Redwood Coast Energy Authority
633 3rd Street, Eureka, CA 95501
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BOARD OF DIRECTORS MEETING AGENDA

Humboldt Bay Municipal Water District Office **July 25, 2019**
828 7th Street, Eureka, CA 95501 **Thursday, 3:30 p.m.**

In compliance with the Americans with Disabilities Act, if you need assistance to participate in this meeting, please contact the Clerk of the Board at the phone number, email or physical address listed above at least 72 hours in advance.

Pursuant to Government Code section 54957.5, all writings or documents relating to any item on this agenda which have been provided to a majority of the Board of Directors, including those received less than 72 hours prior to the RCEA Board meeting, will be made available to the public in the agenda binder located in the RCEA lobby during normal business hours, and at *www.redwoodenergy.org*.

PLEASE NOTE: Speakers wishing to distribute materials to the Board at the meeting are asked to provide 12 copies to the Clerk of the Board.

OPEN SESSION Call to Order

1. CLOSED SESSION

1.1. Closed Session to meet with legal counsel per Government Code Section 54956.9(d)(4), in re PG&E, Bankruptcy Court, 19-30088, Northern District of California.

2. RECONVENE TO OPEN SESSION

3. CLOSED SESSION REPORT

4. REPORTS FROM MEMBER ENTITIES - 4:00 p.m.

5. ORAL COMMUNICATIONS

This time is provided for people to address the Board or submit written communications on matters not on the agenda. At the conclusion of all oral communications, the Board may respond to statements. Any request that requires Board action will be set by the Board for a future agenda or referred to staff.

6. CONSENT CALENDAR

All matters on the Consent Calendar are considered to be routine by the Board and are enacted in one motion. There is no separate discussion of any of these items. If discussion is required, that item is removed from the Consent Calendar and considered separately. At the end of the reading of the Consent Calendar, Board members or members of the public can request that an item be removed for separate discussion.

6.1 Approve Minutes of June 27, 2019, Board Meeting.
6.2 Approve Disbursements Report.
6.3 Accept Financial Reports.

7. REMOVED FROM CONSENT CALENDAR ITEMS

Items removed from the Consent Calendar will be heard under this section.

8. OLD BUSINESS

8.1 Program Administrator Application

Per Public Utilities Code 381.1 (f), approve the enclosed energy efficiency and conservation program plan and authorize the Executive Director to submit the document to the California Public Utilities Commission and to make any edits and alterations necessary to address California Energy Efficiency Coordinating Committee (CAEECC) input and varying procedural and regulatory requirements.

8.2 Comprehensive Action Plan for Energy Update

Approve the Comprehensive Action Plan for Energy public engagement plan and timeline recommended by the Community Advisory Committee.

8.3 Renewable Energy Power Purchase Agreement with Snow Mountain Hydro, LLC

Approve a 15-year power purchase agreement with Snow Mountain Hydro, LLC for the full capacity of its Cove Hydro project up to 5.6 MW, and authorize RCEA's executive director to execute all applicable documents and adjust the contract terms as needed to reflect the nominal capacity, as approved by the California Independent System Operator.

8.4 Special District Risk Management Authority Board Election

Approve the official 2019 SDRMA Board of Directors election ballot casting RCEA's vote for up to three of the five candidates for a four-year term.

9. NEW BUSINESS – None.

COMMUNITY CHOICE ENERGY (CCE) BUSINESS (Confirm CCE Quorum)

Items under this section of the agenda relate to CCE-specific business matters that fall under RCEA's CCE voting provisions, with only CCE-participating jurisdictions voting on these matters with weighted voting as established in the RCEA joint powers agreement.

10. OLD CCE BUSINESS – None.

11. NEW CCE BUSINESS

11.1. Community Choice Energy Program Updates – DG Fairhaven Biomass Contract and California Community Choice Association Membership Dues

Approve increase to RCEA's annual CalCCA membership dues up to $108,960.

END OF COMMUNITY CHOICE ENERGY (CCE) BUSINESS

12. STAFF REPORTS – None.

13. FUTURE AGENDA ITEMS

Any request that requires Board action will be set by the Board for a future agenda or referred to staff.

14. ADJOURNMENT

NEXT REGULAR MEETING
Thursday, August 22, 2019, 3:30 p.m.
Humboldt Bay Municipal Water District Office
828 7th Street, Eureka, CA 95501

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Materials Received

After Packet

Publication

Lori Taketa

From: Greg King <siskiyouland@gmail.com>
Sent: Monday, July 22, 2019 5:04 PM
To: Lori Taketa
Cc: Ken Miller
Subject: Comments regarding RCEA's position on Terr-Gen Wind Farm proposal
Attachments: Ellin Beltz Terra_Gen comments.pdf; RCEA Board re Windfarm_SLC_2019.pdf

Follow Up Flag: Follow up
Flag Status: Flagged

July 22, 2019

Redwood Coast Energy Authority

Via email: ltaketa@redwoodenergy.org

Re: Proposed Terra-Gen Wind Farm

Dear RCEA Board,

Following are comments from Siskiyou Land Conservancy, a 501(c)3 non-profit conservation organization, regarding the Terra-Gen wind farm proposal for Monument and Bear River Ridges. Also attached are comments made recently by Ellin Beltz, for reference.

Please distribute these comments to all RCEA Board members.

Thank you,

Greg King
President/Executive Director
Siskiyou Land Conservancy
P.O. Box 4209
Arcata, CA 95518
707-498-4900
siskiyouland@gmail.com
www.SiskiyouLand.org

Siskiyou Land Conservancy

July 22, 2019

Redwood Coast Energy Authority
Via email: ltaketa@redwoodenergy.org

Re: Proposed Terra-Gen Wind Farm

Dear RCEA Board,

Recently the RCEA Board of Directors voted to contract with Terra-Gen (TG) for a Power Purchase Agreement (PPA) pending TG's success in permitting.

Your unanimous vote to acquire PPA from TG's proposed wind factory before you have even considered any public input to the Draft Environmental Impact Report (DEIR) sends a strong message of support for a project irrespective of it's social or environmental consequences. Because this project is in the permitting pipeline dependent on the votes of the Planning Commission (PC) and the Humboldt County Board of Supervisors (BoS), your decision is politically influential and could adversely impact local carbon reduction initiatives well into the future.

You have therefore prejudicially influenced the PC and the BoS, and disregarded public concerns, signaling to an alarmed public that overriding concerns will trump biological impacts, threats of wildfire, local opposition, and the loss of opportunities to genuinely create a working example of what it takes to be a rural model of energy resilience.

The climate-watch organization 350.org recognizes this influence in its July update celebrating your vote: "The vote may bolster Terra-Gen's approval chances…"

Every time I ask someone, including RCEA Board members, why we should settle for Terra-Gen's ultimately destructive proposal, I hear the same irrational response: *"We have to do this now because of our climate emergency."*

Actually, what we have to do now is to respond to this emergency in a way that brings people together and shares our energy wealth with a broad spectrum of residents, rather than handing that power of local decision making over to a huge multinational corporation.

Terra-Gen's project neither brings people together nor shares energy wealth. At its core the project is extremely dirty and benefits very few. The impacts, however, will be numerous and robust, starting with the decimation of the biologically unique, and critical, habitat that exists on and around Monument and Bear River Ridges. The windmills will actually worsen our climate crisis because of the massive greenhouse gas (GHG) emissions that will occur during the 18 months of construction, the logging of over 1000 acres of trees plus other vegetation, and disruption of 3 million cubic feet of ancient soils. As a recent University of California Davis study warned: “In Wildfire-Prone California, Grasslands [are] a Less Vulnerable Carbon Offset Than Forests.” (*Environmental Research Letters, 2018*)

Aside from all its terrible impacts, TG’s project also opens up our wind market to significant and ultimately destructive levels of exploitation by global fossil fuel powerhouses such as Energy Capital Partners, Terra Gen’s parent company, and other major energy conglomerates. Allowing Terra-Gen to pursue this project represents an extremely misguided collaboration with RCEA, Schatz and Humboldt County. Our shift to reliance on onshore windpower to make us “net energy exporters” would render us perfect servants to these multinational entities.

When fears of this unholy alliance surface, we are reassured that expensive transmission upgrades or lack of other acceptable wind sites limit this threat.

Similarly, whenever the decentralized energy option is proffered, RCEA staff and Board are quick to proclaim that: “large daily and seasonal variability of PV greatly limits the amount of energy that the electric grid can carry without major transmission upgrades.” (North Coast Journal 6/27/19).

However, RCEA’s strategic plans for implementing onshore wind, as noted in the minutes from a recent RCEA meeting, reveal that in fact you are prioritizing onshore wind development for energy export, which of course will require major transmission upgrades:

“Power Resources: Onshore Wind

Promote Large-Scale Wind Energy. Provide information about the potential for cost effective commercial-scale wind farms in the county. Educate the public about the benefits and impacts of wind energy systems. Work with utilities, local government, and private companies to develop ***onshore*** *wind energy projects.”*

And to accommodate the aptly named IOU (Investor Owned utility) electricity, our limited transmission capacity is simply on the to-do list:

“Upgrade the Electricity Transmission and Distribution System. Upgrade the regional transmission and distribution electrical grid to enable increased development of both utility-scale renewable energy projects as well as community-scale distributed generation systems, including capability to export surplus renewable electricity generation from Humboldt County to other areas of the state.”

Considering our terrestrial wind habitat as a resource to exploit with belittling regard for the impacts reminds me of the gold miners who hosed our watersheds, the dam-builders who plugged our streams, and the salmon canners who depleted the salmon runs before the coup de grace delivered by the clearcutters who decimated our forests. All these short-sighted entrepreneurs were blinded by seemingly irresistible resources, just like the oil and gas or uranium peddlers of today. In doing so they defiled the original home of Native inhabitants who lived here for thousands of years, and who most recently came out in full opposition to the proposed Terra-Gen wind farm.

It is irresponsible and arrogant to state, as Michael Winkler did in the NCJ recently, that "Potential negative impacts of the project can be reduced to levels acceptable to the community," before public concerns are even considered. Tell that to the Wiyots and Eel River and Bear River Valley residents. Tell that to California and U.S. taxpayers who shelled out half a billion dollars for Headwaters Forest, in large part to protect marbled murrelets, one of several protected species that could be decimated by Terra-Gen's project.

But our main observation is this: Humboldt County does not need to generate 135 MW of electricity to feed the grid, or purchase 90MW from a dirty local power source in order to do our part to reduce our carbon footprint.

We have far superior ways to answer the climate emergency, secure our energy future, share our energy wealth, preserve our biodiversity, protect our neighbors, and reduce our GHG emissions.

It's called by many names: widespread distributed rooftop solar PV, networked smart grids, genius grids.

Widespread incentivized rooftop solar PV reduces our fossil fuel use in ways that benefit the most people and cause the least harm, along with enhancing forest carbon sequestration and passive solar in our local planning.

And it fits Mr. Winkler's definition of an ideal energy source, which would be "…low-cost, available when we need it and *have low impacts*."

Cost comparisons of solar with onshore wind must consider the absence of undesirable impacts with solar compared to the astronomical ones of onshore wind; the equity wealth to homeowners; the advantage of electric vehicles as clean, quiet, transportation and mobile storage and supply; the resilience of dynamic independence from the grid; the affordable electrification of heating and cooking, thereby eliminating much of our current use of natural gas (the GHG methane).

Meanwhile, TerraGen's power will contribute less than ½ of 1% of California's renewable energy portfolio, and we will have to buy our 90MW of their dirty electricity at market rates.

Transportation GHGs, Electric Vehicles (EVs), and minigrids

Transportation in Humboldt accounts for 60% of our GHG emissions. California has recognized that we have to electrify our transportation if we are to meet our climate goals. The smartest way to generate that electricity is with local solar:

"We found that technically feasible levels of energy efficiency and decarbonized energy supply alone are not sufficient; widespread electrification of transportation and other sectors is required.” (“The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity” *Science* 06 Jan 2012)

According to Michael Winkler’s OpEd in the NCJ:

“In Humboldt County, energy is used as a transportation fuel and as electrical and heat energy in homes, businesses, industries, and agriculture. In 2010 it is estimated that Humboldt County spent $460 million to meet local energy demands, the majority of which left the county. Approximately half of the energy was used as a transportation fuel (gasoline and diesel), with large amounts also used to meet end use electrical demands and end use natural gas heating demands. Primary energy sources were comprised mainly of natural gas, gasoline, diesel, and biomass (wood waste and firewood).”

Electrification from home-grown solar generation can replace most of these fossil fuel sources.

EVs & V2G

The best way to interest people in electric vehicles is with rooftop solar, since the fuel comes form one’s own roof. The car then becomes a mobile electrical supply and storage vehicle.

EVs are clean and quiet, require very little maintenance and no petroleum products, and they can run for over 500,000 miles.

Genius minigrids pair EVs with sophisticated interfaces so that multiple users can draw power as needed, cars can be charged, and electricity can be sold to the grid:

“Vehicle to grid [V2G] uses excess rechargeable battery capacity to provide power to the electric grid and money to the vehicle owner during times when peak load demands exceed the power being currently generated by the renewable energy source. It is essentially a distributed battery system to complement the distributed energy system serving as a buffer.” (Forbes 12/18, 2018)

Southern California Edison Vice President Lisa Cagnolatti reinforced the concept: “…allows EVs to go from simply consuming energy to potentially becoming a fully functioning component of the smart grid.” (Forbes 12/18,2018)

Dynamic independence from the grid along with mobile storage contributes to resilience during emergencies, including planned shutdowns when the risk of wildfires is high.

Feeding dirty electricity to the grid from this Terra-Gen project does none of that. We would buy it anyway from the grid. We already buy hydro from Shasta and solar from Fresno instead of from here, there’s no logical reason to destroy the critical biodiversity hotspot of Bear River and Monument Ridges, and assault Scotia, Rio Dell and the Wiyot, when we could buy clean re-powered wind power from the grid, and develop our own local solar resources now.

Wind power can be clean or dirty, and Terra-Gen's is the dirtiest. Wind power from new virgin sites is much dirtier than wind power from re-powered sites. This site is particularly dirty, because no one has ever installed a wind power factory in a site like this, and doing so will transform this biologically rich and diverse habitat into a nightmare of extensive roads and transmission lines, cement, noise, vibration, and constant human activity.

The rural pastoral setting so hospitable to endemic populations of rare and threatened species is all the more vulnerable to cumulative impacts precisely because it is managed; and it harbors islands of untouched habitat and grasslands, all of which would be terribly degraded.

Only in Terra-Gen's high priced PR do we find the incredible assertion that such an industrial facility can be hidden in the midst of forest, ridge, range and grasslands, and that 500-600 foot tall lighted windmills will somehow be invisible from 3,000-foot ridgetops that are visible from three Counties. The same PR uses "virtue signaling" to inspire our knee-jerk reaction to our climate emergency with unquestioning support of their otherwise destructive project.

Sonoma Clean Power is re-powering 283 old wind turbines in Alameda County with 20 modern ones to provide Mendocino and Sonoma Counties with electricity. Vestas is replacing 400 wind turbines with 20 in Tehachapi, where Terra-Gen has over 300 MW of power from turbines 20 years or older that could be re-powered and cleaned up. Re-powering actually reduces impacts at these old sites, where the landscape impacts have already occurred and transmission infrastructure is nearby, which is why it has been so popular in Europe for years, and is gaining traction here.

Currently, RCEA treats distributed energy as a poor stepchild to onshore and offshore wind, rather than as the priority, despite solar being the fastest growing power source in the US. Affordable, off the shelf, behind the meter, modular minigrids are already available with financing that "…enables customers to get the benefits of the microgrid without upfront capital outlay."(www.scalemicrogridsolutions.com.)

RCEA includes in its mission the implementation of: "Distributed Generation & Storage," described in detail in its own policies that appear to be superseded by the Terra-Gen wind farm proposal:

"RCEA will support the deployment of distribution connected solar and storage technologies as core strategies toward achieving the program's environmental, economic, and community goals.

"Administer and Implement the Public Agency Solar Program. Continue to implement the solar and energy-storage technical assistance program for public agencies; ***integrate grid-connected resources and microgrids as feasible.***

"Administer and Implement the Community Solar and Storage Program. Evaluate, design and launch community solar and storage program services that support the increased adoption of ***grid- connected solar and storage technologies.***

"Integrate Vehicle to Grid Storage. Integrate vehicle to grid storage solutions with transportation and IDSM goals and objectives.

"Low-carbon Transportation

"RCEA will ***decarbonize regional transportation*** through efforts to reduce vehicle miles travelled, increase advanced fuel vehicles adoption and fuel efficiency, and expand advanced fuel infrastructure.

"***Designate 'Renewable Energy Parks.'*** Work with County and City planning departments to designate areas of the county preferred for renewable energy development.

"Develop Distributed Generation. Encourage studies to identify key facilities throughout the county that would benefit from distributed generation and cogeneration energy systems. Encourage development of responsive environmentally preferable distributed generation and cogeneration energy systems where appropriate. Encourage and publicize demonstration sites.

"Provide Education on Renewable Energy and Distributed Generation. Provide educational and promotional programs that encourage and demonstrate the use of renewable energy and environmentally preferable distributed energy generation and cogeneration systems.

"Provide Feed-In-Tariff Power Procurement Program for Small Generators. Offer long-term contracts at a set rate for Renewable Portfolio Standard-eligible renewable energy generators of 1MW or smaller.

"Power Resources: Solar:

"Support Solar Energy Development. Support local efforts to develop ***solar electric systems and solar hot water systems in the county***. Support development of local training programs for solar contractors and installers. Educate the public about the benefits of solar energy systems. Develop programs that facilitate an increase in the number of solar energy systems in the County."

Mortgage Backed Rooftop Solar

To prioritize and actualize this package of laudable goals, we must include efforts to amortize the cost of rooftop solar with a home mortgage, and concentrate Requests for Proposals (RFPs) on commercial entities (hopefully more local than Terra-Gen) for widespread installations. Fortunately, paired with an EV, the payback time for such installations is on the order of 4-5 years.

Local expertise at RCEA, Schatz, and elsewhere contain all the technical and social skills to develop resilient energy, and become leaders in its inevitable deployment everywhere.

However, RCEA's priority does not appear to be the production and support of resilient energy, but instead of net energy exporting.

This failure is not a financial, technological, or meteorological problem, it is a political one. We are already implementing smart grids in Blue Lake, at the airport, and with plans for others. Conferences on implementing the emerging smart grid technologies are happening all over. California plans to triple subsidies of EVs, and solar panels and battery costs are plummeting. Real local jobs associated with this strategy dwarf the 15 imported ones that Terra-Gen will use to monitor its windmills 24/7—monitoring that is necessary because these complex machines fail, and the transmission lines and turbines risk wildfires.

Offshore Wind

The impacts from terrestrial onshore windpower at the proposed site are unacceptable, divisive, and especially irrational in light of our immense offshore wind resource, which may be developed with acceptable impacts.

There are potentially in excess of 1,100 MW of electric power 20-30 miles offshore to feed the grid and Humboldt County. A pilot 120 MW offshore wind project could be on-line by 2025, serving Humboldt it's 90MW of homegrown electricity, exporting the additional 30MW, with none of the awful consequences of Terra-Gen's proposed wind farm—a project that would not be online until 2021, and would emit thousands of tons of greenhouse gas emissions before then. The 5-year window of dirty Terra-Gen electricity is simply not worth it!

<u>Resilient Energy=Resilient Economy</u>

<u>Shift in RCEA Paradigm to "Resilient Energy"</u>

•Distributed energy should be our priority, along with offshore wind. It should NOT be the poor stepchild of a centralized grid feed.

•Our policymakers should be instituting mortgage-based financing for rooftop solar, soliciting RFPs and consultations regarding genius minigrids, including solar in codes and zoning initiatives, and attending the many conferences on mini-grids.

•Net Energy Exporting should rely on offshore wind.

•Clean windpower should be purchased from the grid, as we do hydro and solar, from companies that re-power aging windpower sites.

•Imported solar electricity should be replaced with electricity generated from solar PV in Humboldt County.

•Eschew onshore windpower.

•Emphasize regeneration and protection of carbon-sequestering forests and grassland soils.

•Continue to encourage passive solar zoning and conservation strategies.

V2G support from current published sources:

“Thus, EVs support the state's renewable integration targets while avoiding much of the tremendous capital investment of stationary storage that can instead be applied towards further deployment of clean vehicles.”

“Achieving deep global greenhouse gas reductions targets requires the electrification of transportation soon and at significant scale.”

“By displacing the need for construction of new stationary grid storage, EVs can provide a dual benefit of decarbonizing transportation while lowering the capital costs for widespread renewables integration”

“With some vehicles being V2G capable by 2025, vehicles provide renewables integration capability far exceeding that of the Storage Mandate during critical days. Thus, our results show that substantial capital investment, as much as several billion dollars, can be avoided if EVs are used in lieu of stationary storage. In other words, the California Storage Mandate can be accomplished through the ZEV Man- date, provided that controlled charging is also widely deployed. The capital investment for stationary stor- age can instead be redirected to further accelerate the deployment of clean vehicles and vehicle-grid integration, and could even be used to pay EV owners when their vehicles are grid-connected with controlled charging. In this manner, not only are clean vehicles an enabler for a clean electricity grid at substantially lower capital investment, but the avoided costs of supporting renewables with stationary storage can be used to further accelerate the deployment of clean vehicles.” (Environmental Research Letters 13(5):054031 · May 2018)

“Vehicle-to-grid (V2G) refers to efforts to bi-directionally link the electric power system and the transportation system in ways that can improve the sustainability and security of both. A transition to V2G could enable vehicles to simultaneously improve the efficiency (and profitability) of electricity grids, reduce greenhouse gas emissions for transport, accommodate low-carbon sources of energy, and reap cost savings for owners, drivers, and other users.” *(Environ. Res. Lett.* **13** (2018)

/s/ Ken Miller, Director
Siskiyou Land Conservancy

/s/ Greg King, President
Siskiyou Land Conservancy

HUMBOLDT WIND ENERGY PROJECT

Photo Credit: Los Alamos National Laboratory
Christian Steiness/Vattenfall/Flickr

DRAFT ENVIRONMENTAL IMPACT REPORT

DEIR SCH #2018072076

Comments by Ellin Beltz

June 14, 2019

RECEIVED
JUN 14 2019
Humboldt County
Building Division

Comments must be directed to:
Humboldt Wind Energy Project Planner County of Humboldt Planning Department 3015 H Street Eureka, CA 95501 CEQAResponses@co.humboldt.ca.us

June 14, 2019

Humboldt Wind Energy Project Planner
County of Humboldt Planning Department
3015 H Street
Eureka, CA 95501

CEQAResponses@co.humboldt.ca.us

Dear Sir or Madam:

Thank you for the opportunity to comment on the Humboldt Wind Energy Project.

I am a retired university lecturer from New York City and Chicago. Before moving to Humboldt County in 2001, I taught at Northeastern Illinois University, University of Chicago, Field Museum and Morton Arboretum among other academic institutions. I helped write the Master Gardener Program which is taught here by others. After moving here, I taught for College of the Redwoods at their Hoopa Extension campus and continue to teach online. My degrees are an B.S. in Biology and an M.S. in Environmental Geology I have published a book on Frogs of the world with Firefly (formerly Facts-on-File) Press. I was an official delegate to the First World Congress of Herpetology in Canterbury England. I served for three years on the Planning Commission of the City of Ferndale and have more than passing familiarity with the CEQA process.

This DEIR runs to nearly 1000 pages. The maps and figures are scattered throughout the appendices and the document internally contradicts itself in multiple locations.

I initially planned to comment only on the impacts, but as I went through the document I found so many mistakes, things overlooked, contradictions, and other signs of rushed document preparation, that I began to write the list which became this comment.

Back in the day, if a student of mine had handed this in for credit, I would have marked it with an big red "F" and said "try again next semester." I would hope you would have the same reaction - and that the document is sent back to be redone and recirculated. As it stands presently there is no support for any statement of overriding concern. Based on this DEIR as detailed in my comments, I support the "no project" alternative.

Sincerely yours,

Ellin Beltz
[redacted]
Ferndale, California 95536
[redacted]

2.0 PROJECT DESCRIPTION

2.1 INTRODUCTION

Contains the map, objectives, purpose, alternatives, statement of overriding considerations, etc

2.2 Proposed Project

2.2.1 Project Location & map

Currently Figure 1 is missing some information that a reasonable person would need to understand the impacts of the project. Suggest updating Figure 1, accurately labeling Federal and State areas, such as the National Wildlife Refuge, Six Rivers National Forest, Headwaters Forest, Humboldt Redwoods State Park and accurately showing the boundaries of each. Additionally, all aspects of this project should be indicated on this single figure: siting locations, Gen-tie route, staging areas, permanent Operations facility, and so on.

2.2.2 Project Objectives

I have listed the objectives and Humboldt County Policies affected by this project and comment on each as follows.

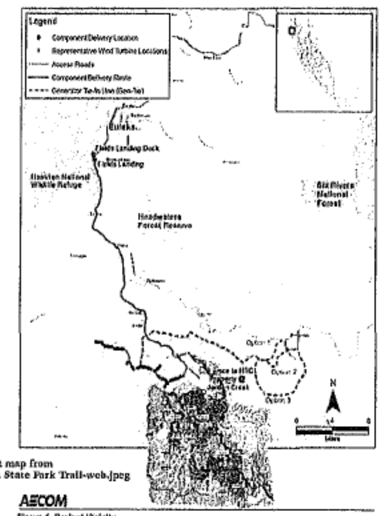
•Tax credits to TerraGen if built before December 2020
Yes, profits and tax credits will go out of Humboldt to the developers LLC and their financiers.

•Statewide portfolio renewable and volatility
"Because the project would generate energy from wind power, a renewable source, it would assist the state in meeting the goals and targets established under SB 100 to procure 60 percent of its power from renewable sources by 2030."
No. Project provides 0.005% of California's renewable power generation according to this document. That's half a penny on the dollar of the whole. I wouldn't consider a half-penny "assistance" for much of anything. Besides, for this, at least 1,058,658 gallons of diesel will burn over 18 months of construction. Transportation gas was not broken out, nor was oceanic transport costs and delivery of specialized cranes and other equipment.

• Promote sustainable energy in Humboldt County
No. Continues purchases of transmitted grid power.

Create 155 MW green energy
•No. By the time the electrons get to Bridgeville, Planned losses to transmission are 12% of generation. Thus 20MW will vanish and the result will be 135MW maximum.
•No. Besides planned transmission losses mitigation measures for flying things include shut downs and slow downs, further reducing the power generated to an unknown level.

•Displace 372K MT/yr CO2 that would otherwise be required to generate 155MW with natural gas



Inset map from
Hum State Park Trail-web.jpeg

AECOM

Figure 1. Project Vicinity

Prepared for: Humboldt County
Notice of Preparation of EIR for Humboldt Wind Energy

base map from EIR
page 5

AECOM
5

FIGURE 1
Site map with Humboldt Redwoods State Park Overlay
and additional captions.

Yes, but significant and incompletely calculated emissions occurring in the first year and a half and amortized over 25 years to hide their true effects on the environment. Greenhouse gasses should be accounted for accurately. Millions of gallons of diesel fuel are going to burn in Humboldt County. Air quality will be exceeded. The CO_2 is going up in 2019 and 2020, not in little chunks over the 25 years. While this may fulfill some form of bureaucratic checklist from the standpoint of global warming it's a huge lie. The CO_2 goes up now, in the 12 years we need most. Account for it accurately.

• Near transmission infrastructure
No. It's 20 miles South of Eureka, 12 miles South East of Fortuna, 22 miles North of Garberville and just South of Scotia. The Bridgeville substation is 25 miles from the project site and 44 miles from Eureka.

•Employment
Unclear. Variable numbers in the DEIR, at most 300 temporary plus 15 permanent jobs by imported employees who may rotate. Transportation workers seem to have been omitted. In contrast, the Eureka McDonalds employs 30 people, Target about 65-125 people, Blue Lake Casino more than 100, and so on up to the larger employers including St. Joseph Hospital (900+), and Humboldt State University (1400+). Adding 15 jobs for 30 years is statistically insignificant even in Humboldt County.

• Promote walkable cities and alternative transport
No. The entire project is rural. Everyone will drive everything and themselves.

•Tax revenue
Miniscule. TerraGen leases, not owns, so will directly pay no property taxes. The landowners would be paying the taxes anyway, some of them are apparently in or adjacent to Williamson Act parcels - which was not mentioned in the DEIR. The tax is stated to be 1 percent of total cost less deductibles, thus at most around $2.5m annually, 14% into General Fund with the remainder to schools and other funds. An additional $7 million would be paid during construction. (TerraGen slide show) This amount is so small compared to the amount of staff and legal time that the tax revenues may not displace early costs for years to come. The project will not pay for the damaged Highway 101, taxpayers of the state of California will have to do that; the developer only offers to repair county roads damaged in transport and construction.

•Provide environmentally safe power (county goal)

No - modeling inaccuracies. They state this will displace 372,000 metric tons per year of carbon dioxide due to generating 155 MW. I question this number because their calculations do not take into effect the Carbon sink effect of all the trees removed for the project and Gen-tie line, and the disruptions to the present carbon sink in the grasslands where 3 million cubic tons of soil will be moved around.

No - environment. Entire construction is fossil fuel powered, transportation fuels were not included, and the accounting method amortized this greenhouse gas injection over 25 years. The earth is supposed to pass a tipping point in 12 years, there is no reason to add to it like this.

No - environment. Clearing is 895 acres of forest habitat alone; 759 acres will be replanted planned to regrow for 30 years. By then, the project will have to be decommissioned, and much of this area may have to be cut down again to get the stuff out. We don't know - decommissioning statements are put off until 30 years from now. The nearly 900 acres of forest cutover alone is greater than the entire area needed to replace the proposed 155 MW with local solar.

No - environment. Recent peer-reviewed studies have shown major down-wind effects on air and fog created by wind turbines. The down-wind effects of the project, while mandated by the county, are not analyzed in this DEIR.

2.2.3 Project Components

This section is very vague.

"Theoretical maximum energy generation" is stated like that because the wind does not blow all the time and if they have to turn them on and off to protect the condor, eagles, raptors, marbled murrelets, bats and other creatures to avoid potential significant impacts, so the generation will be less than this. However, they do not calculate how much less this might be.

