STATE OF CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

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

COMMENTS OF THE UTILITY REFORM NETWORK ON PROPOSED CHANGES TO THE RENEWABLES PORTFOLIO STANDARD ELIGIBILITY GUIDEBOOK

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Lower bills. Livable planet.

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COMMENTS OF THE UTILITY REFORM NETWORK ON PROPOSED CHANGES TO THE RENEWABLES PORTFOLIO STANDARD ELIGIBILITY GUIDEBOOK

In response to the March 14, 2013 workshop notification, The Utility Reform Network (TURN) submits these comments on proposed revisions to the Renewables Portfolio Standard (RPS) Eligibility Guidebook.

I. PIPELINE BIOMETHANE ELIGIBILITY

The draft Guidebooks include new rules governing the eligibility of pipeline biomethane based on the requirements of AB 2196 (Chesbro 2012). TURN does not have any concerns about the rules for biomethane used by an onsite generating facility or delivered through a dedicated pipeline. For transactions involving a "common carrier" pipeline, TURN's concerns are explained in the following sections.

A. Requirements for biomethane transactions executed after March 28, 2012 or for transactions not previously reported to the Energy Commission

For any transactions executed after March 28, 2012 involving biomethane delivered "through a common carrier pipeline", AB 2196 establishes three criteria, all of which must be satisfied, in order for any subsequent electric generation to be deemed an eligible renewable energy resource. These three criteria require physical flow to California, new incremental injection of biomethane, and direct environmental benefits in California. Taken together, these three requirements are intended to ensure that biomethane injected into a pipeline, where it is mixed with fossil natural gas and then burned at a conventional power plant, actually provides tangible, demonstrable and incremental environmental benefits within California. TURN recommends some clarification and modification to the Draft Guidebook implementation of the eligibility requirements.

1. Physical Flow Mandate

Public Utilities Code §399.12.6(b)(A) mandates that the biomethane must be injected into a "pipeline that physically flows within California or toward the generating facility for which the biomethane was procured under the original contract." The intent of this "physical flow mandate" is to ensure that the biomethane displaces fossil natural gas burned at a California power plant.

The draft Guidebook implements this mandate by requiring that new contracts meet three separate requirements. First, the biomethane must be injected into a pipeline within the WECC or interconnected to the WECC. Second, the applicant must have pipeline capacity (firm or interruptible) or storage contracts along the entire transportation path from injection ("receipt point") to delivery at the power plant. And third, each pipeline segment along the transportation path must physically flow towards the power plant 50% or more of the time averaged over the course of the year.

These requirements differ from the language proposed in the Staff AB 2196 Concept Paper, which explained that:

> If the pipeline is outside California's geographic borders, displacement is not allowed; the pipeline must physically flow only in the direction of the electrical generation facility for which the biomethane was procured under the original contract.[1]

[1] CEC Staff Paper, "Concept Paper for the Implementation of AB 2196 for the RPS," January 2013, p. 10.

The draft Guidebook explains that because pipelines are not necessarily unidirectional, the proposed requirements should substitute for the requirement to "physically flow only in the direction" of the power plant and more realistically represent flow on the interstate pipeline systems to California. While the three-part test in the draft Guidebook represents an attempt to ensure the physical possibility of gas flow towards California, this new approach is flawed because it allows a showing of "displacement" as the basis for satisfying the statutory requirements.

As an alternative to the formulation in the draft Guidebook, TURN proposes that the biomethane must be injected into a pipeline located "to the west of any of the major natural gas supply basins serving California."[2] In any case, there should be no certification of any transaction where the biomethane is injected by the source into more distant "interconnected" pipelines as proposed in the draft Guidebook. TURN's recommendation is based on several important concerns with the draft Guidebook.

First, the requirement to inject into a pipeline that is "interconnected" to a pipeline system within the WECC is essentially meaningless since the interstate pipeline system in the entire United States is interconnected. But interconnection by itself does not at all imply physical flow can occur in both directions. The key geographic distinction is not the WECC (which is an electric system zone) but the location of natural bas supply basins compared to market load centers. TURN is not aware of any natural gas transmission pipelines that could flow gas from east of those supply basins through to California. Indeed, the dynamics of gas flow from production basins to market centers shows that gas must flow from the basins either west or east to market centers. There is no real mechanism for

[2] These supply basins essentially included the Rocky Mountain area basins, the San Juan basin in New Mexico, and the Permian basin in Texas. This is a larger geographic area than encompassed by the WECC.

