariff adjusts every two months based on a rate defined by the CPUC, provided at least five projects have passed the eligibility screens and entered the ReMAT program queue. Given the limited number of eligible projects in development and the potential challenges in meeting the other FIT eligibility screens, there may be a significant delay before five eligible projects have entered the queue which allows the tariff ramp to begin. Even after the ramp begins, it may be some time until the rate provides sufficient economic incentive based on the LCOE estimates projected in this study.
- **Interconnection Screen:** Updated information shows only seven SB 1122 eligible projects in the IOU's interconnection queues as of May 2013, meaning few projects would currently pass this screen for participation in the FIT program. In addition, the five projects in PG&E's current

[5] See D.12-05-035, as modified by D.13-01-041, and D.13-05-034, for details.

interconnection queue have very high interconnection costs (ranging from $858,000 to $2.6MM) which do not meet the CPUC's definition of a "strategically located" project, as required by Section 399.20 for FIT projects.

Assuming that a set of new projects will need to pass the interconnection screen before the ReMAT adjustment period can begin, it is estimated that it will take approximately 33 months for new SB 1122 eligible projects to begin operation under the ReMAT structure, assuming that a tariff rate of roughly $150/MWh is needed to incentivize project development, as shown in Figure 1-2.

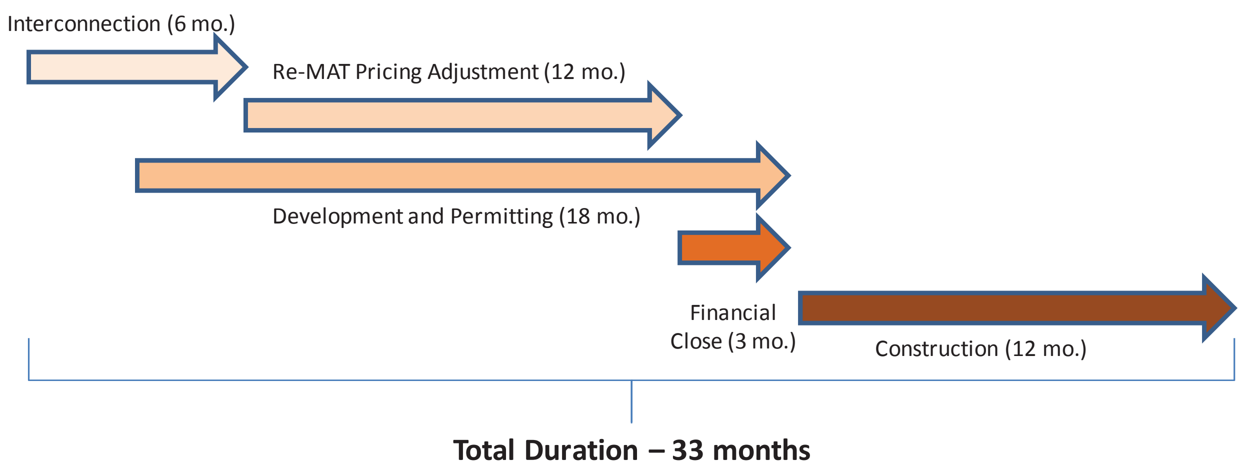


Figure 1-2 Generic Project Development Timeline

Modifications to the ReMAT pricing mechanism could be considered to allow SB 1122 projects to become operational more quickly, while additional modifications could then be considered to potentially limit the costs to ratepayers. However, given the lack of projects currently in the development queue, the establishment of an acceptable price may not be the critical path item in moving projects forward. Potential options to modify the ReMAT pricing mechanism include the following:

- Faster tariff ramp or larger price step changes
- Starting the tariff ramp with less than five eligible projects in the queue
- Accept international experience during the development experience evaluation
- Consider a seller concentration limit
- Price caps

The statutory language authorized by SB 1122 requires significant interpretation by the CPUC during its implementation process prior to the SB 1122 tariff being offered. Some of the issues that may require CPUC interpretation are listed below:

- Definition of "sustainable forest management"
- Classification of projects that use multiple feedstocks
- Definition of "commence operation"
- Feedstock definitions and eligibility of out of state feedstocks
- Verification of feedstock after operation commences

1.3.4 Options for Allocating SB 1122 Resource Targets by Utility

Since resource specific procurement targets are required by SB 1122, different tariffs and resource goals by utility will need to be defined by the CPUC in its implementation of the statute. Three main compliance options are considered here for establishing resource allocation targets by utility:

- **Option 1:** Proportional by peak load
- **Option 2:** Proportional allocation by resource availability
- **Option 3:** Allocation by resource availability, modified for market competition factors

Option 1 will likely be impractical given the limited amount of forest material in SCE and SDG&E service territory, as well as a lack of available dairy/agricultural material for SDG&E. Each of these utilities would likely need to transport material from distant locations to locally developed projects, increasing the delivered cost of energy to ratepayers. Option 2 would be more expensive and require a significant reallocation of procurement between the three resource categories. While the CPUC may perform this type of reallocation, this would require coordination across state agencies which could delay enactment of the tariff.

A summary of the procurement targets based on each utility's share of statewide peak demand, resource availability, projected cost ranges, and estimated yearly compliance costs for each utility for Option 3 can be seen in Table 1-3. Proposed procurement targets for each utility by resource type are shown, along with the resource potential estimates (in parenthesis). This option largely meets the statutory requirements, takes into account resource limitations, and provides the most equitable distribution of costs.

Table 1-3 Utility Resource Targets and Projected Costs, Option 3

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	30.5 *(101)*	33.5 *(340)*	47 *(478)*	129-198	113-173
SCE	55.5 *(115)*	56.5 *(118)*	2.5 *(16)*	129-197	116-177
SDG&E	24 *(26)*	0 *(3)*	0.5 *(3)*	122-187	24-37
Procurement Totals	110	90	50	--	253-387

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

Option 3 maintains the statutorily required allocation of Category 3 resources, requires that SDG&E only obtain the remainder of its obligation from Category 1 given its lack of other options, and then reallocates the remaining resources so that the original targets are preserved with a focus on cost equity. However, even if SDG&E was to focus solely on Category 1 material within its service territory, it may still be challenge to meet SB 1122 procurement goals given the resource limitations. In addition, SCE would need to utilize roughly half its resource potential to meet Category 1 and Category 2 requirements, which may stress the available resources and potentially result in higher delivered costs.

There are a number of other options available for resource allocation, but most would require a change in the net allocation by resource or utility. An option prohibited by statute that would result in the most equitable sharing of costs by ratepayers across utilities would be to allow the utilities to procure energy from projects located in any of the three IOU service territories, rather than requiring each utility to contract only with SB 1122 projects that site in their own service territory. Resource targets then could be based on total statewide potential, with allocation by utility still performed on a percent of peak load basis. This type of allocation would allow greater flexibility in project selection and reduce market power implications for resources that may attract little competition. Administratively, allowing the freedom to select projects regardless of service territory would make policy implementation easier.

2.0 SB 1122 Background

SB 1122 (Rubio, 2012), signed into law by Governor Jerry Brown in September 2012, directs the CPUC to establish procurement mandates for the three large investor-owned utilities totaling 250 MW from small-scale bioenergy projects. The bill outlined specific requirements for project and resource eligibility, proposed allocation by bioenergy category, and utility obligations. This section provides background on the legislation and the intent of this report's analysis.

2.1 REQUIREMENTS

A summary of the bill's requirements, as defined by the statute itself, is provided below[6]:

> *This bill would require the commission…to direct the electrical corporations to collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013. The bill would require the commission, for each electrical corporation, to allocate shares of the additional 250 megawatts based on the ratio of each electrical corporation's peak demand compared to the total statewide peak demand. The bill would require the commission to allocate those 250 megawatts to electrical corporations from specified categories of bioenergy project types, with specified portions of that 250 megawatts to be allocated from each category. The bill would authorize the commission, in consultation with specified state agencies, if it finds that the allocations of those 250 megawatts are not appropriate, to reallocate those 250 megawatts among those categories.*

The three categories of bioenergy enumerated in the bill and their capacity allocations are:

- **Category 1:** For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, 110 MW
- **Category 2:** For dairy and other agricultural bioenergy, 90 MW
- **Category 3:** For bioenergy using byproducts of sustainable forest management, 50 MW. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.

2.2 STUDY INTENT

Black & Veatch was retained by the CPUC to support timely implementation of SB 1122. The intent of this report's analysis is to determine the likely availability of resources, projected costs for compliance, barriers to implementation, and resource allocation options. Estimating the likely resource potential will help determine if the allocation of the 250 MW by resource is appropriate or

[6] Full bill information is available at http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml;jsessionid=cd36e5138d18004eeb1fc4f367a0?bill_id=201120120SB1122

if it needs to be modified per the instructions in §399.20(f)(3)(B).[7] In addition, the allocation by utility is based on the ratio of peak demand to total statewide peak demand (§399.20(f)(2)), not the availability of bioenergy resources in a particular service territory. Identifying suitable resources by service territory will help determine if a utility may face challenges meeting its obligation and if, as a result, whether more flexible measures should be considered. Estimates of levelized cost will provide insight into the amount of participation that may be expected if the tariff payment rate reaches certain levels through the ReMAT mechanism and the pricing levels that may be required to incentivize sufficient development to meet the statutory procurement obligations in each category. Finally, potential challenges with policy implementation, project development, and application of the ReMAT pricing mechanism are also discussed.

2.3 STUDY LIMITATIONS

This analysis is intended to be a high level analysis of the resource availability and costs to comply with SB 1122. It is not intended to capture all potential resources that could be used for SB 1122 compliance. Rather, the goal was to use public datasets that have been peer reviewed to capture a general understanding of the magnitude of the resources technically and economically available and the allocation by utility service territory. Cost estimates reflect a generic plant that may be located in California and do not take into account the variability of available coproduct values, incentives, interconnection costs, and technology options.

[7] All statutory code references, unless otherwise noted, refer to the California Public Utilities Code.

3.0 Resource Quantification

The initial step in our analysis was to provide an estimate for the magnitude of the resource available for SB 1122 compliance. Availability in both dry tons per year and equivalent MW of power generation in California were estimated for the specific resources listed below.

- **Category 1**
  - Biogas from Wastewater Treatment Plant (WWTP) biosolids digestion
  - Biogas from "municipal organic waste diversion, food processing, and codigestion" was quantified through assessments of digestion potential for food waste, leaves and grass, and FOG
- **Category 2**
  - Biogas from dairy cattle manure digestion
  - Biopower from the gasification of agricultural residues
- **Category 3**
  - Biopower from the gasification of sustainable forest management byproducts[8]

The methodology to quantifying each resource can be seen in Appendix A. This section outlines the results by county and IOU service territory.

3.1 TECHNICAL POTENTIAL USING ECONOMIC BREAKPOINTS

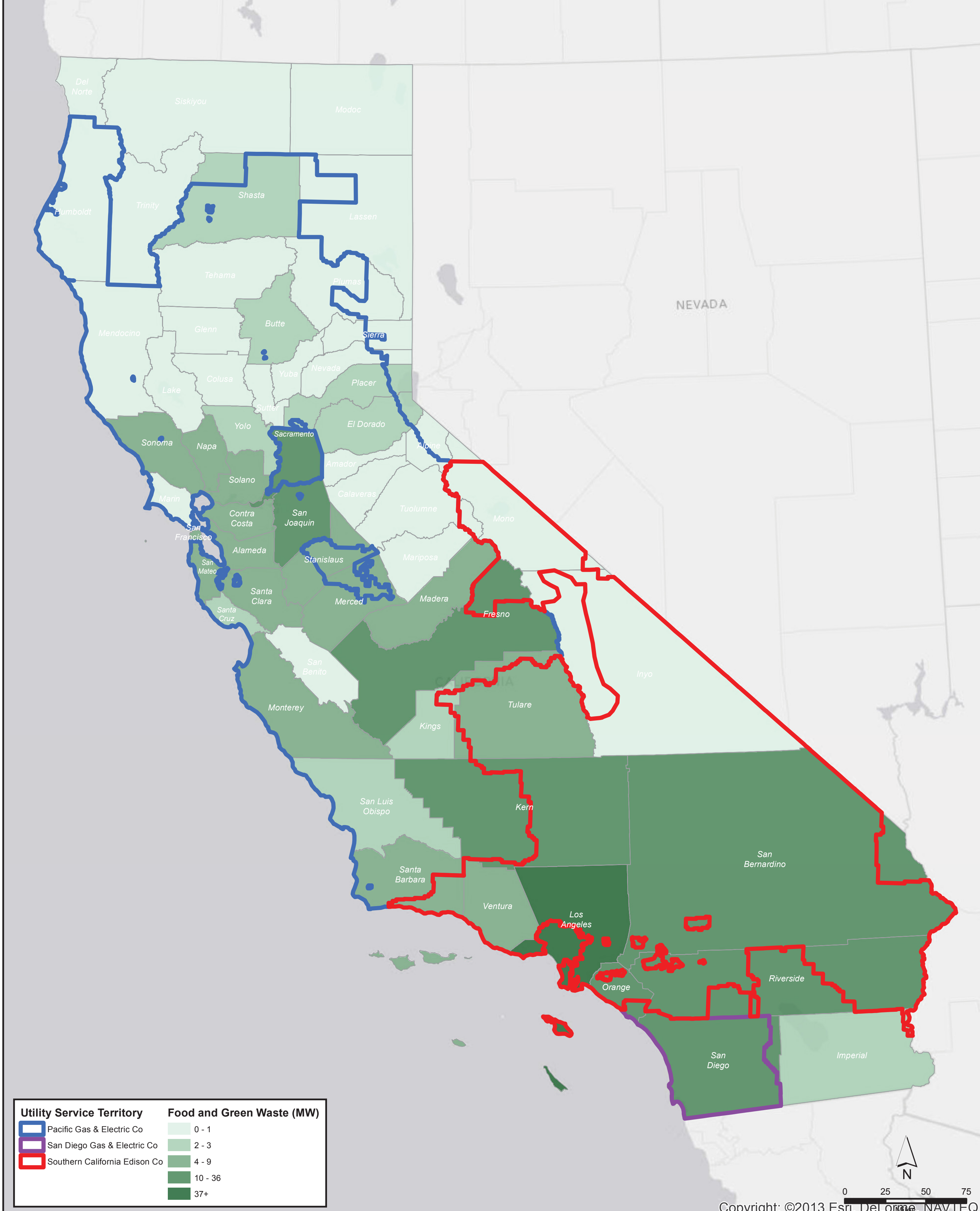
Using the assumptions in Appendix A, Black & Veatch identified 1,453 MW of technical statewide SB 1122 resource potential (using economic breakpoints), with 1,200 MW of resources located within the IOU service territories. The resource potential in MW by county and by utility service territory is shown on the maps below. Tables are provided in Appendix B for organic wastes, dairy manure, forest material, and agricultural residues by county both in MW and dry tons/year.

The goal of the analysis is to capture the magnitude of the resources available and allocation by utility service territory. This assessment is not intended to reflect all potential resources that could be used for SB 1122 compliance. The analysis uses both technical (such as environmental concerns, topography, collection efficiencies, soil fertility and erosion control) and economic considerations (such as project size, alternative uses, and exclusion of poor quality material) to develop a dataset that reflects material most likely to be available for projects utilizing the SB 1122 tariff. While this is not the true economic potential since a full supply curve for each resource is unavailable given the multitude of suppliers to the market and the subjectivity of this term, Black & Veatch used factors that have been previously peer reviewed, discussed with stakeholders, or those that were

[8] The statute is interpreted to mean that all sustainability harvested forest management byproducts are eligible, not just those in Fire Threat Treatment Areas (FTTAs) per guidance of the intent of the legislation provided by CAL FIRE. Therefore, the FTTA location analysis was performed to determine how the 50 MW should be split amongst the IOUs, but material from outside of these locations is eligible for the SB 1122 tariff.

deemed prudent based on industry experience. More information for factors used for each resource type can be seen in Appendix A.