Nine hundred acres of temporary or permanent impacts are stated, but I am unable to match their math by going through the rest of document and adding up the information given in the other tables and discussion. Perhaps they had so many possible alternatives that some disturbance figures are for different configurations. No table that I recall seeing sets up the disturbances for the various alternatives, although there is one showing claimed reductions.

There is no name, brand, size or actual model of turbine stated, nor exact locations. This is supposedly to be left to "final design." Therefore all statements of any form of detail about these throughout the rest of the document are entirely hypothetical as each type of machine has different noise, maintenance, size, blade configuration, and so on. There is no "one-size-fits-all" wind turbine.

TerraGen spokesperson Natalynne DeLapp informed me there are no operating 600-foot tip height wind turbines in the United States. While the impact analysis is as they say for the maximum number of turbines, and the maximum height, studies have shown that the various heights of these machines have different effects on wildlife due to their different sweep heights through the air column.

The DEIR discusses the Gen-tie across/under the Eel River and the Bridgeville Substation connection to PG&E which will lose 20MW to transmission, for just 25 miles.

The project would include the following components...
(*) up to 60 WTGs (capable of generating 2–5 MW of electricity each) erected on tubular steel towers set on concrete foundations, as well as the associated WTG pads, temporary staging areas, and transformers;
(*) temporary construction access roads and permanent service roads, as well as temporary improvements to public roads at two locations along U.S. 101 to facilitate the delivery of WTGs from the Fields Landing Drive delivery site to the staging yard at Jordan Creek;
(*) an up to 25-mile, 115 kV gen-tie, including an underground crossing of the Eel River, following Shively Ridge and ultimately connecting to the existing PG&E transmission system at the Bridgeville Substation;
(*) a project substation located on-site;
(*) an underground electrical collection system linking WTGs to each other and to the project substation;
(*) an underground communication system (fiber optic cable) adjacent to the collection system;
(*) a Supervisory Control and Data Acquisition (SCADA) system between each WTG and the substation and between the project substation and the Bridgeville Substation to monitor and control project output and the transmission of energy into the system;
(*) an up to 5-acre O&M facility, including an operations building, a parking area, and an outdoor storage area with perimeter fencing;
(*) a 10-acre temporary staging area and a construction trailer and parking area located within the O&M facility;
(*) a component offloading location at Fields Landing;
(*) two temporary bypasses off U.S. 101 (Hookton Overpass and 12th Street Bypass) for transporting oversize loads;
(*) up to six permanent meteorological towers;
(*) three 5-acre, temporary staging areas distributed throughout the project site, one of which would include one
temporary cement batch plant on Monument Ridge; and
(*) up to 17 miles of new 24-foot access roads.

Table 2-1 lists each component and its function and the disturbance areas for temporary and permanent conditions.

One math question, 60 x 2 = 120 so there have to be some larger and some smaller turbine included to get to the 155 MW number. This is not discussed at any time that there could be two or more different types of turbines used.

Modern turbines of extreme height now produce 10MW, but the DEIR says none of these will be more than 5MW. Please clarify.

The EIR describes the parts of a generalized turbine as well as FAA lighting and lightning protection, but again fails to state a model, make and actual type to be installed in this project.

Generator pads and base pads 350x350-feet, no more than 2% slope… That's big. That's a football field long and wide, each one, times 60 plus a permanent gravel ring around the base, temporary impact areas to be "stabilized" with the storm water pollution prevention plan and a site-specific restoration plan. These are permanent scars to the landscape which will be clearly visible from outer space forever.

Are there any fees, repayments to the county relative to adding impermeable surfaces (i.e. concrete) to areas which were formerly permeable? If so, how much?

ACCESS ROADS

page 2-12

This road is now 12 foot wide, to be widened to 24 foot wide, with 20 foot shoulder for crane travel. "In areas with steep slopes, the total width of the disturbance area along access roads could be up to 200 feet." Each watercrossing is to be made to bear the traffic with rip rap, culverts and geofabric. Finally permanent access roads would be taken back to 24 feet with 1 foot wide shoulder, but cuts and fills to 60 feet might be left behind.

Please explain how roads compacted with heavy equipment can be considered to be a "temporary disturbance" as 100-year-old road scars still show clearly from outer space? Cuts and fills left behind would be permanent and need to be identified to location.

pages 2-16 & 17

The expansion of Bridgeville Substation covers an existing road, and would appear to block traffic - is this permanent? This figure is not very clear as to intent and the text on page 2-17 does not address the existing road at all. This is of concern due to fire access in this heavily wooded area adjacent to power lines.

page 2-18

O&M Facility with water and septic on 5 acres at Jordan Creek. Will this be visible from the highway and the return of Avenue of the Giants to 101?

Meteorological Towers … up to 12 mets. 6 permanent with blinking lights.
Same with Met towers, it doesn't say where they actually go, but they are the same height as the HUB height of the "Final WTGs selected." This is circular.

page 2-19 - 2-21 Construction

"Construction would begin in fall 2019 and would last 12–18 months. The sequence of construction activities would generally be as follows: tree clearing, site preparation/grading, access road construction, construction of WTG foundations, WTG installation, installation of the collection system, substation construction, gen-tie installation, switchyard installation, final testing and WTG commissioning, installation of O&M facilities, and cleanup and restoration. Approximately 3 million cubic feet of earth would be excavated on-site to construct the proposed project. All grading would remain balanced within the project site, so no export of soil is anticipated."

- Things I could not find in the document which relate to this section include:
- Where is that 3 million cubic feet of earth going to go? The DEIR reads elsewhere that they will minimize disturbance on site, but the dirt has to go somewhere if they are not exporting it.
- Did they account for the carbon released by disturbing this soil? I couldn't find it in the DEIR.
- What will be done with the trees logged? Exported, chipped, burned, or what is the plan? Is there a Timber Harvest Plan?
- Winter and its effects on weather, flooding, road conditions, landslides on newly cleared roads is not mentioned. Local conditions and winter weather are limiting for construction. Examples of mega-projects delayed by local weather include the St. George Lighthouse (1883-1891) and the 2016-present Route 36 project.
- To finish on the applicant's schedule and timeline means being able to ship into and drive away from Humboldt Bay for 30 days without delay. This may result in the project not achieving one of its most important goals - getting up and running by December 2020 when the Federal subsidies run out.
- A description of the applicants understanding of how onshore and offshore weather influences schedule compliance during winter operations should be provided. Note that the Humboldt Redwoods HCP mentioned in section 3.5b does not permit winter operations as described by the DEIR.
- A description of how the project would meet the subsidy goal if delayed.

Section 2.3.1 Component shipping and staging.
page 2-19 "Transportation by sea would take place when weather conditions and the sea state are acceptable," summary: Barged by 2,200 foot towline to tugboat, dragged through the jetty on a shortened towline, mooring barge, components offloaded by crane at

One of the appendices has a drawing of the barge and components another section describes 20 tower bases on a barge, 2 rows of 10 … each one 157,630 pounds. These Appendix figures could be incorporated in the DEIR, or at least referenced to Appendix letter and page number. At over 1000 pages, it should be on the applicant to be sure information is available - not on the public to index their document for them.

How does the crane/s get into the county? It just appears on page 2-20 deux ex machina. The unloading crane is not alone, there are other cranes required to assemble components which are also not mentioned. According to published reports each one of these cranes requires multiple oversized truck trips to deliver - and remove. In a public meeting to the Board of

Supervisors, one of the TerraGen representatives mentioned that these would come overland from I5 via 299 or 36. This transport is nowhere mentioned in the DEIR.

Offloaded they might ship components directly, or let it all pile up in Field's Landing. Barge activities are only scheduled for 30-day period which seems rather short duration of component arrival due to difficult offshore conditions. Working to 10 p.m. in a residential community seems late. In fall and winter, useful daylight is over at 3 p.m. so it seems they would also need supplemental lighting, which is not addressed in this document.

Night lighting can attract invertebrates and associated bats and birds to the project. Due to Eagle Cams on the Internet, it is known that this part of the bay is Bald Eagle nesting territory. Humboldt Bay has night herons, brown pelicans, harbor seals and other marine mammals. No mention of natural history at the offloading site, and no wildlife studies were performed there.

No Eelgrass survey was found. The Eelgrass map figure 3.5-4. data was copied from an agency and is out of date.

No night lighting or studies on wildlife were done at Humboldt Bay delivery site. This should be discussed, otherwise it is either an unaddressed or impact to be dealt with later on the Bald Eagles, marine mammals like harbor seals, bats and night flying birds. Noise at Fields landing was not discussed later in the document and not specified here. Impacts of noise on residents and creatures was not mentioned. This is a major omission due to plans to work 7 a.m. to 10 p.m. at this location for at least one month continuously.

page 2-21 gives a general description of South Bay Depot Road modifications to get trucks in and out. Later in the DEIR this generalization is rephrased "This turn would require repositioning one communications pole a short distance to the north, increasing the right-hand turn radius, and possibly repositioning the stop sign and other road signs a short distance to the south given the need for wide right-hand turns."

Ownership of the modified land is not mentioned, but to prevent concerns about imminent domain or encroachment, it should be discussed.

The wetland to the west of this onramp in not discussed.

While shown as a small red outline on Appendix M, Figure 2, Page 1 of 5, a larger scale more detailed drawing should be provided showing the ownership of all parcels and easements affected by these changes and how public access will be maintained to the freeway during component transport. This comment pertains to all bypass and overpass drawings for project which - if they exist at all - are currently split in two parts, and buried in the Appendix.

As an unaddressed point of public safety later in the document, this on-ramp is the only south-bound access for the Field's Landing community, and it is one of the few turn around points for emergency vehicles to go from northbound to southbound lanes on 101.

2.3.2 Component transport.

Wind turbine component transport is a highly specialized profession and series of vehicles. The folks who do this travel the country with their own pilot cars, flaggers, RVs and so on. (https://www.houstonchronicle.com/business/energy/article/As-wind-turbines-grow-larger-so-does-the-6840315.php)

Each turbine will take up to 15 loads to deliver the parts, 9 to 12 loads are oversized. This quantity of trips is stated several ways in the document, and there is considerable difference between the results. This will be pointed out at relative points.

The effects of changes to Highway 101 which is a vital lifeline to all the residents of the county, as well as visitors and tourists, is of great concern. The highway was landscaped when it was built in the 1960s, many of the plantings are mature, some are rhododendrons and other native plants specifically placed in the understory by CalTrans as part of floristic beautification over the last 50 years.

It does not appear the project applicant has done any bird/bat surveys or assessments, identified actual trees for removal or considered riparian or wetland impacts of their proposed changes to 101.

page 2-21 "Transport of heavy components may require localized clearing or pruning of vegetation, temporary relocation of obstacles such as fences and overhead power lines, and/or placement of temporary mats and fill material to support the loaded vehicle weight."

page 2-21 "Most project components could be transported directly to the project laydown yard at Jordan Creek without requiring any improvements to the U.S. 101 corridor. However, depending on final WTG selection and the transportation plan, the base tower section may exceed the allowable height of two overpasses: Hookton Road and 12th Street."

page 2-25 "Additional detours off U.S. 101 are planned that would not require physical improvements other than trimming vegetation to provide truck clearance:" at Loleta, 'Finch Creek' and Palmer Boulevard."

This section seems incomplete and information is missing. Two exits are confused with each other ("Finch Creek" is actually "Singley Road Separation" at Fernbridge Exit), two overpasses are named to be a problem but three are bypassed, as are two flat-deck bridges. The other 18 bridges and overpasses on the route are not discussed. It is not possible to tell if they were examined for any project limiting features.

Some of the bypasses are mentioned in Project Description 2.0 text and figures, others are mentioned in figures in Appendix M. Not all the bypasses are mapped. Not all the bypass maps of the same bypass show the same changes.

Due to this incomplete information, it is impossible to know the actual scope of effects on Highway 101.

Specifically I request the following improvements to the DEIR for all bridges, over passes, underpasses and exits (including grade crossings) from Fields Landing to Jordan Creek:

* Add Highway Exit numbers to discussion about bypass areas to standardize discussion and prevent error.
* Provide accurate descriptions and maps in one place in the DEIR. Currently bypass maps and descriptions are located in Section 2.0, the Transportation section 3.12 https://humboldtgov.org/DocumentCenter/View/72214/30-31-Environmental-Setting-Impacts-and-Mitigation-Measures and the maps in Appendix M. https://humboldtgov.org/DocumentCenter/View/72237/M-Biological-Resources-Wildlife-Assessment-Humboldt-County-Ca
* Provide detailed information where "fill material to support the loaded vehicle weight" (page 2-21) would be used.
* Perform and provide appropriate wildlife assessments for all exit areas to be bypassed, native plants and mature trees to be removed.
* Discuss direct and indirect impacts on the National Wildlife Refuge, the Bear River Casino, Humboldt Creamery, Mercer-Fraser, the City of Fortuna Waste Water Plant, the City of Fortuna Park, Recology and steel waste yards, and the other businesses at Dinsmore Road and 12th Street.
* Update the project description to include grading at Fernbridge/"Finch Creek" and removal of native plants on CalTrans berm apparently not noticed during DEIR preparation. Describe in detail the mitigation for changes.
* Provide details where cuts will be created at other locations for passage.
* Provide detailed maps or descriptions of revegetation and restoration plans for any bypasses affected.
* Discuss effect of transport on Rohner Creek at 12th Street and the creek at Hookton slough and describe how the small county bridges in those locations will bear the weight of the components and transport.
* Review and update the 12th Street re-entry to 101, it appears some details for this ramp have been omitted, including no outlines on any drawings of area of effect.
* Provide a statement of need for Fernbridge/"Finch Creek" (Exit #692) bypass.
* Address why the **Tompkins Hill Road Overhead, #04-0121**, and the actual Finch Creek Exit #691 are not being bypassed while the Fernbridge/"Finch Creek" and Palmer Boulevard exits are. The ages and weight restrictions are similar.

* Directly address in table or text why 18 other bridges and overpasses on the route do not need to be bypassed. This is important because it would be difficult to achieve the December 2020 subsidy cut off date Goal if any one of these were found to be inadequate during transport.

Comment and request for changes about Hookton Slough bypass.
* Describe why this lengthy and discontinuous bypass (shown on drawings Appendix M as below) is needed to get around Exit #696 Hookton Road OC Overcrossing #04-0166.
* Accurately represent the Hookton bypass in maps and text in the DEIR. Half of this bypass is in the Coastal Zone (Appendix M, Figure 2, page 2 of 5 in red outline; vegetation types are shown in Appendix M, Figure 3, pages 2 through 6 of 9). Neither of these two figures are directly comparable to Figure 2-19, (page 2-26).
* Obtain Coastal Commission permission and any required consultation with the National Wildlife Refuge at Hookton.
* Study and provide mitigation measures in the DEIR for the proposed culvert, gravel and geofabric bypass on the Northern Red-legged Frog (Rana aurora), a species of special concern.
* Perform wildlife assessments to determine the potential impact on birds, birds of prey and bats and provide mitigation measures in the DEIR as needed for endangered, threatened and species of special concern at Hookton Slough. This was done for ridgetop habitats, but not for the port, bypasses or gen-tie line.
* Describe dust control measures from construction and use of the gravel "Visitor Access Road" which directly abuts and accesses the National Wildlife Refuge.
* Prepare crossing or culvert plan for the bridge crossing the stream which runs into the Slough.
* Describe in detail the post construction revegetation of mature trees, snags and willows removed for the bypass.
* Prepare a winter plan for when Hookton intersection and/or the temporary bypass floods in the winter with particular attention to keeping the gravel out of the slough and the Bay.
* Provide mitigation measures in this DEIR for the modifications to or loss of riparian habitat marked on the map in Appendix M, Figure 3, page 5 of 9.
* Describe emergency and public access to the coast, the Humboldt Bay National Wildlife Refuge, Table Bluff County Park and Table Bluff Ecological Reserve as well as to the Wiyot Reservation and adjoining residences during construction/removal of the bypass and/or during transport operations.

Summary concerning constructing bypasses:
There is insufficient information in the DEIR, considering all sections and appendices to fully understand the plans and associated impacts to the natural landscape, freeway roadside with historic plantings, side roads, small waterways and access.
Sufficient information should be included in the final DEIR along with updated maps in all sections they occur. Unplanned detours to move turbine components would create unanticipated and unplanned impacts some of which may be severe.
page 2-25 "All improvements would be removed following WTG delivery, which is expected to last up to 6 months. The sites would be restored to pre-installation conditions" and "After construction, all temporary impact areas would be restored to their preconstruction state as

appropriate for the project site, in accordance with County requirements or permits and authorizations issued by other regulatory agencies. All construction debris and waste would be stored outside of any jurisdictional drainage and in locations that would avoid unnecessary movement of the material. When removed, material would be disposed of at an appropriate location by a local, licensed disposal company."

There is no statement how they will restore the mature trees and vegetation removed along and adjacent to Highway 101 to make these changes.

* See also **page 2.3.11**. Provide clarity about "in accordance with County requirements or permits and authorizations..." repeated in both places. Otherwise this seems like piecemealing or figuring it out later might result as there are currently no assessments of the pre-construction condition in the DEIR.

* Provide waste disposal information, information on storage sites, what is to become waste and method of disposal. This is not a discussion of which landfill to ship to. This is more a question of how much fuel will be used to truck out the construction debris and the anticipated tons of operational debris cited later in the DEIR. It is consistent in this document that the effects of subcontractors are not included in Fuel, Greenhouse Gas, (sometimes) Noise and other sections. I think all the effects of the proposed project should be included - not just some of them.

* Discuss why this section says "all improvements would be removed" when other sections say that access roads are permanent. Perhaps a map should be provided to show the applicant's intent of "all improvements" versus "access roads."

In conclusion for this section, Highway 101 is the lifeline of Humboldt and Del Norte Counties and the shutdown or loss of any bridge would be a disaster. Of particular concern are bridges at Tompkins Hill Road, Fortuna Main Street, three crossings of the Eel River, near approaches to Humboldt Bay, several crossings of smaller waterways, and the Van Duzen Bridge.

*As the document tends to repeat items, some are skipped here but will be discussed in their appropriate section of my comments.

page 2.3.13 Staging area and batch plant.

* How many trees and of what species and age composition will be removed for the nearly 20 acres of development for this part of the project? I do not see a timber plan, I do not see where the dead trees will be taken, used, sold, or transported.

* Is the fuel for the batch plant generators included in the fossil fuel tables, greenhouse gas and air quality calculations?

"All waste and debris from batch plant operations would be hauled off-site and disposed of at appropriate locations." Do these appropriate locations match those defined later in document or are these somewhere else? It's not clear.

page 2.3.14 Construction traffic

Table 2-2, page 2-33 presents heavy truck trips but it appears not to be included in any calculations for fossil fuels or greenhouse gasses. It is not comparable to the table in on **page 2.13.17** which shows construction vehicles - that does not include the transporters or their 30 vehicle pace teams described elsewhere in Transportation, Noise and Air Quality. It is not enough to discuss the heavy truck trips, also included should be fuel, water, and waste disposal vehicles, pace cars, flaggers trucks, vehicles to place and remove cones and signs and so on to be comparable and to complete tables equivalent to that for construction labor and equipment. The lack of accounting for these vehicles extends to their fuel uses not being included in the Construction fuel figures and also not in the green house gas figures - which is a serious omission.

All the transport should be placed in one section. There is no reason for anyone to have to flip around to find out what matches, and what doesn't match between, Section 2.0, Section 3.12, Section 3.11, Section 3.8 and other locations where project traffic is discussed.

page 2.3.15

Does not say where the 5,000 gallons diesel in temporary earthen berms will be built or stored other than "above ground" probably somewhere near the batch plants. Perhaps a description of where on the project footprint and a discussion of any earthquake or groundwater proofing for these tanks could be provided.

The fuel deliveries may not be accounted for on **pages 2.3.14 and 2.13.17** because it reads "It is assumed that commercial vendors would replenish diesel fuel stored on-site as necessary." Which means they are not accounting for the fuel needed to deliver the fuel they will use.

Lubricating oils are also used on the nacelles and takes up to 400 gallons per oil change per turbine (agreed to at TerraGen presentation by Natalynne DeLappe). I do not see this mentioned on Table 2-3.

Herbicides are listed and claimed to be for fire management. No further details are given. Additional chemicals are mentioned only in the footnotes. Later in the document keeping the Gen-tie grass down is mentioned, but again no details of mowing, or herbicide use.

No mention is made of chemicals planned for the O&E septic system at Jordan Creek.

Regarding: The project applicant would develop and implement a fire protection plan before construction and operation. This is one of the over thirty-five (35) deferred sub-plans and permit applications referenced in this document but not included.

Besides making it impossible for public comment, if this is approved in Summer 2019 and they want to start in September 2019, that leaves them about 30 days to develop and implement a fire protection plan for thousands of acres of agricultural and farm lands relative to their construction activities - one cigarette and the entire grassland could go up - trailers dragging chains - hot mufflers in dry grass - diesels that can't be shut off - workers from somewhere else unaware of local hazards - electrical transmission lines (remember Paradise) - there's many potential hazards and not a lot of time left to plan for them. The omissions in the DEIR do not give me great confidence that later plans presented to local districts will be complete.

Table 2-3, page 2-34 lists lead-acid storage batteries, but fails to mention their addition to the Bridgeville substation mentioned elsewhere.

Table 2-3, page 2-34 The presentation of herbicides does not seem to include their use on or along the transmission corridor - although that is mentioned elsewhere in the DEIR.

2.3.16 Water Supply and Use
This summary will be discussed later in comments with **3.1.3 Utilities page 3-8** as it would otherwise just be repeated.

2.13.17 Construction Schedule, Personnel and Equipment
pages 2-35, 36 & 37
There are two tables in this section that will be referenced. Table 2-4, **page 2-35** and Table 2-5, **pages 2-36 and 2-37**.

Three hundred workers are listed on "Work force and Equipment," Table 2-4. Of those 30 are listed as "laborers" the rest are specialized.

I think this list overlooks a significant number of workers for activities described elsewhere in the DEIR.

- There are no truck drivers.
- There are no vegetation removal workers, no loggers, no log truck drivers.
- There are no workers for bypass construction.
- There are no workers for batch plants and concrete delivery.
- Aquatic delivery and operations are not mentioned; no barge delivery or winch operators. Crane operators at delivery point in Fields Landing are excluded because it reads "Turbine component unloading crew (pad site)" and does not mention the Fields Landing site.
- No component delivery workers

I think this list overlooks a significant number of pieces and types of equipment for activities described elsewhere in the DEIR.
The Equipment list, named "Typical Construction Equipment," has similar omissions.

- Trucks are listed here (there were no drivers on Table 2-4).

- No bypass construction equipment listed, all the work is relevant to the project footprint, Bridgeville and the Gen-tie construction .
- No vegetation removal equipment, even for Gen-tie.
- No aquatic delivery equipment, no tugboats, barges, dock generators, crane for dock, and generators/lights as needed for night work.
- No component delivery equipment. Not listed are the oversized vehicles for turbine components and cranes, chase cars, and pilot vehicles associated with turbine component and oversize crane deliveries.
- No batch plant equipment is listed including powering generators.

Because this equipment, almost all fossil-fuel powered, is not listed, I have no confidence in the Fuel calculations, Emissions calculations, Greenhouse Gas and Air Quality statements and assurances.

Table 2-2, page 2-33 presents heavy truck trips but fuel for those appears not to be included in any calculations for fossil fuels or greenhouse gasses.

It is obvious that these tables were used to generate the fuel calculations. Since the above activities are not listed on these tables, I am assuming that the fossil fuel for them is not calculated in the other parts of this DEIR.

It looks like the amount of fossil fuel needed to build this might be up to double or more what is presented in this DEIR if all vehicles and equipment were included.

Fossil fuel requirements and/or emissions for significant construction associated activities do not appear to be presented and discussed in the Greenhouse Gases and Air Quality sections.

Thus all the CO2 figures are off, all the air quality figures need adjustment and the places that need to be modified to more accurately reflect reality are located throughout the document.

2.4 Operations and Maintenance Activities

2.4.1 Operations and Maintenance Plan

Standard maintenance results in 30 years of human disruptions in area where presently there is hardly any.

2.4.2 Public access and safety

Night lighting and daytime strobes in this area is a potentially significant impact in an area which currently has none. Yes, lights are mandated by the FAA, but no they wouldn't need to be there without the proposed project.

The DEIR's only concerns about fire seem to be vegetation fires, but in other areas of the country the turbines themselves catch fire. Elsewhere in the country wildfires have been started by nacelles catching fire, lightning strikes and other ignition sources. Please address in detail the fires caused by turbines themselves, not the turbine response to a wildfire started somewhere else and arriving at a turbine as well as any hazardous materials issues first responders might encounter in such a situation.

The wind farm fires reported in the news are mostly of the "nacelle catches fire" with clouds of black smoke. Over 2000 acres in Arlington, Oregon, were burned on August 2, 2018.

First responders around the U.S. have also responded for injuries and deaths in turbine construction and maintenance accidents. The DEIR did not address the need for high-angle rescue gear and training for local first responders.

2.5 DECOMMISSIONING

The decommissioning plan is extremely vague. Decommissioning discussion and any DEIR for same is deferred thirty years in the future. The county has already had experience with large landowners and employers filing for bankruptcy, it would be good to learn from this experience.

The decommissioning bond is stated to be between TerraGen LLC and Humboldt Redwoods Company (Natalynne DeLappe, public comm. 2019). If both entities dissolved, willingly or in any other way, the county is exposed for the full amount of decommissioning - without even an outline of a plan in this EIR.

An actual plan and irrevocable performance bond should be deposited with the County as a mitigation measure prior to any permits being issued. The applicant can also deposit a bond with Humboldt Redwoods, Russ Ranch and any other landowners for decommissioning, so taxpayers are not impacted if one, or all these entities dissolve. The ownership of TerraGen is currently by two Hedge Funds: ~ARC Light Capital Partnership (NYC) @ 60% and Global Infrastructure Partnership (Great Britain) @ 40%. There is no guarantee that any of these entities will exist in 30 years.

Missing in the Maintenance Plans

There is little to no discussion about maintenance needs of component parts, but other places in the country have had to replace blades, nacelles and towers long before 30 years of operations. Repairs are not mentioned in this DEIR. Repairs and replacements would create secondary impacts - but we do not know what they are since this section doesn't list them. Nacelles and tower parts are oversize components according to this DEIR and replacing them is not discussed. Los Alamos National Laboratory states "Modern wind turbines have a design life of 20 years, and yet break down 2-3 times in the first 10 years."
(https://www.lanl.gov/discover/publications/1663/2014-april/wasted-wind.php)

Blade replacement is not discussed. The blades have at most a 25-year life. With no specifics on the turbines to be used, it is impossible to be more specific. Some blades have failed immediately post-construction, some bend like rabbit ears in high winds, or break off and land at a distance, others are fine until they're in their double decades. Wind speed alone is not the only factor in blade life. An entire sub-industry of wind energy is devoted to blades, but I do not see any plan for what to do with these blades when they have to be replaced - at 25 years of age, which is during the 30 year anticipated age of project. Each would have to be transported out, with the same problems as getting them in (roads, bridges and port) or chipped up and then disposed of. In a presentation, TerraGen spokesperson Natalynne DeLapp stated used blades are garbage and blamed our "disposable" culture. And giggled.

With a rotor diameter of 492 feet (ES.3.1 Project Location and Components), each blade would be about 240 feet long. If we would assume that they are about 25 feet wide and 25 feet thick, multiplying by that length gives a volume of 150,000 cubic feet or 5,556 cubic yards. If the size were less, (240 x 25 x 10) the result would be 60,000 cubic feet or 2,222 cubic yards. For reference a typical garbage truck holds about 180 cubic yards resulting in about 13 to 25 garbage truck loads per blade - assuming the chips could be perfectly placed without air in between.

Since garbage in Humboldt County is trucked out, where exactly will this 2222-5556 cubic yards per blade, times three blades, times 60 turbines (399,960 - 1,000,080 cubic yards) of debris, for one renewal of the blades end up? These projects typically renew the blades every ten to fifteen years, resulting in those figures needing to be doubled or tripled.

New blades, nacelles and towers would have to be shipped in and the old parts removed. Whether any of this would require the bypasses be reopened is not mentioned in the DEIR.

I do not think this has been adequately discussed and could leave the county with a massive liability if there is no performance bond to guarantee removal of all blades, parts of blades and other components.

The county might be left holding the bag for decommissioning costs if there was no performance bond. This has happened to other wind farms in other parts of the country and the ability for corporations to declare bankruptcy and hand off parts of their operations, but not all of the associated liabilities is so common that they teach classes in it. Let it not happen to Humboldt County.

Table 2.6 Permits

Nowhere do I see a timber harvest plan for all the trees being removed. Later, in Impacts, the DEIR says that the first project construction phase is inconsistent with the provisions of the Humboldt Redwood Company HCP. This impact would be potentially significant.

I think timber removal should be addressed in a manner consistent with a Timber Harvest Plan which requires information about trees. The DEIR approaches trees like acres of corn. "OK, boys, get out the harvester and let's cut everything in the corridor." I don't think that's the way to save species, creating miles of edge habitat willy nilly through one of the last great places on earth.

Note: The Permits section is the only place I have seen marine aquatics listed, but I think it's standard boilerplate because it relates to biological opinions and incidental take permits, not anything specific to Fields Landing.

Sections 3.0 & 3.1 ENVIRONMENTAL SETTING, IMPACTS, and MITIGATION MEASURES

This part of the document defines terms and then discusses impacts that they did not find to be significant in areas related to planning, water, and so on. It discusses short-term, long term and permanent effects, defines direct / indirect impacts and cumulative impact.

3.0.3 pages 3-3, 3-4 and 3-5. "No feasible mitigation measures are available ... if the impact would be significant and unavoidable, and no feasible mitigation is available to reduce the magnitude of the impact to a less-than-significant level."

This statement is directly applicable to California Fully Protected species as discussed below

Impacts Found not to be Significant 3-5
3.1.1 Land Use and Planning
page 3-5
The DEIR presents the Humbold County General Plan, as amended... Zoning ... "The impact related to a conflict with an applicable habitat conservation plan or natural community conservation plan is addressed in Section 3.5, "Biological Resources." See Section 3.3, "Agriculture and Forestry Resources," for a discussion of the effects of the generation component related to agricultural land and timberland use regulations. To the extent that the proposed project meets the findings of Standard E-S3 in the General Plan Energy Element and the required findings and conditions for CUP approval, the project would not conflict with any land use regulations adopted for avoiding or mitigating an environmental effect, as described above."