physically delivering biomethane from east of the Mississippi through to the western United States.[3]

Second, TURN notes that the requirement for each applicant to hold "contracts for the delivery (firm or interruptible) or storage of the gas with every pipeline or storage facility operator transporting or storing the gas from the initial injection point to the final delivery point at the electrical generation facility" is simply a financial transaction requirement that does not ensure flow or delivery of the biomethane to California. A party must purchase firm or interruptible transportation "rights" that are generally associated with specific receipt and delivery points, although such contracts generally may identify a number of alternate receipt or delivery points. However, whether a party actually uses those contractual rights to flow gas will depend on their physical gas needs as well as market economics. If the contract holder has no need for the gas, they can sell ("release") their contractual rights. Likewise, if the contract holder is not a gas producer who must flow the gas, the contract holder would consider the delivered cost of gas of alternative choices at a given delivery point.[4] If the delivered cost along the path is more expensive than the spot price at a market hub, the contract holder could strand the capacity.

Whether a contract holder actually "flows" gas on a particular pipeline segment can only be determined by examining their actual daily "nomination" requests and the resulting schedules of pipeline flow on a system. If TURN's primary

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[3] See, for example, the EIA "Interregional Natural Gas Transmission Pipeline Capacity" map, which shows that pipeline capacity goes from the Central to the Midwest regions and from the Southwest to the Southeast regions. Essentially there is almost no chance of gas flowing westward of the Mississippi River. While it is true that compression and storage allows some manipulation of gas flow direction (as compared to electricity), there is still not physically realistic to expect gas to flow from market centers towards supply basins. See, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/RegiontoRegionMap.html

[4] The delivered cost is the sum of the commodity and transportation costs. Such an analysis is relevant when gas from multiple basin sources can be delivered to a single delivery point or market hub.

recommendation is not adopted (limit injections to pipelines west of the relevant supply basins), TURN suggests that the proposed contractual requirement be modified to require that the applicant demonstrate that they scheduled the biomethane for injection and used their contractual receipt and delivery rights on a pipeline path connected to California (and meeting the 50% flow test).

Third, the Draft Guidebook's primary mechanism of ensuring physical flow is through the requirement that each "segment" flow towards California at least 50% of the time annualized over a year. This is a useful metric for testing the possibility of gas flow towards California. However, this requirement may prove to be administratively quite burdensome. Staff is proposing to examine the physical flow data on every segment of a contractual pipeline path to determine whether flow was towards California at least 50% of the time. TURN suggests that our recommendation (requiring injection west of the production basins serving California) is a simpler method of demonstrating physical flow to California.

2. Demonstration of environmental benefits

Consistent with §399.12.6(b)(3)(C) of the Public Utilities Code, the draft Guidebook requires that contracts executed after March 28, 2012 demonstrate either a reduction or avoidance in criteria air pollutants, a reduction or avoidance of pollutants that could have an adverse impact or surface or ground water within California, or the mitigation of a local odor nuisance in California. The Draft Guidebook explanation parallels the Staff Concept Paper and the statutory language. However, TURN remains concerned that the Guidebook may not categorically foreclose applicants from attempting to demonstrate compliance by making claims that do not satisfy the plain intent of the statutory provisions.

Specifically, the Guidebook should clarify that the statutory requirement involves "environmental benefits *to California*." The language must make clear that environmental benefits, no matter how demonstrable, do not qualify if they do not result in specific benefits to California air or water quality. Moreover, <u>the Guidebook should categorically state that the reduction of greenhouse gas emissions associated with biomethane capture and injection may not serve as the basis for any showing pursuant to §399.12.6(b)(3)(C).</u>

For example, Subsection 1 (concerning "criteria air pollutants") explains that an applicant must provide the necessary demonstration or baseline data to demonstrate "an emission reduction or avoidance."[5] For clarity, the language in the bullet points should be modified to reflect that the "reduction or avoidance" must impact the "emission of any criteria air pollutant *in California*." Generic reductions of criteria pollutants outside of the state do not meet the statutory requirement. The definition of criteria pollutants should also not include carbon dioxide or natural methane even if either of these gases are subsequently determined to be a criteria pollutant by the US Environmental Protection Agency.