Figure 3-1 Organic Waste Biogas Potential (Category 1)



CPUC Cat.1 Organic Waste Bioenergy Potential

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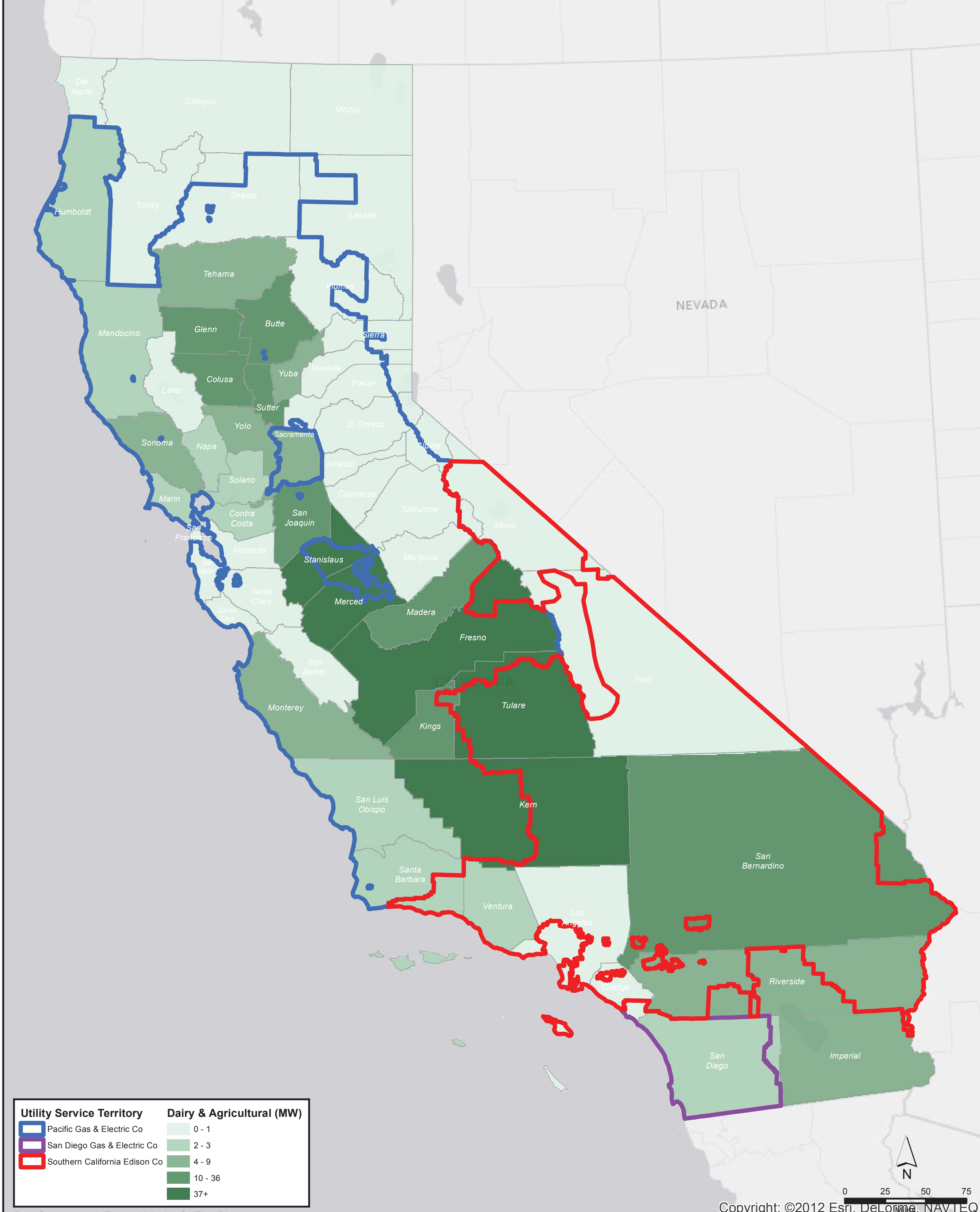
Figure 3-2 Dairy and Agricultural Bioenergy Potential (Category 2)



CPUC Dairy & Agricultural Bioenergy Potential

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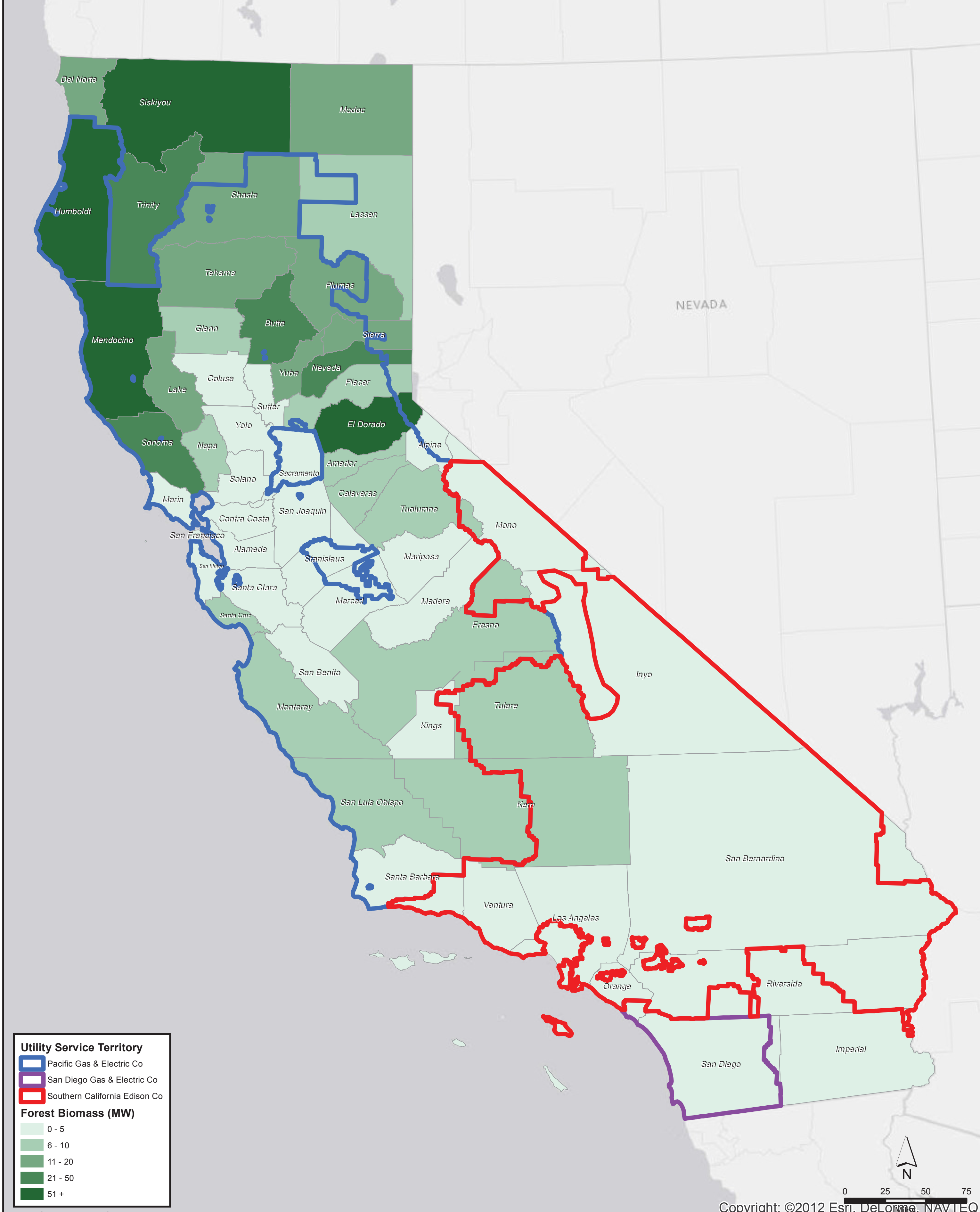
Figure 3-3 Forest Bioenergy Potential (Category 3)



CPUC Forest Resource Potential

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3.2 TRANSMISSION AVAILABILITY

The cost and availability of transmission are concerns that have been raised by small bioenergy projects looking to interconnect to the grid and export power. Many types of bioenergy resources are located in rural areas far from load, which often have less transmission availability compared to urban areas with more robust grids. However, unlike wind and solar resources, some bioenergy resources, primarily solid biomass, are transportable and in some instances can be moved to better locations for interconnection purposes.

To determine potential interconnection challenges on a county-level basis, Black & Veatch worked with Energy + Environmental Economics (E3) to evaluate substation transmission availability. E3 began by using 2010 load shape data at IOU substations developed as part of the renewable DG technical potential analysis being performed at the CPUC. To estimate the interconnection potential, the minimum substation load at each location was calculated to determine the maximum feasible interconnection capacity available without triggering upgrades. Data was then gathered on the MW of projects currently in the interconnection queue in each county, and a ratio of queue demand to substation potential calculated. Figure 3-4 shows the results of this analysis. Counties with more interconnection demand than potential without upgrades are shaded red, a ratio of 50 to 99 percent queue demand to potential are yellow, while a ratio of less than 50 percent is green. These categories are arbitrary and should only be used for understanding relative difficulties; they are not intended to suggest that siting a project in a red or yellow county will be infeasible, or that there will be no issues in siting a project in a green county. For detailed information on circuit level interconnection information for individual projects, the publicly available IOU interconnection maps should be referenced for a better understanding of transmission availability.[9]

The results of the analysis shows that Southern California has high transmission potential but more demand than availability capacity in most counties, while Northern California has less transmission potential but lower new interconnection demand. With the exception of Santa Barbara County, all counties in the SCE and SDG&E service territories had a ratio of demand to capacity of over 100 percent. While thousands of MW of transmission potential were identified in Southern California, the strong demand for new interconnections may make development in some locations a challenge.

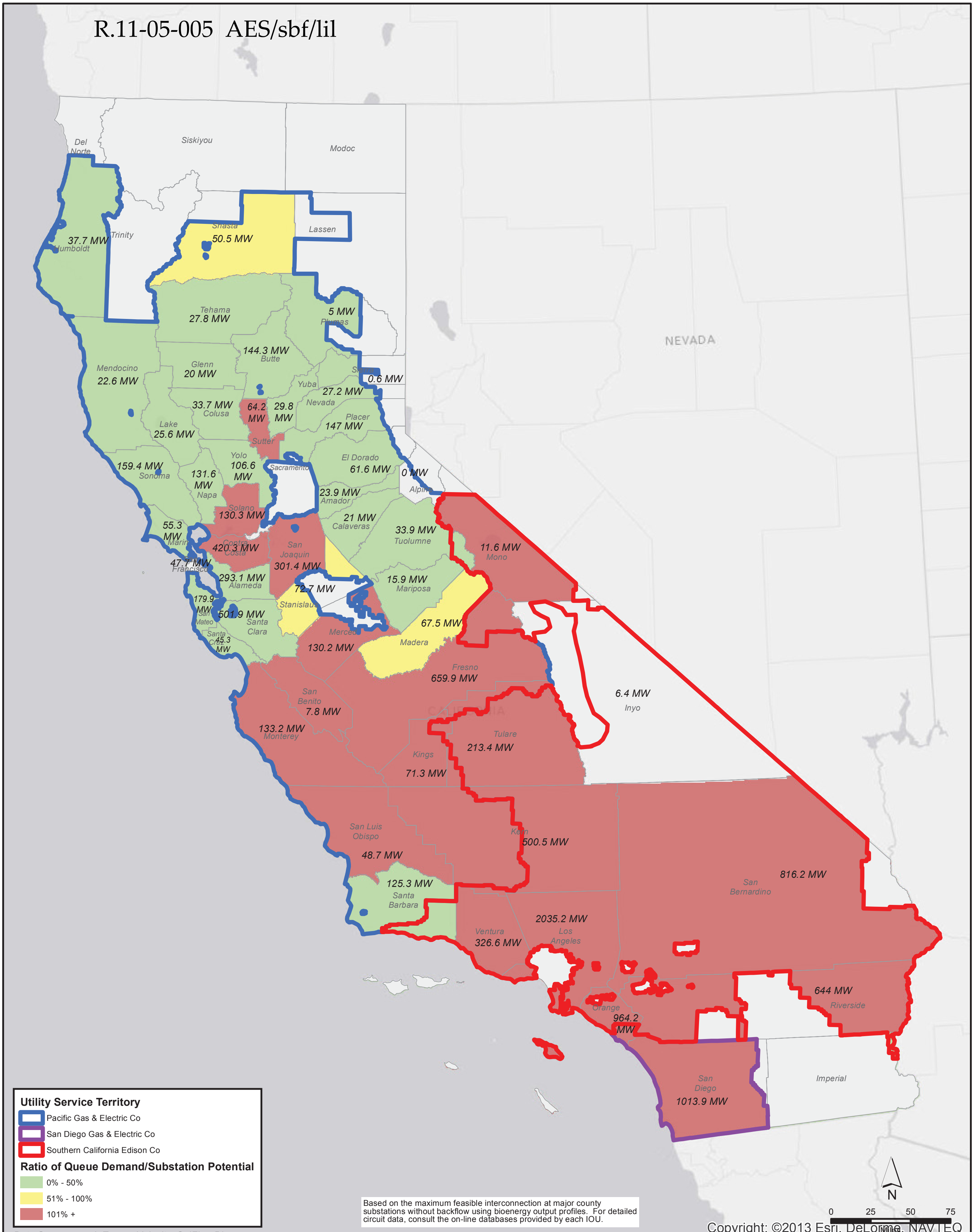
Northern California shows fewer projects in the interconnection queue (many counties in the PG&E service territory have ratios of demand to capacity of less than 50 percent), but many counties have relatively low potential for low cost interconnection. Several counties with high levels of forest and agricultural biomass energy potential (see Figure 3-3) are showing 40 MW or less of low cost

[9] Information can be found at the following locations:
PG&E: http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/
SCE: https://www.sce.com/wps/portal/home/procurement/renewable-alternative-power-contract-opportunities/
SDG&E: http://www.sdge.com/generation-interconnections/interconnection-information-and-map

interconnection potential. If multiple projects choose to site in these counties due to the resource potential, this could create interconnection issues.

When evaluating project development options, developers should consider both the proximity of available resource potential and interconnection availability. Counties that have significantly greater transmission availability compared to available resource potential should, in general, face fewer burdens to SB 1122 project interconnection.

Figure 3-4 County Level Interconnection Availability



CPUC Bioenergy Interconnection Potential

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The ability of some biomass projects to move to more strategic interconnection locations may help mitigate some of the transmission issues for those projects. For biomass projects located in an area with multiple feedstock providers, moving 10 miles to a better interconnection point may have little impact on overall costs or feasibility.

3.3 SUMMARY AND COMPARISON TO SB 1122 GOALS

Table 3-1 provides an estimate of SB 1122 potential by resource and by utility service territory. The estimates take into account only the resources physically located within each service territory because of the statute's requirement that SB 1122 projects must locate within the service territory of the contracting utility. Overall statewide resource potential is higher. Because some bioenergy material can be moved and thus could be transported from outside a utility service territory to a facility sited within it, this estimate is conservative but represents a reasonable proxy for estimating the potential for each utility to meet SB 1122 requirements with local resources.

Table 3-1 Utility Resource Potential, MW

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	TOTAL POTENTIAL	SB 1122 TARGET
PG&E	101	340	478	919	111
SCE	115	118	16	249	114
SDG&E	26	3	3	32	25
Total	**241**	**461**	497	1200	250
SB 1122 Target	110	90	50	250	

From a resource perspective, this estimate indicates that there is roughly five times more material available for SB 1122 projects compared to the requirements of the statute. Dairy/agricultural residues and forest material have the largest availability, with five to ten times the amount of material available when compared to their SB 1122 procurement targets. Forest biomass potential would be even greater, with more availability in Southern California, if shrublands were included in this potential estimate. While shrub biomass should be an eligible resource under Category 3 and is often located in high fire threat areas, the cost and other technical issues with resource collection have led to it rarely being used as a feedstock for bioenergy production. Biogas from Category 1 has the lowest availability, with just over twice as much estimated potential available compared to the statutory procurement target. Food waste from MSW represents the largest share of Category 1 potential, with just over 50 percent of this resource type. Collecting and separating this food waste can be a challenge relative to other SB 1122 resources given the heterogeneous nature of municipal solid waste and the multitude of different haulers and local regulations that must be addressed in order to collect sufficient material.

If only material in each utility's service territory is used to meet SB 1122 requirements, PG&E would have by far the most feedstock availability. PG&E will need to procure approximately 111 MW to meet its SB 1122 procurement requirement based on its share of statewide peak demand; roughly eight times this level of feedstock is estimated to be available in its territory. SCE is estimated to have roughly twice as much feedstock available relative to its SB 1122 procurement requirement, while SDG&E is estimated to have barely enough available feedstock to meet its procurement requirement. SCE likely has more dairy potential than agricultural residues in its service territory, which is an important distinction given the difference in energy generation cost between these two resources within the same SB 1122 category. Projects in SDG&E's service territory would need to rely upon Category 1 feedstocks if local supply was desired, since there are few other options for bioenergy production in the area. Alternatively, material could be transported to SDG&E's service territory, but this may raise the overall cost to SDG&E ratepayers to comply with the statute.

