BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	)))))	Rulemaking 15-02-020 (Filed February 26, 2015)

BIOENERGY ASSOCIATION OF CALIFORNIA'S REPLY COMMENTS ON THE DRAFT TARIFF, STANDARD CONTRACT, AND RELATED DOCUMENTS IMPLEMENTING DECISION 14-12-081

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The Bioenergy Association of California (BAC) submits these Reply Comments on the utilities' Draft Tariff, Standard Contract, and Related Documents Implementing Decision 14-12-081. In general, BAC agrees with most of the comments and recommendations made by other parties, with three important exceptions described in Sections B, C and D, below. BAC also shares the serious concern raised by many parties that the utilities' extensive proposed changes to the contract and PPA template were not required by D.14-12-081, do not address issues unique to bioenergy, and would prevent successful implementation of SB 1122.

BAC's Reply Comments focus on the following issues:

A. BAC agrees with numerous parties that:

1. Changes to the ReMAT tariff and contract (PPA Template) should be limited to those changes required by D.14-12-081.

2. The Commission should reject the utilities' proposed changes to forecasting.

3. The utilities must revise their definition of "affiliate" to be consistent with D.13-05-034 and D.14-12-081.

4. The utilities must remove automatic cancellation provisions from the PPA Template, particularly for reasons beyond the seller's control.

5. The PPA Template should allow more than two contract change in a ten- to twenty-year contract.

6. The transfer of greenhouse gas reductions should not include reductions greater than carbon neutrality.

7. If the requirement for Guaranteed Energy Production is not removed, then changes should be made to the penalty provisions related to GEP.

8. The proposed documents should be revised to clarify that megawatts are not subscribed until electricity is delivered after the Commercial Operation Date.

9. The proposed tariff/contract should clarify that BioMAT projects may also receive EPIC and other grant funds.

B. BAC agrees with Harvest Power that the requirement for "developer experience" should be modified, but recommends an alternative definition of "developer experience."

C. BAC agrees in part with AECA's recommendation to revise the daisy chaining restriction, but recommends an alternative change and only if applied to all sectors, not just the dairy sector.

D. BAC opposes AECA's suggestion to allow dairy projects to switch from Category 2 to Category 1 after beginning operation.

1. Changes to the ReMAT tariff and contract (PPA Template) should be limited to those changes required by D.14-12-081.

BAC agrees with numerous parties that commented on the extensive changes proposed by the utilities that were not required by D.14-12-081 and that would prevent successful implementation of SB 1122.[1] As Harvest Power noted in its Comments, D. 14-12-081 requires that the proposed tariff, PPA Template and other documents "retain the terms previously approved for the Renewable Market Adjusting Tariff ("ReMAT") and its standard contracts, except to the extent necessary to adjust to the characteristics of bioenergy facilities and the requirements of SB 1122."[2] Placer County Air Pollution Control District (PCAPCD) summarizes the issue well by stating that the proposed tariff and contract should not go beyond the Decision and be used to make new policy.[3]

The Commission made clear in D.14-12-081 that proposed changes must be "evaluate[d]…according to the standard of whether they are necessary to allow the mandates of SB 1122 to be met" and that the Commission would reject changes that it determined were not "necessary in order to facilitate the integration of the SB 1122 mandate into the RPS FiT."[4] As Phoenix Energy commented, the utilities have proposed numerous changes that were not required to meet the mandates of SB 1122 and that, taken together, would seriously undermine SB 1122.[5]

The utilities proposed extensive changes that were not called for by D.14-12-081 and would, in many cases, undermine SB 1122. Although the proposed changes are far too numerous to identify in Reply Comments, we urge the Commission to reject all changes that were not required by D.14-12-081. In particular, we agree with the comments of Phoenix Energy and Harvest Power that the Commission should strike the following proposed changes to the PPA Template that were not required by D.14-12-081 and would undermine SB 1122:

> **a. Proposed Standard BioMAT Contract Section 2.6.2:** The proposed reduction in the quantity of energy that the Buyer is obligated to buy in any given

[1] Comments of Harvest Power at pages 3 and 13-14; Comments of Phoenix Energy at pages 9-10; Comments of Placer County Air Pollution Control District (PCAPCD) at page 1.
[2] Comments of Harvest Power at page 3.
[3] Comments of PCAPCD at page 1.
[4] D. 14-12-081 at pages 67 and 69.
[5] Comments of Phoenix Energy at pages 9-10.