Similarly, Subsection 2 (concerning "adverse impact on waters of the state") requires an applicant to demonstrate the "direct and quantifiable relationship between the capture and injection of biomethane from the source into a common carrier pipeline and the reduction or avoidance of pollutants that could have an adverse impact on waters of the state." The Draft Guidebook defines "waters of the state" by using the definition from the Water Code, which conceivably includes ocean water within the territorial boundary of California. An applicant

[5] Draft Guidebook, page 19. ("If an acceptable demonstration is not made, an applicant must provide baseline emissions data of at least one criteria air pollutant (or its precursor) from the biomethane source, and show that the capture and injection of biomethane from the source into a common carrier pipeline results in a reduction or avoidance of emissions of the criteria air pollutant (or its precursor).")

should not be permitted to make a showing that a reduction in greenhouse gas emissions by the biomethane source may help to mitigate climate change and thereby help avoid an "adverse impact on waters of the state".

The Staff Concept Paper explained that there is "an abundance of empirical evidence in the literature documenting the environmental benefits of specific activities (pathways) related to biogas" which demonstrate the environmental benefits of specific activities related to biogas and the impacts on water systems.[6] TURN presumes that this is a reference to the obvious benefits of better biomass waste management on water quality due to reduction in runoff contamination through biomass waste storage and digestion. However, TURN can envision applicants exploiting this definition to argue that emissions reductions literally anywhere reduce atmospheric pollution, which in turn can eventually impact ocean water quality and could thus impact California coastal water quality. Such an attenuated third-hand impact is akin to almost any environmental emission, given that ultimately molecules of gas travel through the global hydrologic cycle. It is not at all the type of water pollution reduction benefit envisioned in the statute.

B. "Count in Full" Treatment for any biomethane supply contract executed prior to March 29, 2012

The draft Guidebook identifies the expected treatment of various types of biomethane and electric procurement arrangements for purposes of determining whether the generation will be treated, for purposes of RPS compliance, as "count in full" under §399.16(d) of the Public Utilities Code.[7] The draft Guidebook envisions that practically all biomethane generation will fall into one of three possible classifications based on the date of execution for the underlying

[6] Staff Concept Paper, p. 12.
[7] Draft Guidebook, pages 20-22

procurement transactions. Although these three classifications are useful, they may only perpetuate ambiguity for certain transactions.

The draft Guidebook should be amended to ensure that "count in full" treatment is assigned to any eligible biomethane procurement contract executed prior to June 1, 2010 regardless of the date of any PPA for generation services. As the Commission is well aware, practically all the biomethane procurement involves Publicly Owned Utilities (POUs) with generating facilities owned by the utility itself. These POUs do not have specific agreements regarding the use of their pre-existing generation to consume biomethane. A focus on the date of the relevant PPA may create opportunities for certain POUs to assert claims designed to allow for pre-June 1, 2010 biomethane purchases to receive Product Content Category treatment.

One example involves a Sacramento Municipal Utility District biomethane supply contract executed on December 15th, 2009, for gas that will not be delivered until early 2014.[8] Since SMUD does not have a PPA for the generation services (to be provided by the Consumes plant it owns) and the biomethane is not set to flow until 2014, the draft Guidebook may not provide sufficient guidance. This transaction, if eligible at all, should be limited to "count in full" treatment because the relevant commercial agreement (for the procurement of biomethane) was executed prior to June 1, 2010.

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[8] The SMUD contract with Heartland may prove ineligible due to the fact that SMUD did not submit an application for pre-certification prior to March 29, 2012 and the fact that delays in the project could result in biomethane flowing after the April 1, 2014 cutoff date.

II. THE COMMISSION MUST REVIEW THE ELIGIBILITY OF PREVIOUSLY CERTIFIED SMALL HYDRO FACILITIES GIVEN CHANGES TO THE STATUTORY ELIGIBILITY REQUIREMENTS SINCE THE INCEPTION OF THE RPS PROGRAM

The draft Guidebook outlines the eligibility criteria for small hydroelectric facilities and notes several relevant statutory requirements in §399.12(e) of the Public Utilities Code. Specifically, the draft Guidebook notes that any facility achieving initial commercial operations prior to January 1, 2006 must demonstrate that it "was under contract to, or owned by, a retail seller or local publicly owned electric utility as of December 31, 2005."[9] The Guidebook does not reference the additional Public Resources Code requirements for any small hydroelectric facility with a first point of interconnection outside of California that did not achieve initial commercial operations prior to 2005.