This part of the DEIR is talking about regulations for General Plan and Zoning. The significant impacts that cannot be overlooked come later in the document. This section essentially lays out the rules the document is to follow.

"Electromagnetic interference and other safety issues are discussed in Section 3.9, "Hazards and Hazardous Materials." Noise impacts are discussed in Section 3.11, "Noise." Appearance and design, including height, are discussed in Section 3.2, "Aesthetics." Utilities are discussed in

Section 3.1.3, "Utilities." Compliance with the Uniform Building Code is discussed in Section 3.7, "Geology and Soils."

My comments will follow along in the same order as the project documents.

page 3-6

Military overflights are noted, this requires the County to get with the Government to ensure no problem. I do not see they anyone has contacted the military about it. Elsewhere military has stopped erection of turbines in their flyways.
(https://www.news9.com/story/39239744/florida-company-halts-wind-turbine-construction-in-western-oklahoma)

3.1.2 Population and Housing

page 3-8

"It is expected that specialized workers with unique skills to erect the wind turbine generators and construct the collection line, gen-tie, and project substation would typically travel to a project site and stay in the community temporarily until the job is complete. These workers would relocate to the next job site rather than residing in Humboldt County permanently once the job is completed."

"None of the project components would result in displacement of housing, and thus, none of the options would require the construction of new housing."

Summary: 315 workers will be needed. 300 for 12-18 months and 15 over 30 years. They do not expect the 300 workers to be from this community or to remain here (in one part); they do expect the workers to be from here and remain here (in another part). (Referencing Section 3.1.2. Population and Housing, contrasted to Section 3.1.4 Recreation, and 3.1.5 Public Services)

If the workers are brought in from outside, there appears to be a significant impact that is not addressed in the DEIR. There is no suggestion of where these 300 people will be housed for 18 months. There is little spare housing and a substantial homeless problem here already. Even some HSU and CR students are homeless. The DEIR does not say they will provide housing, and there's no RV park big enough to handle an influx of 300 RVs and trailers (prohibited in cannabis areas like the Rio Dell log deck) and would require sewer hookups.

I do not understand how 300 temporary workers be brushed off as "no impact" when there's no housing available for so many people (not students) at one time. For scale, they would be about 10% of the population of Rio Dell. This is a significant impact to housing. (See also Section 3.1.4 Recreation, and 3.1.5 Public Services)

3.1.3 Utilities
page 3-8

WATER SUPPLY
The DEIR calculates 60 gallons per day potable well-water for each of the the 15 permanent workers and that they will use it for each of the 365 days a year (60 x 15 x 365 = 328,500 gallons) Acre-foot = 325,851.43 U.S. Gallons.

Use of 62-acre-feet of treated sewage water from Scotia was planned for construction-related activities, dust, soil and concrete. It will be delivered by truck, but I do not see water trucks listed in the construction vehicles in Section 2.0 as mentioned. Subsequent to writing this comment, I have been informed in writing that City of Scotia is unable to provide this water - it would violate their agreement with the state - and TerraGen never asked to use the water. So where is the construction water going to come from now?

Additionally the DEIR does not address the water needs of the 300 temporary workers.

At the 60 gallons per worker per day as above
300 temporary workers [tw] x 60 gallons per day [g/pd/tw] = 18,000 gallons per day [gpd]

12 months: 365 days x 18,000 g/pd = 6,570,000 gallons (20 acre-feet)
18 months: 547 days x 18,000 g/pd = 9,846,000 gallons (30.21 acre-feet)

Notice that Table 3.1-1 on page 3-9 is only for post construction water use by this project. There is no table for during construction water use.

If they will have potable water delivered by truck for their temporary workers, those trips need to be accounted for in fuel use and air quality and a source of the water provided.

This appears to be a significant impact that is not addressed in the DEIR.

WASTEWATER
While the 15 permanent employees dump 60 gallons per day into a new “appropriately sized septic system” (no map or location and no chemicals listed) where the 300 temporary workers will be depositing liquid and solid personal waste is not addressed.

If it’s portable toilets or other transportable facilities, they never said where they go relative to waterways, and did not account for the fuel or vehicles to transport them.

If it’s some other method, it has not been defined. Therefore I do not think they can say “no impact” here as they have left off at least 20-acre-feet per year of liquid discharge from the daily needs of their temporary workers as well as 100% of temporary worker solid personal waste, which could be as high as 300 pounds per day.

If temporary workers use less water, and/or less sewage for some reason, that should be defined and discussed in this document because significant potential for stream contamination exists because the ridges are the headwaters for all waters flowing downwards from the ridge tops.

No water or sewer use was described in relation to the construction route transport, Gen-tie or Bridgeville substation expansion. Worker sanitation features should be available along the route, as transporters are too big to dodge in and out of gas stations and it is just not an option to use the bushes.

Dry Waste
The project in operation will produce up to 4,000 pounds per week of solid waste (0.28 ton/day) of solid waste, although what exactly they are doing to create that much trash is not mentioned.

If they've amortized their construction waste into a weekly over the life of the project, they do not mention it. If it is construction waste all generated at the same time, what will be the effects on our roads 299 and 36 of having that kind of load removed on a fairly fast timetable?

They mention that they are within the permitted amounts of garbage for the various open landfills. However they do not mention or calculate the energy used to transport 208,000 pounds per year of trash to the landfill.

I do not have enough information to really understand why 2 tons a week of garbage would be produced by wind turbines in operation. There are 15 people in the operations center, that would be 266 pounds per person of trash, which doesn't make sense.

This level of dry waste is what a factory would create - not green energy.

3.1.4 Recreation
page 3-11
They say no new residents and completely forget their 300 bored out-of-town workers. I think this is significant and needs to be addressed

3.1.5 Public Services
page 3-11
"As discussed above in Section 3.1.2, "Population and Housing," many construction workers and O&M employees would come from the local labor pool, and the available labor force in the county would be sufficient to meet much of the employment demand."

That is the exact opposite of what was stated on page 3-8, Section 3.1.2 Population and Housing. Previously - and per standard procedure for wind farms - the DEIR said that the builders are specialized and will come and leave. That the workers leave at the end of the job was the basis of the no impact in Section 3.1.2!

Even if Section 3.1.2 is wrong, and if it were possible for them to hire the specialized wind turbine workers they need from the local population - what is the effect on the local economy when they are released from their jobs at one time?

If they are hiring all 300 local, please state how hiring unqualified and untrained workers for specialized high-angle work up to 50 stories affects their insurance and dates of completion.

3.1.6 Energy pages 3-12 and 3-13
This discussion omits all marine activities (tugs, barges, dock installation) and do not account for the delivery crane or turbine erection cranes.

"Energy demands during construction would be associated primarily with construction equipment and vehicle fueling; energy (fuel and electricity) would be consumed by construction vehicles and equipment operating on site, trucks delivering equipment and (page 12) supplies to the project site, and construction workers driving to and from the site. Operational activities would include energy consumption associated with vehicular use and the O&M facility." (p. 13)

No mention is made of the additional fuel barges that would be required to deliver the additional gasoline and/or diesel fuels for the project over and above what is already imported.

I also do not believe they have adequately accounted for water and waste transport fuel use as previously mentioned.

The fuel use of the extra barges and their effects - if any - on protected mammals such as Harbor seals is not included in the discussions. I believe if it were included that this section would change from "no impact" to "significant."

3.1.7 Mineral Resources
page 3-14
I fail to see how the "applicant is not proposing any form of mineral extraction" when they will use an enormous amount of sand and gravel in their construction. The minerals will have to come from somewhere, they cannot brush this off as no impact because they may already exist somewhere in the county. I would like to see an accounting of the actual amount of material they require compared with the regular rate of extraction per year in the County. It may be that what they feel is "Common" would require extraordinary effort to extract which they have not considered.

3.1.8 Paleontological Resources
page 3-15
I do not disagree with their findings or have any questions on this section.

Section 3.2 AESTHETICS

page 3.2-1

"The region contains many notable recreation areas and resources, such as Humboldt Redwoods State Park along U.S. Highway 101 (U.S. 101), the King Range National Conservation Area/Lost Coast, and the Humboldt Bay National Wildlife Refuge."

No view points were shown from within Humboldt Redwoods State Park.

As shown in Figure 1, the turbines are close to - just over one valley - from the the Thornton Multi-Use Trail, the Peavine Multi-Use Trail, The Peavine Ridge Spur at Prairie Road - part of the Carl A. Anderson Redwoods Natural Preserve which runs north of the Mattole Road. The Bull Creek State Wilderness is to the south of the road as shown on State Parks maps. (https://www.parks.ca.gov/pages/425/files/HumboldtRedwoodsSP_WebBrochure2014.pdf)

The proximity to the trails is clearly shown on Figure 3.2-1 where the Monument Ridge turbines would be the next thing over the valley for nearly the entire length of the trail and from parts of Grasshopper Trail, and from Grasshopper Peak, the high point. No mention of these viewpoints - or the effects on visibility from the Natural Preserve and Wilderness Sections of the Humboldt Redwoods State Park was made in the DEIR. No "KOP"s (key observation points) were modeled from inside the State Park.

pages 3.2-7 through 24 are images from the various KOPs.

All these images of visualization share a single repeating problem. The faceplate maker, size, width of column and quantity of turbines has never been defined. It's left to "final design." So these images are about as imaginary as possible. I object to using imagery that does not accurately reflect the actual appearance and I request that they also show imagery at night to show the number and location of flashing red dots that would be present on the horizon. From their own maps these will be visible from Fields Landing to Scotia with views from within the State Park and high point views as far as the King Wilderness.

These effects on view are huge for an area dependent on tourism. As is stated in this DEIR section, regular commuters and visitors prefer an orderly vista. The turbines - at twice the height of the nearest large redwood - are vastly out of scale for this landscape.

I have listened to three of spokesperson's Natalynne DeLapp's presentations on the subject so far, and I have to say, that I prefer the look of the reforesting hillside without the turbines a lot better than I like it with the turbines in Figure 3.2-4 - from Scotia. The turbines dominate the town poking up from the ridgetop, and look extremely untidy because all the arms are at different angles all the time. They don't look modern, the same designs have been used since the 1980s.

It would be instructive to have views with midwinter lighting, when the sun is nearly behind the ridges and the turbines would cast long shadows in the pale light. A sunrise view from the Mattole Road with the line of spinners backlit with the red orb. Or perhaps backlit and multiplied many times their size as shadows in the fog with dark shadows cast many miles away. These lighting conditions occur now with 300 foot tall redwoods, it's unlikely they would not occur with these towers. Light conditions are not always perfect, and views aren't always from roads. Just because tourists like blue skies, doesn't mean we have them 365 days a year on the North Coast.

Figure 3.2-5 is perhaps the most afflicted view - except for Scotia - mere 5 miles away, the turbines stick up out of the forested hillsides like some kind of space invasion. They are just not scaled to the landscapes of the county. I disagree with spokesperson DeLapp who claims that cows ruin the view for her (KHUM Radio 5-27-19 8:20 a.m.). The cows are far more natural than the giant metal things in the background of the mockup and they are in scale with deer and elk.

Figure 3.2-6 View from Riverwalk. Clearly visible on the horizon in a high sun photo and again would be more obvious in winter with low angle sun. This is a popular walkway and convention center.

Compare and contrast the visitor friendly Riverwalk and Lodge with the project. No one visits wind turbines as a tourist attraction. If they did, there would be a visitor center, fancy videos and maybe docents to explain what is going on. But instead there's chain link fences surrounding closed off plain industrial buildings - with no relevance to the redwood architecture of the region - just metal industrial, and blinking lights all night long on the ridge.

Figure 3.2-8 The Mattole has been called "one of the last great places on earth, perhaps too beautiful to stay that way." The mockup in this figure shows a lineup of turbines like two opposing football teams, one on each ridge. Again the blades are pointing every which way, they look very sloppy compared to the natural beauty shown in the figure without them. What day of the year would the sun rise directly behind the project and cause shadows all over the Mattole? As it is south east of the KOP this will obviously occur.

Figure 3.2-9 KOP#8 first caption says 17 miles from "the Project," second caption says "nearest turbine 10 miles" - a difference of a mere ten miles in one photo. Again, the turbines loom on the horizon. I disagree they have any relevance to the foreground even if the occasional piece of farm equipment has a wheel. That's like saying that you can put them on the freeway because trucks and cars have wheels. They are over sized to this environment. Whether this is 10 or 17 miles away - this is too much visual impact on too many residents and visitors for the huge release of greenhouse gases from fossil fuels to build them and the pittance in taxes the county will take in over 30 years.

Figure 3.2-10 Visible from Table Bluff at 23 miles from Project and nearly 17 miles from nearest turbine. Twenty-three miles of visual effect from one project everything between here and there has a pretty clear view of them too.

Personal observation, they will be visible from the turn at Tompkins Hill Road along 101 to Scotia without difficulty wherever you can see the ridges now. They will be up to six times taller visually than the Doppler Radar Station currently visible above Ferndale, which is slightly over 100 feet tall.

While a 50mm lens might model the natural world, it has no peripheral vision. These will be visible front on, sideways, and in all views from now until decommissioning in 2049.

Besides the lack of imagery from areas not along roads and parking lots, and the odd lighting to minimize the tower bases, and the lack of accurate width of tower bases and heights in the simulations, a mitigation measure in this section states "The WTGs shall be clustered or grouped to break up overly long lines of WTGs." Based on Figure 2-1, it appears that the placement of the WTGs does in fact create overly long lines.

This project will change the views for longer than it would take a baby born this year to graduate college. I consider that very significant, especially for Scotia, a town barely getting started after being owned by a single entity for all prior history.

This is too much of a visual and aesthetic effect for an area described in the DEIR **page 3.2-2** “Most of Humboldt County’s land area is rural, without urban development (e.g., streetlights, nightlights, interior lighting, and paved areas) that create skyglow and light trespass, commonly referred to as light pollution. Skyglow is defined as the added sky brightness caused by the scattering of light into the atmosphere.”

Table 3.2-1 Rates current landscape units and current conditions. It does not make any statement about how the visual quality would change with the turbines. Half, 18 out of 36 boxes, are rated “moderately high.” This is the kind of aesthetic experience desired by tourists and residents, and one which the county has previously worked very hard to maintain.

page 3.2-27
Discusses FAA lights being added to an area without nighttime lighting. Adding night time lighting will create light pollution where currently there is none. This is an impact for which no mitigation is possible.

There is no mention in Biological Section 3.5b of the effects of blinking red FAA mandated lights, or day time strobes on bats or birds. Migrating birds have been known to be affected by lights; bats are of course attracted to lights because insects concentrate there.

page 3.2-27
The DEIR states the FAA requires a bright white color. In 5.3b for bats they mention a possible mitigation of painting them purple. Paint is not included in hazardous materials lists (section 3.9), in fact it says the pieces would be painted prior to shipping.

page 3.2.27 Presents aspects of the Humboldt County Plan.
CO-G1 Conservation of Open Spaces: distinguish and showcase ... natural environment... while not impacting the ability to provide livelihoods, profitable economic returns and ecological values.

This project fails this goal. It will damage nearly 1000 acres of land, with effects on the highway and port. If the owners of the lands for lease are broke, they can sell. There is no requirement to turn a profit for local residents or outside corporations at the expense of the environment. The jobs will go to outsiders. There are no mitigation methods proposed that will make up for the take of fully protected, endangered, threatened and SSC species, thus it fails on ecological values.

Standard SR-G1 Conservation of Scenic Resources: Protect high-value scenic forest, agriculture, river, and coastal areas that contribute to the enjoyment of Humboldt County's beauty and abundant natural resources.

This project fails this goal. Policy SR-P1, cutting the gen-tie line removes high value scenic forest, tall turbines dominate agricultural lands in the figures for Rio Dell and Ferndale, the Gen-tie over or under will impact the Eel River, and the turbines are visible from Table Bluff on the Coast and the Humboldt Redwoods State Park - the latter within a couple of miles which was not modeled in this section.

Standard SR-S2: The Jordan Creek O-M building is plain steel industrial ugly with chain link fence. This hardly feels like it is designed to "create a harmonious visual relationship with surrounding development and the natural terrain and vegetation." It would be the first building seen after leaving Avenue of the Giants and rejoining 101.

Standard SR-S4: Obviously fails. Red flashing lights while mandated by the FAA do not fit the character and aesthetics of the county.

Standard E-S3, Item B: This DEIR has not addressed effect on potential down-wind sites other than in technical discussion of the effect of drafting on other wind turbines in the array. But it should. Recent work by researchers at Harvard found that large-scale U.S. wind power would cause warming that would take roughly a century to offset. "Extracting energy from the wind causes climatic impacts that are small compared to current projections of 21st century warming, but large compared to the effect of reducing US electricity emissions to zero with solar... 'Wind turbines generate electricity but also alter the atmospheric flow,' says first author Lee Miller. 'Those effects redistribute heat and moisture in the atmosphere, which impacts climate.'... More than ten previous studies have now observed local warming caused by US wind farms." (Lee M. Miller, David W. Keith. Climatic Impacts of Wind Power. Joule, 2018; DOI: 10.1016/j.joule.2018.09.009 https://iopscience.iop.org/article/10.1088/1748-9326/aae102 https://www.sciencedaily.com/releases/2018/10/181004112553.htm, https://www.city-journal.org/wind-power-is-not-the-answer) None of these ten studies were cited in this DEIR, down wind conditions were never mentioned.

Another peer-reviewed article with information about down-wind effects is "Simulating impacts of wind farms on local hydrometeorology" which showed that "impacts are caused by enhanced vertical mixing due to turbulence in the wake of wind turbine rotors." (Somnath Baidya Roy, (2011). Simulating impacts of wind farms on local hydrometeorology. Journal of Wind Engineering and Industrial Aerodynamics 99. 491-498. 10.1016/j.jweia.2010.12.013. (https://www.researchgate.net/publication/251518442_Simulating_impacts_of_wind_farms_on_local_hydrometeorology)

Since a down wind site is the Humboldt Redwoods State Park, this should be analyzed. It is obvious that trees along Highway 101 suffer wind damage; it's not hard to extrapolate that these 600 foot tall fans could change the fog layer over the Redwoods and have unexpected secondary impacts.

page 3.2-30
Mentions the Fields Landing dock is in the Coastal Zone but fails to mention that so is most of the Hookton Slough bypass as well as parts of the other bypasses as shown on the figures in Appendix M.

page 3.2-30 Wild and Scenic Rivers.
Both the Eel and the Van Duzen Rivers are designated. The images of the turbines as shown from Riverwalk clearly indicate that the "natural beauty" and "wildness" are damaged.

Section 3.2.3 Impacts and Mitigation
page 3.2-31 THRESHOLDS OF SIGNIFICANCE
The following thresholds of significance are based on the environmental checklist in Appendix G of the State CEQA Guidelines, as amended in 2018. Implementing the project would result in a significant impact related to aesthetics if it would:
> have a substantial adverse effect on a scenic vista; **(YES)**
> substantially damage scenic resources, including trees, rock outcroppings, and historic buildings within a state scenic highway; (NO)
> in nonurbanized areas, substantially degrade the existing visual character or quality of public views of the site and its surroundings (public views are those that are experienced from a publicly accessible vantage point), or in an urbanized area, conflict with applicable zoning and other regulations governing scenic quality; or **(YES)**
. create a new source of substantial light or glare that would adversely affect day or nighttime views in the area. **(YES)**

That's three YES and one procedural NO because there is no state scenic highway.

Impact 3.2-1
Project Impacts on Scenic Vistas and Potential for Substantial Degradation of Existing Visual Character or Quality of Public Views of the Site and Surroundings. The Humboldt County General Plan does not identify specific scenic vistas. However, the project would introduce wind turbine generators, which would be noticeable at all viewing distances depending on atmospheric conditions. The introduction of these tall vertical structures would degrade visual quality. **This impact would be significant.**

Particular attention should be paid to these paragraphs
pages 3.2-53 & 54 "Ground disturbance to widen shoulders and cut and fill slopes, WTG pads, staging/equipment laydown areas, and batch plant pads would result in adverse effects on scenic vistas along Bear River Ridge and on the visual character of the ridge as viewed from surrounding locations. Grading, compaction, and vegetation removal would increase the potential for erosion, which could further degrade visual resources along the ridge."

"The operation of WTGs in the project area would cause long-term effects from the introduction of encroaching vertical elements (towers and blades) and distractive movement (when the rotor blades are in motion)."

"When spinning, the rotor blades would further contrast with the mostly static elements in view. The WTGs would appear silhouetted above the ridgetop trees. Thus, the project would redefine the skyline. The intactness and unity of the views would be reduced substantially. Vividness would be reduced as well for many of the KOPs, because the WTGs placed along the ridgeline would detract from the surrounding views, described above. However, for some KOPs, the vividness would be increased because of the addition of memorable features. Introducing a wind energy generation facility into landscapes that predominantly feature rural residential and agricultural uses would generally reduce the compositional harmony of these views."

Notice, however that blade flicker was dismissed **(page 3.2-65)**, but it says here they would contrast and create visual distractive movement.

page 3.2-60 "Viewers looking south from SR 211 west of the Ferndale Bridge would perceive nearly the entire 34-WTG layout, entirely within a background view. Thirty-one of the 34 WTGs would be partially or mostly visible from this location, and the project would appear to extend across nearly the entire KOP view. Viewer awareness from this area would be high. Despite the distance between the viewpoint and the project, unobstructed views of long duration and the area's inferior vantage point would allow for moderately high viewer exposure... "It is likely that some viewers would perceive the project as a backdrop to a working, nearly entirely managed landscape. ... In nonurbanized areas, substantially degrade the existing visual character or quality of public views of the site and its surroundings (public views are those that are experienced from a publicly accessible vantage point),"

The images of the turbines from Riverwalk in Fortuna substantially degrade the quality of the views, according to the DEIR.

Even choosing their own sites and the best light, it is obvious even to the writer of this part DEIR that the effects on visual quality are not desirable.

going back to page 3.2-34 "Introducing WTGs to Monument and Bear River ridges would generally reduce visual quality from most locations with views of the project site. The WTGs would be visible from the set of publicly accessible representative views discussed here, although the degree to which they would be prominent would vary, and their presence would be restricted to horizons."

I think the project has shown it would have a substantial adverse effect on a scenic vista for over seventeen miles as shown in the project images. This would affect both residents and visitors - and perhaps the tourism economy. Most disturbing is the added night lighting and flashing red lights where currently there are none. There is no way to mitigate for this change.

As no mention was made of down wind effects, as required by the General Plan (Standard E-S3, Item B) no data was provided of these effects on either the adjacent Humboldt Redwoods State Park - with named natural areas - or the adjacent Humboldt Redwoods timber, or the agricultural fields of the Eel River Valley. I think this is a significant omission and that it should be fixed prior to acceptance of this DEIR.

Truly implementing the project would result in a significant impact related to aesthetics because it would have a substantial adverse effect on [many] scenic vista[s] and add night lighting, flashing red lights, where currently there are none.

returning to page 3.2-62
The proposals for mitigation for aesthetics lists a series of "storm water pollution prevention plan, a grading and erosion control plan, and a reclamation, revegetation, and weed control plan would be prepared to reduce impacts as discussed in Section 3.5, "Biological Resources"; Section 3.7, "Geology and Soils"; and Section 3.10, "Hydrology and Water Quality." ... the same problem here as before, with fast-track construction time table - when would these plans be filed, and how would they be able to be reviewed carefully in the timeframe presented. There is simply not enough information to know if this will be able to be done in the time frame provided by applicants.

Section 3.3 Agriculture and Forestry Resources.
page 3.3-2

Discusses parcels in the project footprint currently within Williamson Act contracts. In general, Bear River Ridge and part of the Gen-tie are most overlapped with these parcels. The DEIR does not mention changes to taxation - if any - for these parcels if affected by or built upon as part of this project. Many of these parcels pay reduced taxes because they are in the Act which intends to protect prime agricultural land. Realizing that the general plan allows wind power in this Zoning type, does not mean that these particular parcels are the best fit for this kind of project. Noted elsewhere (page 3.3-11) 27 acres of Williamson Act land would be permanently unavailable to agriculture, which is claimed to be less than significant. My question, if 27 acres is taken out of agricultural production, does the land still get the tax break?

page 3.3-8 Policy AG-P6: Agricultural Land Conversion
I do not think an overriding public interest exists in this conversion, nor do I think there are no feasible alternatives.

page 3.3-9 Policy FR-P8 Protection of High Quality Timberlands
I think this project is in conflict with this goal because elsewhere in the DEIR they plan to do things (like build in winter) which violates the Humboldt Redwoods Habitat Conservation Plan. If the HCP says that these things are required to maintain forest health, then this DEIR cannot come along and say the opposite. But that is what is happening. More trees than the HCP specifies will be cut; the agreements of which kind and where just tossed because all the cutting will be where the developer wants it to be.

There is no discussion of down wind effects at all in the DEIR, this is required by Standard E-S3, Item B (page 3.2-28+). Down wind effects along the highway damage and kill redwoods, which is obvious to anyone driving 101 between Stafford and Garberville. Since there is no data provided by the DEIR, we must rely on observation and common sense and say that - like elsewhere in the U.S. - the changing wind patterns created by the industrial turbines will have an effect on adjacent property. Since they are surrounded by Humboldt Redwood timber company and Humboldt Redwood State Park (also full of trees), I think the down wind effects will occur first on those trees and damage High Quality Timberlands.

Since I wrote the foregoing paragraph, I read a recent work by researchers at Harvard which found that large-scale U.S. wind power would cause warming that would take roughly a century to offset. "Extracting energy from the wind causes climatic impacts that are small compared to current projections of 21st century warming, but large compared to the effect of reducing US electricity emissions to zero with solar… 'Wind turbines generate electricity but also alter the atmospheric flow,' says first author Lee Miller. 'Those effects redistribute heat and moisture in the atmosphere, which impacts climate.'… More than ten previous studies have now observed local warming caused by US wind farms." (Lee M. Miller, David W. Keith. Climatic Impacts of Wind Power. Joule, 2018; DOI: 10.1016/j.joule.2018.09.009 https://iopscience.iop.org/article/10.1088/1748-9326/aae102 https://www.sciencedaily.com/releases/2018/10/181004112553.htm, https://www.city-journal.org/wind-power-is-not-the-answer) None of these ten studies were cited in this DEIR, down wind conditions were never mentioned.

page 3.3-12

For all the trees they cut, if they are "merchantable timber" do they plan to cut, haul and process at local mills? Ninety-one acres of foot print will never be able to be reforested, but they do not mention the trees that will be cut on the Gen-tie line and the open space maintained with herbicides. There is no mention of TPZ (Timber Protection Zone) or a HCP (Habitat Conservation Plan) or a Timber Harvest Plan associated with the Gen-tie clear cut. I think that the Gen-Tie clear cut should be addressed as part of the total impact. And while it is compatible with The California Codes Government Code Section 51100-51104 reads in part "This chapter shall be known and may be cited as the California Timberland Productivity Act of 1982...(b) The state's increasing population threatens to erode the timberland base and diminish forest resource productivity through pressures to divert timberland to urban and other uses ... Legislature (2) Discourage premature or unnecessary conversion of timberland to urban and other uses. (3) Discourage expansion of urban services into timberland... compatible use: (4) The erection, construction, alteration, or maintenance of gas, electric, water, or communication transmission facilities."

Wherein compatible uses include electrical transmission facilities; Generation Facilities do not appear to be a conforming use. I think the DEIR should address this.

Section 3.4 AIR QUALITY

Impact 3.4-1

"Short-Term, Construction-Generated Emissions of ROG, NOX, and PM10. Short-term, construction- generated emissions would exceed NCUAQMD's significance threshold for NOX. This impact would be significant."

page 3.4-15 & 16

The DEIR models construction related emissions, but fails to include any logging equipment, or logging trucks removing the trees they will have to cut down for access roads. Logging is not even mentioned in this section, although it is said to be the first thing that will have to happen to allow construction. **(page 3.3-12)** Two-stroke engines such as chainsaws are some of the worst air polluting gasoline devices, but they're not even mentioned - although obviously they will be in use.

The impact of the loss of 75 to 100 foot wide corridor of forest which will be cleared for the transmission lines is not mentioned.

Trees absorb CO2, removing trees will lead to more CO2 in the atmosphere. Is the amount of CO2 "saved" by this project greater than the amount displaced by the project's removal of vegetation? I did not see this calculated anywhere in this section. They do mention construction transportation emissions, but not logging and removal emissions.

There are no emissions modeled from ocean transport and delivery operations.

There are no emissions modeled for bypass construction and removal.

There are no emissions modeled for subcontractor operations although the subs wouldn't be here if the general wasn't working.

3.4-17
Omits transportation of components - focusing on the construction not delivery.

Dust is stated to be planned to be controlled here, but it is unclear where they plan to control dust as they have only mentioned it in connection with the batch plants and construction on their actual footprint. Obviously pouring gravel along Highway 101 would also produce dust, but this is not accounted for in this section. Nor is a water source given for any dust control at Hookton or Fields Landing.

page 3.4-18
Table 3.4-3 is for Construction-Related Emissions only
"As shown in Table 3.4-3, emissions associated with construction of the proposed project would exceed the NCUAQMD maximum daily thresholds of significance for NOX. Therefore, construction of the proposed project could result in the short-term generation of a substantial level of emissions of criteria air pollutants and precursors. This impact would be significant."

page 3.4-19
"As shown in Tables 3.4-5 and 3.4-6, maximum daily emissions of NOX would still exceed NCUAQMD threshold of significance. Therefore, this impact would be significant and unavoidable." An either/or mitigation is proposed but its not really mitigation, but minimization as it does not eliminate the problem but attempts to reduce by temporal dilution, slowing work to reduce less.

page 3.4-20
Please explain how this sentence is accurate. "Construction of the proposed project would result in emissions that would exceed NCUAQMD's daily emissions thresholds for NOX, even with implementation of mitigation. Project construction would not exceed annual emissions thresholds."

If daily emissions are exceeded, and the project takes a year to 18 months to complete (as stated elsewhere), then the exceeded time for emissions would be 18 months and it would exceed annual emissions thresholds.

page 3.4-22
"Each of these activities would occur in a distinct location, and emissions would be distributed throughout the region, not concentrated in the immediate vicinity of sensitive receptors."

This is the "dilution is the solution to pollution" logic and also introduces sampling bias. In this pathway it's presumed ok to create a whole bunch of places of new pollution, adding greenhouse gasses, NOX and other pollutants to a landscape which is currently functioning as a large carbon sink because the work places are far apart. If I built three factories all at the same time, I would have to consider the cumulative impact of my three factories, not brush off my impacts as "they are too far apart to matter."