Settlement Interval, from 110% of the Contract Capacity under ReMAT to 100% proposed for the BioMAT. This provision also proposes a new obligation under BioMAT for the Seller to pay the Buyer for any energy delivered in excess of the Contract Capacity when real-time market prices at the point of injection are negative; no such obligation exists under the ReMAT.

b. Proposed Standard BioMAT Contract Section 2.6.3: The proposed reduction in the quantity of delivered energy excess paid the contract price, and the proposed change of price paid excess energy from 75% of contract price to wholesale market price are impermissible departures from the ReMAT.[6]

In addition, BAC supports Harvest Power's recommendation to remove the following changes proposed by the utilities:

c. Proposed Standard BioMAT Contract Section 2.7.4: The proposed cap of 105% of all Time of Delivery ("TOD") adjustments; no such cap exists in the ReMAT.

d. Proposed Standard BioMAT Contract Section 5.8.5: This provision requires the installation and maintenance of communications and remote operation equipment; no such obligation exists under the ReMAT.

e. Proposed Standard BioMAT Contract Section 5.17: This provision requires the bioenergy facility to pay for an independent engineer report on the safe construction and operation of the facility; no such obligation exists under the ReMAT.

f. Proposed Standard BioMAT Contract Section 13.9.1: The proposed extension of time for the IOUs to terminate a contract based on interconnection issues, beyond the time allowed under the ReMAT.[7]

2. The Commission should reject the utilities' many proposed changes to forecasting that were not required by D.14-12-081.

The Utilities have proposed extensive and inconsistent changes to the forecasting provisions in the ReMAT which were not required by D.14-12-081 and which will impede its implementation.

[6] Comments of Harvest Power at page 12; Comments of Phoenix Energy at pages 8 and 10.
[7] Comments of Harvest Power at pages 12-13.

While the utilities' proposed forecasting changes were extensive, a few are particularly egregious and highlighted below.

a. PPA Template Section 13.2.1.

The utilities proposed the following, significant changes to this section without explanation:

> "Determining Seller's Liability for Forecasting Penalties. If in any hour of any month in the Delivery Term Seller fails to comply with the requirements in Appendix D of this Agreement with respect to Seller's ~~Available Capacity~~Expected Generation Output forecasting, and/or the sum of Energy Deviations for each of the ~~six~~ Settlement Intervals in that hour exceed the Performance Tolerance Band described in Section ~~15.2.2,~~14.2.2, then Seller is liable for a forecasting penalty ("Forecasting Penalty") equal to one hundred fifty percent (150%) of the Contract Price for each ~~kWh~~MWh of electric Energy Deviation, or any portion thereof, in that hour."

The utilities' addition of the word "or" in the fourth line means that sellers would be subject to penalties whenever their output varied by more than 3% of what was forecast (the Performance Tolerance Band). Based on BAC members' experience, engine performance or station-load can vary frequently. They may exceed this bandwidth by small amounts most or all of the time and may exceed it by large amounts periodically. This is especially likely in the early years for project developers. Since the penalty is 150 percent of the variance between what was forecast and what was delivered, it can add up substantially, putting the entire SB 1122 program at risk. It would put many projects at risk of not getting financing and or losing their profit margin once built, and thereby risking project failures.

In the current ReMAT contract, the penalties are for failing to provide a Day Ahead forecast, which is a reasonable requirement and should be the same for the BioMAT. By adding the word "or," the utilities are inserting a fundamental shift in the burden on sellers that is not called for by SB 1122 and is substantially different from the ReMAT. The Bio-MAT contract should not add burdens to the Re-MAT unless justified by the utilities for reasons that are specific to small-scale bioenergy projects.

<u>Recommendation:</u>

Strike all of the proposed edits to this section, especially the proposed addition of the word “or” in the fourth line. BAC also urges the Commission to reject PG&E’s proposed change from "Available Capacity" to "Expected Generation Output," which is not consistent with SCE’s language and is not required by D.14-12-081.

b. Appendix D of the PPA Template

The utilities have proposed extensive changes to Appendix D that were not required by D.14-12-081, were not consistent between the three utilities, and were not justified. Many of the changes and inconsistencies would undermine D.14-12-081 by increasing the burdens on developers and by distorting the bioenergy market.

1. Proposed changes to Sections C3 and C4

The utilities proposed changes to Sections C3 and C4 would significantly expand the seller’s obligation to notify the utility of Day Ahead and Hour Ahead changes. In the ReMAT contract, sellers are required to notify the utility of changes greater than 1 MW. The utilities’ proposed changes to Sections C3 and C4 would eliminate the 1 MW threshold and requires sellers to notify the utility about all forecast changes regardless of how small the change or whether it would impact the utility at all. D.14-12-081 did not require this change, which would significantly increase the reporting burden on sellers. The utilities’ proposed language would also change the term “Available Capacity” to “Expected Generation” without explanation of the reason or the impact of this change.

<u>Recommendation:</u>

The Commission should strike all of the utilities’ proposed changes to Sections C3 and C4.

2. Additional changes in SCE’s Appendix D

SCE has proposed additional changes to its Section F.2.7.1.3 of Appendix D that greatly expand the forecasting requirements and risks to BioMAT developers, requiring sellers to report any changes from the Forecast within 20 minutes after energy delivery and adding a “Best Efforts” standard. Aside from the vagueness of the term “best

efforts," this added requirement increases burdens on developers without justification. If allowed, it will also distort the statewide bioenergy market by increasing burdens and risks in SCE's territory compared to the other utilities' service territories.