Any facility deemed RPS eligible must meet the requirements for a "renewable electric generation facility" and any additional criteria associated with an "eligible renewable energy resource." A small hydroelectric facility with a first point of interconnection outside of California that did not achieve initial commercial operations prior to 2005 must therefore satisfy BOTH of the following requirements:

(1) The facility must have sold its electricity to a California RPS-obligated retail seller or local publicly owned electric utility as of January 1, 2010. *(Public Resources Code §25741(a)(2)(C)(ii))*

AND

[9] Draft Guidebook, page 29.

(2) A retail seller or local publicly owned electric utility must have procured the electricity from the facility as of December 31, 2005. *(Public Utilities Code §399.12(E)(1)(A))*

The Guidebook cannot ignore the Public Resources Code criteria. This section must be revised to include the requirements of §25741(a)(2)(C)(ii) as applied to pre-2005 small hydroelectric facilities that do not directly connect to the California transmission system.

TURN's review of the current CEC database of RPS eligible facilities shows over 360 MW of certified out-of-state small hydroelectric facilities with initial online dates prior to January 1, 2006.[10] Of this quantity, 220.75 MW is certified as "MJU Only" and 143.75 MW is certified as "out-of-state".[11] It is not clear whether the CEC performs any regular assessment to determine whether these small hydroelectric facilities, all of which have a first point of interconnection outside California, actually comply with both applicable statutory requirements.

Many of these facilities may have originally received certification based on the original statutory language of SB 1078 (Sher 2002), which permitted small hydroelectric facilities "procured or owned as of the date of enactment of this article" to be eligible "only for purposes of establishing the baseline of an electrical corporation".[12] The date of enactment for SB 1078 was January 1, 2003. SB 107 (Simitian 2006) amended this section to require that any existing small hydroelectric facility "shall be eligible only if a retail seller owned or procured the electricity from the facility as of December 31, 2005."[13] SBx2 (Simitian 2011) further amended the eligibility criteria by adding an additional requirement for

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[10] Includes facilities listed as "approved" and "pending" certification. See http://www.energy.ca.gov/portfolio/documents/list_RPS_certified.html

[11] The Guidebook makes no reference to the difference between these two classifications.

[12] Prior Cal. Pub. Util. Code §399.12(a)(3), enacted by SB 1078 (Sher 2002).

[13] Prior Cal. Pub. Util. Code §399.12(b)(1)(A), enacted by SB 107 (Simitian 2006).

any "renewable electric generation facility" with a first point of interconnection to the transmission network outside California. Any such facility that commenced initial commercial operations prior to January 1, 2005 must demonstrate that "electricity generated by the facility was procured by a retail seller or local publicly owned electric utility as of January 1, 2010."[14]

Based on informal communications with Energy Commission staff, it appears that some of these facilities may not meet the statutory criteria of having been "under contract to, or owned by, a retail seller or local publicly owned electric utility as of December 31, 2005." If any facilities do not meet the statutory criteria, they should be immediately decertified. There is no legal basis for the CEC to continue to permit ineligible facilities to participate in the RPS program.

III. IT IS INAPPROPRIATE, AND UNLAWFUL, FOR THE COMMISSION TO ALLOW EXISTING SOLAR THERMAL FACILITIES TO RECEIVE RPS CREDIT FOR ELECTRICITY GENERATED USING NON-RENEWABLE FUELS ABOVE A DE MINIMUS QUANTITY

The draft guidebook continues the CEC's efforts to implement the requirements in Public Utilities Code §399.12(h)(3) regarding the limits on using more than a *de minimus* quantity of non-renewable fuels to generate renewable electricity which counts towards RPS targets.[15] These requirements were established by the

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[14] Cal. Pub. Resources Code §25741(a)(2)(C)(ii).

[15] Cal. Pub. Util. Code §399.12(h)(3) Electricity generated by an eligible renewable energy resource attributable to the use of nonrenewable fuels, beyond a de minimis quantity used to generate electricity in the same process through which the facility converts renewable fuel to electricity, shall not result in the creation of a renewable energy credit. The Energy Commission shall set the de minimis quantity of nonrenewable fuels for each renewable energy technology at a level of no more than 2 percent of the total quantity of fuel used by the technology to generate electricity. The Energy Commission may adjust the de minimis quantity for an individual facility, up to a maximum of 5 percent, if it finds that all of the following conditions are met:

(i) The facility demonstrates that the higher quantity of nonrenewable fuel will lead to an increase in generation from the eligible renewable energy facility that is significantly greater than generation from the nonrenewable fuel alone.