Another goal of SB 1122 is to create a market for forest material that when harvested helps reduce the risk of high intensity wildfires in the state.[10] According to CAL FIRE, millions of acres of California forests are at high risk for wildfire. Placing greater incentive on better managing both public and private forests for wildfire prevention could lead to economic benefits if this threat of wildfire is reduced. More information on the wildfire threat and the potential impacts of SB 1122 can be seen in Appendix C.

[10] The statute specifically allocates Category 3 (forest) project capacity based on availability from "sustainable forest management in fire threat treatment areas", in an attempt to stimulate projects in these areas.

4.0 Levelized Cost of Generation Estimates

Black & Veatch created estimates for the levelized cost of electricity (LCOE) that would be needed to support SB 1122 projects based on a broad set of capital and operating cost assumptions. These assumptions were entered into a financial pro forma to estimate the LCOE. Major financial and technology specific assumptions can be seen in Appendix D.

The LCOE estimates are intended to bracket the range of likely SB 1122 project costs, and are not intended to reflect any particular project. LCOEs will vary considerably based on site specific development requirements, feedstock costs, coproduct values, and available incentives. Detailed, project specific analysis should be performed when attempting to estimate the LCOE for any individual projects. The cases reflect the use of emissions control equipment required in the most stringent air permitting districts in the state. If this equipment was not installed, the net LCOE would likely be 5 to 10 percent lower. Projects are also assumed to be "strategically located" when estimating interconnection and transmission costs.

4.1 CATEGORY 1 ANAEROBIC DIGESTION

4.1.1 Existing Digestion

The results for a large project with an operating digester that is not beneficially using its biogas or that has excess digestion capacity can be seen below. Costs are based on new gas cleaning and cogeneration equipment, with sizing reflecting the largest facility that would be SB 1122 compliant. As shown in Appendix A and B, the "commence operation" requirements of SB 1122 using the CEC definition from the Renewable Portfolio Standard Eligibility Guidebook may limit the availability of projects qualifying under this category.

Table 4-1 Category 1 LCOE Estimate, Existing Digestion

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	3	3	3
Capital Cost ($/kW)	2,145	2,681	3,217
Operating Cost ($/kW-yr)	144	180	216
LCOE ($/MWh)	51	63	76

Adding new reciprocating engines at existing facilities producing biogas that is not currently being utilized or that has excess capacity leads to LCOEs in the $51 to $76/MWh range. Obtaining tipping fees to utilize wastes in cases where excess capacity exists could further reduce the LCOE. Installation of a biogas utilization project for any of the WWTPs listed in Appendix B would lead to higher LCOEs due to the smaller project size. All costs listed above include gas cleaning, environmental controls, cogeneration, and development infrastructure. Costs for biogas cleaning and flue gas emissions controls leads to a LCOE higher than typical for natural gas cogeneration units in the United States.

4.1.2 New Digestion

The results for the development of new digestion units using Category 1 resources can be seen below.

Table 4-2 Category 1 LCOE Estimate, New Digestion

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	3	3	3
Capital Cost ($/kW)	7,760	9,700	11,640
Operating Cost ($/kW-yr)	392	490	588
Tipping Fee ($/ton)	30	20	10
LCOE ($/MWh)	88	155	219

The additional cost from the construction of a new digester can be seen when comparing the LCOE of power shown above to the LCOE for the Existing Digestion case. Obtaining a tipping fee for the Category 1 material brought to the digestion unit provides a significant revenue stream that is helpful to reduce the overall cost of exported power. If no tipping fee is available, the LCOE increases to the range of $156 to $246/MWh. It should be noted that this cost estimate assumes the largest possible SB 1122 compliant project, which would be likely only in large metropolitan areas in California. Smaller projects would likely have higher LCOEs.

4.2 CATEGORY 2: DAIRY BIOGAS AND AGRICULTURAL BYPRODUCTS

4.2.1 Dairy Cattle Manure

The results for the dairy manure digestion cases can be seen below. The basis for this cost estimate was a complete mix, stand-alone facility at a large flushed freestall dairy consisting of roughly 5,500 head of cattle. The size of the facility has roughly the same ton per day throughput as the Category 1 design, but the power production is significantly lower due to the lower gas yield for dairy manure relative to Category 1 wastes. Few individual dairies in the state have this number of cattle; while a larger project would likely have a lower LCOE, most dairies would be this size or smaller.

Table 4-3 Dairy Cattle Manure LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Project Size (MW)	1	1	1
Capital Cost ($/kW)	8,720	10,900	13,080
Operating Cost ($/kW-yr)	760	950	1,140
LCOE ($/MWh)	218	288	346

The lower gas yield and lack of a tipping fee for dairy manure digestion relative to Category 1 digesters leads to a higher LCOE than the previous anaerobic digestion analysis. However, unlike food waste digestion, dairy manure digesters are eligible for AB 32 offset credits. While offset credits are not included in the base case analysis given the uncertainty for offset prices, demand, and eligibility, a $20/tonne CO_2 credit value would produce revenue of roughly $500,000/year for a manure digestion project, lowering the LCOE by $60/MWh from the numbers listed above (to roughly $225/MWh for the medium case). Codigestion with higher gas yield feedstocks would also be helpful in lowering the LCOE.

4.2.2 Agricultural Residues

The cost estimate for solid biomass assumes use of the same technology, regardless of the feedstock used (woody material or agricultural residues). While the handling and treatment of these materials will differ prior to feeding them to a gasifier, the cost difference is expected to be within the range of uncertainty in this analysis. Feedstock costs are based on discussions with stakeholders for average delivered fuel costs currently seen in California.

Table 4-4 Agricultural Residue LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Capital Cost ($/kW)	5,000	6,000	7,500
Non-fuel Operating Cost ($/kW-yr)	347	553	590
Size (MW)	3	3	3
Feedstock Cost ($/dry ton)	20	30	40
LCOE ($/MWh)	138	204	258

4.3 CATEGORY 3: FOREST MANAGEMENT BYPRODUCTS

The capital and operating costs for producing power from forest residues are assumed to be similar to those for agricultural residues presented above. The only difference with the agricultural residue LCOE estimate is the delivered cost of fuel. The cost for forest residues is estimated to be higher ($30 to $60 per dry ton, relative to a range of $20 to $40 per dry ton for agricultural residues) to reflect the greater costs for harvesting, collection, and transport currently seen by bioenergy plants in California today. Cost estimates associated with the development, construction and operation of a 3 MW biomass power generation facility from forest residues are summarized in Table 4-5. Site specific situations can result in a greater variability of costs beyond the ranges presented here.

Table 4-5 Forest LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Capital Cost ($/kW)	5,000	6,000	7,500
Non-fuel Operating Cost ($/kW-yr)	347	553	590
Size (MW)	3	3	3
Feedstock Cost ($/dry ton)	30	45	60
LCOE ($/MWh)	148	219	281

As can be seen above, the cost of generation from these facilities can vary considerably based on the cost assumptions used. Of particular importance is the feedstock cost; projects located at facilities with an ample supply of inexpensive feedstock, such as those at sawmills and nut processing facilities, will have much lower LCOEs compared to facilities that must procure material from further away. If feedstock was free, LCOEs would drop by 15 to 20 percent; conversely, if the feedstock cost in the base case rises by $10 per dry ton, this would increase the LCOE by roughly $10/MWh. If properly sited, the scale of the facility will significantly reduce both the quantities of biomass fuel required and the distance from which fuel must be collected relative to utility-scale (i.e., 20 MW and greater) biomass power generation facilities.

4.4 LARGE DISTRIBUTED BIOENERGY AND OTHER RESOURCES

As part of the broader DG work performed by Black & Veatch for the CPUC's Energy Division, the estimated costs for bioenergy DG projects up to 20 MW have also been developed. While a project of this size would not be eligible for the SB 1122 tariff, it would be allowed to bid into the Renewable Auction Mechanism (RAM).[11] As a point of comparison, Black & Veatch analyzed

[11] See CPUC Decision 10-12-048 which established RAM as a reverse auction mechanism for the procurement of renewable DG projects sized up to 20 MW.

whether bioenergy generators utilizing SB 1122 eligible resources would be more cost effective if developed at the RAM size, rather than at SB 1122's statutorily mandated 3 MW maximum project size. Of the resources considered, only solid biomass (forest or agricultural residues) conversion would be feasible at the 20 MW size due to the large amount of feedstock energy required to sustain a plant of this size. This size or larger is common for utility scale bioenergy plants, while few anaerobic digestion projects even come close to this size.

Cost estimates associated with the development, construction and operation of a 20 MW biomass power generation facility using woody biomass are summarized in Table 4-6. As with the other technologies, site specific situations can result in greater variability of costs beyond the ranges presented here. The cost of equity for the large scale case was reduced relative to the SB 1122 projects to reflect the lower risk involved in financing a project of this nature.

Table 4-6 20 MW Low Solids Biomass LCOE Estimate

	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE
Capital Cost ($/kW)	5,140	5,770	6,810
Non-fuel Operating Cost ($/kW-yr)	310	347	379
Size (MW)	20	20	20
Feedstock Cost ($/dry ton)	40	50	60
LCOE ($/MWh)	142	166	197

When compared to 3 MW biomass projects, the cost of 20 MW projects tends to be better understood, has less variation, and is typically lower. While feedstock costs are higher and capital costs are comparable or slightly lower per unit of capacity, the much lower non-fuel operating costs and better heat rates typically lead to lower LCOEs. Biomass facilities at this size use technologies that are more commercially proven, likely leading to greater reliability and capacity factors, along with easier project financing.

4.5 COST SUMMARY

A summary of the range of LCOEs, along with the unique factors that may influence the delivered cost of power, is shown in Table 4-7. A graphical representation of the range of likely costs for projects without financial incentives, coproduct values, or disposal costs is shown in Figure 4-1.

Table 4-7 SB 1122 LCOE Summary by Feedstock Type, $/MWh

RESOURCE AND SIZE	LOW ESTIMATE	MED. ESTIMATE	HIGH ESTIMATE	UNIQUE COST FACTORS
Category 1				
Existing Digestion (3 MW)	51	63	76	Gas cleaning and infrastructure requirements
New Digestion (3 MW)	88	155	219	Tipping fee, coproduct value, digester type
Category 2				
Dairy Cattle Manure (1 MW)	218	288	346	Solids disposal costs, fertilizer value, AB32 credits, codigestion, digester type
Agricultural Residues (3 MW)	138	204	258	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Category 3				
Forest Material (3 MW)	148	219	281	Interconnection cost, coproduct value, fuel costs, cogeneration applications
Generic project estimates not taking into account incentives or coproduct values/disposal costs				

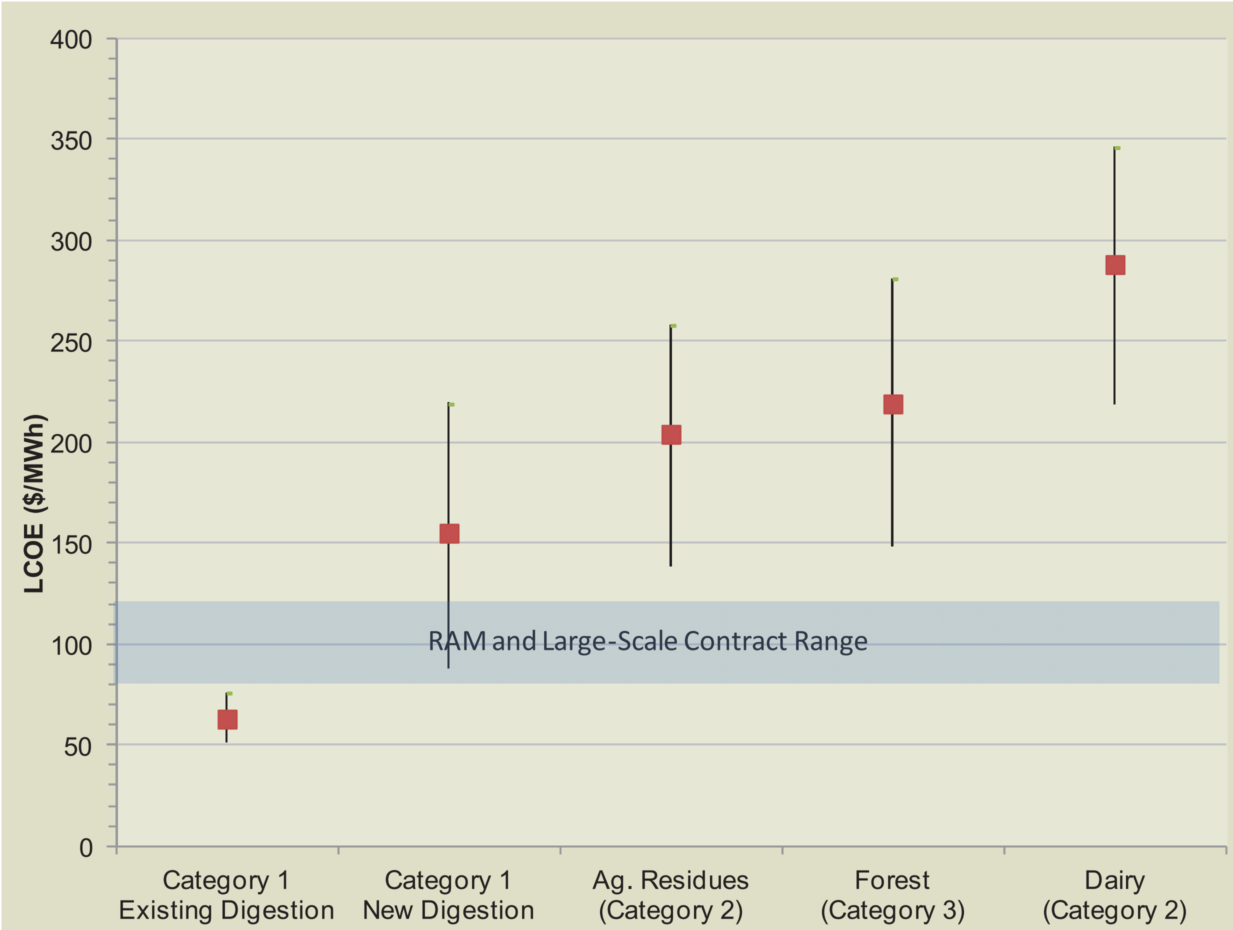


Figure 4-1 SB 1122 LCOE Range, No Incentives

SB 1122 eligible projects that can receive a fee for their feedstock (some Category 1 anaerobic digestion, such as food waste) or that have a readily available resource (WWTPs with existing digesters either not beneficially utilizing their gas or those with excess capacity) will have the lowest LCOEs. However, the availability of SB 1122 eligible Category 1 biogas available from digesters not beneficially using their biogas is very small (roughly 4 MW). The lower gas yield and lack of a tipping fee for dairy manure digestion relative to Category 1 digesters leads to a higher LCOE. However, unlike food waste digestion, dairy manure digesters are eligible for AB 32 greenhouse gas offset credits (not reflected above), which may provide revenue in later years. Forest and agricultural residue projects may also be able to obtain revenue through the marketing of coproducts such as heat and biochar.

Without incentives or value for the coproducts, the required LCOE for most SB 1122 compliant projects will be higher than PPAs recently signed by the IOUs as part of the RAM and large scale procurement efforts. Many of the contracts signed under these solicitations have been larger solar PV projects which have recently come down substantially in price. If SB 1122 projects are able to take advantage of some of the currently available incentives and/or obtain value for their coproducts, the LCOEs for some resources are likely to become more comparable to the range of prices recently seen in other solicitations. Figure 4-2 shows the LCOE range for SB 1122 projects if projects took advantage of the 30 percent ITC.