Recommendation:

The Commission should require all three utilities to use the ReMAT Appendix D except for changes needed by all three utilities to adjust for site host load.

3. The utilities must revise their definition of "affiliate" to be consistent with D.13-05-034 and D.14-12-081.

BAC agrees with the comments of the PCAPCD that the utilities definition of "affiliate" must be revised to be consistent with D.13-05-034 and D.14-12-081.[8] The utilities erroneously add the phrase "or any ownership interest" to the definition of "affiliate" for purposes of determining the minimum number of bidders in the queue.[9] The phrase should be struck for two important reasons. First, it goes beyond the requirements of D.13-05-034 and D.14-12-081. Second, it will dampen or prevent investment in SB 1122 projects and could prevent Categories 2 and 3 of SB 1122 from meeting the minimum bidder requirements.

As PCAPCD noted:

> [T]he "any ownership" language will restrict program functionality because projects could be excluded from triggering price increases when a project proponent or its affiliate has even an ancillary, minimal ownership interest in a second project. Minimal cross-over interests in companies does not appreciably increase risks of price collusion or program corruption because information sharing and decision making authority are not at play with fractional interest ownerships or investors. This departure from Commission direction will only serve to postpone price increases that are absolutely critical for the program's success.[10]

[8] Comments of PCAPCD at page 2.

[9] Section H.a. of PG&E's ReMAT Tariff.
http://www.pge.com/includes/docs/pdfs/b2b/energysupply/wholesaleelectricsuppliersolicitation/standardcontractsforpurchase/ReMAT_Tariff.pdf.

[10] Id at pages 1-2.

BAC agrees with the conclusions in the report attached to Placer County Air Pollution Control District's Comments, which summarizes the results of interviews with multiple prospective investors in small-scale bioenergy projects who all agree that the expanded definition of affiliate proposed by the utilities would prevent investment in SB 1122 eligible projects and therefore would prevent successful program implementation.[11]

Recommendation:

The Commission should strike the phrase "or any ownership interest" from Section Hof the utilities' proposed tariff.

4. The utilities must remove automatic cancellation provisions from the PPA Template, particularly for reasons beyond the seller's control.

BAC agrees with the comments of PCAPCD and Phoenix Energy that Commission should delete or revise the utilities' proposed auto-cancellation provisions, particularly when cancellation would occur for reasons beyond seller's control.[12] As both Phoenix and PCAPCD note, these provisions would stifle or prevent investment in BioMAT projects because the seller, and therefore the investor, would bear risks outside their control. This is not a commercially reasonable transfer of risk and would, under the Uniform Commercial Code, be considered an "unconscionable contract"[13] where one party bears all the risk for factors that either the other party controls (interconnection) or are beyond either party's control (force majeure).

While BAC agrees with the concerns raised by Phoenix and PCAPCD, BAC recommends the following changes to correct the auto-cancellation provisions:

a. Amend Section 1.1.2.2 as follows:

Subject to Section 1.1.4, if Seller has taken all commercially reasonable actions (including but not limited to Seller's timely filing of required documents and payment of all applicable fees, and completion of all electric System Upgrades

[11] Id. and Attachment to PCAPCD's Comments.

[12] Phoenix Energy Comments at pages 4-6; PCAPCD Comments at page 5.

[13] Uniform Commercial Code section 2-302. In the Official Comment, the UCC states that the "basic test is whether, in the light of the general commercial background and the commercial needs of the particular trade or case, the clauses involved are so one-sided as to be unconscionable under the circumstances existing at the time of the making of the contract."

needed, if any) to have the Project physically interconnected to the Transmission/Distribution Owner's distribution system, but fails to secure any necessary commitments from CAISO or the Transmission/Distribution Owner for such interconnection and upgrades due to delays beyond Seller's reasonable control ("Transmission Delay"), then the Guaranteed Commercial Operation Date shall be extended ~~six (6) months~~ equal to the Transmission Delay;

b. Amend Section 1.1.2.3 as follows:

In the event of Force Majeure or delay caused by Buyer, without regard to Transmission Delay or Permitting Delay, ("Force Majeure Delay")~~,~~ the Guaranteed Commercial Operation Date shall be extended on a day-to-day basis for a cumulative period equal to the delay caused by Force Majeure or by the Buyer; ~~of not more than six (6) months~~; provided that Seller complies with Section 10~~; or~~

c. Delete subsection (f) of the Force Majeure provision in the BioMAT PPA Definition Section:

~~(f) Any delay in providing, or cancellation of, interconnection service by a Transmission/Distribution Owner or the CAISO, except to the extent such delay or cancellation is the result of a force majeure claimed by the Transmission/Distribution Owner or the CAISO.~~

d. Amend Section13.3 as follows:

Except as otherwise set forth in Section 13.2.2.14 above, if an Event of Default has occurred, the non-defaulting Party shall have the right to: (a) send Notice, designating a day, no earlier than five (5) days after such Notice and no later than twenty (20) days after such Notice, as an early termination date of this Agreement ("Early Termination Date"); (b) accelerate all amounts owing between the Parties; (c) terminate this Agreement and end the Delivery Term effective as of the Early Termination Date; (d) collection any Settlement Amount under Section 13.5; and (e) if the defaulting party is the Seller and Buyer terminates the Agreement prior to the start of the Commercial Operation Date, Buyer shall have the right to retain (or if the Collateral Requirement has not been provided, collect) the entire Collateral Requirement. Defaulting Party shall have the right to contest the Early Termination Date consistent with Section 18.

5. The PPA Template should allow greater flexibility in the first two years and additional changes in a ten- to twenty-year contract.

BAC agrees with the comments of Harvest Power, Phoenix Energy and PCAPCD that BioMAT contracts should allow more flexibility in contract quantity for the first two years of a project and one additional change to contract quantity for each additional five years of the contract.[14] Harvest Power explained the need for greater flexibility in the first two years of a project:

> "Bioenergy plants typically experience considerable variability in output in the first year or two of operation. In addition to the usual shakedown issues typical of conventional fossil-fueled facilities, bioenergy facilities often require considerable adjustment and adaptation to their feedstocks, which, as discussed above, are both highly localized and variable, and which do not have the benefit of reasonably predictable performance bands based on historical meteorological data that is available to wind and solar facilities."[15]

PCAPCD also explains the need for greater flexibility in the first two years:

> "the IOU template offered to allow for a contract quantity reduction within the first year of the contract, but due to the ramp up needs of many bioenergy technologies and such technologies relatively new use here in California, we highly recommend that period of time be two years. Also, the performance periods are two years for purposes of calculating quantity and for other purposes, and therefore it makes more reasonable sense to allow for that period of time."[16]

Both Harvest and Phoenix also explain the rationale for allowing an additional change to contract quantity at least once every five years for 10 to 20 year contracts. BAC agrees with both parties that given the immature stage of small-scale bioenergy development and the variability of both the feedstock and the regulatory environment, it is not reasonable to ask seller's to commit to fixed delivery quantities over a 20-year period.[17]

Recommendation:

BAC recommends revising the BioMAT contract section 2.2 as follows:

> Contract Quantity. The "Contract Quantity" during each Contract Year is the amount set forth in the applicable Contract Year in the "Delivery Term Contract Quantity Schedule", set forth in the Cover Sheet, which amount is net of Station Use, and, for Excess Sale arrangements, Site Host Load. Seller shall have the

[14] Harvest Power Comments on pages 7-9; Phoenix Energy Comments at page 9; PCAPCD Comments at page 6.
[15] Harvest Power Comments at pages 7-8.
[16] PCAPCD Comments at pages 6-7.
[17] Harvest Power Comments at page 9; Phoenix Energy Comments at page 9.

option to update ~~decrease the Contract Quantity for any or all Contract Years of~~ the Delivery Contract Quantity Schedule ~~one (1) time~~ if the Contract Capacity is adjusted based on the Demonstrated Contract Capacity within ten (10) Business Days of Buyer's Notice of such adjustment to the Contract Capacity or the date of the Engineer Report, as applicable. Updates to the Delivery Contract Quantity Schedule may occur two (2) times for a ten (10) year contract, three (3) times for a fifteen (15) year contract, and four (4) times for a twenty (20) year contract. Additionally, Seller may provide Notice to Buyer during Contract Year 1 or Contract Year 2 of the Delivery Term to request a one (1) time decrease to the Contract Quantity for any or all Contract Years in the Delivery Term Contract Quantity Schedule. Upon Buyer's approval, the adjusted amounts shall thereafter be the applicable Delivery Term Contract Quantity Schedule.

6. The transfer of greenhouse gas reductions should not include reductions greater than carbon neutrality.

BAC agrees with all parties that addressed the issue of Green Attributes, that the utilities should not be entitled to the benefit of carbon reductions that go beyond carbon neutrality or other Green Attributes that are not related to power generation.[18] In addition to BAC, the four parties that addressed the issue all agreed that the Green Attributes that are transferred to the utility buyer are only those attributes related to power generation and to reducing carbon emissions to zero.[19]

The Commission recognized the need to reconsider this issue when it adopted the ReMAT definition of Green Attributes in D.13-11-024. The Commission should revise the definition of Green Attributes for several reasons.