Legislature to prevent the use of non-trivial amounts of non-renewable fuel to generate "renewable" power that counts towards RPS compliance targets. For new facilities, the Guidebook adheres to the new statutory requirement (enacted in 2010) that renewable generation may not include more than 2% non-renewable fuel with opportunities to use up to 5% if certain criteria are met.[16]

However, an entirely different approach is taken with respect to three categories of existing renewable generation facilities – (1) existing solar thermal generation that was previously eligible for ERFP funding, (2) any generators certified as a Qualifying Facility by the Federal Energy Regulatory Commission prior to 2002, and (3) any facility awarded a power purchase agreement by an Investor-Owned Utility in the 2002/2003 interim RPS solicitations. Any of these facilities may consume up to 25% non-renewable fuel while still being permitted to count 100% of generation as "renewable".[17]

This exemption for existing facilities violates state law. Although TURN understands that Qualifying Facilities (QFs) may retain their eligibility while consuming up to 25% non-renewable fuel, there is no obvious relationship between QF eligibility and RPS credit. Many QFs are not renewable and do not qualify under the RPS program at all. The mere fact that QFs are permitted to boost their operational output through the burning of natural gas is of no consequence. State law clearly prohibits any RPS eligible facility from using more than 5% non-renewable fuel to produce an RPS-eligible Megawatt-hour.

TURN is not suggesting that QFs and other renewable facilities that burn more

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(ii) The facility demonstrates that the higher quantity of nonrenewable fuels will reduce the variability of its electrical output in a manner that results in net environmental benefits to the state.

(iii) The higher quantity of nonrenewable fuel is limited to either natural gas or hydrogen derived by reformation of a fossil fuel.

[16] Draft Guidebook, page 47.

[17] Draft Guidebook, pages 48-49.

natural gas are ineligible under the RPS program. The CEC is required to prorate the output from such facilities and only provide RPS credit based on the fraction of the input fuel that is provided by renewable resources.

There is no statutory justification for exceeding the 5% non-renewable fuel cap for existing facilities. The CEC may not unilaterally decide to exempt any existing facility from this requirement. Had the Legislature intended to provide differential treatment for any subgroup of existing generators, the statutory language would have made this treatment clear. The statutes are unambiguous in their application of the 2% default, and 5% maximum, to all existing and new facilities.

As a matter of policy, encouraging facilities to burn natural gas in order to receive RPS credit is not justified. Under the Guidebook rule, many existing facilities will boost their output by increasing natural gas usage merely to realize higher RPS prices (and greater facility revenues). This behavior contradicts one of the key goals of the RPS program -- using renewable energy to displace fossil fuel consumption in California.[18]

The CEC does not have the authority to ignore the unambiguous letter of the law. The fact that facilities were previously eligible for CEC incentives, or qualify as QFs under federal law, is not relevant to the implementation of §399.12(h)(3). TURN urges the CEC to comply with the law and apply the relevant *de minimus* standards uniformly without regard to the vintage or federal status of the renewable generating facilities.

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[18] Cal. Pub. Util. Code §399.11(b)(1).

IV. ELIGIBILITY FOR STORAGE FACILITIES

TURN supports the new Guidebook section relating to Energy Storage technologies. This revision represents an appropriate opportunity for the CEC to begin the process of including storage technologies in the portfolio of eligible RPS products. The proposed criteria in the Guidebook represent a reasonable start but should include two important caveats. First, the Commission must retain the authority to deny or revoke certification if a storage system is not actually being used for the purpose of storing and redispatching renewable electricity. To the extent that a storage system is actually being used to redispatch non-renewable energy, no RPS credit should be available even if the system was previously certified. This means that any certification should require ongoing verification and demonstrations that the stored energy comes from the identified renewable resource.

Second, the Commission must ensure that there is no 'double counting' of renewable output as the result of deploying storage units. This includes applications where the unit may be used to store renewable energy that would otherwise be supplying station service loads or other onsite purposes. There are undoubtedly many possible configurations in which storage units could be used to effectively manufacture additional renewable energy by allowing power that might otherwise not be tracked by WREGIS to be counted. The use of storage for this purpose should be discouraged and monitored.

History suggests that market participants will push the boundaries of CEC certification and attempt to exploit any loopholes that may be uncovered over time. The Commission must be ready for these efforts and take all available measures to prevent any unintended consequences that may unfold.

Respectfully submitted,

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