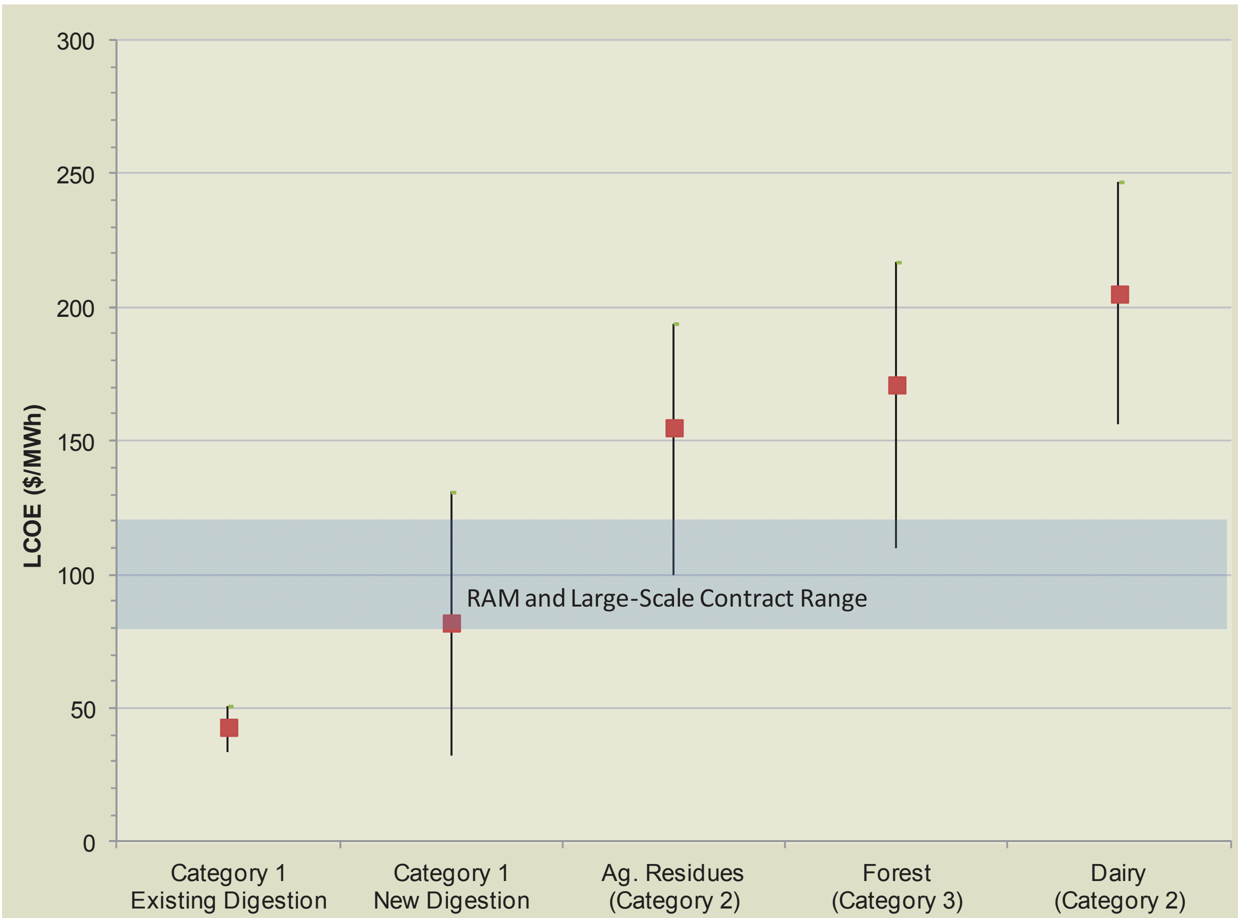


Figure 4-2 SB 1122 LCOE Range, With 30 Percent Investment Tax Credit

There are a few examples of currently operating bioenergy projects that have applied for and received a FIT PPA from one of the IOUs using an SB 1122 eligible feedstock. The project names, sizes, and accepted FIT price can be seen in Table 4-8. Each project is in PG&E's service territory and each meets the requirements of AB 1969. No SB 1122-type projects have been awarded contracts under the RAM.

Table 4-8 On-line Biomass and Digester Gas Projects with FITs

PROJECT NAME/TECHNOLOGY	SIZE (KW)	PRICE ($/MWH)	DATE TARIFF ACCEPTED	NOTES
Castelanelli Bros. (Digestion)	300	100.43	2009	Lagoon digester, high incentives, already operating
Blake's Landing Farms (Digestion)	80	84.48	2010	Lagoon digester, high incentives, already operating
Ortigalita Power (Biomass)	750	110.46	2011	Incentives, coproduct value

Each of the projects listed above received incentives, has strong coproduct values, and/or sunk costs that make the tariff rate required to be economically feasible fairly low. Each of the dairy digestion projects use a simple technology with a low gas yield (lagoon digestion), received multiple funding sources (not all of which may be available to SB 1122 projects), and were initially placed into operations years before the FIT. The biomass facility, which gasifies orchard trimmings and almond shells, receives value for coproduct heat and biochar. These examples demonstrate the types of additional incentives that would be required to be competitive with current renewable energy procurement prices.

5.0 Implementation Assessment

A range of technical and procedural issues may need to be addressed to be able to develop projects that utilize the SB 1122 tariff. Given the lack of an existing market for small-scale bioenergy generators, of key importance is whether the ReMAT pricing mechanism will adequately incentivize the development of SB 1122 projects. Additionally, given the state's resource potential by SB 1122 category and its distribution, consideration was made for whether the existing statutory targets by resource are appropriate. These issues are addressed in this section.

5.1 TECHNICAL ISSUES

Black & Veatch expects that both anaerobic digestion and biomass combustion or gasification would be used for SB 1122 compliant projects. The use of anaerobic digestion technology and internal combustion engines for power generation is proven for projects under 3 MW. Wet digestion (under roughly 15 percent solids) is the industry standard in the United States, with the greatest deployment at WWTPs. "Dry" digestion (up to roughly 40 percent solids) is being used more frequently for food wastes and other organic wastes. This technology is proven in Europe, but few projects using this technology have been implemented in the United States. There is likely to be an operational learning curve until greater experience is gained with dry digestion units in California.

Relative to anaerobic digestion at this scale, there is less experience and greater operational risk in the development of biomass gasification facilities for power generation from projects under 3 MW. The vast majority of operational biomass units in the state and throughout the United States are of a much larger scale, utilizing conventional steam boilers and turbines.[12] This adds uncertainty to the likely costs and operational performance for biomass gasification projects sized at less than 3 MW.

Other potential technical and development issues include the following:

- Siting and Development
    - Rigorous environmental regulations in California may require advanced emission control equipment, which may increase permitting timing, along with raising capital and O&M costs.
    - Development costs are high relative to other types of distributed generation, namely solar PV.
    - Financing can be challenging due to the small size, limited experience, and lack of long-term, mature markets for feedstock and coproducts.

[12] The Biomass Power Association shows very few operational solid biomass power projects specifically for power export to the grid (http://www.usabiomass.org/docs/biomass_map.pdf). In addition, only 8 of the 101 biomass projects certified or pre-certified by the CEC as RPS compliant are 3 MW or less. The average size of currently operating facilities is 25 MW.

  - Siting of new bioenergy projects may face some public and agency resistance due to emissions, odor, traffic, and perceptions about the sustainability of biomass use for power generation

- Digestion
  - Digestion might not fit into a WWTP's biosolids management plan. For example, WWTPs that incinerate biosolids might not want to install digestion, which decreases the heating value of solids fed to the incinerator.
  - Sidestreams from digestion will increase loadings to the liquid treatment processes at WWTPs.
  - Footprints for digestion and associated facilities are relatively large, which might be a concern for potential sites with limited land availability or high land lease costs.
  - Food and yard waste feedstocks for digestion are typically comingled or contaminated with other materials, requiring separation that will add to project costs and can impact operational performance.
  - Prices for biosolids coproducts from digestion could be volatile due to quality, supply, and market demand.
  - Residues generated in the digestion process must be further processed for beneficial use as a fertilizer or for disposal.
- Gasification
  - There are relatively few gasification technology suppliers for small-scale gasification systems that have demonstrated the capability to provide and fulfill performance guarantees and secure project financing.
  - Designs will need to carefully address syngas quality to assure reliable operation of equipment downstream of the gasifier.

5.2 REMAT APPLICATION

The Renewable Market Adjusting Tariff (ReMAT) pricing mechanism has been adopted by the CPUC to set the tariff payment rate for any contracts executed under the § 399.20 FIT program[13]. Section 399.20 was originally added to the Public Utilities Code by AB 1969 and originally only required electrical corporations to make a tariff or standard contract available to public water and wastewater customers. Since 2007, the Legislature has adopted several amendments to this code section, including those contained in SB 380 (Kehoe, 2008), SB 32 (Negrete-McCleod, 2009), and SB 2 1X (Simitian, 2011). The CPUC first implemented the § 399.20 FIT program through its adoption of Decision 07-07-027. Consistent with the statutory requirements under AB 1969, codified in § 399.20(5)(d), the CPUC adopted the Market Price Referent (MPR) as the tariff payment rate for the § 399.20 FIT Program. In 2012, the CPUC supplanted the MPR with the ReMAT as the pricing mechanism used for setting the price for the FIT program established under § 399.20. The utilities will start offering contracts with payment rates set by the ReMAT pricing mechanism on November 1, 2013.

[13] See CPUC D.12-05-035, as modified by D.13-01-041, and D.13-05-034.

The intent of the ReMAT is to establish a more dynamic price setting mechanism for FIT programs that takes into account market pricing and technological changes. It establishes a set of binary project screens to help manage the project queue and reduce the impact of market manipulation. Instead of just defining a set price for projects applying for a FIT, the ReMAT starts at a level established by recent RAM pricing, then will adjust based upon the number of projects entering the queue and accepting (or not accepting) the price. Once a project accepts the offered ReMAT price, the price will remain fixed for the term of the contract. The offered ReMAT price will then move up or down every other month based upon the level of capacity subscription at the previously offered ReMAT price.

There are a set of project viability criteria that must be met before a project will be eligible for the FIT and able to join the ReMAT queue. The CPUC adopted these criteria to promote the participation of viable projects capable of achieving commercial operation in a timely manner, and to efficiently manage the project queue if projects fail to comply with these criteria. The FIT eligibility criteria include the following:

- **Bid Fee:** $2/kW bid fee
- **Interconnection:** System Impact Study, Phase I study, or passed the Fast Track screens or supplemental review
- **Site Control:** Attest to 100 percent site control through (a) direct ownership, (b) lease, or (c) an option to lease or purchase that may be exercised upon contract execution
- **Development Experience:** Attest that one member of the development team has (a) completed at least one project of similar technology and capacity or (b) begun construction of at least one other similar project
- **Online Date:** 24 months with one six month extension for regulatory delays

Issues that may arise with the use of these viability criteria and other concerns with application of the ReMAT pricing mechanism in its current format are outlined below.

5.2.1 Requirement that FIT Projects be "Strategically Located"

The feed-in tariff statute (§ 399.20(b)(3)) requires that all projects be "strategically located." The CPUC, in D.12-05-035, found "strategically located" to mean that a generator must be interconnected to the distribution system and sited near load, which the CPUC defined as meaning in an area where interconnection to the distribution system requires $300,000 or less of upgrades to the transmission system. For SB 1122, in some instances this may require that potential project sites be moved to maintain their compliance with this requirement. Completing the interconnection studies required by the ReMAT eligibility screens will help with queue management and project prioritization, allowing generators to evaluate whether they comply with this requirement.

Based on current interconnection queue data, the ReMAT requirement is that projects must have completed a Phase I, System Impact Study, or Fast Track may delay the ability of bioenergy projects to use the SB 1122 tariff. Updated interconnection queue information (both Rule 21 and WDAT) were reviewed from both on-line information and data recently produced by the IOUs as part of the CPUC's Open Interconnection Proceeding, R.11-09-011. From this data, it appears that, as of May 2013, there are very few SB 1122 sized bioenergy projects that would be able to pass the ReMAT interconnection eligibility screen; SDG&E has zero projects, PG&E five, and SCE two. SCE also has six projects listed as MIC (Internal Combustion – Methane) which may or may not use methane derived from bioenergy sources. Data from PG&E shows that it took roughly six months between the application and the completion of the initial interconnection study for projects added to the queue in 2012.

Moreover, this data shows that the bioenergy projects currently in the interconnection queues may not be compliant with the CPUC's interpretation of the statutory requirement that FIT projects be "strategically located." For instance, the five bioenergy projects in PG&E's interconnection queue have interconnection and network upgrade costs in excess of the $300,000 maximum imposed by the CPUC, ranging from $858,000 to $2.6MM.

5.2.2 Development Experience

Meeting the Development Experience screen will depend on how the definition of "similar technology/project" is applied. For anaerobic digestion projects, wet digestion technology at WWTPs is common, but digestion of food wastes, yard wastes, and animal manure is much less common in the United States. However, there are a number of European developers and technology providers that are interested in participating in the US market that likely have the proper experience if foreign experience is acceptable and the feedstocks used are deemed similar enough. Thousands of small-scale anaerobic digestion projects are in operation worldwide. Small-scale solid biomass power plants using gasification technology have a much smaller commercial track record throughout the world. There is a limited number of operating commercial facilities, although there are many technology developers that have operating pilot plants.

5.2.3 Tariff Level and Ramp Rate

The ReMAT is initially set at $89.23/MWh. Once at least five eligible projects that meet the project viability criteria have entered the project queue, the price will adjust every two months based on whether the amount of capacity offered by the utility is oversubscribed (adjusts down) or undersubscribed (adjusts up). The tariff adjusts every two months based on a rate defined by the CPUC. If no projects accept the tariff by the 12th month after the initial offering, for instance, the tariff will be $60/MWh over the base price (i.e., the offered price would be $149.23/MWh).

Given the limited amount of development that has occurred on SB 1122 eligible projects and the challenges in meeting the interconnection eligibility screen, there may be a delay in the tariff ramp until sufficient projects have entered the queue. Assuming that a set of new projects will need to pass this screen before the ReMAT adjustment period can begin, it is estimated that it will take roughly 33 months for a set of SB 1122 eligible projects to begin operation under the current structure, assuming that a tariff rate of roughly $150/MWh is needed to incentivize development and there is a SB 1122 project only queue. This estimate takes into account interconnection screening, ReMAT price adjustments, development needs, permitting, financial close, and construction, as shown in Figure 5-1.

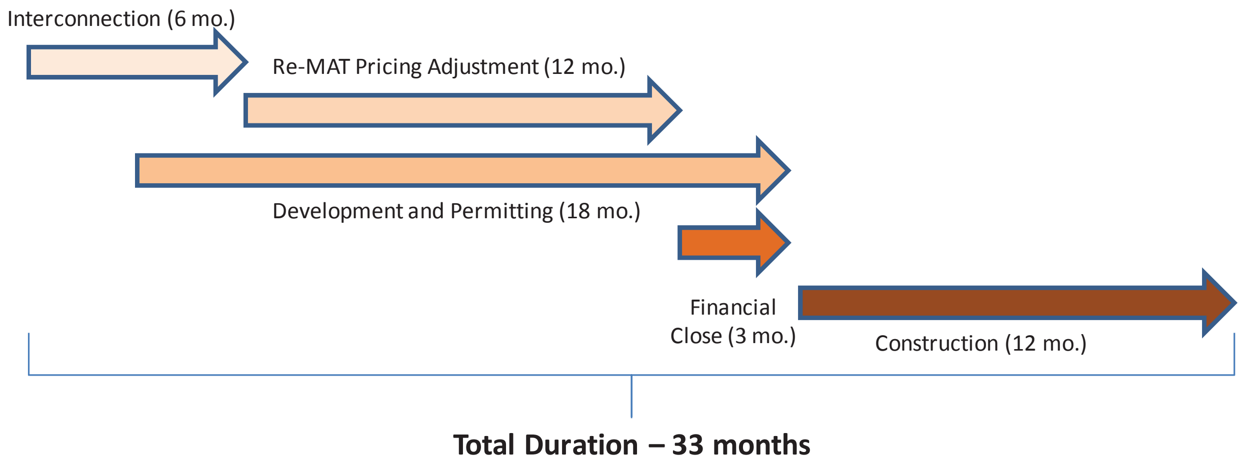


Figure 5-1 Generic Project Development Timeline

The project timing could be reduced if projects already under development apply for the tariff, if a lower tariff value is required for economic development than projected, or if the ReMAT mechanism is modified to result in a higher offered payment rate sooner. Note however that reductions in both development timing and modifications to ReMAT would be needed to significantly reduce the overall timing; reducing one and not the other may not be sufficient. It is expected that most SB 1122 projects will require three years or more after the tariff becomes effective before achieving commercial operation.

5.2.4 Seller Concentration and Feedstock Availability

In some markets, namely San Diego Gas & Electric's service territory, we have identified a limited availability of resources to meet SB 1122 obligations. This implies that most projects applying for a FIT contract there will be approved due to a lack of applications, potentially leading to higher prices due to limited competition. If a small number of providers had the majority of access to available resources in the area, this also could impact prices. For this reason, it may be helpful to implement a seller concentration restriction for the SB 1122 tariff.

There is no price cap in place that would protect ratepayers in the event that limited resource availability leads to undue price impacts, although the IOUs do have the ability to file a motion with the CPUC to suspend the program if there is evidence of market manipulation or malfunction. Price caps may need to be considered given the wide range of resources that must be procured and the potential for high costs.