First, the definition that the Commission adopted in D.13-11-024 was taken from AB 2196, which was focused on pipeline biomethane rather than electricity generation. As Assemblyman Gatto, author of AB 1900, which was double-joined with AB 2196, noted in his letter to the Commission on the Proposed Decision on SB 1122:

> "SB 1122 promotes bioenergy in the electricity sector, just as AB 1900 is intended to promote pipeline biogas. The Proposed Decision on SB 1122 conflates the natural gas and electricity sectors, which have very different legal, regulatory and technical requirements. I am particularly concerned that the

[18] Comments of Agricultural Energy Consumers Association (AECA); Comments of PCAPCD at page 4; Comments of Green Power Institute at pages 1-4 ; Comments of Harvest Power at pages 14-15.
[19] Id.

> Proposed Decision on SB 1122 incorrectly applies the definition of biogas from AB 1900, which is focused on pipeline injection and was not intended to affect electricity generated through biogas under SB 1122."[20]

The Commission implicitly acknowledged that AB 1900 and the RPS are different regulatory frameworks when it changed the Proposed Decision's definition of "biogas" from the one adopted pursuant to AB 1900 (related to pipeline biomethane) to the one adopted by the California Energy Commission pursuant to the RPS. The same reasoning applies to the definition of Green Attributes and why the Commission should not use a definition adopted in AB 2196 for purposes of pipeline biomethane.

Second, including non-power related attributes would deny project developers and owners the financial benefits of carbon reductions that go beyond carbon neutrality, such as carbon offsets that are available for methane destruction that is not required by law. This would deny one of the benefits of bioenergy that SB 1122 was intended to promote, which is the significant reductions of greenhouse gas emissions – including reductions beyond carbon neutrality – that some biomethane projects can provide. It would also make SB 1122 projects more expensive because it would deny the financial benefit of carbon offset credits or other incentives for greenhouse gas reductions beyond carbon neutrality. As the *Final Consultant's Report on Small-Scale Bioenergy*, prepared for this Commission in 2013, noted in its findings, AB 32 credits could greatly influence the cost of some eligible projects.[21]

Third, this contradicts the first part of the definition of Green Attributes adopted in D.13-11-024, which provides:

> Section 3.1.1.1 For all electric generation using biomethane as fuel, Seller shall transfer to Buyer sufficient renewable and environmental attributes of biomethane production and capture to ensure that there are zero (0) net emissions associated with the production of electricity from the generating facility using the biomethane. [emphasis added]

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[20] Letter from Assemblyman Mike Gatto to Commisisoner Carla Peterman, dated November 24, 2014, and submitted to parties in R.11-05-005.

[21] *Final Consultant Report: Small Scale Bioenergy: Resource Potential, Costs, And Feed In Tariff Implementation Assessment*, prepared by Black & Veatch, October 31, 2013, at page 1-5 and Table 1-2. Included as Attachment 1 to the Final Staff Proposal on SB 1122 Implementation, filed in R.11-05-005 on November 19, 2013.

In other words, the Commission assumed that value of carbon reductions that would be transferred to utilities would be equivalent to zero net carbon emissions, not any reductions that go beyond zero (carbon negative projects).

Fourth, this contradicts the utilities' own accounting of greenhouse gas reductions under the RPS. The utilities each use an avoided emissions factor to calculate greenhouse gas emissions that assumes the greenhouse gas reductions are from avoided fossil fuel use. The utilities' emissions factors assume that RPS power is carbon neutral and therefore attribute greenhouse gas reductions to each MW of RPS power equivalent to the reduction in emissions from fossil fuel power. As PG&E explains in their fact sheet on the greenhouse gas emissions factor:

> "Electricity generated from fossil fuels such as natural gas or coal emit CO_2 while other sources of electricity such as hydropower, wind, solar, and nuclear power are considered to be carbon-free."[22] [emphasis added]

In other words, the utilities themselves assume that RPS eligible power is carbon neutral. Transferring the right to, and benefit from, carbon reductions that exceed carbon neutrality would contradict the utilities' own calculations of the greenhouse gas benefits attributable to the RPS and, therefore, SB 1122.

Finally, there is no justification for transferring the Green Attributes of bioenergy that are unrelated to power production. As both the Green Power Institute and PCAPCD stated in their comments, Renewable Energy Credits only apply to power generation and the benefits of generating renewable power in place of fossil fuel power.[23] Nothing in the RPS statutes or program rules has quantified or attempted to transfer to the utilities the upstream benefits of forest fuel treatment and collection, the value of recycling credits in the solid waste sector, the benefits of collecting dairy waste or other benefits associated with the fuel collection and treatment, which may be required or done for other purposes in addition to preparing the feedstock for SB 1122.

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[22] "Greenhouse Gas Emission Factors: Guidance for PG&E Customers," April 2013. Available at: http://www.pge.com/includes/docs/pdfs/shared/environment/calculator/pge_ghg_emission_factor_info_sheet.pdf.

[23] Comments of PCAPCD at page 4; Comments of Green Power Institute.