This section also omits to mention the barging/unloading/transport of components at Field's Landing which is primarily a residential community. I think the effects of air pollution on that community should be studied since they will be affected 7 a.m. to 10 p.m. for up to half a year.

This is currently one of cleanest air basins in California. There is no reason to change that for a year to a year and a half for a construction project, no matter how noble the goal thereof.

Section 3.5b Biological Resources

Operational Impacts
page 3.5-70 "The project's primary operational impacts of concern would be collisions of birds and bats with WTGs while flying through the rotor swept area, and barotrauma for bats. Operational impacts on birds may also result from (page 3.5-71) collisions with the Gen-tie, though this would be limited because all energized project components, including the entire Gen-tie and all power lines, would be constructed in accordance with the current suggested practices of the Avian Power Line Interaction Committee (APLIC) (2006, 2012) to protect birds from electrocution and collisions."

Barotrauma is not discussed elsewhere in the document, or listed on "IMPACT 3.5-18 Operational Impacts on Bats. Operation of the proposed project could result in mortality of and injury to a large number of bats, including special-status bat species, as a result of interaction with wind turbine generators. This impact would be potentially significant." (Section 3.5-134.)

page 3.5-72
Project site is one quarter mile from Federally Designated Critical Habitat for Special Status Marbled Murrelets. This doesn't seem like the best choice for a wind turbine site. Certainly there are sites in California where the wind blows that doesn't have this - and the many other following environmental impacts.

page 3.5-72
What is "Marbled Murrelet Compenstory [sic] Mitigation," please?

Discussion follows of corvid (crows, ravens and jays) predating on murrelet nests. The proposal to retrofit Van Duzen County Park is insufficient. This approach has been tried in multiple places - if it helped murrelets recover as a species, by now they would be increasing in population. And they're not.

Going back to 5.3-72 to 5.3-75

Mitigation Measure 3.1-1 in three sections. First part, Mitigation Measure 3.5-1a. (page 73) says "to the extent feasible" - which is again putting off to the future information which should be included in this DEIR, and also giving the power to change things to the applicant without public review. Mitigation Measure 3.5-1b reads "if the above is infeasible" (page 74) and 3.5-1c Plans a Worker Awareness Program which does not currently exist. Some of the items on their list such as "identification and values of special status… species" often take years to actually learn; else why would people have biology degrees to identify things. That the "on-call biological services provider (page 75) is not on-site seems to be a bad idea. Notice that while this training is said to include all species, it's mentioned in Marbled murrelets.

page 3.5-78

Corvid numbers are known to decline where trash is covered and drains filtered "in these parks, jay abundance has been successfully reduced by minimizing food accessibility since 2005." Notice the data shows that corvids are reduced, not that murrelets have increased. Coincidence is not causation.

This species has been studied and USFWS has issued recovery guidelines which were not cited in the DEIR. For a full list of papers and guidelines for this Threatened species, please see ECOS, Environmental Conservation System, USF&WS, https://ecos.fws.gov/ecp0/profile/speciesProfile?sId=4467

page 3.5-79

"The area of the old-growth/mature tree stands associated with the compensatory mitigation was measured using Google Earth." How accurate is Google Earth for this measurement? Please provide citations for the Google Earth method of measuring old growth and mature tree stands, as well as the date of the imagery - along with discussion and ground truthing that those stands are still there. It is, after all a timber producing area and most of the Google imagery of Humboldt County is several years out of date. Just because the bottom of the page says (C) 2019 doesn't mean that's when the images were taken.

Why were previous studies of the area not cited?

"Predation rates by corvids on murrelet eggs were based on studies within the redwood forest regions of California, and the effectiveness of changes in predator presence was assessed using predator impact data from the scientific literature."

This literature should be cited here in the DEIR - but there is nothing.

I think their calculations are very precise for having little to no input data and not including the 25 mile long new corvid habitat being created along the Gen-tie route.

Now the DEIR breaks away from murrelets specifically for a section on mortality.

3.5-80 Mortality searches
This section gives parameters for finding carcasses, but does not define "the area where carcasses are expected to land" in repeatable way. The section continues with a discussion of small, medium and large sized carcasses.

page 3.5-80
Describes how they do carcass detection, but nowhere says how far from each turbine they will look. "The wind energy facility search area (the amount of area searched for carcasses relative to the area where carcasses are expected to land around a WTG);" Which is not an acceptable definition of area to be searched. They do propose that "the absence of detected mortality does not necessarily mean that no mortality has occurred." Because you cannot prove a negative, of course and - predators.

I think this search area radius needs to be defined. At a minimum it should be the sweep of the blades relative to the base, meaning, if the blades (all three of them) measure 100 feet from side to side, that a circle centered on the tower, with a radius of 100 feet (circumference 200 feet) be the search area. So Blade sweep times 2 = Mortality Search Area. This would be a minimum measurement for two reasons: (1) The blades sweep items and heave them sometimes quite a distance; (2) The wind vortex created by the blades moves corpses on their way to the ground.

Cadaver dogs have been used successfully at other sites to accurately assess mortality. In every account I have read, searchers describe amazement at how far things get thrown from the turbines. I have personally witnessed bird strike and blade throw at Palm Springs, California and in Indiana. The tossing distances were considerably farther than I would have expected.

Searches should be conducted by independent biologists at not less than annual levels. The DEIR proposes monitoring for the first three years, and "road and pad" searches subsequently. I do not feel this is sufficient.

Mitigation Measure 3.5-2b needs to have clearly defined search areas, times and methods of search. The effectiveness of these methods should be defined and augmented by peer-reviewed literature not personal communications.

Next, the DEIR document has a series of sections about impacts to species.

For all the following sections, biological observations and mitigation measures are proposed, but only the ridge-top footprint was studied. The Gen-tie line (approximately 25 miles by 100-feet wide) was not studied. Fields Landing environment was not mentioned. No Eelgrass survey was performed. Night lighting is not mentioned, although Scope, Transportation, and other sections mention night work. Night time lighting would not only be a problem for the species on the ridge-tops but for Brown Pelicans, Bald Eagles and Harbor Seals (Phoca vitulina) at the delivery site in Fields Landing.

In general, the mitigation methods proposed are disappointing. Mostly they are not true mitigation but an attempt at minimization or even post-mortality "what do we do now" committee forming approach with meetings and reports generated.

Many of the proposed mitigation methods contain the phrase "if feasible" which is great for the developer and potentially terrible if at some point in the future the developer decides that something is no longer "feasible," this would permit it to not get done. Also the way that "feasible" is decided is not mentioned, so any subcontractor could basically do whatever they wanted and it could become "feasible" after the fact. These methods do not seem to honor the goal of environmentally sensitive development stipulated by the county or the goals and intents of CEQA.

Some sections of the DEIR are light on scientific reference and citation, have one year or less of data, and are supported by too many personal communications (pers. comms.). The Biological section needs to include hard science, proper survey durations, accurate citation to published and peer reviewed materials as well as functional mitigation measures backed.

page 3.5-81+

The Marbled Murrelets proposed mitigation includes:

* slowing turbines (creating less MW)
* avoiding murrelet areas - they found 135 total, is that statistically significant for placement?
* "if the Gen-tie is to be placed on a ridgeline", show that it's not high use for murrelets. During construction they are unlikely to remain in the area. That is circular logic.
* Gen-tie won't go within 200 meters of old-growth or mature conifers big enough to have murrelets.

But, "If the two criteria above are demonstrated to be infeasible..." the Gen-tie will get built anyway.

Here's one of the uses of "infeasible" which essentially hands all the power in the relationship to the applicant after the preparation of the DEIR. The CEQA process is supposed to provide a snapshot of all conditions and plans prior to project approval, allowing agencies and the public input to the process. This one does not.

It is known and referenced in this document that Marbled murrelets travel up to 80Km inland, at air heights between 90 and 250 meters. Wind turbine mortality has occurred at other wind farms. The DEIR states "We sampled marbled murrelet activity from seven radar stations located along the Bear River and Monument ridges and one low-elevation station located near the Eel River."

No murrelets were sampled along the 25 mile by 100 foot wide planned footprint of the Gen-tie. I think this is a significant absence of data collection as the creation of that electrical corridor will open the entire area to predation by corvids, fragment habitat, and lead to wind death of adjoining trees to the corridor - as demonstrated by tree thinning and death where other openings have been made.

The only transmission line area studied for the DEIR was at the Eel River. This is insufficient data to make decisions about a 25 mile corridor elsewhere .

"We recorded more morning flights (83% of all flights) than evening flights across the sampling period." *Which means a lot of murrelets coming home got missed.

Consider their natural history: A single egg, laid on the branch of an old tree, up to 88 km inland. Pairs bond, reuse the same nest or nest stand. They forage at sea, averaging 1.4 km off-shore and up to 99 km along-shore in northern California. Hébert, Percy & Golightly, Richard. (2008). At-sea distribution and movements of nesting and non-nesting Marbled Murrelets Brachyramphus marmoratus in northern California. Marine Ornithology. 36. https://www.researchgate.net/publication/242735372_At-sea_distribution_and_movements_of_nesting_and_non-nesting_Marbled_Murrelets_Brachyramphus_marmoratus_in_northern_California

Marbled murrelets live about 10 years, and reach sexual maturity at 2 to 3 years old. They have long-term pair parents share foraging in 24 hour shifts. Imagine if one of them does not come home. How is the other to eat or feed chicks? Since they average 10 years old, there are not many natural accidents which take them out in their prime and their slow rate of breeding would have been an advantage prior to about 1860 when there may have been as many as 60,000 marbled murrelets on the California coast. They have been reduced to 10% of their pre-1860 populations.

Simply put, two long-living bonded murrelets produce one egg at a time on a branch in a special kind of forest. This is not a recipe for a fast breeding or easy to replace organism.

Taking any one murrelet will break a life-partnership, may result in nest abandonment if the loss is in the same season, reduces the breeding population and probably reduces breeding success of the remaining partner in subsequent years. This is not able to be "mitigated" with trash can lids and drain filters in Van Duzen County Park. The 25 miles of new clear cuts are likely to increase corvid predation. The turbines are likely to kill at least as many as they predict - perhaps more - it's a very flexible model with wiggly input data. Change one factor a tiny bit and you get big changes in output. This DEIR's proposed mitigation does nothing to change or minimize the impacts on the species. The new transmission cut through the forest will allow corvids and other predators into murrelet habitat they've not had easy access to before.

Impact 3.5-1 is said to become "less than significant" based on the above mitigations proposed - however since they are modified with "feasible" and "infeasible" I do not think that this truly reduces the "potentially significant" impact because too much is left to some unknown time in the future when something might change.

page 3.5-85
"However, given the uncertainty as to the feasibility and effectiveness of these compensatory mitigation and yet-to-be developed adaptive management measures, operational impacts on marbled murrelet would be significant and unavoidable."

"Yet to be developed ..." means there's no mitigation - it's put off to some vague time in the future at the whim of the applicant

As a creature that lives in two realms, land and ocean - the murrelet is susceptible to two sets of impacts. "In 1992, the Oregon, Washington, and California population of this species was listed as threatened under the Endangered Species Act (ESA) due to the loss of nesting habitat from logging and urbanization, as well as mortality associated with gill-net fisheries and oil pollution." (https://www.fws.gov/wafwo/species/Fact%20sheets/5%20Year%20Status%20Review%202004.pdf McShane, C., T. Hamer, H. Carter, G. Swartzman, V. Friesen, D. Ainley, R. Tressler, K. Nelson, A. Burger, L. Spear, T. Mohagen, R. Martin, L. Henkel, K. Prindle, C. Strong, and J. Keany. 2004. Evaluation report for the 5-year status review of the marbled murrelet in Washington, Oregon, and California. Unpublished report. EDAW, Inc. Seattle, Washington. Prepared for the U.S. Fish and Wildlife Service, Region 1. Portland, Oregon. pages 1-370)

This declining species does not do well with disturbance. Murrelets have been proposed to be extinct by 2050 due to their annual loss of 4-7% a year. (Center for Biological Diversity Natural History Marbled Murrelet https://www.biologicaldiversity.org/species/birds/marbled_murrelet/natural_history.html) This area is one of their last great places. Economically the area receives benefit from birdwatching tourism and the ecology benefits from the completeness provided by non-extinct species. Every one that is lost breaks the fabric in ways that are impossible to describe in advance, but which have long-reaching implications for all the DNA-beings on earth.

page 3.5-84
Has a controversial proposed measure, but there is no statement of who would pay for the proposed canopy manipulation work in the California Parks, that it would benefit the species, and if it were done, it would change the Carbon benefit of this project by releasing stored carbon from even more trees being harvested.

At the end, the compensatory mitigation proposed is changes at Van Duzen Park, and statements that they will "achieve the performance standard of creating at least one marbled murrelet for every indiviudal [sic] taken as a result of the project." These are not widgets being stamped out in a factory. The model for the numbers is based on assumptions. The 25-mile-long Gen-tie predator corridor is still not addressed.

They also do not address impacts from Gen-tie 25-mile clearcut, trash and waste from 300 temporary workers, changes to the habitat by clear cutting at the ridgetops which might result in changes to marbled murrelet use of those ridgetops, and worst of all - every source says - minimize human disturbance. Building this project guarantees 30 years of constant human disturbance in an area where now there is very little. The turbines require maintenance, the road vegetation must be cut, the grass around the turbines mowed, herbicides applied, and so on. None of this is "lack of human disturbance."

The "mitigation" measures proposed for the murrelet (3.5-2a/2b and 2c) do not seem to have any relationship to even the most cursory natural history of the species, the amount of disturbance, and outright take of the species this project would incur. They are - instead of mitigation - minimizations based on untested ideas but which would have no apparent benefit to keeping the population relatively undisturbed and subject to the HCP already agreed upon by Humboldt Redwood. The impacts from the Gen-tie line clearcuts are not offset by proposed mitigation. Mortality searches need to be accurate and independent. Prepare all documents prior to the approval of the DEIR - not at some unspecified time in the future.

Impact 3.5-2 Operational Impacts on Marbled Murrelet is still considered potentially significant even with these measures. I agree because the proposed mitigation methods have no documented success - and because they say they will be taking adults.

California Fully Protected Species
At this point I digress into a discussion of California Fully Protected Species which I feel should have been included in the DEIR.

California has a law dating back to the 1970s which was implemented to protect animals at risk of going extinct before the Federal Endangered Species act was signed into law. In short, "Fully Protected species may not be taken or possessed at any time and no licenses or permits may be issued for their take except for collecting these species for necessary scientific research and relocation of the bird species for the protection of livestock." (https://www.dfg.ca.gov/wildlife/nongame/t_e_spp/fully_pro.html)

Fully protected species of birds and mammals found in this area which may be affected by the project include:
American peregrine falcon (Falco peregrinus anatum)
Bald eagle (Haliaeetus leucocephalus)
Brown Pelican (Pelecanus occidentalis californicus)
California condor (Gymnogyps californianus)
Golden Eagle (Aquila chrysaetos)
Ring-tailed cat (Bassariscus astutus)
White-tailed kite (Elanus leucurus)
https://www.dfg.ca.gov/wildlife/nongame/t_e_spp/fully_pro.html

Any discussion of animals on this list should reference their status as "fully protected species" in the state of California.

Since the state says "no licenses or permits may be issued for their take," I do not understand why the following sections are based upon the idea of getting incidental take permits. This law seems to be clear-cut, there is no way to get a permit to take one of these, let alone taking hundreds as discussed in the following sections.

I will not reference this every time I mention these animals but by definition include the concept of certain fully protected species in all sections of my comments whether specifically referenced or not.

Referencing Appendix E - Eagle & Raptor Aerial Nest Survey

Eagle nest surveys were conducted March 27 & 29, 2018 and Mary 1 & 3, 2018 from helicopter. They did not fly around the Monument turbine proposed sites. (Appendix E - Eagle and Raptor Aerial Nest Survey Report, Figure 5, unpaginated, but 22/25 in the pdf file) The same figure shows few to no flights over the immediately adjoining Humboldt Redwoods State Park.

Referencing Appendix H - Eagle Use Survey Report
Table 1. Survey effort by plot number for eagle use surveys.

Notice the lack of data for plots #28, #29, #30 & #31 during peak raptor season. The reason given is "Biologists conducted 6 survey events at plots 28–31, which were added later when land access was granted."

The accompanying Figure 3 Appendix H (page 22/28 - unpaginated in report) shows that #28, #29, #30 and #31 are on Bear River Ridge - a concept not made clear in the text.

Anyone who likes eagle watching knows that Bear River Ridge from October to April is eagle watcher heaven. Eagles are more active and easier to see. So I read on with interest to see how many eagles the trained biologists had found in this area that I visit often and in which I regularly see eagles - often times without looking for them, they are just there. I expected paid professionals would see a lot more eagles than I do.

I was very surprised. Tables 4 & 5 and Graph 1 (pages 6 & 7, Appendix H) show they spent 129.75 hours to see 11 eagles for 32 minutes total.

Even adding in the one they saw incidentally, their total is only 12 eagles during a year. All were within 800 meters (874 yards) and below 223.2 meters (732.61 feet) in height. This is one of the few places in the document that metric is used. But once you convert it - it's obvious they use area swept by the rotor blades.

Graph 1 (page 7, Appendix H) shows they saw next to nothing in the winter which is atypical. Graph 2 (page 8, Appendix H) lumps together all the sample sites - even though we know they didn't have access to the Bear River Ridge sites until later. Figure 4 (page 23/28) also lumps the data and doesn't point out the absence of months of data from Bear River Ridge - which skews the optics of this image.

page 8: Section 4.5 Age Class and Behaviors
They saw three sub-adult and one juvenile eagle - the rest were adult. That 4 of 11 sightings were not adult shows that there must be breeding occurring in the area.

Table 6 (Appendix H) breaks it out even further, both Bald Eagles and Golden Eagles - California State Fully Protected Species have to be breeding in the area, twenty-five percent (25%) of Bald Eagles and fifty-seven percent (57%) of the Golden Eagles seen were sub-adult.

However as shown in Appendix E - Eagle & Raptor Aerial Nest Survey, they were unable to locate these nests. "Stantec found no active bald eagle or golden eagle nests in the survey area during the aerial surveys, including all the previously-documented (i.e., historic) sites." (Appendix E - page 6)

Conclusion regarding Appendix E & Appendix H
I have a great deal of trouble accepting this part of the data. I am just flabbergasted that they couldn't find eagles - although the lack of Bear River Ridge data may be part of it. They didn't find any active nests - even though what they saw flying around proves that nesting is happening. I never thought of myself as an awesome bird watcher, but I've seen more than a dozen in the last year, with being outside probably less hours than they spent - and certainly less hours in prime habitat.

I think this data set is missing and needs to be redone with different observers with a consistent access to all sites during all seasons of the year.

On the good side, these Appendices have much better project maps than the main portions of the DEIR. Perhaps the good maps could be added to the main body of the document for greater clarity - as these show Staging Areas, and other features glossed over in the main portion of the document.

Back to Section 3.5b, page 3.5-85
For every dead eagle the DEIR proposes retrofitting 32 electrical poles. Why is this necessary if their lines are to be built to current code - it would seem unnecessary to go along and re-build the poles 32 at a time, right after they were just built. If they are retrofitting old poles, will they wait until they have hundreds to do, or do 32 at a time, and if so where? None of this is clear from this section.

page 3.5-86
Eagle populations are going up in Humboldt County. Six historic nesting sites within 2 miles of turbines. Project site is in the Mid-Latitude Pacific Flyway Eagle Management Unit, so it seems

counterproductive to place an impact right there especially as eagles are doing less well out here than they are in the Midwest where there are greater remaining grasslands. The DEIR states no active eagle nests have been detected by their surveyors. Nests are used over time, one was "abandoned" for 22 years and then became active again. Next they hide their dismal observation rate by calling it 0.031 eagle per 1 hour survey period.

page 3.5-86
The DEIR offers pre-construction eagle nest surveys, but remember these are the folks who couldn't find any nests from a helicopter and did find sub-adult eagles showing breeding is happening. I really don't expect a lot from their efforts on this deferred set of surveys - as one can easily see the results from the first time.

page 3.5-88
Suggests that clearing the 25 miles long Gen-tie will create foraging habitat for eagles - and of course eagles get electrocuted on electric wires. I think this creates an unaddressed potential impact because if they make habitat - the eagles will use it and may run into the new lines as well.

page 3.5-89
"Based on a visual assessment of satellite imagery..." seems to mean * we glanced at an air photo and guessed * as the range is "a minimum of 25-50 percent grassland."

Please provide peer-reviewed citations for the "Glance and Guess Grasslands Areal Assumption Determination Method" used at this point in the DEIR. This is important because "Glance, Guess and Assume" results in "less than significant" impact findings.

"<u>Impact 3.5-5 Operational impacts on Bald and Golden Eagles.</u> Operation of the WTGs would pose a risk of collision to bald and golden eagles. This impact would be potentially significant." And blame the eagles, "direct impacts on bald and golden eagles through injury or mortality if they were to collide with operating WTGs." Not if they were struck by a blade.

As for the potentially significant impact, I totally agree, both are fully protected species and under California law no permit can be given for take. This isn't research or livestock. However the DEIR continues as if taking bald and golden eagles is an option, so we shall follow along.

page 3.5-90
After the millions of tax dollars spent on their conservation, it's very hard for me to wrap my head around accepting the death of 114 eagles and other large birds every year as they estimated. These birds would not die of wind turbine strike if this project were not built. "Mitigation" measures are again minimization, not mitigation. No habitat is being bought, no ratios are offered. And both eagles are fully protected so no permits for take should be granted.

They state that the mortality detection outlined for Murrelets will also find Eagles, but as stated before there is no actual method for mortality detection outlined in this DEIR.

The DEIR says they will only study deaths for three years. Given the project is 30 years, they're only offering to sample for ten percent (10%) of the project duration which seems insufficient.

Regarding the same statement quoted at the beginning of this section, all CEQA mitigation measures must be identified in the document, they cannot be counted toward mitigation later. Essentially the DEIR says that if anything is harmed, then they plan to consult on how not to harm things. This is backwards. How to not harm things is the purpose of the DEIR, not to be done after the fact.

There is no mention of any birds in any roadside trees or vegetation to be removed, no mention of the Bald Eagles and Brown Pelicans known from Fields Landing. Eagles are known to nest there from the Eagle Cam on the Internet.

There is no mention of the effects of night work lighting effects on large birds and raptors - or pelicans, shorebirds, night herons, brants or marine mammals - at either Fields Landing or the project site, but Scope, Transportation, and other sections mention night work.

page 3.5-93 Owls
There are 33,213 acres of spotted owl habitat within 0.7 miles of this project.

page 3.5-100
"The Northern spotted owl is covered under the Humboldt Redwood Company HCP and the majority of forested northern spotted owl habitat in the project area is on HRC land. Consistency with the Humboldt Redwood Company HCP is analyzed in Impact 3.5-28 below."

One of the inconsistencies with the HCP is simple. The HCP will wipe out 18% of spotted owl habitat - spread out over 50 years. Clearing of northern spotted owl habitat for the project foot print Gen-tie corridor and other project construction will fragment northern spotted owl habitat. The effect of this fragmentation will be potential increases in predator presence, and increased exposure to wind and sunlight that could alter the microclimate of what was formerly part of the stand interior. These impacts are potentially significant and unaddressed in the DEIR.

The DEIR says 276.9 "temporary loss of owl habitat through timber harvesting" and permanent loss ... 196.7 acres." Since owls use mature and old growth timber, how is any cutting down of owl habitat temporary? The project will last a minimum of 30 years - by then the trees planted after disturbance would only be 30 years old - not yet spotted owl habitat. I think that they underestimate "temporary" here and that the effects are actually permanent - and cumulative because Humboldt Redwood Company will be simultaneously logging as well.

Elsewhere in the DEIR it is stated that the project will not necessarily be in compliance with the Humboldt Redwoods HCP. It is possible that this inconsistency will harm spotted owls, but the information given is incomplete to fully understand their intent.

page 3.5-101
"Develop a map based on the best available information depicting the locations of foraging, nesting, and roosting habitat for northern spotted owls on the project site. This information will guide efforts to minimize habitat impacts during the project's final design."

So, if the project begins in September 2019, and the footprint and faceplate information has been deferred to "final design," and clearing and logging begin immediately - exactly when will this map of all habitat be created?

If that information had been available in this DEIR understanding the potential impacts on species would have been a lot more easily transmitted and understood. This project is obviously time sensitive, but that's no excuse to push required elements off to later dates. Time won't get longer if the planning is procrastinated. There really is no time for a good job to be done on final design under this timeline. Which may result in a situation of the developer insisting the project must go through no matter the environmental cost because they have run out of time to do it right. I think this repeated pushing off to later what should be essential parts of any plan violate the intent of the process and betray the intent of the County Plan for "environmentally sensitive" renewable energy.

Mitigation is suggested as easements on land, or habitat purchase, at some point in the future, but it's not outlined in detail in the DEIR. Some of the land suggested for conservation easement is already publicly owned and should not required additional protection. This looks like another place where important details are being put off to some future date. It looks like procrastinate and avoid because there was no specific commitment in the DEIR - and many commitments are modified with "if feasible."

I disagree with the findings of "Impact 3.5-27 Impacts on Nursery Sites. Construction of the proposed project would avoid colonial bird-nesting sites (rookeries), and would avoid and minimize impacts on bat nursery roost sites. The project site would remain largely undeveloped, and project operation would not result in additional impacts on suitable nursery sites. This impact would be less than significant."

Due to the lack of Highway 101 surveys, as well as Gen-tie surveys, I disagree with their conclusion that this is less than significant due to insufficient data.

page 3.5-100
Impact 3.5-7 - again potentially significant, for disturbing "approximately 546.8 acres" of spotted owl habitat, of which 89.7 are permanent. The easiest way to avoid this is the "no project" alternative.

page 3.5-100 Has an interesting discussion, wherein it states that they will create a "temporary loss of owl habitat" and permanent loss. My question is this. Since spotted owl habitat is "preferably in closed-canopy, uneven-aged, late-successional, and old-growth forests," how does the project applicant intend to turn "temporary" lost habitat into habitat the owls can use again.

Please describe in detail how late-successional or old-growth forests can regrow in the 30-year-life of the project mitigating a "temporary" impact. Mitigation proposed is for permanently affected habitat only.

Referencing Appendix I Biological Resources... Spotted Owls, Section 5.2, page 6
"... sound sources can be expected to range from low (e.g. chainsaws) to Moderate (e.g., pickup truck), to High (e.g., concrete batch plant)."

In the real world, using a chainsaw requires ear protection and standing next to a pickup truck doesn't. I think there is something wrong with this section; and if they can't get something this simple correct - I tend to doubt the attention to detail and veracity of other parts of their work. The sound levels of the construction equipment should be actually described in correct relationship. Sound conclusions throughout the document should be checked to see if this caused any kind of cascading error.

Looking at the figures in this Appendix shows how close the proposed project is to Foraging, Nesting and Roosting Habitat as well as non-Habitat. The former three occupy far more land than the last; showing that the project is setting itself directly into the landscape utilized by Spotted Owls. And there is not a protocol level survey yet for this project.

Return to Section 3.5 page 3.5-101
The proposed mitigation for spotted owls will not happen until about 1 to 2 years after the facility is running. Many owls can die in that time. Barred owl management is mentioned, but its controversial and not widely supported.

page 3.5-102
"...permanent protection of suitable habitat at a 3:1 ratio."
Is it usual to wait two years for project applicants to purchase mitigation land - or acquire conservation easements? Seems like more "Effects now, repairs later" which isn't in the spirit of this process.

page 3.5-103
Existing roads are 30 feet, to grow to 200 feet wide during construction. This scar will stay even if the roads are reduced to less than 200 feet later.

page 3.5-104

Barred owl data being used to extrapolate to spotted owls. If the two were the same they'd have the same name. Just because there was no data from elsewhere doesn't mean that collision likelihood is low. It means you have no data for this species. How many WTGs in spotted owl territory now? None, right? i.e. No Data.

One comment from page 105 needs to be mentioned here. The biologists surveyed in daylight. Owls are active at night. The biologists did not get a lot of Owl data. There is most likely an obvious and good reason for that, since you have to be out there, looking for Owls at night to find any.

"The benefit to the affected population shall be demonstrated to offset take by creating one northern spotted owl for every spotted owl taken as a result of project operation."

So if we took any single human being out of the population, we could just replace him/her with a tiny baby with no parents and it would be a benefit? Forgive my sarcasm in the foregoing, but it is biologically obvious that any old bird doesn't just replace any other old bird in a long-lived bonded mating, slow reproducing species in decline.

Some birds are better breeders than others, some are past their breeding lifespan but of course still have habitat and social value within their own community. To say that one bird is as good as another shows that this is not about conservation.

Notice also on page 104 that Mitigation Measure 3.5-8 "Avoid ... Northern Spotted Owls" then just goes into Mitigation measures listed earlier for Eagles (maintain landscape, tower design, electrified armoring) ... part of which is if they kill any, they'll get together with the agencies, and everyone will feel terrible together, but the animals will still be dead. There is not a single value added for the spotted owl here until at least 3.5 years after construction starts. They live within 0.7 miles of 30,000 plus acres of the project site. It's in the middle of prime spotted owl habitat; owls are known to get chopped up by turbines; and there is no spotted owl data for wind turbines. This whole section is guess work with no data and "mitigation measures" that are not even minimization until after take.

IMPACT 3.5-8 Operational impacts on spotted owls are also considered potentially significant prior to some minimization measures as listed above. The owls are blamed for colliding with the blades, not the blades hitting owls who have not evolved to deal with giant objects whirling at a hundred miles an hour.

page 3.5-103

What is the peer-reviewed citation for 30 years of dispersal data? Obviously I would not be able to find it if it were in Hamm, pers. comm., 2019 - the first following citation. Usually three decades of data would be published somewhere responsible - not summarized in a personal communication. I find this section weak for lack of citations. There is no way to verify anything.

page 3.5-104
This area is great for raptors. There are 21 species including vultures.

page 3.5-105
Stantec surveyed for birds in the daytime. The DEIR says daytime bird surveys probably missed night owls. At least they acknowledge the sampling bias - although they did nothing to offset it.

page 3.5-106+
Besides the two eagles & the spotted owl, twelve special-status could occur on the site, nine were observed (Table 3.5-5).