5.2.5 Potential Tariff Modifications

Given that few SB 1122 eligible projects are currently in the utility interconnection queues, several possible changes could be made to ReMAT that would stimulate the small-scale bioenergy market. Listed below are some options that could be considered for modifying the existing ReMAT program rules to either stimulate the market or, on balance, to protect ratepayers:

- **Faster Tariff Ramp or Larger Price Step Changes:** As shown in Section 4, few bioenergy projects have signed FIT contracts to date, due in part to the low FIT price offered relative to what is likely needed to provide enough financial incentive for small-scale bioenergy projects. While some SB 1122 projects may be viable at the ReMAT starting price of $89.23/MWh, many projects will likely need higher prices to be economically viable. A faster tariff ramp rate or larger price adjustments may accelerate the pace of overall project development by providing a sufficient pricing incentive earlier. However, given how few small-scale bioenergy projects are currently in the utility interconnection queues and the expected project timelines for project development, it still may take three years or more for SB 1122 projects to achieve commercial operation after the tariff becomes available.
- **Start Tariff Ramp with Less Than Five Projects:** Waiting until five eligible SB 1122 projects have entered the ReMAT project queue before the price can adjust may create development delays and may be unachievable in some instances, given the small amount of procurement required for some service territories and feedstock types. Project viability screens should remain since they are important to prevent projects that are unlikely to be developed from taking up queue space. The number of eligible projects needed to start the price changes could be uniformly reduced or set proportional to the procurement target. These changes could have a negative consequence, however, if they lead to gaming of the ReMAT price.
- **Accept International Experience:** There is a large amount of experience in small scale bioenergy projects outside the United States. This experience should be accepted as part of the project viability screens to open the market to a wide range of developers.
- **Consider Seller Concentration Requirements:** D.13-05-034 removed the seller concentration screen from the FIT Program. Depending on the targets set for each utility and resource, it may be prudent to reinstate seller concentration limits to avoid market manipulation in locations that may face restricted competition due to limited resource availability. A limit based on a percentage of the capacity target (e.g., less than 25 percent) may be appropriate.
- **Price Caps:** Limited supply of certain types of feedstocks in some of the service territories could create very strong feedstock demand, which could raise prices and impact the overall cost of generation. For this reason, price caps may be considered as an option to protect ratepayers and prevent disproportionate cost burdens. One option would be to relieve utilities of their obligations to meet SB 1122 procurement requirements if the price cap is reached.

5.3 STATUTORY INTERPRETATION

The wording of SB 1122 leaves some implementation issues unclear and subject to the interpretation of the CPUC. Some of the potential issues are identified below:

- **Eligibility of Out of State Feedstocks:** SB 1122 defines an eligible "electric generation facility" as being one located in a utility service territory, but the statute does not require that the feedstock for that facility originate from within California. This opens the possibility, for instance, that out of state biogas could be pipelined into California to an SB 1122 eligible facility. Most biogas that is imported to California is combusted in large combined cycle facilities. It is unlikely that there will be a significant economic incentive to develop an anaerobic digestion out of state, clean the gas to pipeline quality, then combust the biogas in a small electric generation facility. In addition, implementation of AB 2196 is providing further guidance on RPS eligibility of out of state biogas. Since economics will likely make out of state projects less viable than in-state projects, there is unlikely to be a need for the CPUC to restrict the feedstock type.
- **Feedstock Definitions:** There are a range of biomass feedstocks that could be used to meet SB 1122 requirements. The CPUC may need to clarify the definitions for what falls into each of the SB 1122 allocation categories. Specifically, a distinction should be made for the difference between feedstocks used for food processing and agricultural bioenergy production, and the types of feedstocks that qualify for "codigestion".
- **Use of Multiple Feedstock Types:** Some existing anaerobic digestion and solid biomass conversion units in California use multiple SB 1122 eligible feedstocks. The majority of anaerobic digestion facilities use only one type of SB 1122 feedstock, although there are some planned digesters looking to use agricultural residues and food wastes, or manures coupled with other wastes. Gasification facilities under 3 MW will have more dedicated feedstock supplies than much larger facilities, but may still be interested in using different feedstock types. If different tariff rates are established for each feedstock type utilizing the ReMAT pricing mechanism, the CPUC may consider requiring that projects declare a single product category for which they are applying for a contract. As a result, the CPUC may need to consider a requirement that a project source a majority (or some other percentage) of its feedstock from the category to which the project applies for a contract. Fuel switching during project operation does not appear to meet the statute's intent, which was developed to incentivize specific feedstock types.
- **Definition of "Commence Operation":** SB 1122 states that eligible projects will "commence operation on or after June 1, 2013". For the purposes of this resource and cost assessment, eligible projects are assumed to mean new projects that are not currently producing power. It is also assumed that changing the feedstock, electric generation unit, or power disposition (from on-site use to power export) will not qualify an operating project as SB 1122 eligible per the CEC definition outlined in Appendix A.
- **Definition of "Sustainable Forest Management":** Only forest products that are harvested sustainably qualify for the SB 1122 tariff. The resource potential shown here uses CAL FIRE data and assumptions for forest material that would be considered sustainable. The CPUC may need to consider whether to adopt a definition of "sustainable forest management" for projects seeking a contract in this category.

- **Determination of Feedstocks Used:** Because projects will be selected partially on the basis of the feedstock used that fits into a specific allocation category, the CPUC or utilities may need to perform some sort of feedstock monitoring and determination.

5.4 OPTIONS FOR RESOURCE TARGETS AND COST OF COMPLIANCE

With the exception of Category 3, SB 1122 is not clear on the utility specific procurement goals for each of the different resource categories. For example, while 110 MW of Category 1 material is required to be used, there is no clear direction for how this is to be allocated amongst the utilities. Having one tariff or capacity goal per utility regardless of the feedstock would lead to the least expensive projects being developed first, which will likely favor certain technologies and resources. This could be a low-cost option if resource specific goals were not required.

Different resource goals by utility likely need to be defined to provide incentives for each resource type in every service territory. Failure to do so could lead to some resource types being fully subscribed through projects in one utility, making it difficult or expensive for other utilities to meet their goals. For example, if Category 1 projects are quickly developed in PG&E and SCE service territories, taking up all the statewide allocation, SDG&E would have a challenge in economically meeting its net procurement goal given a lack of other resource types.

Three main options are considered here for resource allocation targets by utility: 1) proportional by load, 2) by resource availability, and 3) by resource availability with adjustments for market competition factors. Equivalence by cost was also considered, but as shown below, this may be a challenge given the lack of identified resources in San Diego. Besides these options, alternative procurement options which would require changes in the statute are also discussed. The allocation goals under each method and the range of potential costs are outlined below.

5.4.1 Assumptions

The allocation of forest (Category 3) material is defined by statute to be "based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas". From discussions with CAL FIRE, this is intended to mean that the ratio of the 50 MW defined in the statute should be split based on the amount of Fire Threat Treatment Area (FTTA) material in each of the IOU service territories. Based on the work performed in the draft report and further elaborated upon in Appendix A, the split is estimated as shown below. This allocation was used in Option 1, with modifications that largely meet the intent of this distribution used in Options 2 and 3.

Table 5-1 Category 3 Resource Allocation

UTILITY	FTTA RESOURCE POTENTIAL (MW)	PERCENTAGE (ROUNDED)	ALLOCATION
PG&E	277	94	47
SCE	15	5	2.5
SDG&E	2	1	0.5
Total	**295**	**100**	**50**

A blended cost of SB 1122 compliance by utility in $/MWh and estimated net yearly expenditure was estimated by using the LCOE estimates determined earlier in this report. The range of potential incentives and coproduct values make compliance cost estimates a challenge. The intent is to provide a relative understanding of the different costs in each service territory given resource availability and likely procurement choices. Unless otherwise specified, a few major assumptions were applied in each case:

- The Low and Medium LCOE estimates were used to bracket the cost range in service territories that have sufficient resources to meet the procurement target. Medium and High LCOE estimate are largely used if more than 50 percent of the resource within the service territory is utilized.
- Agricultural bioenergy projects are selected in PG&E's and SDG&E's service territory over dairy digestion due to lower cost and higher availability. SDG&E imports agricultural residues to meet its obligation when insufficient material is available locally.
- SCE complies with the dairy/agricultural goal through a mix of 50 percent dairy digestion and 50 percent agricultural resources. Half the dairy digestion projects are assumed to receive AB 32 carbon reduction credits.

5.4.2 Option 1: Proportional by Load

The first allocation performed is on a proportional basis per the overall procurement goal and the split of resource defined in the statute. The allocation of forest biomass was first set, then the split between Categories 1 and 2 was defined. For example, after Category 3 is set, Category 1 material represents 55 percent of the remaining allocation for each utility (110 MW / 200 MW). A summary of the procurement targets, resource availability, and projected cost ranges for each utility can be seen in Table 5-2. Targets for each utility by resource type are shown, along with the resource potential estimates (in parenthesis) developed in Section 3.

Table 5-2 Utility Resource Targets and Projected Costs, Proportional by Load

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	35 *(101)*	29 *(340)*	47 *(478)*	127-195	111-171
SCE	62 *(115)*	50 *(118)*	2.5 *(16)*	126-194	113-174
SDG&E	13 *(26)*	11 *(3)*	0.5 *(3)*	140-200	28-40
Procurement Totals	110	90	50	--	252-385

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This allocation will likely be impractical given the lack of available dairy/agricultural material for SDG&E. To meet the Category 2 allocation, SDG&E may need to bring in material from distant locations or use lower quality materials, increasing the LCOE. This is reflected in the higher compliance cost estimates developed for this table. Also, developing a program to procure the low levels of forest resource for SCE and SDG&E would be administratively burdensome for this small allocation.

5.4.3 Option 2: By Resource Availability

A second option is to assign targets based on the availability of resources in each service territory. To do this, the resource percentages in each service territory were calculated, and then the utility procurement target was multiplied by this percentage. As an example, forest residues in PG&E's service territory represents 52 percent of the SB 1122 compliant resources in their service territory (478 MW forest potential / 919 MW net potential). PG&E's forest target would therefore be 52 percent times its 111 MW target, or 58 MW. Note that while this will assure that each utility capacity target is met, it will change the net allocation by resource type. This type of reallocation is acceptable per the statute, provided that the CPUC consults with other state agencies. Targets based on this analysis are shown in Table 5-3.

Table 5-3 Utility Resource Targets and Projected Costs, by Resource Availability

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	12 *(101)*	41 *(340)*	58 *(478)*	135-205	121-181
SCE	53 *(115)*	54 *(118)*	7 *(16)*	130-200	117-178
SDG&E	20 *(26)*	2 *(3)*	2 *(3)*	140-200	28-40
Procurement Totals	85	98	67	--	270-404

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This resource allocation leads to 12 percent of each resource type in PG&E's service territory being used, 46 percent of SCE's, and 80 percent of SDG&E's. In this allocation, the overall target for each resources type has changed relative to Option 1. Category 1 procurement decreased by 25 MW, dairy/agricultural procurement has increased by 8 MW, while forest allocation increased by 17 MW. While the CPUC may perform this type of reallocation per §399.20(f)(3), this would require coordination across state agencies which could delay enactment of the tariff.

This allocation of resources has impacted the likely costs. Compliance costs for PG&E would likely be more expensive than the proportional by load case due to use of more agricultural and forest residues, while SCE costs have increased slightly due to the use of more forest residue. SDG&E's compliance costs may not change considerably; while the amount of dairy, agricultural, and forest residues have all declined, the amount of Category 1 material that must be procured has doubled from the proportional by load case. Using such a large amount of this resource and the lack of competition may keep procurement costs high; it is assumed that the average cost would be the Medium LCOE estimate, with the cost ranges bracketing this assumption..

5.4.4 Option 3: By Resource Availability, Using Market Competition Factors

As can be seen from the results of Options 1 and 2, allocating by load only may be impractical while allocating by resource availability only would require a reallocation of resource targets. A hybrid option would be to maintain the statutorily required allocation of Category 3 resource (as shown in Option 1 and Table 5-1), require that SDG&E only obtain the remainder of its obligation from Category 1 resources given its lack of other options, and then reallocate the remaining resources so that the original targets are preserved. The distribution of Category 1 and Category 2 material between SCE and PG&E could be based off of cost equity by attempting to keep the blended LCOE between PG&E and SCE the same. As can be seen from Option 1, the blended LCOEs using this allocation are very close. By slightly adjusting these allocations, projected cost equity can be achieved as shown below.

Table 5-4 Utility Resource Targets and Projected Costs, Option 3

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	30.5 *(101)*	33.5 *(340)*	47 *(478)*	129-198	113-173
SCE	55.5 *(115)*	56.5 *(118)*	2.5 *(16)*	129-197	116-177
SDG&E	24 *(26)*	0 *(3)*	0.5 *(3)*	122-187	24-37
Procurement Totals	110	90	50	--	253-387

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

Even if SDG&E was to focus almost solely on Category 1 material within its service territory, it may still be challenge to meet SB 1122 procurement goals given the resource limitations. In addition, SCE is utilizing roughly half its resource potential to meet Category 1 and Category 2 requirements, which may stress the available resources and potentially impact the delivered cost.

5.4.5 Other Options, Not Authorized by SB 1122

There are a number of other options available for resource allocation, but would require a change in the net allocation by resource or utility compared to what is defined in SB 1122. Obtaining cost equivalence, where each utility is roughly paying the same blended cost, is unlikely to be possible unless the utility procurement targets are modified. The lack of resources in SDG&E's service territory will likely create challenges in meeting SB 1122 targets at a price commensurate with PG&E and SCE.

If the allocation by service territory could be modified, greater flexibility and potentially lower net compliance costs may be possible. Two major options for new procurement targets if the amount by utility was changed are:

- Option 4: A flat procurement percentage based on resource availability
- Option 5: Amounts equal to the ratio of the resource availability in each service territory compared to the statewide potential

A flat target of 21 percent by resource within each service territory would greatly change the allocation by utility. The 250 MW statewide goal would now be comprised of 192 MW from PG&E, 52 MW from SCE, and 6 MW from SDG&E. This also more than doubles the net forest procurement over the SB 1122 goals. The breakdown by resource and utility is shown below.

Table 5-5 Non Compliant Utility Resource Targets, Using Flat Procurement

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	21 *(101)*	71 *(340)*	100 *(478)*	130-200	200-300
SCE	24 *(115)*	25 *(118)*	3 *(16)*	130-195	50-80
SDG&E	5 *(26)*	0.5 *(3)*	0.5 *(3)*	100-160	5-10
Procurement Totals	50	96.5	103.5	--	260-400

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This option keeps close LCOE equity between PG&E and SCE, along with lowering the compliance cost for SDG&E. However, PG&E will pay significantly more on an annual basis, and the net compliance cost is no better than the previous cases due to the shift from Category 1 to more forest and dairy/agricultural residues.

Option 5 would be to allocate by the percentage of statewide resource potential. This percentage would be multiplied by the overall target for that resource type to develop the procurement target. For example, PG&E has 96 percent of the identified forest resource (478 MW of the 497 MW statewide utility potential), so it would receive 96 percent of the 50 MW target, or 48 MW. Targets using this approach can be seen below.

Table 5-6 Non Compliant Utility Resource Targets, Using Resource Potential

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	46 *(101)*	66 *(340)*	48 *(478*	125-195	160-246
SCE	52 *(115)*	23 *(118)*	1.6 *(16)*	110-180	69-110
SDG&E	12 *(26)*	1 *(3)*	0.4 *(3)*	90-160	9-16
Procurement Totals	110	90	50	--	238-371

Targets for each utility and resource are shown, along with the estimated service area potential in parenthesis.

This option has the lowest net cost of all the options considered, up to $30MM lower than the previous cases. PG&E would likely pay the most per MWh and on an annual basis in this scenario. This would also create a greater administrative burden on PG&E based on the number of SB 1122 projects that would now be interconnected to their system.

The two tables above assume that projects must be developed within a utility's service territory to count toward their compliance requirement. Another option, which would require a modification in the SB 1122 statute, would be to permit utilities to remove this siting restriction (Option 6). For example, if SDG&E was allowed to procure energy from projects located in other utility service territories, this could lower the cost of compliance even once electric wheeling charges are included. Resource targets could then be based on total statewide potential, with allocation by utility still performed on a percent of load basis. Using the resource estimates developed in Section 3, this would set a target of 50 MW for Category 1 (20 percent of statewide potential, thus 20 percent of the 250 MW target), 97 MW for dairy/agricultural residues (38 percent), and 103 MW for forest residues (42 percent). Allocating this potential by utility load would lead to the following distribution.