Recommendation:

BAC recommends revising Section 3.1.1.2 as follows:

> For all electric generation using biomethane as fuel, neither Buyer nor Seller may make a marketing, regulatory, or retail claim that asserts that a procurement contract to which that entity was a party resulted, or will result, in greenhouse gas reductions related to the destruction of methane if the capture and destruction is required by Law. ~~If the capture and destruction of the biomethane is not required by Law, neither Buyer nor Seller may make a marketing, regulatory, or retail claim that asserts that a procurement contract to which that entity was a party resulted, or will result, in greenhouse gas reductions related to the destruction of methane, unless the environmental attributes associated with the capture and destruction of the biomethane pursuant to that contract are transferred to Buyer and retired on behalf of the retail customers consuming the electricity associated with the use of that biomethane, or unless Seller's procurement contract with the source of biomethane prohibits the source of biomethane from separately marketing the environmental attributes associated with the capture and destruction of the biomethane sold pursuant to that contract, and such attributes have been retired.~~

7. If the requirement for Guaranteed Energy Production is not removed, then changes should be made to related penalty provisions.

BAC supports the comments of Phoenix Energy and Harvest Power that the requirement for Guaranteed Energy Production (GEP) should be removed.[24] BAC further agrees with Phoenix Energy that GEP should be removed for all utilities, not just Southern California Edison, and that if it is not removed, it should be revised to reflect the pre-commercial and variable nature of small-scale bioenergy production.[25] BAC agrees with Phoenix on the following points:

- GEP represents a significant risk, and therefore cost, to small-scale bioenergy production;
- Removing GEP for just one utility – SCE – would create significant market distortion;
- GEP should be removed from all three utilities' contracts or should not be removed at all; and

[24] Comments of Harvest Power at page 7; Comments of Phoenix Energy at pages 6-8.
[25] Comments of Phoenix Energy at pages 6-8.

- If GEP is not removed, it should be revised to reflect the pre-commercial and variable nature of small-scale bioenergy development.[26]

Recommendation:

BAC urges the Commission to delete Section 11 of the utilities' proposed PPA Template for all three utilities. Alternatively, we recommend revising Section 11 to allow for 170 percent fluctuation.

8. The proposed documents should be revised to clarify that megawatts are not subscribed until the Commercial Operation Date.

BAC agrees with the comments of PCAPCD and AECA that MW should not be considered subscribed until after the Commercial Operation Date.[27] As PCAPCD explained, some of the utilities' proposed tariff language could be interpreted to mean that the utility can claim credit for megawatts when a contract is executed or when a facility is tested, but before the Commercial Operation Date (or the utility is actually purchasing the power).[28] BAC supports the recommendations of PCAPCD to clarify that megawatts are not allocated until the Commercial Operation Date.

Recommendation:

Delete the following from the second sentence of Section E (1):

> The Applicant will submit a PPR for a Project to the IOU in whose territory the Project is located. ~~, and execution of a Bio-MAT PPA will result in the capacity of that Project being attributed to the capacity target for the IOU with which the Bio-MAT PPA was executed~~.

Amend Section G Capacity Allocation, #4, to state that:

> Any capacity associated with Bio-MAT PPAs that are terminated prior to the delivery of any electricity <u>after the Commercial Operation Date</u> to [PG&E; SCE; SDG&E] will be allocated by [PG&E; SCE; SDG&E] to the Fuel Resource Category corresponding to the Fuel Resource Category of the terminated Bio-MAT PPA <u>and will not be attributed to the total capacity target for the IOU with</u>

[26] Id.
[27] Comments of PCAPCD at page 3; Comments of AECA at pages 4-5.
[28] Comments of PCAPCD at page 3.

which the PPA was initially executed. Any capacity associated with Bio-MAT PPAs that are terminated after the delivery of any electricity to [PG&E; SCE; SDG&E] will not be re-allocated, and will result in the capacity of that project being attributed to the capacity target for the IOU with which the BioMat PPA was executed.

9. The proposed PPA Template should not exclude EPIC and other grant funds.

BAC agrees with the AECA that the proposed PPA Template should be clarified to allow BioMAT projects to receive EPIC (Electricity Program Investment Charge) and other grants intended to reduce the costs of BioMAT projects to ratepayers.[29] As BAC noted in its opening Comments, this Commission required 20 percent of EPIC's Technology Demonstration and Deployment fund to be allocated to bioenergy.[30] The California Energy Commission, in carrying out that requirement, stated explicitly in Program Opportunity Notice 14-305 that it was intended to meet state laws including SB 1122.[31]

Recommendation:

BAC recommends revising Section 4.3.1 of the Utilities' proposed PPA Template to ensure that it does not prohibit projects from receiving EPIC grants by striking the following language:

> "Seller has not participated in the Self-Generation Incentive Program (as defined in CPUC Decision 01-03-073) ~~and/or other similar California ratepayer subsidized program relating to energy production~~ or rebated capacity costs with respect to the Facility and Seller does not maintain a Program Participation Request for the Project in the Renewable Market Adjusting Tariff program (as established by CPUC Decision 13-05-034)."