Removing trees removes nests. Even if the birds aren't using them right away is not a good idea. Raptors reuse nests. So a bird not there when they survey is not *this has no effect,* but *we didn't see any.* Yet again, no data. It is not possible to draw valid conclusions when data is missing.

Construction impacts are potentially significant. Habitat removal is apparently less than significant. But it is not well explained and it feels like information that should and could be provided here was omitted.

page 3.5-109
Operational impacts are expected to be potentially significant, and again the birds are blamed for colliding with operating WTGs.

The highest rate they found was 5.69 avians dead per WTG/year. So for this project 300 birds a year, lowest estimate. Special status raptors comprised 12/227 (of all raptors) in Stantec Survey, or 5%, thus we can suggest that 5% of the raptors killed every year would be dead special status raptors.

Notice that of the 16 facilities in the region, Peregrine falcon (1), and five other special-status raptors have been killed. Peregrine falcons are a California Fully Protected Species for which no take permits can be issued.

page 3.5-110
Another way they calculated was median raptor mortality of 0.74 raptor per mW per year. There could have up to 114 dead raptors per year. This would be 5.7 Special Status Raptors per year (5%).

They note that mortality is higher at wind farms in the Pacific Region and promptly try to compare the project to an inland site in a Christmas Tree Farm. "...[T]he habitat at Hatchet Ridge is similar to that at the project site," and add "Because raptors generally occur at low densities given their large territory sizes and are long-lived, often with a relatively low reproductive rate, this impact on raptors could be potentially significant, particularly for special-status species expected to occur regularly on the project site such as the Cooper's hawk, sharp-shinned hawk, burrowing owl, ferruginous hawk, and northern harrier. This impact would be potentially significant." I agree that this is potentially significant. From a taxpayer standpoint, millions of dollars have been spent to conserve species we are now being asked to chop up to benefit project investors.

The suggestion to compare to Burney came up so many times that I read the Burney EIR. Burney is a far inland site, nowhere near a redwood, outside of murrelet and spotted owl habitat and with fewer biological issues compared with this DEIR. Their turbines are also shorter than 600 feet and there are fewer of them in Burney, so really no comparison.

page 3.5-111+

The DEIR proposes mitigation which would not begin for three years. "After collection of 3 years of post-construction monitoring data, the Humboldt County Planning & Building Department will review the data and, in consultation with USFWS and CDFW, will determine which, if any, specific WTGs generate disproportionately high levels of avian mortalities (based on evidence of statistically significant higher levels of mortality relative to other WTGs)"

They do not state if the Humboldt County Planning and Building Department is able to review the data on dead birds. But that would be after - by their own estimates - 342 Raptors had died. You or I kill one - we go to jail. They plan to kill over 300 and sit around and talk about how not to do it again - three years later? The phrase "any feasible measures" reappears, if the applicant decides something isn't feasible, it won't happen. There is no attempt to purchase habitat or do anything that would actually benefit these species. Finally on 3.5-111 it's stated that the take of as many as 114 raptors/year is "significant and unavoidable."

Besides all the other bird mortality discussed, I think discussion of taking any of California Fully Protected species, with forethought - as expressed in this DEIR - is no different that expressing intent to break any other law of the state. This is not the only law this DEIR is intending to ignore; they state they will do winter construction in violation of the Humboldt Redwoods HCP.

I would like to know why it is ok for corporations - otherwise judged to be individuals - to be treated any differently than any other individual when it comes to Fully Protected species for which none of the permit loopholes are applicable to industrial scale wind. This is not a casual question. Please describe in detail.

The DEIR mentions that the Cape Mendocino Grasslands Important Bird area at the project footprint, and that Fields Landing on the edge of Humboldt Bay is an Important Bird area, without making the connection that citing this project in areas recognized as important bird habitat is only setting up for impact later.

page 3.5-115

The Horned larks section is troubling. There are two citations for Horned larks.

One from 1931 when 50 pairs were observed nesting (Grinnell, J. 1931. The Streaked Horned Lark Breeds in Northwestern California. Condor 33:74–75.) The entire text of this publication reads "The Streaked Horned Lark Breeds in Northwestern California.--Through the special effort and generosity of Mr. George D. Atwell, of Eureka, the Museum of Vertebrate Zoology possesses four horned larks from Humboldt County which I identify as Otocoris alpestris strigata. Mr. Atwell collected these on the prairie-topped divide at about 1800 feet altitude between Bear River and Eel River in Humboldt County about seven miles from Capetown. The birds there numbered about fifty pairs in the early summer of 1929. One of the birds, a male, no. 63976, was taken on May 9 with a nest and four fresh eggs which Mr. Atwell collected. Another ofthe four birds is a juvenile (no. 63983) not quite fully grown, taken June 2. In so far as known to Mr. Atwell in May and June, 1929, this colony, occupying a territory about one by one-half mile in extent, was the only one in Humboldt County. While perhaps not extreme for strigata, the three adult males collected by Mr. Atwell are, together, as regards both measurements and color tones, much nearer that race than any other; indeed I cannot distinguish one of them from a breeding male from Salem, Oregon. The juvenile is darker colored than any juvenile, of whatever race, I have seen from elsewhere in California. J. GRINNELL,--Museum of Vertebrate Zoology, University of California, Berkeley, December 7, 1930."

The second citation is a document review by "Stantec 2018g/Appendix J." Please turn to Appendix J, page 46, where the only cited reference to Stantec occurs at 2018, "Draft Humboldt Wind Energy Project Biological Resources Work Plan, Prepared for Humboldt Wind, LLC. 49 pages + appendices." So this report is unpublished and the data from it is unavailable for Horned larks. And it's not 2018g, so I am not even sure it's the paper being referenced here. There is no Stantec 2018g in the References section either.

The lack of citation continues, the remainder of this section is credited to unpublished "personal communications." While I agree that amateur naturalists have and continue to make a great contribution to anecdotes in natural history - as in the Grinnell citation above; basing a study of this importance on one published paragraph and a conversation or two is not at all the same as utilizing published peer-reviewed papers from scientific journals.

At a minimum, the California Department of Fish and Game species page https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=1971 and range map https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=68696 could have provided recent citations and range information. They were apparently not consulted.

This reinforces the view that this DEIR was rushed because a complete literature review has not been performed. Other special status birds which may occur on the project footprint were not found. Whether that is sampling bias or lack of occurrence was not made clear. Owl sampling bias of only looking in the daytime would certainly reduce the number of owls observed, and so on.

page 3.5-112 & 115
Contains the only mention of birds at Humboldt Bay, but does not list the Pelican or the Bald Eagle, only special-status birds. It mentions the Eelgrass at Fields Landing and references figure 3.5-4. But it still doesn't regard this as part of the project area. It claims no impacts on Eelgrass, it claims no impacts on avian habitat in Humboldt Bay, but it doesn't mention night lighting.

I think that's incomplete. All species should be listed and the effects of 3 p.m. to 10 p.m. every night lighting for more than 30 days plus the noise and human activity will be significant.

This section also mentions why they don't do any impact on riparian areas is because the Gen-tie will go under the Eel River. However, if one of the other options is chosen and the line goes over the river, this section is incomplete because then construction would shift to the river banks - for which no data is presented.

page 3.5-121
How will the compensatory mitigation be provided? There are no details.

page 3.5-126
"Operational impacts on the project area's horned lark population could cause this population to decrease below self-sustaining levels. This operational impact would be potentially significant." I suspect the horned larks might find it unfortunate, too. This is followed by exactly zero mitigation for this identified potentially significant impact.

page 3.5-128
The DEIR proposes to only do post construction mortality monitoring for the first 3 years of project operation and "road and pad" thereafter. I think that mortality monitoring for all species should continue for the entire life of the project with outside biologists, not company workers, doing the mortality surveys in a large enough area and with the use of specialized wildlife cadaver dogs to obtain accurate count of dead creatures in all the foregoing categories. If we must have this project and they must die for global warming, we should document and honor their deaths by recording them and publishing the data.

page 3.5-121
"Regionally, horned larks are only known to breed in grassland areas of eastern Bear River Ridge, so any loss of grassland habitat on Bear River and Monument Ridge would be potentially significant for this small and disjunct population."
Another page, another impact.

pages 3.5 - 128 +

The bat appendix stated that 1.3 million bats are hit by existing wind farms across the U.S. and that to study the bats in this area, 10 or 11 detectors near the ground and one detector at 40 meters up were used to collect data. All their results are generalized from these 11 or 12 data points, all on the ridge area of the project footprint, none from 101 transport corridor, Fields Landing, the Gen-tie route or Bridgeville. Data was collected for a relatively short period of time.

Appendix L: Biological Resources - Acoustic monitoring Page 2

They used 10 sample locations. "Nine of these locations were located along the Bear River and Monument ridgelines and one was located at a low elevation site, near the Eel River"

Their conclusion: "California myotis (Myotis californicus) was the most frequently identified species at five individual detectors and overall, accounting for 25,642 of 53,281 (48.1%) identified passes (Table 3). Big brown bat was the second most frequently identified species and accounted for 9,555 passes overall (17.9%); however, most big brown bat passes occurred at a single detector (Monument 5). Silver-haired bats were also identified often and were the most commonly identified species at two detectors (Monument 3 and Monument 4). Yuma myotis (Myotis yumanensis) were the most commonly identified species at the lower elevation Eel River detector and Mexican free-tailed bats (Tadarida brasiliensis) were most commonly identified at the Bear River Ridge and MET High detectors. Species composition was notably different at the met High detector, where high frequency Myotis species were notably absent in comparison to other detectors (Table 3).

Graphs 13–18 illustrate species composition per detector…."Myotis activity was lesser at the Met High detector, with silverhaired [sic] bats and Mexican free-tailed bats accounting for most activity recorded in the airspace that will be within the rotor-swept zone of turbines. Previous studies have documented vertical stratification of bats within redwood forests, with Myotis more active near ground level and species including silver-haired, hoary, and Mexican free-tailed bats more active at and near the forest canopy (Kennedy et al. 2014). Although not detected in large numbers, Townsend's big-eared bats were present at six detectors during the survey period. At the met tower location, this species was detected by the low detector but not at the high detector." (page 19, Data table, page 14 — Appendix L)

No sample stations were located on the Gen-tie and the sample locations did not even cover their full project footprint. Notice on Figure 3 (unpaginated, but page 32/75 in the pdf) that the sampling locations are not the same as for the eagles. For bats, there is only one data point on all of Bear River Ridge (instead of 4), and so on. Data is on pages 5-11. (Appendix L)

Townsend's big-eared bats were detected at sixty percent (60%) of the sampling stations on the ridge line areas. No surveying for any bats was done along the Gen-tie to or at Bridgeville. No sampling was done from the 600 foot high area of rotor sweep, the highest tower was 40 feet. It is also impossible to do species abundance with acoustics as there is no way to distinguish between one bat many times, or many bats one time each - or any possible combination thereof up to the number of acoustic hits.

Back to Section 3.5, page 3.5-128
They did find bats "... [I]ncluding 10 species that occur at the project site," Later it's 12 of 13 species. This kind of casual error would seem meaningless on the surface but when so many errors appear in every section of a document, one has to wonder about the quality control in the data collection, and/or editing process.

page 3.5-129
"Conduct a habitat assessment to identify potential bat roost sites." Meaning they haven't yet done it but plan to start in September, at the same time as the logging which will destroy the roost habitat. Remember the goal is to get this done by December 2020, there's no time to do studies that could minimize the impacts. And there hasn't been a full two years of studies done for this project, despite the fact they have had time to do them before now.

page 3.5-131
"...tree removal under the guidance of the qualified biologist who has experience identifying bat roosts" The way this is written, they have a specific person in mind, but nowhere is this person identified. This should be a qualified outside biologist, not the same people who did the bird and bat work for this DEIR. It seems this could also be skimped in the rush to start in September 2019 with project goal completion by December 2020 for Federal subsidy. The sheer number of trees they propose removing cannot be examined carefully in the amount of time that remains for the work prior to just logging it all out.

page 3.5-132
"Avoiding the use of nighttime lighting and/or disruptive work around important night roosts." This seems to be limited only to the construction footprint and only during construction. After construction blinking red night lights and daytime strobes are FAA mandated. Fields Landing does not seem to be considered in this section, although there are bats there as well, and nighttime work is planned at the dock/storage areas.

page 3.5-134
"Most bat species are vulnerable to mortality and injury at wind farms as a result of collisions and other interactions with WTGs. Survey data suggest bat mortality from wind farms of up to 70 bats per WTG per year in North America (Arnett et al. 2008), with the highest rates documented along forested ridgelines. Collectively, researchers estimate that more than 500,000 bats are killed every year across Canada and the United States (Arnett and Baerwald 2013; Hayes 2013; Smallwood 2013 in Frick et al. 2017). Mortality monitoring has documented that hoary bats make up the highest proportion of bat fatalities (38 percent) at wind energy facilities (Arnett and Baerwald 2013). In one recent collaborative study, researchers concluded that even with no increase in wind energy generation beyond that available in 2014, the hoary bat population is expected to decline by as much as 90 percent in the next 50 years as a result of wind

energy–related fatalities, with the possibility of near or total extinction." (Frick, W. F., E. F. Baerwald, J. F. Pollock, R. M. R. Barclay, J. A. Szymanski, T. J. Weller, A. L. Russell, S. C. Loeb, R. A. Medellin, and L. P. McGuire. 2017. Fatalities at Wind Turbines May Threaten Population Viability of a Migratory Bat. Biological Conservation 209:172–177 - cited in the DEIR)

So if the hoary bat is going extinct from wind farms, it's not environmentally sensitive or responsible to site more wind turbines in its known habitat as there are other forms of green energy which do not kill hoary bats and will not contribute to pushing the creature to extinction.

Out of sheer curiosity, I did some math. At 70 bats per year, times the maximum 60 turbines, that's 4,200 bats per year for the project. Over 30 years, 126,000. There is no mitigation for take at that scale, certainly nothing proposed in this DEIR.

Reviewing "Impact 3.5-18 Operational Impacts on Bats. Operation of the proposed project could result in mortality of and injury to a large number of bats, including special-status bat species, as a result of interaction with wind turbine generators. This impact would be potentially significant." (**3.5b Biological Resources, cite: Section 3.5 page 134.**)" It would seem that "a large number of bats" is accurate, but it could be thousands or even in the hundreds of thousands, but the dEIR does not quantify it.

page 3.5-135

"As described in Section 3.5.1, "Environmental Setting," acoustic monitoring for the proposed project documented the presence of 12 of the 13 bat species potentially occurring in Humboldt County, and confirmed expected habitat use patterns. Most of the species recorded at the project site are species of conservation concern, including the Townsend's big-eared bat, western red bat, hoary bat, silver-haired bat, and four Myotis species. Overall bat activity in the project area may be relatively high..."

The DEIR is now back to 12 species (not 10) as on page 3.5-128. Credibility is in the details.

Townsend's big-eared bat (Corynorhinus townsendii) is one of the species of Special Concern found on/near the project footprint.

While all bat species have been studied somewhat, the large Townsend's big-eared bat is well known even though it is so reduced from its former range. The National Park Service page on Townsend's big-eared bat reads:

"Historically, this species has declined due to direct killing by people and because of destruction or disturbance of roost sites. These animals are sensitive to light and movement so if they are disturbed during the day, they awake and their ears begin to move as they try to identify the intruder. If the disturbance occurs for more than a few seconds, the entire group takes flight and the roost may be abandoned...Only about half of the maternity colonies known to exist in California prior to 1980 were active by 1991, resulting in an estimated 54% decline of adult females...Consequently, for this species to exist, minimization of human disturbance is essential. In addition, it is essential that habitat be preserved.

The Townsend's big-eared bat:
*Has an average lifespan is 16 years; bats may live up to 30 years.
*Is a highly maneuverable flyer; capable of flying at slow hovering speeds.
*Prefers open roosting areas in large rooms with their fur erect to provide maximum insulation and with their ears coiled back." (https://www.nps.gov/chis/learn/nature/townsends-bats.htm)

One offspring per year and great roost loyalty keep a long-lived species in balance, but these traits are a disadvantage when unusual predators arrive. Declines are attributed to loss of roosts, habitat loss and other human disturbances. When the species was more common it was easier to study. The natural history and behaviors of the species are consistent enough across the range to refer to Pierson, E.D. and W.E. Rainey (1998. Distribution, status, and management of Townsend's big-eared bat (Corynorhinus townsendii) in California. BMCP Technical Report #96-7, submitted to State of California, The Resources Agency, Department of Fish and Game. 36 pp. https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=83812) both for observations and historical data. Although they did not survey Humboldt County, Pierson and Rainey's recommendations include protecting maternity sites from disturbance as well as avoiding the killing of the long-lived adults. Their literature cited is a trove of information on this and other species to the turn of the 21st century - as a pre-Internet age citation list it is invaluable. In 1998, the scientific name was Plecotus townsendii townsendii, presently assigned to the genus Corynorhinus. Literature searches should include both names as older works are often not found - and not cited in the DEIR. Perhaps a more complete literature review would fill in some of the unknowns cited in this document - as several of them were found on the internet NPS site with search.

page 3.5-130
"As an alternative to doing extensive surveys to determine habitat use patterns and/or to determine whether the roost is used by Townsend's big-eared bat, the project applicant shall assume that all potential roost habitat rated 2 (high suitability) is identified roost habitat rated 3 (identifiable roost), and shall remove it and compensate for its loss as described below."

Please have the applicant explain how this method will not result in the removal of Townsend's long-eared bat, and other SSC bat species rookeries as was stated elsewhere in the DEIR. (page 3.5-131, et alia)

This "Assume, Remove and Compensate Method" doesn't seem to fit with the ecologically sensitive goal of the project or the spirit and intent of CEQA.

page 3.5-131
One thing really sticks out about the mitigation measures proposed for the Townsend's big-eared bat. First the DEIR says that no bat nurseries for Townsend's will be taken.

To put this in context, these bats use special ventilated basal cavities in old growth called "nurseries" (https://www.nps.gov/chis/learn/nature/townsends-bats.htm) and they fluff out their fur to thermoregulate. Not much is known about life inside the cavities, as any disturbance causes them to leave.

The DEIR says that killing adults would be mitigated by artificially creating bat roosts in otherwise healthy trees or creating artificial roosts. No citations were provided to show that either method has achieved any goal in the past.

Despite that problem, there is an additional situation caused by this proposal because this would be creating a basal cavity - probably with a chainsaw - in the bottom of a healthy old redwood or other tree to attempt to mimic natural chambers, the full effects and desirability of which to the Townsend's big-eared bat is not known. Townsend's are also known to abandon roosts if disturbed - at a loss to the species of that year's young in some cases. Creating fake roosts won't bring them back. And damaging healthy trees with basal cuts doesn't help the forest. It would appear to be a unmentioned secondary impact.

page 3.5-133

The DEIR claims that because bats in bachelor and migratory roosts can fly, they can fly away from construction disturbances. Then follows an interesting statement that "hoary bats and red bats change roosts frequently and mothers can move their young; therefore they too would have capacity to fly away from disturbance." Capacity is not the same as being good for the bats. It leaves out the effects on the mom of having to tote around a baby. If the disturbance is during the day - like most construction - the bats may become confused and unable to save themselves. This is not addressed.

page 3.5-134

"Impact 3.5-18 Operations can cause dead bats, potentially significant."
Besides the Townsend's big-eared bat, other Species of Special concern detected at the site include hoary bat, western red bat, silver-haired bat, and four Myotis species

"Hoary bats have been captured in exceptionally high numbers, especially during the fall, at the Humboldt Redwoods State Park study site approximately 4 miles from the project site. This discovery of what may be fall swarming behavior of hoary bats has not yet been documented anywhere else, it could represent a vital life history component for this species (Szewczak, pers. comm., 2018), and it may demonstrate a seasonal concentration of mating hoary bats from all over western North America (Johnston, pers. comm., 2018). Locating a wind farm so close to this unique concentration of hoary bats may increase the mortality of this species if they use or are attracted to the project site following construction."

page 3.5-136
"Because little empirical demographic and population data exist for the species, it is difficult to evaluate the significance of such high fatality (Frick et al. 2017 - previously cited from DEIR)."

In other words, just kill a lot and then worry about the effects? Really? How do you get from hoary bats are declining and could be extinct (as above) to "difficult to evaluate"? If the curve is trending downward, and additional creatures are expected to be killed, then the curve will continue a downward and expected trend. Reducing species to zero is not the intent of the California Environmental Quality Act, nor desirable for the environment.

Besides those two bat species, there are still more bat species of special concern to consider: the western red bat, silver-haired bat, and four Myotis species. The DEIR tells exactly nothing about any of them other than their existence and offers no mitigation methods for their demise or harassment. It is important that all species be studied, particularly Species of Special Concern. I think the applicant needs to fully address the 3D spatial use by bats around the footprint - and study for all bats along the Gen-tie line - which so far is not considered at all.

I found the concept that a committee (TAC) would be formed to talk about dead things, figure out if bats are being pushed to the edge, and identify minimization measures "while recognizing the operational needs of the facility" to be weighted to the concerns of the applicant more than those of the species or the environment and I do not think it is a valid mitigation measure to sit around and talk. This is not even mitigation sometime next year, this is "we ran out of time to finish writing our species reports and turned it in anyway because we're on a deadline" and "we're going to do whatever we want anyway" in plain English.

"The primary method that has been shown to reduce bat fatalities at WTGs is the use of operational minimization protocols during high-risk periods."

So less power to save the bats, just like less power to save the birds, and less power when there's high wind, and less power when there's no wind, and so on. Obviously there is not a serious intent to meet the 155 MW goal, which could easily be met by installing sufficient solar panels.

"For example, ultraviolet visual and ultrasonic acoustic bat deterrent systems offer promising potential to reduce bat collisions with WTGs (Szewczak and Arnett 2008; Arnett et al. 2013; Hein 2018; NRG 2018). Over the life of the project, such approaches in development may be found appropriate for use with the proposed project."

"Promising potential" means it's not a real thing yet.

These lights are not mentioned in the lighting section creating yet another unaddressed impact.

Notice that on the table, nine of 13 bat species expected are of conservation concern. The siting of this wind farm seems to not fulfill the qualification for "environmentally sensitive siting" put forward by the County and which is one of the goals of the entire process.

I feel that the bat studies are incomplete due to:

- Limited number of detectors
- Different sampling sites than for eagles and other species.
- Partial year data (one day in March, detectors from April to October and no data for rest of year),
- No Gen-tie, Highway 101 and Fields Landing project location data for bats.

It's known that birds, raptors, owls, bats, all will be killed by this project over the 30 year operational life. Mitigation measures offered include post mortem meetings and much report writing along with maybe putting a few conservation easements on land which may be decided upon later and a lot of statements of "if operationally feasible" which puts all the power in the hands of the applicant (and subcontractors) to decide on a case by case basis what is feasible or not at some later date up to 30 years from now.

This creates piece-mealing and puts off to the future impacts which aren't even considered in this document. This is neither the way to tread lightly on the environment, nor to fulfill the spirit and intent of the CEQA process.

The DEIR bat mitigation measures are:

- Unproven with documented peer-reviewed literature.
- Able to create secondary impacts (nesting cavities).
- Generally inadequate for expected mortality.
- No thresholds at which mitigation is required to initiate.
- No guarantee of access for California Dept. of Fish & Wildlife for SSC species.
- Full of paperwork and meetings after expected mortality expectedly occurs.
- Particularly inadequate for the ones for which no mitigation measures were proposed, which include several Species of Special Concern.
- Primarily focused on mid-air strike.
- Changeable. "If feasible" should be removed wherever used.
- Incomplete. No Bat Roosting Habitat Map
- Incomplete. Barotrauma was not mentioned.
- Incomplete. Habitat loss was not offset.

No one will dispute that wind farms kill flying creatures - insects, birds and bats. Therefore the impact is obviously potentially significant (the sad pun in that statement is unintended).

Mammals page 3.5-139 & 140
While the Humboldt Redwood Company has documented Ringtails ten miles north of the site with camera traps, badgers are documented only with a personal communication.

No Ringtails were observed - although they are easy to spot at night. This is possibly due to sampling bias created by biologists being there in daylight and ringtails being out at night. (Also see Owls, 3.5-93 above for same potential sampling bias.)

Amphibians page 3.5-146
Red-legged frogs at Humboldt Bay National Wildlife Refuge are mentioned as well as on the project site in the hills. However, I disagree with their statement that habitat is "marginal" at the National Wildlife Refuge. Having given many frog programs for them over the years, I know that Red-legged frogs are extremely abundant in natural and modified wetlands within a quarter mile of the proposed gravel bypass. However the DEIR doesn't give a mitigation for what is going to do happen to them at Hookton Slough "Visitor Access Road" culvert with geofabric and tons of gravel. Nor how they will mitigate for the loss of the linear water features parallel to the Highway and the Wildlife Refuge, nor at the wetland at Field's Landing entry ramp to Highway 101, or at Strong's Creek in Fortuna, and other locations along their transportation section where bypasses are being created. I would think fish would be impacted also by this bypass but it's not mentioned.

page 3.5-147
The DEIR mentions a major concern about drilling under the Eel River and one which I have personally observed on a Schlumberger project. In horizontal drilling, the drill bit is lubricated with bentonite "mud" made from volcanic ash and water. Sometimes the bentonite will leak out (some say "frac-out") during the process and smother vegetation, animals, spawn and eggs in the water and on land. River flow would distribute this fine, sharp and acidic material all the way to the ocean. pages 3.5-158 and 159 describe the reactions to frac-out should it occur.

The way to reduce this potential impact to zero is not to do it at all. There is no other way to guarantee this environmental disaster will not occur.

page 3.5-151+
Pre-construction Survey Plan for Amphibians and Reptiles is proposed as a mitigation measure. This should be done before the DEIR was issued.

No mitigation measure other than survey is proposed for Western Pond Turtle although there is habitat for the species in the footprint.

page 3.5-152
The Yellow-legged frog for some reason has purchase of mitigation land after one year of power generated. This doesn't seem to be listed for any other species. Is there some particular

reason this species is special like this? Saving land won't do the species any good if the streams are all silted up from winter logging.

page 3.5-157

"Pinning the barge against wooden piles connected to the shore by a mooring line" does not seem to be the same as described elsewhere in the EIR where they mentioned a type of pin dock.

page 3.5-159

A Special Status Plant Survey in Spring & Summer 2019 needed because they only did a "reconnaissance level" plant survey in 2018. So all this section is based on not much data again. Read carefully, they are relying on California Native Plant Society data and personal communications. But then page 160 they quite firmly have a number of acres of disturbance for plants they didn't apparently see.

page 3.5-167

Specific mitigation for only checkerbloom is proposed.

page 3.5-168

The revegetation plan is described as "Locally sourced seed mix", but above the DEIR talks about seed mixes to deter small mammals. One or the other is correct - quality control needs to decide which it is.

page 3.5-171

Discusses Eelgrass. But says no survey was done, because data was available from other sources and the Eelgrass beds mapped in 2016 by CDFW "do not overlap with the project boundaries." However "Eelgrass occurs in the immediate vicinity of the proposed unloading location," and its visible on "recent aerial photos" beyond the old mapped boundaries. Even so, no Eelgrass survey.

Fully loaded barges will draft about 7 feet, low tide can be 2.5 feet. The potential for bottoming out on the Eelgrass exists. But the impact is given as less than significant if nothing goes wrong. And we all know Murphy's law and that time and tide wait for no man. One problem with their process and a 7 foot draft barge will be 5.5 feet deep in low tide Humboldt Bay mud (and Eelgrass).

There is no mitigation proposal for Eelgrass damage, as well as no current map.

Over a decade ago, a decorated bike race called the Arcata to Ferndale Kinetic Sculpture Race was required to do an Eelgrass Survey for three hours use of one day of the year on a slough. I think if that requires a survey, that the developer of a major project impacting the bay for over a month with tugboats, barges and piers has to do one too. There cannot be two laws - either an Eelgrass survey is required for everyone - or it would be required for no one.

page 3.5-173

Table 3.5-15 "Sensitive Natural Communities Other than Riparian Habitats" doesn't use standard nomenclature and puts different species assemblages together than have been considered in peer-reviewed literature. Please provide citations for this division of Natural Communities. Refer to page 3.5-171 for the statement about "Of the 83 vegetation communities mapped on the project site, 43 are listed by CDFW as sensitive natural communities. Since the named ones on the table are not the same as CDFW published lists, its not possible to compare head-to-head. A full list should be provided.

page 3.5-176

The DEIR plans to replace trees at a 3:1 ratio (three planted for one removed) will just set up the situation described in the marbled murrelets section of replanted forests needing thinning in a few years. There is no indication of sex, species ratio or composition - it's as if all trees are the same.

page 3.5-177

If communities are being compensated at a 1:1 or 3:1 ratio, where is the land coming from to replace the area cut? I don't see any land purchases offered. They cannot plant 3:1 in the Gen-tie corridor, that has to remain open for the full 30 years or more. And there doesn't seem to be any offer to compensate for the cutting of the trees in the Gen-tie line, nor is there a Timber Harvest Plan for those trees. It is not mentioned if the wood is to be sold - isn't there a restriction on selling timber that wasn't taken from a TPZ or wasn't subject to a TPZ when harvested?

page 3.5-182

Back to 10 species of bats, again. As before this shows rushed writing and careless editing.

page 3.5-183

Coastal Development "For the purposes of this DEIR, it is assumed that the project applicant would acquire a coastal development permit from the County through the Local Coastal Program, and from the CCC if required. The project applicant would apply to both entities and comply with any conditions of issued permits. As a result, no impact would occur. This issue is not considered further in this DEIR."

This section reminds me of the "if feasible" part of the mitigation measures. The applicant is making rules for itself - and perhaps not realizing that if this is appealed to CCC it could be months before it was heard. Perhaps because the applicant has only done inland California wind farms - they don't have enough experience with coastal to realize the full temporal potential of that process.

page 3.5-184

"Extent feasible" arrives again, this time to reduce the impact of construction in streamside management areas. Seriously, this is not the intent of CEQA to constantly put off to later, to some subcontractor or laborer to create secondary impacts of unknown type and number just because it makes it easier for the applicant.

Conflict with an Adopted HCP
This section is troublesome. The stakeholders, the county and the community worked on the HCP and now the first person to come along can just decide to honor or not honor it - as it suits them? That is just not how things are done in environmentally sensitive areas. It's not the spirit or intent of CEQA to absolve the applicant of complying with laws and agreements that already exist on the landscape.

page 3.5-187
"18 months... first phase... staging area at Jordan Creek and the access road onto Monument ridge... construction... during the wet season... inconsistent with the provisions of 6.3.3.3 of HRC HCP's ... objectives..."