Table 5-7 Non Compliant Utility Resource Targets, Without Locational Constraints

UTILITY	CATEGORY 1: ORGANIC WASTE BIOGAS (MW)	CATEGORY 2: DAIRY AND AG. BIOENERGY (MW)	CATEGORY 3: FOREST (MW)	ESTIMATED BLENDED COST RANGE ($/MWH)	NET EXPENDITURE PER YEAR ($MM)
PG&E	22	43	46	130-195	112-170
SCE	23	44	47	130-195	115-174
SDG&E	5	10	10	130-195	25-38
Procurement Totals	**50**	**97**	**113**		**252-383**

This type of allocation would allow greater flexibility in project selection and reduce market power by setting resource allocation targets based on total availability while maintaining the targets by utility. These goals also are the most equitable since costs for each utility per MWh will likely be similar, and the net procurement levels remain set by peak load. This would not necessarily be the least expensive option since resource availability, not price, sets the procurement targets, and some utilities will need to pay transmission fees to move the power to their service territory. Administratively, allowing the freedom to select projects regardless of location would make policy implementation easier since utility specific resource availability would no longer be a concern in setting procurement targets. While the FIT under SB 32 has similar service territory constraints, a bioenergy specific FIT would benefit from less restrictive siting requirements by service due to the uneven distribution of available bioenergy resources in the state.

Pursuant to the statute, Option 2 meets all requirements and takes into account local resource availability. The CPUC, however, would need to work with other state agencies to reallocate resources by type in order to enact this option. Option 3 would take this allocation one step further by eliminating resource categories for certain utilities if the procurement efforts are deemed too burdensome for the potential benefit. Option 6 provides the most equity on both a resource availability and utility procurement basis, but would require a statute modification that removes the requirement that FIT projects site in the service territory of the contracting utility. Option 5 (and other potential permutations) may be able to meet the overall SB 1122 obligation at the lowest cost, but these may require major changes in the allocations and lead to disproportionate ratepayer costs by service territory.

Appendix A. Resource Potential Methodology

The methodology for quantifying each resource is outlined below. Peer reviewed public datasets developed by state agencies were largely relied upon for the assessment. Any major screens used, items excluded, and major uncertainties or issues with the data are highlighted.

Category 1: Wastewater Treatment Plants

Three types of WWTPs were identified as possible candidates to develop projects under SB 1122: 1) facilities that have operating anaerobic digestion but are not beneficially using the biogas produced, 2) facilities that do not have operating anaerobic digestion for biogas production or those that completely retrofit their system, and 3) codigestion of new feedstocks at existing digesters that produce incremental biogas.

Based on existing CEC definitions, it was assumed that WWTPs that are already utilizing biogas are not eligible for the tariff if no incremental biogas is produced. To meet the "commence operation" requirements of SB 1122, the CEC definition from the Renewable Portfolio Standard Eligibility Guidebook was used.[14] Per the CEC, a retrofit and repowering of a digester is only RPS eligible and meets the "commence operation" requirement if "the entire digester unit and internal combustion engine or combustion turbine" is replaced. The costs for making these types of changes are largely reflected in the New Digestion cost estimates. While performing this type of retrofit would greatly increase the potential of biogas from WWTPs, the cost and fact that most energy produced from WWTPs is used on site and not exported to the grid makes this potential unlikely to be used for the SB 1122 tariff.

The unit cost of power generation at WWTPs using biogas decreases as the installed capacity increases. The consensus of many in the wastewater industry is that combined heat and power (CHP) applications are economically challenging for facilities with average wastewater influents of less than 10 million gallons per day (MGD). Therefore, when evaluating the potential to install a new digestion unit for wastewater biosolids, this study only focused on WWTPs greater than 10 MGD. Smaller digestion and CHP facilities are technically possible and SB 1122 eligible but are likely to be economically uncompetitive. All facilities with operating digesters that are not currently using their biogas regardless of size were included in the resource potential estimates.

WWTPs could also install new digesters or utilize excess digestion capacity for the purpose of handling other Category 1 materials. This would be SB 1122 compliant, provided that the net

[14] Seventh Edition, May 2013. Available at http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-CMF.pdf. Per this definition, commences operation is the "date on which an electrical generation facility ceases to generate electricity for testing purposes and first generates electricity solely for the purpose of consumption by the facility or any customer or for sale to any procuring retail seller" (p. 117).

generation is less than 3 MW (on-site use and power export combined). It is unclear how much excess digestion capacity is available in California that is SB 1122 eligible and could economically be utilized and thus was not included in the resource estimate.

It was pointed out during the review process that other sources have identified larger amounts of available bioenergy from existing WWTPs, such as CEC estimates of up to 90 MW of new potential. From review of this analysis, it appears that much of the potential is from smaller WWTPs (less than 10 MGD) and from more efficient use of biogas that is already being produced. From the analysis basis outlined above, much of this resource would be uneconomic or ineligible for the SB 1122 tariff. The Category 1 analysis shows that there is ample resource to meet all utility targets; if additional WWTP material was deemed available, this will not impact the resource allocations or projected costs.

An online database (www.biogasdata.org) was used to identify candidate WWTPs in California. This newly released website presents data collected by a team of biosolids and biogas experts across the country, including Black & Veatch, the North East Biosolids and Residuals Association (NEBRA), and many other organizations. Potential biogas and electricity production rates were estimated based on average plant influent flows of identified WWTPs.

After identification of candidate facilities, the MW potential for each facility was estimated using assumptions for the total solids, volatile solids, solids reduction, gas production rate, and methane content. Gas is assumed to be used in a reciprocating engine generator with a 35 percent electrical generation efficiency. The candidate WWTPs identified that are either not beneficially using their biogas or those larger than 10 MGD that could install digestion are shown in Appendix B.

Category 1: Organic Wastes Suitable for Biogas Production

Four types of organic wastes suitable for biogas production were quantified: food processing waste, food waste present in the municipal solid waste (MSW) stream sent to landfills, leaves and grass in MSW, and FOG. These resources were characterized together since all would be eligible for the Category 1 biogas requirement. As mentioned by written comments to the draft report, organic wastes that are currently already being collected and utilized for other purposes (such as compost and alternative daily cover) are also SB 1122 compliant. Including these resources would greatly increase the Category 1 potential. However, these resources may be unavailable or uneconomic when compared to the resources identified through the methodology in this report. The analysis showed that no IOU in the state is likely to be constrained by Category 1 resources; adding these additional potential sources of supply would not change the allocation decisions or projected costs.

Different datasets were used to quantify these resources. For food processing waste, the 2011 California Biomass Collaborative (CBC) and California Energy Commission (CEC) report *California Food Processing Industry Organic Residue Assessment* was used. This report quantifies residues from food processors including fruit and vegetable canneries, fruit and vegetable processors, dairy creameries, wineries, and meat processors. The report excludes data from soft drink manufacturers, sugar refineries, and snack producers, as responses to the CBC surveys were limited. "High Moisture Solids" data from Table ES-2 in this report was used for food processing waste quantification.

For food waste, leaves, and grass, data from the 2007 CEC and CBC report *An Assessment of Biomass Resources in California* was used. This report quantifies the recoverable potential of different MSW components that are currently being landfilled. Food waste and leaves/grass data from Table 2.3.11, Technical Potential in 2017, was used for quantification of these resources. SB 1122 eligible resources that are currently being diverted from the MSW stream and resources already being used in operating anaerobic digesters were not included in the resource potential estimates. The CEC/CBC report estimates the amount of material being diverted and does not include them in the resource estimates, while the amount of this material being used in existing AD (roughly 17 MW of capacity) was deducted from the potential based on CalRecycle data.[15] Finally, gross state FOG potential was developed based on NREL estimates for FOG production of 13 pounds per person per year.[16] CEC 2017 population estimates by county and recoverability approximations (50 percent of the gross stream) were then applied to develop a technical potential.

It was mentioned during the review process that other types of organic wastes, such as urban wood waste, should also be considered as Category 1 eligible. In quantifying Category 1 potential, only feedstocks that are typically used in anaerobic digestion for biogas production were considered, since SB 1122 wording specifically requires biogas production from Category 1. For this reason, urban wood waste and other municipal organic material that would be combusted or gasified were excluded from the analysis.

Power generation potential using these resources was made through operating plant and literature estimates for methane yield per dry ton of material. Food waste yields are from operating experience at EBMUD's facility in Oakland (13,300 ft^3 methane/dry ton), while FOG (39,900 ft^3 methane/dry ton) and leaves/grass (6,650 ft^3 methane/dry ton) are based off of literature surveys from multiple sources. The biogas produced is assumed to be combusted in a reciprocating engine generator with a roughly 35 percent electrical generation efficiency.

Category 2: Dairy Cattle Manure

Several publicly available resources were consulted to develop an estimate of dairy cattle manure in California:

[15] Data on operating and planned digestion projects can be seen at http://www.calrecycle.ca.gov/Organics/Conversion/Events/Digesting12/ADProjects.pdf

[16] Wiltsee, George (for NREL), "Waste Grease Resources in 30 Metropolitan Areas", 1999. Presented at *Bioenergy 98: Expanding Bioenergy Partnerships*.

- Dapper, K., G. Dashiell, L. Tang, *California Dairy Statistics 2011 Data,* California Department of Food and Agriculture, Dairy Marketing Branch
- United States Department of Agriculture, National Agricultural Statistics Service
- United States Environmental Protection Agency, AgSTAR database of operating anaerobic digester projects updated as of September 2012
- Kitto, B., *Final Dairy Waste to Energy Site Selection Report – Addendum No. 1, Attachment 1 (California Dairies)*, California Energy Commission, Contract No. 500-00-036, Task 3.1.2 – Site Selection (2005)

The California Department of Food and Agriculture (CDFA) publication summarizes total head counts of dairy cattle and farms per county in 2011. While this was used as the primary data source, total dairy cattle head counts were omitted for certain counties. The National Agricultural Statistics Service (NASS) database was consulted to obtain dairy cattle head counts as of January 1, 2012 for counties omitted from the CDFA report. From this data, the resource potential from roughly 1.8 million head of dairy cattle was quantified. The total dairy cattle head counts per county were used as the baseline to quantify the generation potential. All available dairies were included in the estimate presented in this study since there is little economic alternative for the use of this material. While it would be less economic for smaller dairies to develop projects, material could be transported from smaller dairies to centralized projects to develop larger, more economic, facilities.

Based on the head counts, capacity estimates were made using USDA assumptions for methane production per cow at a flushed freestall dairy using plug flow digesters (30.6 cubic feet of methane per cow per day). Energy generation potential was then based off the use of an internal combustion engine with a roughly 35 percent electrical generation efficiency. Electricity generation capacities associated with existing anaerobic digesters in California (5.5 MW) were subtracted from the gross potential for counties with operating dairy manure digesters based on operating digester data from the EPA AgStar database. The estimate assumes the same methane production rate regardless of how specific dairies are configured, which may overstate production for some locations that use different systems for manure collection.

Category 2: Agricultural Residues and Food Processing Waste

Two types of agricultural residues were quantified: field residues, such as orchard prunings and material left over during harvest and land maintenance, and food processing waste suitable for gasification that would be produced during material processing and packaging. The data used to quantify field residues came from the 2007 CEC/CBC state resource report, specifically looking at technical potential in 2017 for orchard/vineyard (Table 2.1.17), field/seed crop (Table 2.1.2.8), and vegetable crop residues (Table 2.1.3.7). A two-thirds discount was applied to this data to reflect already operating facilities, assumptions for future competing uses, and availability. This is a broad, conservative assumption which is meant to provide a reasonable approximation of the economic potential for agricultural residues. For example, while this may underestimate the amount of orchard prunings that are available (since there is little competing use for this material), it likely overestimates the vineyard residue potential (since this material is a poor resource for energy generation). Comments from the draft report were reviewed to determine if refinement of the estimate would have a material impact on areas of potential shortage. The only location that was modified was an increase in the San Diego county potential (increased from 1 to 3 MW), since much of its agricultural resource comes from orchards and citrus crops.

The 2007 and 2011 CBC/CEC reports used to quantify food processing waste used for biogas production (Category 1) was also used to quantify food processing wastes suitable for Category 2. The 2011 report was the main data source ("Low Moisture Solids" data presented in Table ES-2), with the majority of the potential from nut shells and hulls. The 2007 CEC report was used to supplement this analysis by including estimated quantities for rice hulls and cotton gin waste.

This resource potential was converted to MWs of capacity using different assumptions for feedstock heating content, ranging from 7,387 to 8,598 BTU per dry pound. The same type of conversion unit (gasification with close coupled engine operating at 21 percent efficiency) used in estimating forest resource potential was used to quantify agricultural residues and high solids food waste capacity.

Category 3: Sustainable Forest Management Byproducts

The data used to quantify the amount of sustainable forest management byproducts was provided by the CEC and California Department of Forestry and Fire Protection (CAL FIRE). The 2005 CEC/CAL FIRE report *Biomass Potentials from California Forest and Shrublands Including Fuel Reduction Potentials to Lessen Wildfire Threat* is the basis for the resource assessment, focusing only on non-merchantable forest slash, thinnings, and mill wastes. Material both within fire threat treatment areas (FTTAs) and outside FTTAs are included. Upon discussion with the CPUC and CAL FIRE, the Category 3 definition was interpreted such that *allocation* of forest resource capacity for each IOU is based on FTTA resources only, but that any forest material that is sustainability harvested is eligible for the SB 1122 tariff.[17] The starting basis for the allocation resource estimate is the FTTA information provided in Appendix A, Tables 12 and 13 of the CAL FIRE report. This is the most current dataset that has been developed by CAL FIRE.

[17] See §399.20(f)(2)(A)(iii). The first sentence states that 50 MW of the 250 MW net SB 1122 allocation will go to "bioenergy using byproducts of sustainable forest management" (any sustainable forest biomass), while the second sentence is interpreted to mean that *allocations between IOUs* was based on "the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas" per guidance of the intent of the legislation provided by CAL FIRE. Therefore, the FTTA location analysis was performed to determine how the 50 MW should be split amongst the IOUs.

The FTTA locations identified by CAL FIRE where resource data was estimated is shown graphically in Figure A-1. The data was consolidated into county-level and IOU specific resource estimates to be consistent with the data developed for the other SB 1122 eligible feedstocks. A county-level quantification of the FTTA resource potential is provided in Figure A-2; the amount of material available in each service territory was used to develop the SB 1122 eligible Category 3 allocation options in Section 5.

To quantify the overall resource amounts, the same CAL FIRE resource types mentioned above were used in the analysis, but material not within FTTAs was also included in the net availability. This produced the resource map presented in Section 3, with county level detail provided in Appendix B.