[29] Comments of AECA at page 9.

[30] Bioenergy Association Of California's Comments On The Draft Tariff, Standard Contract, And Related Documents Implementing Decision 14-12-081, at pages 14-15.

[31] California Energy Commission, PON 14-305, pp. 4-5. Available at: http://www.energy.ca.gov/contracts/PON-14-305/.

B. BAC agrees with Harvest Power that the requirement for "developer experience" should be modified, but recommends an alternative definition of "developer experience."

BAC agrees with Harvest Power that the requirement for "developer experience" should be modified since the growth of this new industry requires some flexibility.[32] BAC also agrees that some amount of developer failure is to be expected in a nascent, pre-commercial industry.[33] BAC is more concerned, however, with the need to stimulate robust market competition and, even more fundamentally, to ensure there will be enough market participants to satisfy the minimum bidder requirements of the BioMAT given the very small number of market participants in the small-scale bioenergy market.

BAC agrees, therefore, with the first part of Harvest Power's proposed definition of "developer experience" to consider all members of the development team in assessing whether a project applicant has sufficient experience. BAC strongly opposes the second part of Harvest Power's proposed definition, however, as it would unnecessarily limit potential market participants, including developers that have received EPIC grants to demonstrate bioenergy technologies, smaller public wastewater agencies and others that have developed pilot scale and pre-commercial projects and are now ready to demonstrate and deploy their technologies at a larger scale.

Both the definitions of "developer experience" in the utilities proposed tariff and Harvest Power's proposed definition would prevent developers that have built successful projects under 1 MW from participating in SB 1122 with a project that is larger than 1 MW. Even if a project developer has successfully developed a 750 kw project using the same technology, that developer would not be allowed to bid into SB 1122 with a 1.2 or 1.5 MW project based on the definition of "developer experience" proposed by Harvest and the utilities. Similarly, a developer that has successfully built and operated a 750kw project would be prevented from bidding into SB 1122 with a 1.5 MW project that uses

[32] Comments of Harvest Power at page 10.
[33] Id.

two parallel 750 kw facilities – exactly the same size and technology that the developer has already built and operated.

This means that implementation of SB 1122 will require far more smaller projects (less than 1 MW) and there will be very few market participants that can bid in with projects between 1-3 MW, reducing competition and increasing the costs to implement the program substantially.

BAC recommends, therefore, removing the size restriction in the definition of "developer experience" as unduly limiting competition in this nascent market.

Recommendation:

BAC recommends revising Section 7 of the utilities' Proposed Tariff as follows:

> Developer Experience: The Applicant must provide to [PG&E, SCE, or SDG&E] ~~PG&E~~ an attestation that at least one member of its development team has: (a) completed the development of at least one project of similar technology ~~and capacity~~; ~~or~~ and (b) experience with interconnection of an electric generator of similar technology to the grid. For the purposes of this paragraph, a "member of the development team" means an active participant who is responsible for the engineering design, construction, or operation of the Project. ~~begun construction of at least one other bioenergy project of similar technology and capacity. A project less than 1 MW will be deemed to be similar capacity to a Project up to 1 MW. A project between 1 MW to 3 MW will be deemed to be a similar capacity to a Project up to 3 MW. For example, for a 3 MW Project, a project of similar capacity cannot be smaller than 1 MW.~~

C. BAC agrees in part with AECA's recommendation to revise the daisy chaining restriction, but recommends an alternative change to the current requirement and only if applied to all sectors, not just dairy.

BAC agrees with AECA that there may be situations where multiple exporting projects may be co-located or located on adjoining properties.[34] Allowing BioMAT projects that combine feedstock from different locations, such as two or more dairy or agricultural operations, to combine generating facilities – so long as the total exporting capacity

[34] Comments of AECA at page 3.

does not exceed 3 MW – should be allowed under the BioMAT without violating the daisy chaining restriction. BAC agrees with AECA that co-locating projects up to 3 MW of exporting capacity should be allowed, even if the projects are separately owned or on adjoining properties. As AECA notes in its Comments:

> Aggregating and co-locating dairy bioenergy projects being developed by similar and potentially overlapping teams and investors, will create economies and efficiencies that will lead to lower prices and related ratepayer benefits.[35]

BAC disagrees, however, that this benefit should only be allowed for dairy operations. It would be equally valuable for Category 1, Category 2 (other agricultural), and Category 3 projects that are eligible for the BioMAT.

In addition, the use of other renewable or fossil generation on the same site should not count toward the 3 MW limit for total bioenergy production. For instance, Inland Empire Utilities Agency, a BAC member, has both solar and biogas production onsite. Its solar generating capacity should not count toward the 3 MW limit under the BioMAT.