The Humboldt Redwood Company HCP says no road building or landing construction in wet season (October 15 to June 1) to prevent erosion. **This is another statement by the developer of their intent to not follow the conditions of the Humboldt Redwood HCP.**

Notice that they don't say a word about the measures they will take during the first phase, logging and vegetation removal. Their list of activities starts with "construction," elsewhere in document separated from logging and vegetation removal.

page 3.5-188
A stop work authority to the County will do absolutely nothing after the predictable landslides occur. Remember Stafford.

Section 3.6 CULTURAL

Impact 3.6-1 Change to the Significance of an Archaeological Resource. Multiple documented or assumed eligible cultural resources in the project area have the potential to be damaged or destroyed by project implementation. This impact would be potentially significant.

Table 3.6-2 says that Bear River Ridge and valley is historic assumed eligible, inside and outside the project site and doesn't have any mitigation for it at all. Same with Scotia Historic District.

The cultural significance of Bear River Ridge was not addressed on the chart

A letter dated July 13, 2018, Ted Hernandez, Cultural Director with the Wiyot Tribe reprinted in the project documents reads: "that the Wiyot Tribe has concerns about the project and locations of project sites."..."The Wiyot Tribe followed up with a letter dated March 29, 2019. This letter outlined three issues of importance to the Wiyot Tribe that the Tribe believes would result in significant unavoidable impacts on the natural and physical environment:

- Bear River Ridge, known as Tsakiyuwit, is a defining feature of the large Wiyot cultural landscape, the southern boundary of Wiyot ancestral territory, and a coastal prairie that supports numerous ethnobotanical resources critical to the survival and cultural of the Wiyot people.
-
- In a separate document (Wiyot List of Plant Species of Environmental and Cultural Concern), the Wiyot Tribe provided a list identifying ethnobotanical plant species, including 27 species that can be found in a coastal prairie environment, and the area that the Tribe has identified as an ethnobotanical area. Evidence of ethnographic use of the ridge is further supported by the presence of the prehistoric sites P-12- 0314, and HUM TG-02, and isolated milling tools. Old-growth Douglas Fir trees provide further evidence of the prehistoric use of fire in the management of the biological environment, including Siskiyou checkerbloom, tarplant (hushurawu'n), and tanoak.
-
- Tribal elders indicated that Bear River Ridge was most likely used as a high prayer spot. In summary, the Wiyot believe that Bear River Ridge qualifies as a tribal cultural resource and that impacts associated with the placement of "sixty 500 foot-tall wind turbines would alter the spiritual and sacred view shed of the Wiyot cultural landscape." Government-to-government tribal consultation was held between the County and the Bear River Band of the Rohnerville Rancheria Tribal Council on March 26, 2019. The AB 52 consultation process has concluded with both tribes."

Notice at the time this consultation was concluded the turbines were only 500 feet high. I think that may violate the spirit and intent of consulting in advance if it just goes and gets changed afterwards.

I agree with the Wiyot people that this ridge should not be changed by installation of wind turbines, whether 500 or 600 or nearly 700 feet, it doesn't matter. The people who lived here sustainably for thousands of years and who owned it before the rules of ownership were overturned by invasion and massacre do not feel this project belongs there. I am guided by their wisdom as they have persisted on and cherished this landscape by an order of magnitude longer than the new settlers.

Impact 3.6-3 Change to the Significance of a Historical Resource. Historic districts and historic landscapes could be affected by the project. This impact on the Scotia Historic District would be less than significant, while this impact on the Bear River Ridge and Valley Historic Landscape and Bear River Ridge Ethnobotanical/Cultural Landscape would be significant

page 3.6-38

"... however, as designed, construction of the WTGs and access roads would result in a significant impact on the immediate surroundings and setting of the historic landscape."

"Project construction would result in direct impacts on the Bear River Ridge Ethnobotanical/Cultural Landscape. The removal of these vegetation patterns would result in a loss of important vegetation patterns of prehistory. Therefore, this impact would be significant." ... "Implementing the above mitigation measures would reduce the impact of the project on historical resources, but not to less than significant. This impact would be significant and unavoidable."

This is not acceptable.

page 3.6-41

"Bear River Ridge The Wiyot Tribe identified Bear River Ridge (Tsakiyuwit) as a TCR. Bear River Ridge is the southern boundary of the Wiyot Ancestral Territory. The entire Wiyot ancestral territory can be viewed from Bear River Ridge. Likewise, Bear River Ridge is visible from anywhere within Wiyot territory, including from Table Bluff and Humboldt Bay where Tuluwat2 is located. In the past it would have been used as a high prayer spot. Bear River Ridge is currently held as private property, restricting access to the tribe, but the tribe does see the ridge as a sacred high place that remains visible throughout Wiyot territory. Constructing WTGs on Bear River Ridge would be a significant visual impact on this sacred high place. No feasible mitigation is available to reduce this significant impact; therefore, this impact would be significant and unavoidable."

The DEIR mentions Yurok reintroduction efforts...", the condor is a spiritual symbol for the tribes of Humboldt County. Therefore, because the potential exists for condors to collide with WTGs, this impact would be significant."

This project will affect the reintroduction zone for the California Condor by the Yurok tribe. (https://www.yuroktribe.org/departments/selfgovern/wildlife_program/condor/ condorproject.htm)

Implementing Mitigation Measure 3.6-4 is claimed to reduce the impact of the project on California condor, a TCR, but not to less than significant. This impact would be significant and unavoidable.

The California Condor is a Fully Protected species by law of the state of California. The wind farm is not eligible for a license or permit for their take - collection is not for necessary scientific research or protection of livestock.
(https://www.dfg.ca.gov/wildlife/nongame/t_e_spp/fully_pro.html)

If it is illegal for an individual to take a member of a Fully Protected Species then by current U.S. law, it is equally illegal for a corporation. I request the California Department of Fish and Game to enforce their laws equally on corporations and individuals. (https://www.npr.org/2014/07/28/335288388/when-did-companies-become-people-excavating-the-legal- evolution)

Also see **Executive Summary Section ES 77 & ES 78** (where they plan to wait 6 month after condor release for any protective action or consultations.

Even if the condor is considered by government to be "experimental" millions of taxpayer dollars have been spent on its salvation and now reintroduction. I do not agree that this project should be built in the ancient range of - and new introduction range - of the California Condor.

I disagree that the blades could be always successfully be stopped from 200 miles per hour to zero were a condor to fly nearby even though currently adult condors have GPS units their flight speed exceeds the ability of the wind operators to stop the blades. If breeding is successful the babies won't have GPS and the wind company would not know where they were located. Plus if the only response is to stop producing energy, then the project goal of producing 155MW of clean energy will not be met.

Section 3.7 GEOLOGY
page 3.7-16
The EIR quotes the California Building Standards Code: "The CBC requires that any structure designed for a project site undergo a seismic-design evaluation that assigns the structure to one of six categories, A–F; Category F structures require the most earthquake-resistant design."

No rating was given for this project because the exact wind turbines to be used are not specified.

page 3.7-16
The EIR quotes the California Building Standards Code: The CBC philosophy focuses on "collapse prevention," meaning that structures are to be designed to prevent collapse during the maximum level of ground shaking that reasonably can be expected to occur at a site."

No exact sites are provided in this project, so this part of the CBC cannot be fulfilled by this EIR.

page 3.7-16
The EIR quotes the California Building Code: "The potential for liquefaction and soil strength loss must be evaluated for site-specific peak ground acceleration magnitudes and source characteristics, consistent with the design earthquake ground motions. Peak ground acceleration must be determined from a site-specific study."

No sites have been selected, thus the EIR provides no site-specific study as required.

This lack of faceplate and location data prevents accurate assessment by the county of potential risks and hazards during a local earthquake.

I feel that their Impact statement 3.7-1 is flawed as they are only considering ground rupture, not any other form of earthquake impact.

page 3.7-20
" Impact 3.7-1 Surface Rupture Along a Known Earthquake Fault.
The project would not be constructed over the surface traces of any active faults. This impact would be less than significant." ... The wind turbines and associated infrastructure (e.g., transmission lines) would not be within or adjacent to a designated Alquist-Priolo Earthquake Fault Zone... (page 3.7-21) although the Cascadia subduction zone is considered capable of producing a large- magnitude earthquake, it is not zoned under the Alquist-Priolo Act. Furthermore, the impacts of surface fault rupture are generally limited to a linear zone a few yards wide, and the proposed wind turbines would not be structures intended for human habitation."

What is being stated here is that they have no active fault scarps and do not expect one to open up under a specific turbine. But the fixation on surface fault rupture is the least of their earthquake worries. It's like worrying what color the check will be when you win the lottery, because the damage comes from ground motion; surface fault rupture is extremely rare.

The maps in the EIR do not agree with The Bedrock and Faults Map of Humboldt County.
(https://humboldtgov.org/DocumentCenter/View/477/Geology---Bedrock-and-Faults-PDF?bidId=)

Mapping all the lines accurately in a Supplemental EIR would permit a more accurate assessment of hazards and risks.

page 3.7-21
"As described in detail in Section 3.7.1, "Environmental Setting," the proposed generation components would be located in a seismically active area. The Cascadia subduction zone and the San Andreas Fault, associated with the Mendocino Triple Junction along with other known active faults listed in Table 3.7-2, have the potential to produce large-magnitude earthquakes that could result in strong seismic ground shaking at the site of the proposed generation components."

"The Safety Element of the General Plan contains policies that would lessen the potential effects from the rupture of a known earthquake fault, strong seismic ground shaking, seismic-related ground failure, and tsunami. Policy S-P6, Structural Hazards, would apply, and compliance with state-adopted building codes and Alquist-Priolo Earthquake Fault Zone requirements for new construction would be enforced, to protect life and property."

page 3.7-22
"Because the CBC already provides for adequate protection to reduce the exposure of people and structures to the adverse effects of surface fault rupture, this impact would be less than significant."

Again the EIR mistakes "surface rupture fault" for what is actually mentioned in the Safety Element which is "rupture of a known earthquake fault." Surface does not equal known, nor vice versa.

Despite citing the Safety Element, the EIR does not state the effects of "strong seismic ground shaking", or "seismic-related ground failure" - although they did rule out tsunami effects.

I do not think that they have adequately addressed the effects on their project other than that their components (unspecified) may fit a building code. The turbines are 50 stories tall on mere 10 foot foundations on - by their own statements - unstable slopes in poorly consolidated materials.

The Bedrock and Faults map of Humboldt County provided by the County website, clearly shows the fault lines underlaying the project site, and they do not appear to be adequately mapped in the EIR. A cursory examination reveals more faults on the county map than on the EIR map. (https://humboldtgov.org/DocumentCenter/View/477/Geology---Bedrock-and-Faults-PDF?bidId=)

The redlines are labeled "certain faults" - and overlaying the project map on this county map results in a serious concern about the project.

This is such a serious concern about the project and related faults, that I think the county should require being named in the 100% replacement cost insurance policy that should be maintained on the facility in case of earthquakes.

Maybe the preparers of the report were not aware, but this area of the country is more seismically active than others, and perhaps historic seismicity was not considered. I saw no discussion in the text of

* The "1906 San Francisco earthquake" which propagated along a fault which is part of the Cape Mendocino system and mapped on the County Map labeled San Andreas. This fault is a short distance from the project footprint. In Humboldt County the event was at least M6.2. The courthouse dome collapsed, "not a chimney was left standing in the Eel River Valley." While it is usually recorded as only affecting San Francisco, major earthquake damages stretched from Eureka to Salinas. Dr. Fusakichi Omori, the inventor of the seismograph, visited Eureka and Ferndale shortly afterward as part of his scientific study of the effects. He visited Ferndale to record the incredible damage and the giant landslide. Locally it is remembered as "the slide that closed the beach road to Petrolia," but examining a map even to this day shows that a very

large area slid a considerable distance, and it is quite fortunate that no one was hurt and there were no houses to damage. Omori wrote:

"At Dungan's Ferry, on the north bank of the Eel River, the ground was full of fissures. Every bar on the river had been opened by fissures, and the gravel toppled over leaving big ditches, some 6 feet deep and over 500 feet long. Coming up on the mainland the road had dropt about 2 feet in one place and was full of small fissures. A 40-acre field was entirely ruined. It was heavily fissured, having dropt down in strips from 2 to 6 feet wide, from 4 to 6 feet deep, and from 5 to 500 feet long, the fissures pointing between south and southwest. All the fields were full of quicksand volcanoes, some 1 to 3 cubic yards in size. They were perfect miniature volcanoes, every one having a crater. It is said they extended 30 miles up the river..."

"Near the False Cape it threw the old hill, on which the Oil Creek coast road ran, out into the ocean for 0.5 mile. It is estimated that 200 acres were thrown into the ocean. Quite a number of cattle went with the hill. The slide is said to have obscured the view of Cape Mendocino light from Trinidad heads.
In Petrolia the shock threw every house off its foundation; in the mountains it opened great fissures, ruining many acres of good grazing land. It is said that the McKee ranch, near Shelter Cove, is entirely ruined by fissures. About 6 miles below the mouth of the Mattole River, at what is called Sea Lion Gulch, the mountains pitched together, entirely obliterating this dangerous place.

Closer to the Jordan Creek staging area, Omori describes the situation,
"Pepperwood, Humboldt County (J. F. Helms). — In the stores and saloons 10 per cent of the property was destroyed by breakage, but on the farms of the neighborhood the damage was mostly confined to the throw of chimneys." The distances given for chimney throw in the Ferndale, Pepperwood and Petrolia areas goes up to fifteen feet. (Omori in The California earthquake of April 18, 1906 : report of the State Earthquake Investigation Commission, in two volumes and atlas.
http://content.cdlib.org/view?docId=hb1h4n989f;NAAN=13030&doc.view=frames&chunk.id=div00006&toc.depth=1&toc.id=div00006&brand=calisphere&query=omori)

Descriptions of surface ruptures, houses thrown from foundations, buildings moved and other effects - some very close to the project site are available in the Humboldt County Chapter of The California earthquake of April 18, 1906 : report of the State Earthquake Investigation Commission, in two volumes and atlas. QE 535 .C3 1969, Bancroft Library, California. (http://content.cdlib.org/view?docId=hb1h4n989f&doc.view=frames&chunk.id=div00056&toc.id=div00007)

* The "1992 Cape Mendocino earthquakes" produced a M7.2 thrust mainshock that struck near Petrolia midday on April 25 and two primary strike-slip aftershocks measuring 6.5 and 6.6 that followed early the next morning. Over 2,000 recorded aftershocks followed. Widespread landslides from the coast to east of Scotia and from the northern extent of the Eel River basin

near Thompson Hill to south of Petrolia resulted. Very few surface ruptures occurred, but damages to Scotia included the loss of their downtown to fire, and many structures were damaged throughout the region.

* Other recent events include the "1980 Eureka earthquake" at M7.3 - effects were felt from Myers Flat to Brookings, Oregon - and the "2010 Eureka earthquake" at M6.5 with a 5.9 aftershock a month later. The seismic risk in the area is so great that the Humboldt Bay nuclear power plant was curtailed and later replaced due to seismic risk.

This section does not provide enough information about seismic risk to WTGs and associated structures because there is

- no faceplate information about how the specific components for this project are intended to perform in earthquakes,
- no analysis of earthquake shaking a 50 story weight centered structure on a 10 foot concrete pad,
- no citations of how recent WTGs and their associated structures perform in extreme seismic events, "strong seismic ground shaking" or "seismic-related ground failure".
- no description of local earthquake magnitudes and effects as related to small skinny objects like windmills, chimneys and towers. Long slender things on shallow foundations are affected by large earthquakes.

Besides ground forces alone, wind and ground forces can cause tower failure.

According to "Collapse analysis of wind turbine tower under the coupled effects of wind and near-field earthquake" Fan, Jian, Qian Li and Yanping Zhang, Research Article, Wiley, 17 October 2018 (https://docs.wind-watch.org/collapse-earthquake.pdf)

Dr. Fan and associates analyze a 60 meter hub height turbine. They wrote "In recent years, with the rapid growth of wind power, wind turbines are being constructed near faults and earthquake zones and wind turbine towers are vulnerable to near–field ground motion. The most notable feature of near–field ground motion is the directivity effect and the fling step effect induced by the pulsed ground motion. The most common form is a velocity pulse–like ground motion. Velocity pulse–like ground motion has a pulse–like waveform, a long pulse period, and rich medium/long period components. The ratio of the peak ground velocity (PGV) versus the peak ground acceleration (PGA) is large. Normally PGV/PGA ≥ 0.2. As the wind turbine tower structure typically has a long period, near–field ground motion triggers an intense earthquake response or even leads to complete collapse."

Specific analysis should be provided for specific faceplate equipment for accurate assessment of true seismic risk.

One source of damage - as pointed out in the Safety Element of the General Plan (Humboldt County) is from ground motion - coupled with wind being applied simultaneously on the blades. This EIR only mentions surface fault rupture, a case as rare as being hit by lightening.

That turbines fall over just from wind has been happening for years, most recently on May 23, 2019 in Oklahoma where a turbine went over in 40 mile per hour winds. (https://kfor.com/2019/05/23/turbine-buckles-collapses-on-oklahoma-wind-farm/)

Other cases of wind load alone being enough to collapse turbines have occurred

- 2018 Thailand - Vestas nacelle collapses at new wind farm (https://renews.biz/48809/thai-turbine-collapse-sparks-vestas-probe/ & https://www.youtube.com/watch?v=CwqRq_CZnes)
- 2017 Wichita Falls, TX (https://www.reporternews.com/story/news/local/texas/2017/06/23/wind-turbine-collapse-under-investigation/425362001/)
- 2014 Fayette County, PA (https://www.wtae.com/article/huge-wind-turbine-falls-in-fayette-county-1/7464674)
- 2010 Arlington, WY, bent and collapsed (http://www.windaction.org/posts/29882-collapsed-turbine-in-wyoming#.XOrFXVNKgjM)
- 2010 JeJu, Korea, 34.6 m/s tower collapse
- 2009 Madison County, NY, collapse (https://www.syracuse.com/news/2009/12/officials_hope_to_learn_why_wi.html)
- 2008 Taiwan, collapsed in Typhoon Jangmi (http://www.engineering.nottingham.ac.uk/icccbe/proceedings/pdf/pf135.pdf)
- 2008 Hornslet Denmark, oscillating tower collapse (https://en.wikipedia.org/wiki/Hornslet_wind-turbine_collapse, https://www.youtube.com/watch?v=CqEccqR0q-o) Same location as cover photo this document.
- 2008 Searsburg VT, blade hit tower which failed (https://www.buildinggreen.com/blog/big-wind-turbine-failures)

This list was found by reading the cited papers, fact-checking, and was supplemented by routine web search which also found other accidents including fires caused by, blades thrown from, and other topics not directly applicable to seismic.

Atul Sudhakapar Patil, Response of a Wind Turbine Structure to Strong Ground Motions and High Velocity Winds, Florida State University Ph.D. thesis, College of Engineering, 2015, pages 1 - 273. (https://diginole.lib.fsu.edu/islandora/object/fsu:253125/datastream/PDF/view)
"Although recorded failures of wind turbines due to the earthquakes are rare due to the scarcity of the event, the wind turbine towers subjected to earthquake loads are expected to fail... commercially produced wind turbines are not catered for each specific type of extreme loads like earthquake load or high wind loads." A study of a specific model of turbine was performed, and different methods of analysis proposed depending on hub heights. Soil structure was found to have an influence, as did wind on the blades at the time the events were modeled. "The authors

stated that the higher modes may play a greater role in overall seismic response. The seismic excitation records with high frequency content may set the structure in the higher vibration modes... For the new taller turbines, the higher modes could be significant." As earthquake intensity increases on all models the fragility index also increases." The seismic loading analysis was studied for National Renewable Energy Laboratory (NREL) 5MW baseline wind turbine considering idling, operating and emergency shutdown scenarios. The authors found that tower moment demand is an important parameter while designing the wind turbine tower in seismic zones... Modern day wind turbine structures are tall and possibly more slender due to the increased height and more susceptible to the strong loading pulses that are caused by near fault directivity." Since there is more data available about wind collapses than earthquake collapses, "Rose et al. (2012) studied the NREL 5MW base line turbine for buckling analysis during the high wind events. The fragility analysis conducted by the authors has shown that the category 2 hurricanes (wind velocity 45 m/s or higher) would buckle 6% of the turbine towers in Galveston Offshore Wind project location. Hurricane Ike in 2008 reported the sustained wind speed of 49 m/s at the reference height of 10 m in the Galveston Offshore Wind project location. The category 3 hurricane (wind velocity of 50 m/s or higher) would buckle 46% turbine towers in Gulf of Mexico coast and 9 of the 14 states of Atlantic Coast... The reasons for failure were established as violent wind, high turbulence and sudden wind change in wind direction." Dr. Patil provides analysis methods for towers bending, breaking, falling over and completely overturning off their foundations as being potential outcomes for earthquake damage to wind turbines, but his work shows there is a big difference between the different types of towers and manufacturer's designs.

Another study A.T. Myers, A. Gupta, C.M. Ramirez, and E. Chioccarelli. 2012. "Evaluation of the Seismic Vulnerability of Tubular Wind Turbine Towers" 15 The World Conferences on Earthquake Engineering (WCEE), Lisbon 2012. (https://www.iitk.ac.in/nicee/wcee/article/WCEE2012_4483.pdf) points out that turbine towers are designed for European installations where seismic is not a risk, and states, they are "particularly sensitive to catastrophic losses because:

* Modern wind turbines, unlike buildings and most other common structures, exhibit no redundancy in the structural system. Thus, if any section of the structural system becomes sufficiently damaged, then the entire turbine is susceptible to collapse.
* Wind farms are typically comprised of many turbines with similar characteristics, for instance all manufactured by the same manufacturer, similar heights, similar foundation designs, etc. Thus, a single seismic event with unfavorable ground motion characteristics could potentially damage most of the turbines at a particular wind farm. This is in contrast to buildings in a city, which have diverse structural systems, dynamic characteristics, and redundancies that limit the potential of any single seismic event to unfavorably affect all buildings." They describe no damage to wind farms in "1994 Northridge Earthquake (M6.7) and "1986 North Palm Springs Earthquake" (M6.1) and state that both had low to moderate ground shaking at the two farms (0.06g and 0.33g), thus they perform model and statistical analysis. "... [T]he characteristics of ground motions can vary substantially from one site to another and some ground motions, such as those that can occur near a fault—which can cause 'pulse-like' ground motions — or at sites

There is just not enough data. Accurate modeling is needed here, not just some statements of great and noble purpose. I agree global warming is a problem. I do not agree this project will solve any of it with the methods outlined in this document.

page 3.8-20 "Implementation Measure E-IM5: Wind Energy Development. Develop wind-permitting guidelines for residential and small commercial-scale wind energy systems. Adopt and modify, as appropriate, the guidelines established in California State Law AB 1207. Educate the public about the benefits of small- scale wind energy systems."

I disagree that this project is consistent with this goal as it is not a residential or small commercial-scale system.

This section assumes that any wind turbine farm is the equivalent of any other; such as the off-shore facility in early planning stages which this EIR does not mention. Offshore wind has much higher wind speeds and the turbines are larger. Offshore wind would develop more power, and fulfill the goals of the county for "environmentally responsible" generation of power, rather than a project that will use an incorrectly calculated number of gallons of diesel, cut thousands of trees, cause wear and tear on the roadways (deterioration of concrete releases CO_2, as does its manufacture) and yet claim to be "green."

Remember the project maximum goal of 155 MW is an increase of one-half of one percent. Not enough to justify the cost and hassle of the permit process nor to be offset by some measly taxes.

page 3.8-21 "The proposed project would not necessarily immediately replace electricity generated by fossil-fuel plants at the same quantity, and the project would generate a small amount of GHG emissions."

Wind power can lead to an increase in emissions as the conventional gas powered electrical plant attempts to keep up with the variable power in the system due to wind. Nowhere is there an analysis of the effect of this project on the King Salmon electrical generation station. Due to the variable nature of wind, the electrical plant will have to turn on and off in response to the variability. Their plants were not built with this as intent, and I think it may cause more pollution to run on/off than steady state.

There are assumptions in the foregoing which lead the EIR to say that the project is a less than cumulatively considerable contribution to the significant cumulative impact of global climate change. The only reason that is true, is that the project is very small. However for Humboldt County, it is a large project and the transport and construction use of diesel, loss of CO_2 sequestration in the essentially stable landscape now, and all relevant factors must be considered to effectively discuss greenhouse gas emissions.

I consider all their impact analysis in this section flawed and all impacts to be potentially significant since they have not been properly examined.

3.9 Hazard

Impact 3.9-4 Potential Hazards Associated with Operation of Wind Turbine Generators. Implementation of the proposed project could cause reasonably foreseeable upset and accident conditions during operation of the wind turbine generators. This impact would be less than significant. ... Because the project applicant must prepare an operation and maintenance program that would substantially reduce opportunities for facility failure that could be a danger to people, and because access to the wind energy generation facilities would be restricted, this direct impact would be less than significant. No indirect impacts would occur."

Unfortunately they have not given an operation or maintenance program, so we have no idea if this is correct or not. Also they are taking county roads and shutting them off to residents if they plan to restrict access at Bear River Ridge and Monument Roads. This was never discussed elsewhere in the DEIR.

The DEIR doesn't discuss accidents, but see Geology comments above for a short list of recent accidents. Many writers in peer-reviewed literature and the public press point out that the wind industry does not report many of their accidents.

Section 3.10 Hydrology & water quality
page 3.10-2
"The project area is characterized by mountainous landscape and steep and highly erodible soils. Several named drainages traverse the site: Stitz Creek, Hoagland Creek, Fish Creek, Greenlow Creek, and Little Larabee Creek. A number of unnamed perennial and intermittent drainages traverse the proposed electrical interconnection areas, project access routes, staging areas, and related facilities of the proposed project. A portion of the existing drainages have been modified by placement of a culvert and covered with fill to permit crossing for logging equipment (Stantec 2018). High seasonal rainfall combined with a rapid runoff rate on unstable soils deliver large amounts of sediments from these and other drainages that may discharge into the Eel River."

Rio Dell and others draw drinking water downstream of this potential sedimentation.

3.10.3 ENVIRONMENTAL IMPACTS AND MITIGATION MEASURES THRESHOLDS OF SIGNIFICANCE

page 3.10-15 "substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin;"

I think not accounting for the 300 temporary workers who might be drawing up to 60 gallons a day from the Pepperwood aquifer would cause difficulty with the recharge to that aquifer and to management of the basin. The permanent workers will draw about an acre-foot a year; there are five times as many temporary workers.

Then there's the question of where the concrete water will come from, and the dust water, since they cannot take it from the Log Pond in Scotia.

page 3.10-21

"If the Humboldt Redwood Company HCP measures cannot be implemented, or if the project applicant seeks to conduct work during the wet season (October 15–June 1), the project applicant shall implement the following measures while conducting tree harvest, road or landing construction, reconstruction, and road upgrades:"

Once again the applicant will decide what cannot be implemented, and if they want to work in the winter, they plan to do it. The measures they suggest might work in the desert or central valley; it's unlikely they would survive a season of local rainfall.

page 3.10-23

"Impact 3.10-3 Potential Water Quality Impacts from Project Operations. Project implementation would alter the permeability of surfaces that could increase runoff from the project area, thereby increasing the potential for transport of pollutants from the project area to local surface waters. This impact would be less than significant."

I think that if anything went wrong up there, or en route, it would be significant, no matter how many reports are written in advance, or earthen berms provided. Notice if you spill fuel it will soak into the earth, so the idea of an earth berm providing much help in a diesel or oil spill doesn't seem like it is 100% guaranteed to work, especially with higher than normal rainfall in the area.

page 3.10-24

"Impact 3.10-4 Potential to Deplete Groundwater Supplies or Interfere Substantially with Groundwater Recharge Such that the Project May Impede Sustainable Groundwater Management. Compaction and widening of roads, installation of turbines and foundations, and operation of the project facilities could require the use of surface or groundwater. This impact would be less than significant. The project's demand for water during operation can be considered a de minimis use and sufficient supply is available to meet existing and future demands with the project on the Pepperwood Area Groundwater Basin, including municipal and industrial uses. This impact would be less than significant."

They forgot their temporary workers demand on the water system and they don't have any construction water. This is not de minimus or less than significant.

Section 3.11 NOISE
page 3.11-16
"Generation of a Substantial Temporary Increase in Ambient Noise Levels in the Vicinity of the Project in Excess of Standards Established in the Local General Plan or Noise Ordinance, or Applicable Standards of Other Agencies. Construction of project components would require temporary, short-term construction activities and haul truck trips to haul wind turbine generator parts and needed construction materials and equipment to the project area. Project-related construction activities and haul truck trips could expose existing sensitive receptors to temporary noise levels that would exceed the applicable noise standards and/or result in a substantial increase in ambient noise levels. This impact would be less than significant... Construction activities would require 12–18 months."

Depends on your definition of "temporary." One and a half years does not seem particularly temporary to people trying to get along with all this stuff that doesn't need to happen ("no project" alternative). There is a secondary impact to the local community in that after the project is finished from a developer standpoint, they will give the county money for county roads to be repaired, and then at some point later, those roads will be fixed. However, they won't be repaying CalTrans for the Highway 101 lane and shoulder damage to surface from overweight vehicles, and residents/visitors/truckers will bear the hassle of waiting through the construction delays while Highway 101 is returned to pre-project condition - at state tax payers expense. There will be a second noise impact created due to the repair work which is not addressed in this EIR.

page 3.11-17
"In addition, the project includes the temporary operation of a concrete batch plant on Monument Ridge at the proposed project substation. Concrete batch plant activities would result in noise levels of 78 dBA Leq at 100 feet."

What is the proposed impact of this noise on the wildlife in the area? Bats sleep during the day when the batch plant would be running.

page 3.11-18
"Although the temporary off-ramp construction would exceed the County's short-term noise standard of 65 dBA Lmax at exterior areas at R-7, the standard is not applicable to contruction [sic] noise."

page 3.11-19
"However, as noted previously, the County's standard is not applicable to construction noise. Therefore, this impact would be less than significant."