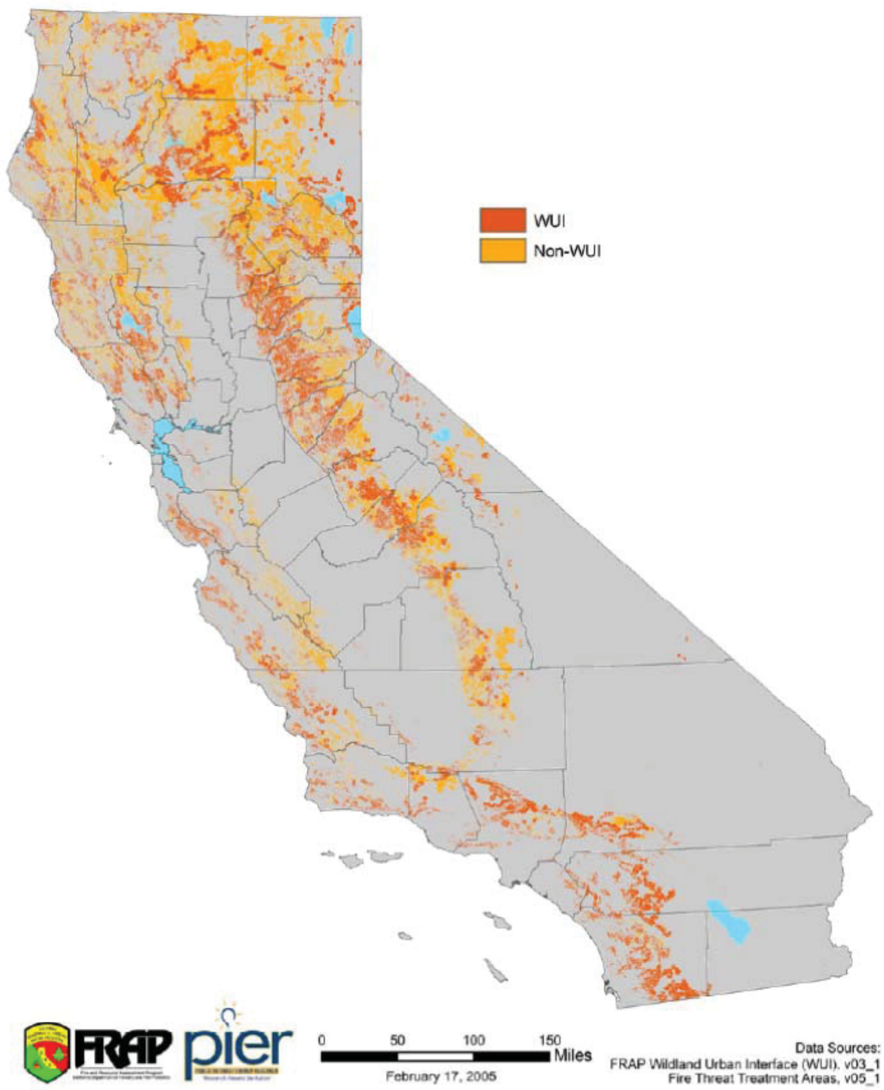
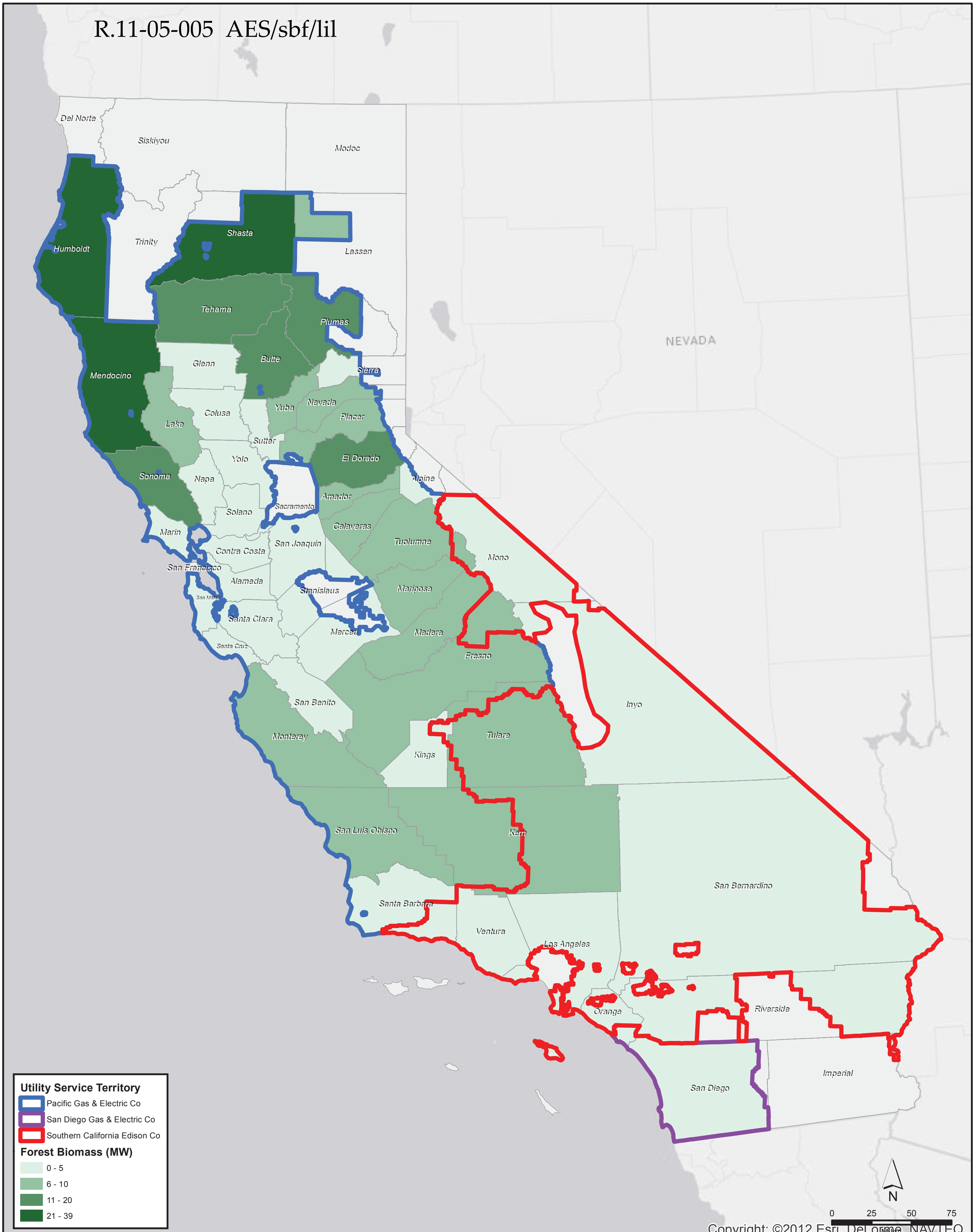


Figure A-1 CAL FIRE FTTA Location Designations

Figure A-2 FTTA Resource Availability by County



CPUC FTTA Forest Resource Potential

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CPUC Forest Residue FTTA.mxd | C.Holmgren | 08/09/2013

Conference calls and meetings were held with CAL FIRE and USFS staff to confirm that the approach for forest resources assessments was reasonable and that the data satisfies SB 1122 requirements. These resource potentials have already been screened so that only material that can be accessed by commercial harvesting operations sustainably is reflected in the resource estimates. Following this analysis, the existing material that is currently being used was subtracted from the resource potential. CEC data was used for the list of operating biomass facilities, with estimates for amount of capacity from woody biomass estimated from public reports and facility information. From this analysis, 335 MW of Category 3 resource was removed, or just under half the operating statewide capacity (the rest is roughly evenly split between agricultural resources and urban wood wastes). After calculation of the potential from this dataset, the estimates were compared to those developed by the CEC and CBC in their 2007 report for forest residuals. Applying a two-thirds discount factor to the CEC/CBC estimate, similar to what was done for the agricultural residues, produces a number very similar to the CAL FIRE estimates.

Material classified as "shrub" was excluded from the resource assessment. This material is more difficult to collect, is typically at locations of higher slope, and of poorer quality than forest biomass. Very little shrub biomass is currently used for power generation given these issues and potential impacts on feeding and conversion at the energy facility. In addition, environmental constraints to large scale shrub collection in Southern California may create limitations on the amount of material than can be harvested. It was confirmed by stakeholders during initial presentation of this data that this is a reasonable assumption.

GIS data from CAL FIRE was provided to Black & Veatch for the layers appropriate for resource quantification. This data for total resource potential (dry tons/yr) was overlaid onto county and utility service area maps to estimate the geographic resource potential. This resource potential was converted to MWs of capacity using assumptions for feedstock heating content (9,027 BTU/dry lb) and the operational efficiency of a small scale biomass gasification unit with a close coupled gas combustion engine (80 percent capacity factor over the life of the project and a net efficiency of roughly 21 percent). Different heat content, conversion efficiencies, and geographic boundaries produce net capacity estimates lower than those estimated by CAL FIRE.

Appendix B. Resource Potential by County and WWTP

Table B-1 County Resource Potential, Dry Tons/Year

COUNTY	CAT 1 WASTES	DAIRY	FOREST	AG. RESIDUES	TOTAL
Alameda	59,551	0	2,623	760	62,934
Alpine	55	0	5,785	0	5,840
Amador	2,271	0	60,518	0	62,789
Butte	9,687	987	167,400	82,322	260,396
Calaveras	2,070	0	48,823	351	51,243
Colusa	4,282	0	13,282	82,484	100,048
Contra Costa	38,906	0	1,222	6,302	46,430
Del Norte	865	10,581	96,012	0	107,458
El Dorado	7,374	0	325,190	846	333,410
Fresno	85,634	375,374	42,679	220,897	724,585
Glenn	3,159	56,992	36,914	87,543	184,609
Humboldt	4,397	43,716	708,729	0	756,842
Imperial	11,591	25,112	0	21,559	58,263
Inyo	667	0	466	5	1,138
Kern	57,585	539,086	44,217	140,367	781,255
Kings	12,241	601,754	15	62,457	676,466
Lake	3,669	0	87,312	4,339	95,321
Lassen	987	0	43,245	327	44,559
Los Angeles	428,441	0	4,114	330	432,886
Madera	29,625	246,270	6,763	79,852	362,511
Marin	8,297	31,190	6,612	30	46,128
Mariposa	630	0	30,784	125	31,539
Mendocino	5,762	0	435,993	5,574	447,328
Merced	22,001	837,181	1,819	113,832	974,833
Modoc	291	0	121,955	2,092	124,338
Mono	1,557	0	11,057	2	12,616
Monterey	28,672	0	57,825	33,658	120,156
Napa	19,579	0	35,870	13,157	68,607
Nevada	3,321	0	205,782	109	209,212
Orange	143,725	0	515	37	144,277

COUNTY	CAT 1 WASTES	DAIRY	FOREST	AG. RESIDUES	TOTAL
Placer	13,963	0	44,830	0	58,794
Plumas	875	0	76,165	0	77,040
Riverside	109,980	151,754	4,360	3,608	269,703
Sacramento	70,027	47,737	209	22,427	140,399
San Benito	4,757	0	24,725	2,883	32,365
San Bernardino	92,501	247,037	8,069	1,295	348,901
San Diego	145,131	7,687	17,415	18,959	189,192
San Francisco	24,595	0	0	0	24,595
San Joaquin	71,975	338,576	1,012	69,119	480,681
San Luis Obispo	16,128	0	50,833	14,534	81,495
San Mateo	25,033	0	16,222	127	41,383
Santa Barbara	19,438	0	22,569	9,814	51,821
Santa Clara	57,593	0	21,957	1,883	81,433
Santa Cruz	8,222	0	46,074	1,204	55,500
Shasta	7,454	0	101,707	2,139	111,300
Sierra	162	0	93,191	0	93,353
Siskiyou	1,377	2,245	519,805	4,209	527,637
Solano	19,738	0	880	12,691	33,309
Sonoma	29,063	92,807	185,200	17,955	325,026
Stanislaus	44,174	576,204	5,975	134,812	761,164
Sutter	5,079	0	1	81,360	86,441
Tehama	3,711	12,417	71,719	14,138	101,984
Trinity	458	0	157,930	27	158,415
Tulare	25,434	1,564,107	41,727	90,533	1,721,801
Tuolumne	1,809	0	39,452	0	41,261
Ventura	41,750	0	5,050	7,583	54,383
Yolo	16,576	0	11,219	36,278	64,073
Yuba	3,320	10,811	124,682	29,152	167,965
TOTAL	**1,857,215**	**5,819,626**	**4,296,500**	**1,536,090**	**13,509,431**

Table B-2 County Resource Potential, MW

COUNTY	CAT 1 WASTES	DAIRY	FOREST	AG. RESIDUES	TOTAL
Alameda	7	0	0	0	7
Alpine	0	0	1	0	1
Amador	0	0	9	0	10
Butte	2	0	26	15	43
Calaveras	0	0	8	0	8
Colusa	1	0	2	15	18
Contra Costa	3	0	0	1	5
Del Norte	0	0	15	0	16
El Dorado	1	0	51	0	52
Fresno	13	15	7	40	75
Glenn	0	2	6	16	24
Humboldt	1	2	111	0	113
Imperial	2	1	0	4	6
Inyo	0	0	0	0	0
Kern	9	21	7	25	62
Kings	2	24	0	11	37
Lake	1	0	14	1	15
Lassen	0	0	7	0	7
Los Angeles	68	1	1	0	69
Madera	5	10	1	14	30
Marin	0	1	1	0	2
Mariposa	0	0	5	0	5
Mendocino	1	0	68	1	70
Merced	3	33	0	20	57
Modoc	0	0	19	0	20
Mono	0	0	2	0	2
Monterey	5	0	9	6	20
Napa	3	0	6	2	11
Nevada	1	0	32	0	33

COUNTY	CAT 1 WASTES	DAIRY	FOREST	AG. RESIDUES	TOTAL
Orange	23	0	0	0	23
Placer	2	0	7	0	9
Plumas	0	0	12	0	12
Riverside	17	6	1	1	25
Sacramento	10	0	0	4	14
San Benito	1	0	4	1	5
San Bernardino	12	10	1	0	23
San Diego	23	0	3	3	29
San Francisco	4	0	0	0	4
San Joaquin	11	13	0	12	37
San Luis Obispo	3	0	8	3	13
San Mateo	4	0	3	0	7
Santa Barbara	3	0	4	2	9
Santa Clara	5	0	3	0	8
Santa Cruz	1	0	7	0	9
Shasta	1	0	16	0	18
Sierra	0	0	15	0	15
Siskiyou	0	0	81	1	82
Solano	3	0	0	2	6
Sonoma	5	4	29	3	41
Stanislaus	7	22	1	24	54
Sutter	1	0	0	15	15
Tehama	1	0	11	3	15
Trinity	0	0	25	0	25
Tulare	4	61	7	16	88
Tuolumne	0	0	6	0	6
Ventura	6	0	1	1	8
Yolo	3	0	2	7	11
Yuba	1	0	20	5	26
TOTAL	**278**	**227**	**673**	**276**	**1,453**

Table B-3 Wastewater Treatment Plant Resource Potential, Biosolids Only

WWTP	CITY	COUNTY	HAVE OPERATING DIGESTERS?	AVERAGE FLOW, MGD	ELECTRICITY POTENTIAL, MW
Coachella VWD - WRP	Indio	Riverside	No	10	0.3
Vallejo Sanitation and Flood Control District	Vallejo	Solano	No	13	0.4
Palo Alto RWQCP	Palo Alto	Santa Clara	No	22	0.7
Central Contra Costa Sanitary District	Martinez	Contra Costa	No	54	1.6
Beale Air Force Base	Beale AFB	Yuba	Yes	0.4	0.01
Crescent City WWTP	Crescent	Del Norte	Yes	1.9	0.06
Pinole/Hercules WPCP	Pinole	Contra Costa	Yes	2	0.06
Banning WWTP	Banning	Riverside	Yes	2.2	0.07
El Centro WWTP	El Centro	Imperial	Yes	4	0.1
Yuba City WTF	Yuba	Sutter	Yes	6	0.2
Manteca WQCF	Manteca	San Joaquin	Yes	6.2	0.2
Simi Valley WQCP	Simi Valley	Ventura	Yes	9.1	0.3

Appendix C. Fire Threat Impacts and Bioenergy Plants

California faces a widespread threat of high intensity forest fires. Based on data from CAL FIRE reported in Appendix A, 48 percent of the state's 101 million acres of forest land are classified as facing high, very high, or extreme fire threats. In recent years, CAL FIRE has seen increased acres burned, greater fire severity, and modification of historic fire regimes. Regions of major fire threats can be seen in Figure C-1.

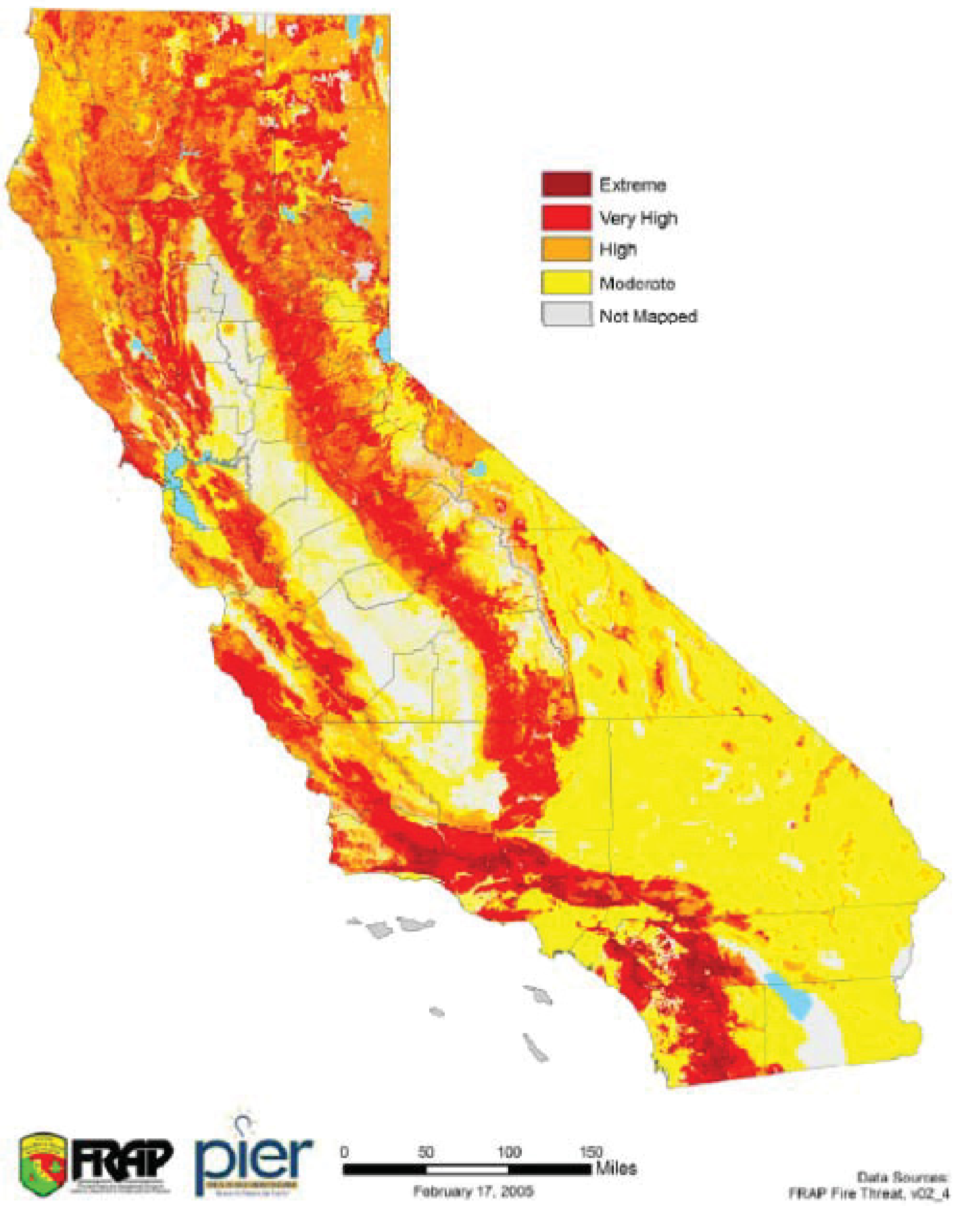

Figure C-1 California Fire Threat Classifications

One of the major intended goals of SB 1122 is to create a market for material that will be harvested from fire threat treatment areas in an effort to reduce the risk of high intensity forest fires in California. CAL FIRE estimates that the SB 1122 goals amounts to roughly 12 percent of the available non-merchantable material in state FTTAs. If these acres were treated for forest thinning, CAL FIRE states that significant reduction in high intensity fire threat on these acres would be expected. Ideally, the areas harvested would need to be selected and treated according to the treatment schedule outlined by CAL FIRE to maintain their fire hazard benefits. Scheduling issues could create interruptions to feedstock availability, since the geographic locations of the treatment areas are scattered, and individual stands are only treated periodically.