Recommendation:

BAC recommends amending AECA's proposed revision to the utilities' proposed tariff by removing the word "dairy" from the phrase added by AECA. The revised section would provide:

> D.8. Daisy Chaining: The Applicant must provide to [PG&E; SCE; SDG&E] an attestation that the Project is the only exporting project being developed or owned or controlled by the Applicant on any single or contiguous pieces of property; provided, however, that the co-location of multiple exporting ~~dairy~~ bioenergy Projects being developed or owned or controlled by one or more entities in addition to the Applicant, including Applicant's Affiliates, on any single or contiguous pieces of property, up to a maximum of 3 MW, is allowed. [PG&E; SCE; SDG&E] may, in its sole discretion, determine that the Applicant does not satisfy this Eligibility Criteria if the Project appears to be part of an installation larger than 3 MW in the same general location that has been or is being developed by the Applicant or Applicant's Affiliates. Such a determination shall be subject to review by the CPUC's Energy Division upon request by the Applicant.

[35] Id.

D. BAC opposes AECA's suggestion to allow dairy projects to switch from Category 2 to Category 1 after the project has begun operation.

BAC strongly opposes the recommendation of AECA to allow dairy projects to bid in to Category 2 and then later to switch to Category 1.[36] AECA, along with BAC, urged the Commission to adopt a very strict definition of dairy projects – requiring 100 percent dairy waste – to distinguish dairy projects (Category 2) from co-digestion (Category 1).

This was, and is, important to prevent projects from "fuel switching," as AECA described it, and to provide clear delineations between the different categories of SB 1122 for accounting and other purposes.[37] As AECA noted in its Comments on the SB 1122 Staff Proposal:

> "Toward this end, the agricultural community wants to avoid the historical pitfalls associated with existing large-scale biomass operations which have widely overlooked agricultural waste streams when cheaper fuel sources are available. 'Fuel shopping' has left agricultural biomass resources high and dry when cheaper urban wood waste is widely available."[38]

In addition to the risk of developers "fuel switching," allowing dairy projects to begin in Category 2 and later switch to Category 1 would give those projects unfair competitive advantages over other co-digestion and Category 1 projects. Dairy projects in Category 2 have the benefits of a prices screen and a lower minimum number of bidders, both of which BAC suggested to ensure that dairy projects can participate in the BioMAT program. In addition, pure dairy projects (in Category 2) have much easier and faster permitting requirements than co-digestion projects, which AECA acknowledged in its Comments when it stated that "In practice, it can take a significant amount of time – one year or more – to obtain the rights to use multiple feedstocks."[39] AECA also noted this in its comments on the SB 1122 Staff Proposal, stating that co-digestion projects are regulated by the Central Valley Regional Water Quality Control Board, consistent with

[36] AECA Comments at page 10.
[37] Comments of AECA on the SB 1122 Staff Proposal, filed December 20, 2013, at pages 3 and 7.
[38] Comments of AECA on the SB 1122 Staff Proposal at page 3.
[39] Comments of AECA at page 10.

the Dairy Manure Digester and Co-Digester Facilities Final Program Environmental Impact Report (EIR) that state regulators completed in 2010.[40]

AECA claims that these permitting requirements for co-digestion projects could delay dairy projects from participating in SB 1122, which is not at all the case. The permitting delays that AECA cited would not affect Category 2 dairy projects that are using only dairy waste. They would only affect co-digestion projects in Category 1.
Allowing dairy projects to begin in Category 2, with the advantages of a price screen and reduced permitting requirements, and then to switch to Category 1 would not only give those projects an unfair competitive advantage but would complicate or thwart the Legislature's desire for 250 MW of bioenergy procurement. Once a dairy project has reached its Commercial Operation Date in Category 2, the utility will count those MW toward their total obligation under SB 1122. If that same project is allowed later to switch to Category 1, then the MW will be counted again in Category 1. In other words, by allowing projects to switch from one feedstock category to another, the program would be double-counting the MW.
The Commission should not allow projects to switch from one feedstock category of SB 1122 to another after they have bid into the queue or begun operation.

Recommendation:
The Commission should reject AECA's proposal to allow dairy projects to switch from Category 2 to Category 1 after they have bid into the program and begun operation.

CONCLUSION:

BAC urges the Commission to reject the extensive changes that the utilities have proposed to the BioMAT tariff and contracts that were not required by D.14-12-081. The extensive changes would thwart the implementation of the BioMAT program and contradict the Commission's direction to make only those changes necessary to

[40] Id at page 10.

implement D.14-12-081. BAC urges the Commission to allow only those changes necessary to implement SB 1122, as outlined above, and to only allow changes that are consistent between utilities and between feedstock types so as not to distort the bioenergy market or give one utility or sector unfair advantages over the others.

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Respectfully submitted,

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VERIFICATION

I am a representative of the non-profit organization herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and, as to those matters, I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 16th of March, 2015, in Kensington, California.

/s/ Julia A. Levin

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