Later the EIR points out that actually using this ramp would exceed the County noise limits **(page 3.1-22).**

page 3.11-19
"Construction activities would generate truck haul trips on area roads for delivery of WTG parts, construction equipment, and materials... each proposed WTG would require up to four nighttime heavy haul trips, which may require using detour routes. This analysis assumed a total of 45 nighttime trips in 1 hour for night-time heavy haul trips—30 support vehicles and 15 heavy trucks—for FHWA model inputs. Based on the number of trips, noise levels attributable to anticipated heavy haul truck traffic could be approximately 55 dBA Leq at a distance of 50 feet from the roadway centerline. Heavy haul trucks would have the potential to travel up to 50 feet from residences along the Singley Road detour route... predicted nighttime traffic noise levels from heavy haul trucks along the detour route could result in a noticeable increase (+3 to +5 dBA CNEL) at residential land uses along the designated route."

"Noise levels generated by temporary off-ramp construction... at Hookton Road, transmission line construction near the Bridgeville Substation, and heavy haul truck trips along detour roadways would result in a substantial increase (i.e., +5 dB) in ambient noise levels. Temporary off-ramp construction at Hookton Road and transmission line construction near the Bridgeville Substation also would exceed the County's land use compatibility exterior noise standard of 60 dBA CNEL."

However all of this is considered in the end to be "less than significant." I fail to see how they went from "over standards" in several places to "less than significant" and I think more information needs to be provided. The potential of noise affecting nearby residents is not limited to Singley Road, the entire community of Field's Landing has been left out, yet should be studied due to transport and delivery noise from barge, crane, transporter and other operations planned to go from 7 a.m. to 10 p.m.

page 3.11-20
The EIR says exceeding noise limits is less than significant, but agrees to mitigation measures which are again minimizations, not actual mitigation for the noise.

I am sure somewhere that adding all these regulations together might add up to this output, but from a "does it make sense in the real world" consideration, citizens are going to literally lose sleep during transport, may be kept awake by the turbines themselves and no turbines as big as the largest size they are proposing have ever been installed in the U.S., so there is no way to see a real world example.

page 3.11-22
<u>Impact 3.11-3 Long-Term Increases in Project-Generated Noise</u>**.** Project operation would introduce new long-term noise sources in the project area. Noise generated by substations and overhead transmission lines would not be anticipated to expose existing sensitive receptors to a permanent increase in noise levels that would exceed the applicable noise standards or result in a substantial increase in ambient noise levels. However, noise generated by wind turbine generators could expose existing sensitive receptors to a substantial permanent increase in

ambient noise levels. With respect to noise generated by substations and overhead transmission lines, and to long-term, low-frequency and infrasonic noise from operation of the wind turbine generators, this impact would be less than significant. With respect to long-term exterior noise generated by operation of the wind turbine generators, this impact would be potentially significant.

Wind turbines are noisy. This is not news. There is no real reason to wreck the redwoods with a low frequency hum or annoy the residents of Eel River Valley (Fortuna, Ferndale) or the Mattole (Petrolia) with noise that isn't there now.

page 3.11-23
"Low-Frequency and Infrasonic Noise As described above, a 'typical' spectral shape was assumed, based on data of other similar WTGs. Table 3.11-13 shows the differences between the A-weighted and C-weighted Leq noise levels, as calculated at each receptor location, assuming simultaneous operation of all 60 WTGs."

There are three uses of "spectral" in this section, all occur after this paragraph. I am unable to find the "as described above" for a shape assumption. The word "shape" searched in the document, yields pages 23 and 24, both at or after this paragraph.

There is not enough information to assess the process without a description or discussion of how this was calculated or why a spectral shape was assumed. It feels like the writer was interrupted at this point, and more information is needed to understand the intent.

With no particular WTG specified, it's impossible to know what shape would be typical anyway.

page 3.11-24
"Therefore, low-frequency noise from the WTGs is expected to be below any of the typical regulations or guidelines if the A-weighted sound level limits are achieved."

* There's a big "if" in there, since there is no faceplate information provided for any particular turbine and the turbines vary widely in noise production according the the American Wind Energy Association. Additional citations in of my comments on Section 3.7 Geology.

page 3.11-24
"Operation of wind turbine generators creates aerodynamic and mechanical noise. Aerodynamic noise is generated by the moving blades passing through the air, which may produce a buzzing, whooshing, pulsing, or sizzling sound, depending on the type of WTG and operating speed."

Again, no faceplate data, so no way to know which "type of WTG" is being considered, so what they do is analyze the worst one that existed when the report was created, which while it may be correct, we have no guarantee that it would be the one used, and the company spokesperson has said several times they want to use the biggest ones ever installed in the United States to date. If they're the newest and the biggest, there's been no time to do the studies to know if they will be seismically safe, or their noise profile.

page 3.11-24
"The project would construct and operate up to 60 WTGs. This analysis was conducted using a WTG with a maximum sound power level of 110 dBA, which is the loudest, or worst-case, turbine that is expected to be used at the project site... Other WTG options range in sound power levels of 105–107 dBA. One-third octave band levels were unavailable for this WTG. Therefore, a "typical" spectral shape was assumed."

Note how the ambiguity of type only makes a 5dBA difference, but also that the one that they tested had incomplete data for certain sounds. As a scientist, I cringe reading assumptions based on data which includes a zero in any column. Because even if you have a very large number to begin with, multiplying by zero always makes zero. (e.g. 99 x 0 = 0) Thus utter lack of data in any part of an equation, renders the output of that equation null.

page 3.11-25
"... if all 60 WTGs were operating 24 hours a day, this could result in increases above ambient noise levels."

The intent is to generate electricity. There is no disadvantage to the developer to run less than 24/7, thus noise must be assumed to be a given.

page 3.11-26
"The long-term exterior noise impact associated with WTG operation would be potentially significant."

As someone who cares about preserving nature and not wrecking places that aren't wrecked already, the statement above is heartbreaking. From quiet paradise with the sounds of birds and wind rustling in the grasses and trees, to industry. And for amortized CO2 tradeoffs and Federal subsidies to the developers.

The only mitigation measure offered is to relocate farther from one of their testing points. Very practical from an engineering standpoint but the message is "wind turbines are loud, deal with it." After reading this section, the "no project alternative" choice became even stronger for me.

- Noise from transport/delivery/road transport was not analyzed at Fields Landing. This is required for analysis of potential marine mammals.

Remember that in Referencing Appendix I Biological Resources... Spotted Owls, Section 5.2, page 6 they called noise from chainsaws "low" and that from pickup trucks "moderate." With that kind of an error, all the DEIR noise analysis is questionable and should be redone.

Section 3.12 Traffic

Impact 3.12-1 Potential to Conflict with a Program, Plan, Ordinance, or Policy. The project would not substantially alter the total number of vehicle miles traveled in Humboldt County, as it is not considered to be a trip-generating land use type. The project would not conflict with a state or local transportation policy, including State CEQA Guidelines Section 15064. This impact would be less than significant.

On **page 3.12-19** the EIR stated "Construction activities would generate truck haul trips on area roads for delivery of WTG parts, construction equipment, and materials... The project would generate 29,250 trips over its 12- to 18-month duration, of which 9,673 would be heavy truck trips. The majority of these trips would occur on U.S. 101."

Yet here in **3.12-1**, it claims no impact, and no conflict with state or local transportation policy - however

- the project requires delivery vehicles which are too wide, too high, too heavy and too long for roads without special California permits
- 29,250 truck trips (assuming that's correctly calculated as delivery of components does not appear to be included in that figure as previously discussed) are significant, especially as 9,673 trips would be trucks too heavy for the roads without permit.
- I would assume keeping the roads in good condition is part of one of the policies cited, but the developers' offer to repair county roads damaged in transport/construction, while the primary road used will be Highway 101, would have significant impact. The residents/visitors/truckers in the county will be forced to live through multi-year bypass construction, transport, bypass removal, and repair road work on 101 at taxpayer expense.
- Repair of roads is partially funded by gasoline road tax, but if the gas isn't actually "pumped" in Humboldt County, the county won't get road taxes.
- Roads are already bad enough here, adding this kind of truck traffic to them is not "no impact."
- Finally I disagree that they are not a "trip-generating land use type" - as over 30,000 trips will take place concurrent with this project, that would not have happened without it.

That this is scheduled for 12 to 18 months does not render these impacts negligible.

Based on current rates of completion for example Route 36 at three years and counting, CalTrans and the County will be having turbine transport damaged roads repaired for years to come. This creates a secondary impact.

<u>Impact 3.12-2 Creation of Hazards from Truck Traffic.</u> A large number of trucks would transport loads over roadways that do not normally see a high volume of truck traffic. These trucks could exceed applicable standards for maximum vehicle width or exceed the width of

most travel lanes. Use of the roadway network by these oversized trucks would shorten the remaining useful life of roadway surface and could create hazardous road condition. This impact would be potentially significant. **Section 4.0 Cumulative impacts**

Electrical Grid & Generation
They did not mention that their generation of 155 MW (135 MW at Bridgeville) would "plug up the transmission grid" and not allow more generation without additions to grid. This could prevent large scale solar, and/or make the offshore wind test unable to be done without new transmission infrastructure. They do not seem to be aware of the offshore wind project currently under discussion.

Citing the Humboldt County Energy Element Background Technical Report, Prepared for: Redwood Coast Energy Authority by Schatz Energy Research Center, Humboldt State University, Principal Author: Jim Zoellick, July 2005.
(http://humboldt-dspace.calstate.edu/bitstream/handle/2148/62/TECH%20REPORT%20FINAL%207_12_05.pdf?sequence=1)

"Although a new, more efficient power plant could potentially produce an excess of power for export from the Humboldt area, PG&E has specified that replacement generation be no more than 150 MW. Even though the existing Humboldt transmission system can support some export of electricity, PG&E claims it is typically undesirable to export electricity out of the Humboldt area because most of the export ends up in the Cottonwood area, and this area is resource rich and already faces congestion problems in exporting its resources." (pages 30-36) After discussing that use of wind and solar would require energy storage systems, the discussion concludes "...[L]ocal electrical generators... are critical to meeting local electricity needs." (page 72) Humboldt Bay Generating Station presently has 163 MW generating capacity. Total peak electrical demand in 2003 was 158 Megawatts (MW), about 0.3% of the state total (note that Humboldt County's population accounted for 0.4% of the state total)... Between 2005 and 2015, non-residential electrical consumption dropped from approximately 600 GWh in 2006 to roughly 430 GWh in 2015, an average annual decrease of -3.54 percent." (pages 3.171 and 2 from 3.17 Energy Consumption and Conservation (PDF).pdf & https://humboldtgov.org/DocumentCenter/View/58846/Section-317-Energy-Consumption-and-Conservation-Revised-DEIR-PDF).

Since the generators are capable of taking care of local needs, the remainder of the power is for export - and PG&E would prefer no more than 150 MW.

The point is, that if this project generates 155 MW at ridgetop and then gets 135MW at Bridgeville, there is no other available electrical line for the offshore wind to distribute the power from that less environmentally destructive project.

This onshore project would thus preclude offshore wind despite the latter being actively sought by our local Congressman, County and members of the general public. That is a pretty big cumulative impact that is not addressed in this document.

It also would seem to be in conflict with PG&E's stated desire for no increase in export to the Cottonwood area which already has a surplus of power as stated in the Humboldt County Energy Element Background Technical Report for the Humboldt County General Plan.

Changing Redwood Forest Microclimate
It is obvious that trees along Highway 101 suffer wind damage; it's not hard to extrapolate that these 600 foot tall 200 mph fans could change the fog layer over the Redwoods and have unexpected secondary impacts. Please see the cover of my comments for visualization of the down-wind effects on turbulence and airflow.

Logging
The DEIR does not mention the cumulative impact of the 500 plus acres of trees removed from the project footprint and the Gen-tie line. As these would be taken at same time as Humboldt Redwood Company continues normal logging operations - at least a couple of years would be way over the usual amount of timber removed.

Decommissioning
Insufficient information was provided about the decommissioning process to adequately assess any impacts or cumulative impacts from removing or rebuilding the turbines.

Section 5 - OTHER CEQA REQUIREMENTS

page 5-1 "Indirect growth inducement would result if, for instance, implementing a project resulted in any of the following: ... a construction effort with substantial short-term employment opportunities that would indirectly stimulate the need for additional housing and services to support the new temporary employment demand; or..."

page 5-2 "In the county, an estimated 1,930 people are employed in the construction trades, which is approximately 4 percent of the total employed workforce in all industries. Based on the pool of residents who are employed in the construction industry, project construction is not anticipated to induce substantial population growth. Furthermore, if workers from outside the region are employed for project construction, the temporary nature of the work would be unlikely to induce nonlocal workers to relocate permanently."

What they fail to address is the sudden introduction of 300 temporary workers into an area without empty housing, available RV parks and an existing homeless problem, as noted in the relevant section of my comments.

page 5-3 The DEIR states "Energy used during project construction would be expended in the form of electricity, gasoline, and diesel fuel, which would be used primarily by construction equipment, trucks delivering equipment and supplies to the site, and construction workers driving to and from the site. No unusual project characteristics would necessitate the use of construction equipment that would be less energy-efficient than at comparable construction sites in other parts of the county. Therefore, fuel consumption during project construction is not expected to be more inefficient, wasteful, or unnecessary than fuel consumption at similar construction sites in the region." Here they acknowledge transportation fuel, which is not accounted for in the Greenhouse Gas section or the Transportation Section, but is also addressed in Noise.

My question on this is "what similar construction sites in the region?" I am unaware of any projects building 60 individual 600 foot tall structures, associated met towers and 25 miles of transmission line anywhere in the region. Please provide the sources on which this statement is based.

page 5-3 "The project would convert forestland and require the commitment of a small amount of grazing land. This conversion would represent a long-term commitment of land to another land use for the lifetime of the project (i.e., 30 years); however, it would not be irreversible because the project area could be restored to its preproject conditions and uses after decommissioning."

Since the forests to be removed along the Gen-tie have not been studied, it is impossible to know if they are mature or second growth. In either case, it will be a very long time before the mature forest capable of supporting marbled murrelets and spotted owls would return to it's "preproject conditions" for a very long time after decommissioning.

"The project would not result in irreversible damage from environmental accidents, such as an accidental spill or explosion of a hazardous material." That statement is unsupported. There are no crystal balls. One turbine nacelle can leak up to 400 gallons of oil, they catch on fire, the towers fall over. Accidents happen. There is no way that this statement can be taken at face value because it is not possible to predict for 30 years. If it were, I am certain the Titanic would not have sunk.

5.2 SIGNIFICANT AND UNAVOIDABLE IMPACTS

page 5-4 "Chapter 3, "Environmental Setting, Impacts, and Mitigation Measures," of this DEIR presents a detailed analysis of all significant and potentially significant environmental impacts of the proposed project; identifies feasible mitigation measures, where available, that could avoid or reduce these impacts; and identifies whether these mitigation measures would reduce these impacts to less-than-significant levels."

While that is the intent of the usual Chapter 3 in a CEQA document, this DEIR's Chapter 3 doesn't do that. In addition to my specific comments about that section, there are multiple deferred plans which should have been submitted as mitigations which do not yet exist.

1) 3.2-2 Transportation Permit
2) 3.2-62 Grading and Erosion Control Plan
3) 3.5-80 Mortality Plan for Wildlife
4) 3.5-87 Preconstruction Eagle Nest Surveys
5) 3.5-101 Spotted Owl Habitat Map
6) 3.5-129 Habitat Assessment for potential bat roost sites
7) 3.5-151 Preconstruction survey for reptiles & amphibians
8) 3.5-159 Special Status Plant survey Spring & Summer 2019.
9) 3.5-1c Worker Environmental Awareness Program
10) 3.5-2c Marbled murrelet mitigation plan
11) 3.6-3b Site Protection Plan
12) 3.6-3c Reclamation Plan and Weed Control Plan
13) 3.7-2 Geology and Soils Reports and Investigations
14) 3.5-22c Eelgrass Monitoring Plan
15) 3.5-23a Preconstruction Botanical Surveys for Special-Status Plants.
16) 3.5-23e Reclamation, Revegetation and Weed Control Plan
17) 3.7-24 Wet Weather Operations Plan
18) 3.7-24 Timber Harvest Plan
19) 3.9 Hazard Materials Plan
20) 3.9-1 Soil Sampling and Testing
21) 3.9-2 Blasting Plan
22) 3.9-3 Safety Hazards
23) 3.9-4 Operations and Maintenance Plan
24) Historical American Survey Report
25) Emergency Plan for Operations
26) Construction Waste Management Plan
27) Conversion Permit
28) Vegetation Management Plan
29) Decommissioning Plan
30) 3.10-1 SWPPP
31) 3.10-1 Erosion Control Plan
32) 3.12-1 Transportation Route Plan
33) 3.12-1 Rehabilitation/Reconstruction of County Roads
34) 3.12-1 and 3.12-2 Traffic Control Plan
35) 3.12-1a Fire Services Financing Plan
36) 3.13-1b Fall Protection and Rescue Plan
37) 3.13-2a Fire Safety Management Plan

In each one of these cases, the DEIR says that the plan will be done at some point in the future. They should be in this DEIR or they are just putting off to the future what should be done for the public and the county to have sufficient information to make informed decisions.

In the case Sundstrom vs. County of Mendocino (1988 202 Cal. App. 3d 296), the courts ruled that studies cannot be deferred. "As to the condition of a future study, the appellate court held this was inappropriate: "By deferring environmental assessment to a future date, the conditions run counter to that policy of CEQA which requires environmental review at the earliest feasible stage in the planning process." (Sundstrom, supra, 202 Cal. App. 3d at p. 307.)
" Putting off thirty-seven (37) required documents seems to be a problem.

The significant and unavoidable impacts identified and acknowledged by the applicant in the DEIR are

SECTION 3.2, "AESTHETICS"
> Impact 3.2-1: Project Impacts on Scenic Vistas and Potential for Substantial Degradation of Existing Visual Character or Quality of Public Views of the Site and Surroundings
> Impact 3.2-3: New Source of Substantial Light or Glare that Would Adversely Affect Day or Nighttime Views in the Area

SECTION 3.4, "AIR QUALITY"
> Impact 3.4-1: Short-Term, Construction-Generated Emissions of ROG, NOX, and PM10

SECTION 3.5, "BIOLOGICAL RESOURCES"
> Impact 3.5-2: Operational Impacts on Marbled Murrelet
> Impact 3.5-11: Operational Impacts on Raptors

SECTION 3.6, "CULTURAL RESOURCES, INCLUDING TRIBAL CULTURAL RESOURCES"
> Impact 3.6-3: Change to the Significance of a Historical Resource
> Impact 3.6-4: Change to the Significance of a Tribal Cultural Resource

CUMULATIVE IMPACT AREAS
> Air Quality
> Biological Resources
> Cultural Resources, Including Tribal Cultural Resources

I agree with all the impacts stated above, however I disagree with their omission of certain Impacts which remain potentially significant because their mitigation methods are non-existent, minimization, procrastination, "if operationally feasible" and/or not particularly effective.

In the Biological Section, I think the following impacts remain potentially significant:

> **Impact 3.5-1 Construction Impacts on Marbled Murrelet** - with insufficient study so far (not two years) and a plan to log 25 to 27 miles of clearcut to Bridgeville without study, I think this impact is not reduced because the Gen-tie corridor was left out and logging and installation of electric lines certainly is construction.

> **Impact 3.5-2: Operational Impacts on Marbled Murrelet** (agree with DEIR)

> **Impact 3.5-5: Operational Impacts on Bald and Golden Eagles:** Because they are fully protected species, there is no way to get a permit to take any. Since their mathematical modeling shows that there will be take, I don't think this impact can be reduced to less than significant.

> **Impact 3.5-7: Spotted Owls:** There's no way to mitigate for 546.8 acres of impact in this DEIR. There may be ways to mitigate for that kind of impact, but it's not in this document. The use of "to the extent feasible" in this impact creates the same situation as it has elsewhere; making later changes to the process without public input.

> **Impact 3.5-8: Operational Impacts on Northern Spotted Owls.** Because less than two years of protocol level surveying was done; because of no survey in the Gen-tie corridor; and because mitigation methods for this species are at best minimization; and "as feasible", there is insufficient information to reduce this to less than significant.

> **Impact 3.5-10 Removal and Modification of Special-Status Raptor Nesting and Foraging Habitat during Construction.** In this impact, the full 862.1 acres of impacts are acknowledged. I do not see how this could be less than significant with nearly 900 acres of nearly simultaneous impacts - especially with their plans to work through winter when raptors flock to Humboldt.

> **Impact 3.5-11: Operational Impacts on Raptors.** Agree. This is significant. Fully protected species should be addressed as well.

> **Impact 3.5-14: Operational Impacts on Nonraptor Birds.** I do not think their mitigation measures reduce the impact to non-raptor birds, most particularly the condor. The California condor may be considered "experimental" in one sense, but it is still a Fully protected species under California law. Take permits are not available. There doesn't seem to be real mitigation for this measure, one of the four items presented is minimization; the others are paperwork and bureaucracy.

> **Impact 3.5-18: Operational Impacts on Bats.** Data flaws, too few sampling stations and they were too short to study the full 600 foot tall (and wide) area of rotor sweep. And because their mitigation measures are non-existent for several Species of Special Concern bats; because the mitigation for Townsend's bats creates secondary impact and is unproven; and for a multitude of other reasons stated in my comments. The phrase "while recognizing the operational needs of the facility" is used on page 3.5-136. It appears to mean that the blades

will turn regardless of the mortality. Section 3.5-129 Habitat Assessment for potential bat roost sites not done.

> **Impacts 3.5-19 and 20:** Daytime surveys missed nocturnal Ringtails, which are fully protected species. The studies were done too quickly to be sure than these impacts can be reduced, and the mitigation methods have difficulty as stated in my comments.

> **Impact 3.5-25: Wetlands:** I disagree for reasons stated in the section on Highway changes, most particularly at Hookton Slough and 12th Street proposed bypasses where bridged streams run under the bypasses which were not addressed in the DEIR.

> **Impact 3.5-27 Impacts on Nursery Sites:** I think this is still potentially significant due to the lack of Gen-tie and Highway 101 surveys result in insufficient data and lack of mitigation methods, as well as procrastinated bird and bat survey work. Taking away over 500 acres of forest which provides bat roosting is significant, and not really enough information is provided in the DEIR, nor real mitigation measures.

> **Impact 3.5-28: Inconsistency with the Humboldt Redwood Company Habitat Conservation Plan.** This is not mitigated in any way that I saw in the document. They propose to clear cut 25 to 27 miles for Gen-tie. At the same time Humboldt Redwood Company will continue logging operations. This is a cumulative impact - taking all these trees in one short time period. Winter operations leading to mass wasting on the steeper than 30% slopes mentioned in the Geology section has potential to foul the downstream waters of both Bear River and the Eel River from which Rio Dell draws its drinking water.

One only needs recall the Stafford Landslide to see why winter operations are not allowed in the HCP. "Pacific Lumber Co. has agreed to pay $3.3 million to the victims of a catastrophic mudslide on the steep slope of a clear-cut mountain that wiped out nearly half of the Humboldt County hamlet of Stafford. The mudslide, wide as a football field and 25 feet high, caught residents by surprise during a torrential rainstorm on Dec. 31, 1996, and Jan. 1, 1997. It destroyed seven houses. Pacific Lumber, Humboldt County's biggest employer, initially denied that its logging operation on the watershed above Stafford was the cause of the mudslide, but settled just as the trial was to have begun."
(https://www.sfgate.com/news/article/Pacific-Lumber-To-Pay-Millions-In-Landslide-Suit-2943883.php Eric Brazil, San Francisco Chronicle, March 9, 2001)

Additionally I think Impact 3.5-28 has potentially significant impact because they have announced their intention to violate the spirit and intent of an environmental law before starting construction. I think this shows the spirit and intent of the project is not to stay within the lines of CEQA - but to do whatever it takes to get this done in time for the subsidies and tax benefits to accrue to the investors.

I wonder about the situation and liability for Humboldt Redwoods Company leasing land to a tenant who has stated their intent to not abide by this lawful agreement.

The thirty-seven deferred or non-existent, but required, mitigation or coordination plans show a lack of applicant commitment to the inclusionary process of CEQA, as the intent to violate the HCP demonstrates lack of understanding of local geology, soils and weather conditions.

Impact 3.2-1 Project Impacts on Scenic Vistas and Potential for Substantial Degradation of Existing Visual Character or Quality of Public Views of the Site and Surroundings...This impact would be significant.

I agree this would be significant and unmitigatible. This section says that the blades contrast and create "visual distractive movement." I think this could be very dangerous if drivers became distracted and it will destroy the visual environment of a large part of the county. Especially at night with the red flashing lights where presently there is darkness.

Impact 3.2-4 Shadow Flicker.
I disagree with their conclusion of less than significant due to the outdoor nature of work and play in the county, no structures capable of blocking the view of 600 foot tall towers on top of the tallest point in the county, and many buildings with full wall of windows overlooking the project area. The DEIR only considers walls with small windows.

Impact 3.4-1 Short-Term, Construction-Generated Emissions of ROG, NOX, and PM10. Short-term, construction- generated emissions would exceed NCUAQMD's significance threshold for NOX. This impact would be significant." I think it will be more significant than they said because they failed to include fossil fuels for subcontractors, equipment transport and logging as discussed in my comments.

Impacts in section 3.8 Greenhouse Gases
As discussed earlier in the comments, the modeling assumptions are flawed, and all impacts need to be reconsidered.

Impacts in section 3.9, 3.10, 3.11 and 3.12 were discussed in the foregoing, with the most important comment that they have not secured construction water and that many of their conclusions disagree with data presented.

6.0 ALTERNATIVES

"If the environmentally superior alternative is the 'no project' alternative, the EIR shall also identify an environmentally superior alternative among the other alternatives." (CCR 15126.6)
• Not always clear if there is one environmentally superior alternative; sometimes there are environmental tradeoffs

Impacts from the Biological Section

Humboldt Wind Energy Project Draft EIR Biological Resources 3.5- pages 69 to 190 Humboldt County

----------- BIRDS ----------------

IMPACT 3.5-1	**Construction Impacts on Marbled Murrelet Nesting.** *Construction of the proposed project could affect the success of marbled murrelet nesting activity if construction activity were to cause disturbance at the nest, thereby reducing productivity. This impact would be* ***potentially significant.***
IMPACT 3.5-2	***Operational Impacts on Marbled Murrelet.*** *Operation of the proposed project could result in injury to and mortality of marbled murrelet, as a result of collisions with project components such as wind turbine generators and the gen-tie. This impact would be* ***potentially significant.***
IMPACT 3.5-3	**Construction Impacts on Bald and Golden Eagle Nesting Activity.** *Construction of the proposed project could affect bald and golden eagle nest success if active nests were directly affected, or if construction activity were to disturb nest sites, thereby reducing adult nest attentiveness and nest productivity. This impact would be* ***potentially significant.***
IMPACT 3.5-4	**Construction Impacts on Bald and Golden Eagle Foraging and Nesting Habitat.** *Construction of the proposed project could remove or degrade the quality of suitable bald and golden eagle foraging habitat. This impact would* ***be less than significant.***
IMPACT 3.5-5	**Operational Impacts on Bald and Golden Eagles.** *Operation of the WTGs would pose a risk of collision to bald and golden eagles. This impact would be* ***potentially significant.***
IMPACT 3.5-6	**Disturbance of Roosting and Nesting Northern Spotted Owls by Construction Activities.** *Project construction noise and activities could increase stress levels in owls during daytime roosting/nesting periods, potentially leading to nest abandonment. This impact would be* ***potentially significant.***
IMPACT 3.5-7	**Removal, Fragmentation, and Modification of Northern Spotted Owl Habitat during Construction.** *Construction of access roads, the gen-tie, and other project facilities would result in disturbance to approximately 546.8 acres of forested northern spotted owl habitat (approximately 457.1 acres of temporary impact and 89.7 acres of permanent impact). This impact would be* ***potentially significant.***
IMPACT 3.5-8	**Operational Impacts on Northern Spotted Owls.** *Northern spotted owls that cross the ridgeline in the wind turbine generator zone as a matter of foraging habit, or during dispersal by young birds, have the potential to collide with WTG blades. This impact would be* ***potentially significant.***
IMPACT 3.5-9	**Construction Impacts on Nesting Raptors.** *Project construction could directly or indirectly affect the nesting success of raptors. This impact would be* ***potentially significant.***
IMPACT 3.5-10	**Removal and Modification of Special-Status Raptor Nesting and Foraging Habitat during Construction.** *Construction of access roads, the gen-tie, and other project facilities would result in up to approximately 862.1 acres of impacts (approximately 729.5 acres of temporary impacts and 132.6 acres of permanent impacts) on potential nesting and foraging habitat for special-status raptor species. This impact would* ***be less than significant.***
IMPACT 3.5-11	**Operational Impacts on Raptors.** *Operation of the proposed project could result in mortality of and injury to raptors, as a result of collisions with wind turbine generators and electrical transmission lines. This impact would be* ***potentially significant.***
IMPACT 3.5-12	**Construction Impacts on Avian Foraging and Nesting Habitat.** *Construction activities associated with installation of proposed project infrastructure, including wind turbine generators and pads, the substation, the O&M facility, and the gen-tie, resulting in removal of forest, woodland, grassland, and riparian habitat would result in loss of avian nesting, foraging, and migratory stopover habitat for special-status birds. This impact would be* ***potentially significant.***
IMPACT 3.5-13	**Construction Impacts on Nesting Birds.** *Construction of the proposed project could affect avian nest success if active nests were to be directly affected or if construction activity were to cause disturbance at nest sites, thereby reducing adult nest attentiveness and nest productivity. This impact would be* ***potentially significant.***
IMPACT 3.5-14	**Operational Impacts on Nonraptor Birds.** *Operation of the proposed project could result in mortality of and injury to nonraptor birds, as birds could collide with or be electrocuted by project components such as wind turbine generators and electrical transmission lines. This impact would be* ***potentially significant.***

----------- BATS----------------

IMPACT 3.5-15	**Construction Impacts on Bat Maternity Roosts or Hibernacula and Loss of Essential Roost Habitat.** *Construction of the proposed project could result in mortality of and injury to bats, including special-status species, and removal of essential bat roost habitat. This impact would be* ***potentially significant.***
IMPACT 3.5-16	**Construction Disturbance of Bachelor Groups, Migratory Roosts, or Solitary Bats.** *Construction of the proposed project could result in mortality, displacement, and disturbance of bachelor groups, migrating bats, or solitary bats, including special-status species. This impact would* ***be less than significant.***
IMPACT 3.5-18	**Operational Impacts on Bats.** *Operation of the proposed project could result in mortality of and injury to a large number of bats, including special-status bat species, as a result of interaction with wind turbine generators. This impact would be* ***potentially significant.***

---------- MAMMALS ------------

IMPACT 3.5-19	**Construction Impacts on Special-Status Mammals.** *Grading and clearing activities, foot and vehicular traffic, and equipment operations associated with preparation of staging areas, construction of access roads, installation of components, and other activities associated with construction of the proposed project would result in loss of habitat for and disturbance of special-status wildlife, including the potential for direct mortality and injury. This impact would be* ***potentially significant.***
IMPACT 3.5-20	**Operational Impacts on Special-Status Mammals.** *The potential exists for special-status mammals present in the project area during project operation to be struck by vehicles. However, this impact would* ***be less than significant.***

-------- REPTILES & AMPHIBIANS -------

IMPACT 3.5-21	**Construction Impacts on Special-Status Amphibians and Reptiles.** *Grading, clearing, horizontal directional drilling, and other activities associated with project construction could result in direct and indirect impacts on special-status amphibian and reptile species and their habitat. This impact would be* ***potentially significant.***

----------------- FISH -----------------

IMPACT 3.5-[illegible]	**Impacts of Project Construction on Special-Status Fish.** *Grading, clearing, horizontal directional drilling, and other activities associated with project construction could result in indirect impacts on special-status fish species and their habitat from project runoff and sedimentation. This impact would be* ***potentially significant.***

------ PLANTS ------

IMPACT 3.5-23	**Impacts on Special-Status Plants during Project Construction and Operation.** *Grading, clearing, and other activities associated with construction and operation of the proposed project would result in loss and disturbance of special-status plant species present in the project footprint. This impact would be* ***potentially significant.***

------ HABITAT ------

IMPACT 3.5-24	**Loss or Disturbance of Sensitive Natural Communities and Riparian Habitat.** *Grading, clearing, and other activities associated with construction and operation of the proposed project would result in substantial loss and disturbance of sensitive natural communities and riparian habitat. This impact would be* ***potentially significant.***

------- WETLANDS ------

IMPACT 3.5-25	**Disturbance and Loss of Wetlands and Other Waters during Project Construction.** *Grading, clearing, and other activities associated with construction and operation of the proposed project would result in disturbance and loss of wetlands and other waters. This impact would be* ***potentially significant.***

-----Migratory Corridors & Nursery Sites ----

IMPACT 3.5-26	**Impacts on Migratory Corridors during Project Construction and Operation.** *Construction of the proposed project would result in the loss of relatively small amounts of land area, such that the project site would remain largely undeveloped. Project infrastructure would not impede movement by birds, bats, and terrestrial wildlife, and project operation would consist of activities that are similar to other land uses in the area. This impact would be* ***less than significant.***
IMPACT 3.5-27	**Impacts on Nursery Sites.** *Construction of the proposed project would avoid colonial bird-nesting sites (rookeries), and would avoid and minimize impacts on bat nursery roost sites. The project site would remain largely undeveloped, and project operation would not result in additional impacts on suitable nursery sites. This impact would be* ***less than significant.***

------ Inconsistent with Humboldt Redwood HCP -----

IMPACT 3.5-28	**Potential Inconsistency with the Humboldt Redwood Company Habitat Conservation Plan.** *The period for the first project construction phase is inconsistent with the provisions of the Humboldt Redwood Company HCP. This impact would be* ***potentially significant.***

• What if the proposed project is environmentally superior to all alternatives but the 'no project' alternative?– Include a table that shows each issue, the relative environmental impacts, and how they compare to the project."