The California Biomass Collaborative reports that there are just over 700 MW of solid biomass power plants operational or under active conversion in the state. In addition, there is roughly 150 MW of idle or not operational capacity and another 123 MW of proposed new capacity. These facilities have an average size of 20 MW and use either urban wood waste, agricultural residues, or forest residues as their main feedstock, with many facilities using a blend of multiple feedstocks. Facilities are typically located near their feedstock source. The vast majority of the operational facilities are in PG&E's service territory, with projects spread throughout the Central Valley, Sierras, and Coast Range. Providing incentives for operating facilities or idle capacity to utilize material from FTTAs could help reduce the threat of high intensity forest fires. However, the size and operational history of these projects would not make them SB 1122 compliant, requiring an altogether different policy to provide these incentives.

Appendix D. LCOE Assumptions

Capital costs include all developer and owner's costs required for project development. These include costs for contractor mobilization, sitework, facilities, equipment, equipment installation, engineering, interconnection, contingencies, and fees. O&M costs include imported utilities, consumables, labor based on average California rates, along with taxes, insurance, and administrative fees for some technologies. Maintenance costs are based on vendor quotes where available; otherwise, general technology assumptions were applied. Given that costs can vary substantially depending on the unique requirements for each specific project, a range of LCOEs representing low, medium, and high cost cases were made. More detail for the items that are included are listed in the project specific assumptions.

Because the cost estimates are for a generic facility and are not based on site-specific information, capital cost estimates presented within this report are considered to be Order of Magnitude (OOM) estimates. OOM estimates rely to a large extent on publicly available cost data and engineering judgment rather than vendor quotations. These OOM estimates are comparable to Class 5 estimates as defined by AACE, International.[18] Similarly, estimates of O&M costs are based on engineering judgment and Black & Veatch experience with facilities of similar type and size. All costs are in 2013 dollars.

Financial Model Assumptions

For every case, the same sets of economic assumptions were used. They reflect typical ownership by a taxable entity with power being sold under a power purchase agreement (PPA) back to a utility. These assumptions will change based on the tax status of the owner and the financing arrangement, along with the technology deployed and the counterparty utilizing the equipment. The assumptions used are:

- Debt/Equity: 60/40
- Debt Rate: 7 percent
- Cost of Equity: 12 percent (except for large scale, where 10 percent was used)
- Debt Length: 15 years
- Project Life: 20 years
- Depreciation: 7 year MACRS
- Tax Rate: 40 percent
- O&M and Fuel Cost Escalation: 2 percent/year
- No terminal value or cost at project completion

[18] "Cost Estimate Classification System," AACE International Recommended Practice No. 17R-97. Originally released August 1997.

The LCOE calculated based on these assumptions leads to an average Debt Service Coverage Ratio (DSCR) of over 1.5 in all cases. This cash flow should be sufficient to support the financing assumptions outlined here.

No financial incentives are assumed in the economic model. There are a range of federal and state incentives that may be available for future projects, depending on future legislative rules and funding. Any incentives likely to be taken advantage of by project developers should be taken into account in FIT pricing. For example, projects that begin construction in 2013 would be eligible for federal investment or production tax credits due to new rules passed under the American Tax Payer Relief Act of 2013. SB 1122 states that projects may use state ratepayer funded incentives, but that the CPUC may require that incentive payments are refunded. Major incentives that may be available to SB 1122 compliant projects include, but are not limited to, the following:

- Federal
  - Investment Tax Credit (ITC)
  - Production Tax Credit (PTC)
  - Biomass Crop Assistance Program (BCAP)
  - New Market Tax Credits (NMTC)
  - Accelerated Depreciation
  - U.S. Department of Agriculture and other Federal Grants
- State
  - Electric Program Investment Charge (EPIC) funds
  - Renewable Energy Credits (RECs)
  - AB 32 Greenhouse Gas (GHG) Offset Revenue

In most cases, no values or disposal costs for coproducts (such as fertilizer, biosolids, and ash) outside of their use in the power generation process have been assumed. The exception is in cogeneration at WWTPs with existing digesters. In this case, it is assumed that the heat from the cogeneration unit displaces imported natural gas used for digester heating. For new anaerobic digestion projects regardless of the location, any heat produced is assumed to be used for digester heating, which is credited by assuming no natural gas purchases. Coproduct values or costs can be significant and greatly impact a project’s economics. However, appropriate values are often location specific.

Interconnection costs can vary considerably depending on the location of the project and the desired power delivery point. “Strategically located” projects commensurate interconnection costs are assumed in the analysis. While this makes interconnection a minor factor in the analysis, this will not be the case for all projects. Significantly higher interconnection and transmission costs could push projects into the higher range of the LCOE estimate.

Technology Specific Assumptions

Category 1 Digestion

The main assumptions used in developing the capital and operating cost estimates for the Category 1 biogas units are listed below. Cost estimates were made for both existing anaerobic digesters that are not currently utilizing their biogas or that have excess capacity and new facilities.

- For all facilities, costs were developed for a 3 MW unit. This reflects the largest project possible that would be SB 1122 eligible to take advantage of economy of scale benefits.
- The digestion system consists of two primary digesters and one secondary digester. All new digesters are complete mix with glass-lined steel tanks. Solids residence time is 15 days and feed total solids are 4.5 percent.
- A gas cleaning system is included that removes moisture, H_2S, and siloxanes.
- IC engines equipped with selective catalytic reduction (SCR) for NOx reduction and catalytic oxidation equipment for CO removal were selected for CHP.
- Capital costs include costs associated with digestion (for facilities that do not have digestion), gas cleaning, and CHP.
- O&M costs include power, labor, equipment maintenance for digestion, gas cleaning, and CHP. Taxes, insurance, and administrative fees are not explicitly included since these costs may not be incurred in all projects, specifically those where an operating facility (not necessarily for power generation) is already in place.
- Costs associated with digested solids treatment and disposal was not included.
- Revenues associated with fertilizer sales were not included.
- It is assumed that sufficient heat is recovered from the CHP system for process heating where new digestion units are built (no supplemental heat is needed).
- Tipping fees of $10 to $30/ton are assumed in the new digestion case. A methane yield of 13,300 ft^3 per dry ton and delivered solids content of 30 percent was assumed.

Dairy Cattle Manure (Category 2 Digestion)

The main assumptions used in developing the capital and operating cost estimates for a dairy manure digestion project are listed below. For this cost estimate, the basis was for a complete mix, stand-alone facility at a large flushed freestall dairy consisting of roughly 5,500 head of cattle. The size of the facility is roughly the same as for the Category 1 unit (on a tons per day basis), but the power production is significantly lower due to the lower gas yield for dairy manure relative to food waste.

- Costs were developed for a 1 MW dairy manure digestion facility.
- The digestion system, gas cleaning, and power generation designs follow a design similar to the Category 1 design. While less expensive systems can be developed (such as a covered lagoon), the low gas yield of these units makes them less suitable for power export projects.

- Capital costs include equipment associated with manure pretreatment and storage, digestion, gas cleaning, and CHP.
- O&M costs include power, labor, equipment maintenance for digestion, gas cleaning, and CHP. Taxes, insurance, and administrative fees are not explicitly included since, as with Category 1, these costs may not be incurred if the dairy will incur only marginal changes due to implementation of the energy project.
- Costs associated with digestate treatment and disposal was not included.
- Revenues associated with sales of fertilizer or AB 32 GHG offsets were not included.
- It is assumed that sufficient heat is recovered from the CHP system for process heating. No supplemental heat is needed.
- Feedstock is provided at no cost.

Forest and Agricultural Residues

For small-scale biomass power applications utilizing solid fuels (e.g., forest management byproducts or agricultural residues), it is assumed that the generation facility will employ a gasification system to produce a syngas that may be fired in IC engine generators. While a combustion system (generating steam to drive a turbine) may be feasible, it is assumed that a gasification/engine system is the most cost-effective. In addition, from a commercial perspective, internal combustion engines at this size are common while small scale steam turbines are rare.

To develop capital cost estimates for solid fuel biomass applications, the following assumptions were employed:

- The site where the project is to be located is assumed to be well suited for construction, with the following characteristics:
  - The site is relatively level and clear, with no major excavation and clearing required.
  - Utilities will be available at the site boundary.
- The facility has a net generation capacity of 3 MW. The facility consists of a 75 ton per day gasification system with necessary syngas cleanup equipment and 3- 1 MW IC engines.
- Capital costs associated with balance of plant and Owner's Costs include the following:
  - Site/civil work (including foundations)
  - Feedstock receiving/storage equipment
  - Syngas cleanup
  - Electrical switchgear
  - Facility structures
  - Interconnection to distribution grid (studies and installation of tie-line)
  - Project development (permitting, engineering, financing, legal)
- Heat rate ranges from 15,000 to 18,000 BTU/kWh, depending on the case being evaluated.

- Woody biomass from forest slash or thinning is assumed. The use of shrub biomass may impact the costs.

To develop estimates of non-fuel O&M costs for solid fuel biomass applications, the following assumptions were employed:

- Annual capacity factor of 85 percent. This is assumed to be an average over the life of the project.
- Non-fuel O&M costs include labor costs, administrative costs, major equipment maintenance, consumables, land lease, insurance, and property taxes.
- Major equipment maintenance is conducted under service contracts.
- Annual O&M budget includes no contingency and no allowance for capital expenditures.

Large Distributed Bioenergy

To develop estimates of capital cost for larger scale bioenergy DG projects, the following assumptions were employed:

- Use of a combustion system (e.g., bubbling fluidized bed or stoker boiler) to generate steam that is utilized to drive a steam turbine generator.
- The facility has a net generation capacity of 20 MW. The facility consists of:
    - A nominal 300 ton per day biomass combustion system
    - Necessary air quality control equipment (e.g., SCR for control of nitrogen oxides and an ESP for control of particulate matter)
    - A 20 MW steam turbine generator
- The project site is assumed to be well suited for construction, with site conditions similar to those assumed for the 3 MW unit.
- Heat rate ranges from 12,500 to 14,500 BTU/kWh, depending on the case being evaluated.
- Capital costs and non-fuel O&M costs associated with balance of plant and owner's costs include the cost categories for the 3 MW facility.

ATTACHMENT 2

Overview of the ReMAT pricing mechanism

1.1 Overview of the ReMAT Pricing Mechanism

Pursuant to D.12-05-035, generators interested in participating in the FIT program must meet the program's minimum project viability criteria and then must submit a program participation request (PPR) to the utility. Each utility will establish a ReMAT Queue on a first-come, first-served basis for each product type, based on the time that a generator submits its completed PPR. Every two months, the utility will offer generators a FIT contract, set at the current ReMAT offer price which will remain fixed for the term of the contract, in the order in which generators appear in the ReMAT Queue until the capacity allocation for that period has been subscribed. If a generator declines to accept the offered price, it will still maintain its ReMAT Queue position for future program periods.[44] SCE and PG&E will offer 5 MW for each product type, for each two-month program period. SDG&E will offer 3 MW.[45]

When the revised program launches on November 1, 2013, the utilities will offer a starting ReMAT price of $89.23/MWh for each of the following three product types: peaking as-available; non-peaking as-available; and baseload.[46] Every other month, the ReMAT price will be subject to an adjustment, for each product type (for each utility), based on market subscription levels at the

[44] D.12-05-035, Section 6.4, at 45.

[45] D.13-05-034, Section 4.1, at 12.

[46] D.12-05-035, Section 6.3, at 42-44.

previously offered price during the prior two month period. As a result, the ReMAT price offered for each product type may diverge after the initial two-month period concludes, as the price adjusts to market conditions.

The price adjustment will only be triggered if there are at least five eligible projects from different developers in the ReMAT Queue for a particular product type.[47] If that condition is met, then the ReMAT price will be subject to adjustment based on the following:[48]

<u>**Price Increase:**</u>

If the capacity subscribed at the offered ReMAT price is **less than 20%** of the capacity offered for that program period, then the price will increase the following program period. If these conditions are met for consecutive program periods, the price will increase by the following increments:

- **First adjustment:** $89.23/MWh **+ $4/MWh**
- **Second consecutive adjustment:** $93.23/MWh **+ $8/MWh**
- **Third consecutive adjustment:** $101.23/MWh **+ $12/MWh**
- **Fourth consecutive adjustment:** $113.23/MWh **+ $12/MWh**

The maximum price increase for any period is capped at $12/MWh. Additionally, if the conditions for a price increase are <u>not</u> met during a given program period, then the next time that a price increase is triggered again, the increment of that increase will reset to +$4/MWh.

[47] D.12-05-035, Section 6.4, at 45.

[48] D.13-05-034, Section 4.1, at 12-15.

Price Decrease:

If a sufficient number of generators accept the offered ReMAT price such that offering contracts to all willing generators would result in subscription of 100% of the capacity offered for that program period,[49] then the price will decrease the following program period. If these conditions are met for consecutive program periods, the price will decrease by the following increments:

- **First adjustment:** $89.23/MWh **- $4/MWh**
- **Second consecutive adjustment:** $85.23/MWh **- $8/MWh**
- **Third consecutive adjustment:** $77.23/MWh **- $12/MWh**
- **Fourth consecutive adjustment:** $65.23/MWh **- $12/MWh**

The maximum price decrease for any period is capped at $12/MWh. Additionally, if the conditions for a price decrease are not met during a given program period, then the next time that a price decrease is triggered again, the increment of that decrease will reset to -$4/MWh.

No Price Change:

If for any program period the number of eligible projects from different developers in the ReMAT Queue drops below five, then the price

[49] Note that, pursuant to D.13-05-034, the utility is not obligated to award FIT contracts to generators beyond its monthly capacity allocation (5 MW for SCE and PG&E, and 3 MW for SDG&E). As a result, if the project that is next in the ReMAT Queue indicates that it would accept the offered ReMAT price, but doing so would exceed the utility's capacity allocation for that period, then the utility need not award that contract. The 100% threshold described here for a price decrease would be triggered, and that generator would be required to wait until the next period.

will remain the same and will not adjust. Alternatively, if there are at least five eligible projects from different developers in the ReMAT Queue, but the conditions for a price increase or decrease are not met, then the price will also remain the same.

Under the current FIT Program, the ReMAT pricing mechanism operates independently to determine the market price for each of three product types: peaking, as-available, and baseload.[50] The ReMAT mechanism sets the market price separately for each utility, for each of these three product types.

(END OF ATTACHMENT B)

[50] Section 399.20(d)(2)(C) Provides that the commission shall establish a methodology to determine the market price of electricity . . . in consideration of the following: the value of different electricity products including baseload, peaking, and as-available electricity….