In this case, the DEIR concludes that "no Project" is the environmentally superior alternative.

By CEQA rules they then select the next least damaging alternative from their list. However, their alternatives analysis is flawed because large parts of the project - and alternatives to parts of the project - have not been discussed.

First and foremost, they have never defined the type of turbine. There's a hand drawn diagram of a tugboat back in the appendices, but not once, do they say How Big, How Tall, Made by Whom, Base Diameter, and so on. The county is being asked to approve a project without sufficient information. The visuals in Aesthetics are not 600 feet tall; their bases are not as wide as the bases needed to hold up 600 foot tall turbines.

They have put off or deferred to later at least thirty-seven (37) plans, documents, maps and other materials mentioned in the DEIR but not finished or included with this document, but which should be to permit agency and public comment as part of the CEQA process.

Experts and agency comments from the early rounds of DEIR preparation were either overlooked or ignored including requests for two years of protocol level surveys, reviewing adjacent lands to address all relevant environmental resources, robust alternatives analysis, two years of radar surveys for the murellet, viewsheds for public parks and so on.

They did not look at other ridges in the county area. Schoolhouse Ridge has similar wind and is closer to Bridgeville but was unexamined.

They do not have to cut 25 linear miles of trees to get a Gen-tie line to Bridgeville. When Shell Oil proposed a similar project, they were going to tie into Rio Dell substation - much closer to the project site. Despite citing project materials from the Shell documents, this alternative was not addressed.

They have no alternative source of construction water since Scotia cannot legally provide it. They have no alternative source of water for their temporary workers since the aquifer they're tapping for the permanent workers cannot provide that amount of water - let alone add the concrete and dust water.

All alternatives will impact or take California State Fully Protected Species including: Brown Pelican (Pelecanus occidentalis californicus), Golden Eagle (Aquila chrysaetos), Bald eagle (Haliaeetus leucocephalus), White-tailed kite (Elanus leucurus), American peregrine falcon (Falco peregrinus anatum), Ring-tailed cat (Bassariscus astutus), and the California condor (Gymnogyps californianus). "Fully Protected species may not be taken or possessed at any time and no licenses or permits may be issued for their take except for collecting these species for necessary scientific research and relocation of the bird species for the protection of livestock." (https://www.dfg.ca.gov/wildlife/nongame/t_e_spp/fully_pro.html) The project affects the reintroduction zone for the California Condor by the Yurok tribe. (https://www.yuroktribe.org/departments/selfgovern/wildlife_program/condor/condorproject.htm) (page 3.6-41)

CONCLUSION REVIEW

While I realize the foregoing is long, I would like to review some of the salient points.

LEFT OUT OF DEIR

* No exact faceplate information for turbines - no ability to assess risk or noise. Different turbines behave and fail differently.

* No exact locations/footprints for turbines. No way to judge actual localized effects. (page 3.7-16)

* No statement of the amount of fuel to be used to deliver turbine components. (3.1.6 Energy, page 3-13) Construction fuel is shown on a table and discussed, but transport fuel is omitted (3.1.6 Energy, page 3-13) and cannot be part of the total as the types of vehicles which use it are not shown on the tables.

* No Eelgrass survey. Old data from an agency on the only map they provide. (Figure 3.5-4 and page 3.5-171)

* No modeling of view or air quality from Humboldt Redwoods State Park. (page 3.2-1) State parks, and special natural zones within the park, should be added to EIR Figure 1, at present the name of the park is half cut off by the lower boundary of the map.

* No mention of 50-year old trees and landscaping (rhododendrons and azaleas) along 101 at Loleta Drive and other ramps - just "trees and vegetation to be cleared." Obviously they won't grow back over the 30-year project life span.

* No protocol level surveys for Spotted Owls. (Section 3.5b)

* No Timber Harvest Plan for the 100 foot-wide by up to 25-mile Gen-Tie corridor 300 plus acre clear cut.

* No accounting for delivery of the lift or erection cranes - by land or water, these also take 25 truckloads in specialized vehicles and trips to deliver. (North American Windpower, October

2013,
https://edgarcountywatchdogs.com/wp-content/uploads/2014/07/evaluation-of-Apex-decommissioning-All.pdf)

* No delivery or arrival method for cranes and other construction equipment: sea or land? How much fossil fuel?

* No mention or studies of delivery effects on marine mammals or bald eagles, night herons, bats or other wildlife in the harbor and port.

* Lack of or insufficient studies of night lighting and noise during construction at Fields Landing, Jordan Creek staging area or on ridgetop footprint. Lights for night operations could impact birds, bats, marine mammals, and local residents but are not mentioned in the EIR. They plan to work to 10 p.m. and sunset can be as early as 3 p.m. in winter.

* No discussion of transport effects on residents in Fields Landing, Shively, Fernbridge, Fortuna, Rio Dell and Scotia, as well as unnamed communities along the delivery route; instead all were dismissed as the occasional house on a large lot, and not addressed as an impact.

* No listing of all bridges, overpasses, underpasses and grade crossings on Highway 101 which would be affected by transport and construction. Only some bypasses are given statements of need, some bridges to be gone over are of the same weight restrictions as bridge/s to bypass. The absence of a complete list does not give confidence that all obstacles to progress were adequately considered.

* No clue how long it will take to repair Highway 101 after the active transport phase. Bypasses go in and out, but then 101 itself will need repairs to right lane and shoulder from Fields Landing to Jordan Creek. This secondary impact is unaddressed in the EIR.

* No discussion of replacement supplies or components delivery methods or route changes.

* No decommissioning data. Just worry about that in 30 years, ktxbai.

* No description of unloaded truck route compatibility from Jordan Creek to Fields Landing. This might have been overlooked, but the heights of some of the bridges and overpasses are not the same going north as south. Since they were not discussed, it's impossible to tell if they are immaterial, were forgotten, or overlooked. The confusion of road names and exits in the document does not give great confidence for quality control.

* No discussion of the effect on potential down-wind sites other than in technical discussion of the effect of drafting on other wind turbines in the array. (Standard E-S3, Item B, Humboldt County Plan, page 3.2-29) At risk is Humboldt Redwoods State Park and the timber holdings of Humboldt Redwood Company. See the cover of this report for the effect of turbines on airflow.

TEMPORARY WORKERS
* The number of temporary and permanent workers changes throughout the document. Assume 15 permanent and 300 or more temporary.

* The document assumes in one section that the county can absorb 300 specialized imported workers with housing and food, but that their arrival and departure will have no impact on the area. (3.1.2 Population and Housing) A few sections later, it claims all 300 workers will be local and there will be therefore no impact. (3.1.5 Public Services) It can't be both ways.

* Potable water for temporary workers is not mentioned. They would have a 20-fold-increase on the water demands than the 15 permanent workers at the water consumption rates given. (3.1.3 Utilities, Water Supply)

* Temporary worker wastes are never mentioned. (3.1.3 Utilities, Wastewater)

MAINTENANCE
* No discussion of blade replacement other than by TerraGen spokesperson. Blades last 25 years, the project decommissions in 30. At least one blade replacement set per turbine (60x3 = 180) will be required over the life of the project and others may be required if blades fail. https://www.enr.com/articles/42352-are-four-wind-turbine-failures-in-five-weeks-too-many-for-nextera-energy That they all need to be replaced by 25 years, and that is not mentioned in the EIR creates secondary impacts from the project and more deferred mitigation.

* Road suitability for removal of components. Overlooked and unmentioned industry standard blade and component replacement over the 30 year life of the project. The effects of decommissioning are put off to 30 years in the future.

* Regular annual oil changes for each turbine were not really discussed in more than passing in this EIR. I learned that by reading about turbines from industry sites and videos https://www.youtube.com/watch?v=frYuXLTrM6w This process is automated and can cause no problems until the first time it does, at risk is 400 gallons of oil per turbine times 60 turbines each year, 24,000 gallons a year of maintenance oil.

* Gen-tie line maintenance would include herbicide use as would perimeter maintenance around other temporary and permanent facilities.

* Operational 4,000 pounds a week (0.28 ton/day) solid waste. That's factory level debris, not clean energy. (3.1.3 Utilities, Dry Waste)

PERMANENT physical effects
* Concrete turbine pads and surrounding compaction zone (350x350 foot times 60) are permanent.

* Ten acre staging area scar from batch plant.

* Scars from 40 foot to 200 foot wide access roads, later regraded to 25 feet.

* Logged off bypasses on Highway 101. Mature trees and habitat from Fields Landing to Jordan Creek will be cleared or trimmed wherever it gets in the way. No surveys for animals or plants on the route to be cleared.

* Visible from Humboldt Redwoods State Park on the Thornton Multi-Use Trail, the Peavine Multi-Use Trail, The Peavine Ridge Spur at Prairie Road, parts of the Grasshopper Trail and Grasshopper Peak, all within the park areas of special natural significance.

* Towers and blinking red lights in line-of-sight will affect views from Fields Landing to Scotia. (figure 3.2-10 and figure 3.2-4) The EIR calls this potentially significant. (Impact 3.2-1, page 3.2-33)

* Light pollution (pages 3.2-26, 3.2-27, 3.2-63 & 3.2-64) Shadow flicker is dismissed because there's more walls than windows (page 3.2-65) like no one works outside and tourists stay in houses.

* Seventeen miles of new 24-foot access roads closed to all but as needed workers for 30 years. If you're going to build 24-foot wide, perfectly paved roads, seriously, build them where they do some good for more than 15 permanent workers and a bunch of lizards. Seventeen miles would fix half the Wildcat-Mattole Road, leading to less greenhouse gas emissions while everyone creeps around the monster potholes at 10 mph.

* Conflicts with Humboldt County General Plan sections:
CO-G1 (page 3.2-28+), Standard SR-G1 (page 3.2-28+), Policy SR-P1 (page 3.2-28+), Standard SR-S2 (page 3.2-28+), Standard SR-S4 (page 3.2-28+), Standard E-S3, Item B (page 3.2-28+), Policy AG-P6 (page 3.3-8), Policy FR-P8 (page 3.3-9), Policy AQ-P9 (page 3.8-19), Policy AQ-P11 (page 3.8-19), Policy AQ-P17 (pages 3.8-19 & 20), Standard AQ-S6 (pages 3.8-19 & 20), Implementation Measure E-IM5 (page 3.8-20). There may be other conflicts with the Humboldt County Plan elements in the EIR besides these which were obvious.

SLUMPS, SLIDES, FIRES, FAILURES and COLLAPSES

*The EIR identifies steep slopes and unstable soils throughout the construction footprint. Cutting all the trees on the access roads in fall 2019 may result in landslides in rainy season.

* Out of area workers and oversized vehicles may cause grass or forest fires. One flicked cigarette, dragged chain or sparking electrical wire and this could be Paradise repeated.

* Wind turbines catch fire. Others have fallen down. Some have done both. Blades break and fall off. The risks of these events in a rural fire-prone area are greater than the EIR implies.

* According to the wind energy industry advocacy group, wind turbine fires represent 10 to 30 percent of reported wind turbine accidents. No agency in Humboldt is equipped or able to fight a fire on a 50-story structure.

* 10 foot deep circular foundations, up to and over 50 stories high in a seismically active (to 7.2 known magnitude) and fire-prone region in unstable soils on slopes to 10 percent. Major earthquakes on less than 20 year average separation. What could possibly go wrong?

WEATHER
* It is unlikely they can stay on schedule with a winter construction season. Even Humboldt Redwood slows or stops in season and these are the same lands and same tasks. The EIR states they would continue to log and work in winter, which is not permitted under the Humboldt Redwoods HCP. (page 3.5-187)

* Winter also influences the ability to ship over the bar into Humboldt Bay but no mention of adverse weather slowing or impeding the goal to finish by December 2020 (one full and one half winter seasons) is not mentioned.

PUBLIC SAFETY
* Local first responders have no experience in high-angle rescue or fire-fighting at 500 plus feet.

* Damages to the right lane and shoulder of Highway 101 would put CHP and motorists at daily risk from uneven surfaces and rock throw until the Highway was repaired - at least 18 months later plus the time to actually fix it (Hwy 36 is 3 years so far). This is an unaddressed secondary impact.

DATA MODELING
* The proposal suggests the tallest wind turbines in the US, so new that study data is not available for seismic risk and noise, plus no one knows how they'll perform once installed because there aren't any in North America yet. No data means modeling is not applicable.
* Modeling on animal species was damaged by incomplete data and unsupported assumptions.

CONFUSING ALTERNATIVES
* Many alternatives are presented, however EIR does not provide breakouts of differences in Greenhouse Gas emissions or fossil fuels required to build the different foot-prints. In only one example: Riparian studies were not done at the Eel because they claim drilling underneath it would have no effect, however they have to have a staging area for bentonite containment materials and access somewhere. I don't see that they accounted for riparian habitat issues should they have to go over the Eel. Other examples abound. It is not possible to make a "better" choice based on the lack of input data for the alternatives.

WILDLIFE IMPACTS

Incorporate into this summary all foregoing statements about wildlife, with the following specific comments

- Project is in known Marbled Murrelet flyway. The Marbled Murrelet was the catalyst for the Headwaters Deal and important to the Humboldt Redwoods Habitat Conservation Plan. Clearcut Gen-tie will open 25 miles of forest to raven predation. Mitigation suggested to reduce corvids has been implemented in other locations, but hasn't stabilized or increased murrelet populations. (page 3.5-78) A failed mitigation method is not mitigation. USFWS murrelet recovery guidelines were not followed or cited in the EIR. (page 3.5-78) Marbled murrelet impact stated to be "significant and unavoidable." (page 3.5-85)

- There are 33,213 acres of spotted owl habitat within 0.7 miles of this project. (page 3.5-93) No data on how spotted owls do with turbines, this would be a first in habitat.
- Turbine noise in the State Park and project footprint area with unknown effect on Townsend's long-eared bats, Spotted Owls and other wildlife.

- Models predict 300 dead birds a year, up to 114 raptors, up to 5% special status raptors (Cooper's hawk, sharp-shinned hawk, burrowing owl, ferruginous hawk, and northern harrier). (pages 3.5-109 & 110)

- Plans will impact or take California State Fully Protected Species including: Brown Pelican (Pelecanus occidentalis californicus), Golden Eagle (Aquila chrysaetos), Bald eagle (Haliaeetus leucocephalus), White-tailed kite (Elanus leucurus), American peregrine falcon (Falco peregrinus anatum), Ring-tailed cat (Bassariscus astutus), and the California condor (Gymnogyps californianus). "Fully Protected species may not be taken or possessed at any time and no licenses or permits may be issued for their take except for collecting these species for necessary scientific research and relocation of the bird species for the protection of livestock." (https://www.dfg.ca.gov/wildlife/nongame/t_e_spp/fully_pro.html)

- *Project affects the reintroduction zone for the California Condor by the Yurok tribe. (https://www.yuroktribe.org/departments/selfgovern/wildlife_program/condor/condorproject.htm) (page 3.6-41)

CARBON DIOXIDE

*The amount of fuel stated is too low, thus the CO2 emitted in the first two years will be higher than stated. It's not going to really help the atmosphere or stop global warming at all.

*The calculations are incomplete; they omit the fossil fuel used in transportation and by subcontractors. (3.1.6 Energy, page 3-13) The only diesel fuel listed is for turbine construction and does not include water/fuel delivery, logging or component transport into the harbor, fuel for log trucks, chainsaws, specialized transport vehicles, pace cars, garbage trucks and so on.

*The EIR regularly omits the effects of subcontractors and their equipment. Simply buying services from someone else does not relieve the applicant of accounting for the effects.

*The EIR brushes off the loss of trees - carbon dioxide sinks - to be removed for the GenTie and other construction as "they would have been cut anyway" under the Humboldt Redwoods HCP. Mitigation measure proposed for murrelets - thinning canopies - would also remove carbon sinks. (page 3.5-84) The loss of the forest Carbon capacity and the amount of carbon released by disturbing 3 million cubic feet of dirt should be added to the equation.

* The calculations are amortized over 25 years. The reality is most of the CO2 will be released in the first 1.5 years by TerraGen and over an unknown amount of time by the state to repair 101 afterwards.

* By the time the equality of their 25-year-amortization equation kicks in, the 12-years-to-crisis point will be a six months in the past.

SPEED is not always ACCURACY

* The EIR was prepared in a hurry (Natalynne DeLapp, public comm. 2019). The natural areas studies are incomplete. The applicant wants subsidies for building these by December 2020. If anything is in the way, the plan calls for "clearcut, flatten and pave" with a rather "full speed ahead" gusto that suggests a fairly hefty payout awaits successful conclusion and that the laws and agreements here do not matter if they get in the way of the almighty dollar. One only has to see the hasty errors in section after section of the EIR to know the speed at which the work will be performed.

* "Finch Creek" exit as stated is actually Fernbridge exit. The number of workers changes. Some things are included in tables, and mentioned in the text, then forgotten in the mitigation. The name of the state park is cut off on Figure 1. The same figures are presented twice in Aesthetics. First it's ten species of bats, then 12, then back to 10 and finally they forgot to mention two of three species of special concern. The report looks and reads as if it were prepared at full speed and it lacks a full two years of species data.

* "Google Earth" was used to model old growth and mature trees. (page 3.5-79) LOL.

* There simply isn't time to prepare final engineering drawings, and all the other documents that go with them - and study the environment prior to doing final engineering - simultaneously. But that is what is going to happen starting in September 2019 according to this EIR.

* The various project alternatives proposed for consideration are not separately modeled or described in the text. It is impossible to determine the best alternatives other than "no project" without being able to know the impacts, mitigation and results which would change based on the various alternatives.

MITIGATION is not intended to be MINIMIZATION

* Wind farms kill flying things. No one disputes this. Thirty years of wind farms have wiped out so many birds and bats that it's obviously an impact. And no, cats don't kill condors, bald eagles, golden eagles, or many of the other species at risk. But wind farms do. What is not stated is any proactive effort to do things to benefit species. Three of the four bat species of special concern are mentioned once, and never mentioned again. (pages 3.5 - 128 +, page 3.5-134-136) No discussion about effects and no effort to mitigate for them.

* Wind farms are known to harm whole species. The EIR states that with no new generation capacity, existing wind farms will drive the Hoary Bat to extinction by 2050. (page 3.5-134) We are a hotspot for Hoary Bats - perhaps one of the most significant parts of its range and will kill bats as stated in the EIR. I do not know how any "mitigation" is possible after realizing that new wind farms will hasten this species to extinction in an area which is known by their own survey work to host this species. Money won't bring back the dead. Tourists don't come here to see dead things.

* Wind farms kill large, expensive flying things. Millions if not billions of tax payer dollars have been spent to save Bald Eagles, Golden Eagles, Condors, marbled murrelets, horned larks, and other interesting and special species which the EIR says will be killed and then offers some feeble minimization strategies, including trash can lids for Van Duzen County Park and discussions with the county of how to kill less, maybe.

* The mitigation sections are very weak. There is no habitat being purchased upfront, only an offer of purchases or conservation easements - if - problems occur - and even that discussion won't start for a year or two after electricity is being produced.

* Spotted owls use old growth and mature trees. The EIR states that some loss from project is "temporary" and will be revegetated for the owls. It will take more than our lifetimes for those trees to mature - there is no possible way that the 546.8 acres will only be temporarily affected. (Impact 3.5-7, page 3.5-100)

* Data and mitigation omissions are frequent and curious. Species - even those of special concern - are shown on tables, or introduced, but then never mentioned in mitigation. Subsequently a conclusion is offered that the proposed mitigation measures will benefit everything and that replacement birds can be "created" by post-mortem meetings and trash can lids in a state park. Such is obviously not possible. Specific examples of this are listed in my comments on Section 3.5b.

They have not yet demonstrated good neighborly behavior by running heavy trucks up Monument Road after assuring the City of Rio Dell that they would not; and by assuming they could take Scotia's log pond water with heavy trucks, all day every day for a year and a half. Stating their intention to violate the Humboldt Redwoods HCP also shows a lack of neighborly intent.

Last and certainly not least,

* There is no way to get a take permit for California Fully Protected Species - including the California Condor - except for research or livestock protection. This project is neither, and this is not discussed in the EIR. If it is illegal for an individual to take a member of a Fully Protected Species then by current U.S. law, it is equally illegal for a corporation. I request the California Department of Fish and Game to enforce their laws equally on corporations and individuals (https://www.npr.org/2014/07/28/335288388/when-did-companies-become-people-excavating-the-legal-evolution).

GOOD NEIGHBORS

They have not yet demonstrated good neighborly behavior by running heavy trucks up Monument Road after assuring the City of Rio Dell that they would not; and by assuming they could take Scotia's log pond water with heavy trucks, all day every day for a year and a half. Stating their intention to violate the Humboldt Redwoods HCP also shows a lack of neighborly intent.

CONCLUSION

"As described in the EIR many of these impacts can be fully mitigated but some cannot, and they would remain significant and unavoidable." Many of the impacts are initially tagged "potentially significant." Mitigations offered range from discussions to conservation easements - which do not make up for the lost of around two square miles of habitat, with linear effects over a minimum of 25 miles. Despite the EIR lessening impacts to "less than significant," in many cases - as noted - I disagree with their conclusions.

Most significantly, I disagree with how the CO2 and other greenhouse gas emissions are calculated and applied as "offsets."

The CO2 calculations are amortized over 25 years. The world has 12 years to change. This project is entirely built with fossil fuels which will be emitted into the atmosphere in the first two years. Amortization doesn't change the basic concept that this will be worse for the planet not better because it will take 12.5 years to offset half the carbon emissions that went up in the first two years. By that time, our 12 years is up.

Therefore, this project fails the project goal for reducing greenhouse gas emissions, because it does not account for them entering the atmosphere until years after they were emitted. It is not a "reduction" at all since additional fossil fuels would be burned here which would not be burned if this project did not occur.

There are at least two places where the applicant discusses plans to knowingly violate existing laws and agreements. (1) Plans to ignore the Humboldt Redwoods HCP regarding winter work, and (2) Plans to take California Fully Protected species for which no permits or licenses are available.

Many places in the document provide incomplete or conflicting information. This is merely a list of a few of the points noted in my comments:

- The biological data in the appendixes is good, but they studied less than the required two years for protocol level studies.
- Fields Landing aquatic and terrestrial biomes are unstudied.
- No Eelgrass survey, map data old and inaccurate by their own text.
- Except for one brief mention, fully protected species are not discussed; for these no permits can be issued for take.
- The number of workers and whether they are local or temporary from elsewhere is stated both ways - neither is supposed to be significant.
- Noise, air quality and/or greenhouse gas sections mention transportation vehicles and trips that are unmentioned in 2.0 Scope and which appear to have been left out of the CO2 calculations. These omitted vehicles could double the fossil fuel cost.

There are too many omissions and changing facts in this document to fully understand the scope, impacts and effects of the project.

"CEQA also requires that each public agency avoid or mitigate to less-than-significant levels, wherever feasible, the significant environmental effects of projects it approves or implements. If a project would result in significant and unavoidable environmental impacts that cannot be feasibly mitigated to less-than-significant levels, the project can still be approved, but the lead agency's decision makers must issue a statement of overriding considerations explaining in writing the specific economic, social, or other considerations that they believe make those significant effects acceptable."

I do not believe they have mitigated to less-than-significant levels of impact and I do not believe there are grounds for a statement of overriding considerations to be issued.

I do not think this project is the only way to replace Carbon Dioxide, especially with the method of spreading out the CO2 over 25 years to "offset" its carbon. With the known and predictable losses to wildlife and habitat, I do not think this project provides "environmentally safe power" or that it is a good fit for the county. For these and all the reasons stated in the body of my comments, I firmly support the "no project" alternative.

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BOARD OF DIRECTORS MEETING AGENDA

Humboldt Bay Municipal Water District Office **June 27, 2019**
828 7th Street, Eureka, CA 95501 **Thursday, 3:30 p.m.**

Chair Michael Winkler called a regular meeting of the Board of Directors of the Redwood Coast Energy Authority to order on the above date at 3:30 p.m. Notice of this meeting was posted on June 23, 2019. PRESENT: Vice Chair Austin Allison, Alternate Director Chris Curran, Estelle Fennell, Dwight Miller, Robin Smith, Frank Wilson, Chair Michael Winkler, Sheri Woo. ABSENT: Dean Glaser. STAFF PRESENT: General Counsel Nancy Diamond; Power Resources Director Richard Engel, The Energy Authority Client Services Specialist Jaclyn Harr, Executive Director Matthew Marshall, Account Services Manager Mahayla Slackerelli, Clerk of the Board Lori Taketa.

REPORTS FROM MEMBER ENTITIES

Director Smith reported that opposition to Humboldt Wind's Monument Ridge wind energy project is strong in Ferndale and that RCEA might want to send a representative to Ferndale to clarify the agency's position.

Director Woo reported that the Humboldt Bay Municipal Water District is meeting with the State Water Resources Control Board to move forward on dedicating a portion of the District's water rights to instream flow for fish and wildlife benefits.

Director Allison reported that the Eureka City Council elected not to opt up to RePower+ based on city staff's projections of the resulting increase to the city government's electricity costs. The Council approved a 100% renewable electricity by 2025 goal so the transition is only delayed.

Director Fennell reported that Humboldt County joined the Sonoma County Water Agency, California Trout, and the Mendocino Inland Water and Power Commission, in a notice of intent to file for an operation license for the Potter Valley Project, a regional approach to assuming PG&E's project. Director Fennell stated the importance of finding a two-basin solution to the Project's relicensing and of expanding regional membership to include tribes and other interested parties. Director Fennell will contact Executive Director Marshall about including an overview presentation by the County's consultant on a future RCEA Board meeting agenda.

Director Wilson reported that the Rio Dell City Council will appoint a candidate to replace a Councilmember who moved away from the city.

ORAL COMMUNICATIONS

Member of the public Walt Paniak of Arcata stated that an explanation of renewable energy credits should be added to the RCEA website.

CONSENT CALENDAR

3.1 Approve Minutes of May 23, 2019, Board Meeting.
3.2 Approve Disbursements Report.
3.3 Accept Financial Reports.

Chair Winkler invited public comment. No one came forward to speak. Chair Winkler closed public comment.

M/S: Miller, Fennell: Approve Consent Calendar items 3.1, 3.2 and 3.3.

The motion passed on a unanimous voice vote. Ayes: Allison, Curran, Fennell, Miller, Smith, Wilson, Winkler, Woo. Noes: None. Absent: Glaser. Abstentions: None.

OLD BUSINESS

5.1 FY 2019-2020 Budget

Executive Director Marshall presented a staff report on the proposed annual budget, pointing out roughly $4 million in construction costs for the airport microgrid project, which will be funded through a California Energy Commission grant, and a USDA loan to be repaid by RCEA using ratepayer funds. Electricity sales remain the largest source of revenue; wholesale power purchases are the largest expense.

The Energy Authority Client Services Specialist Jaclyn Harr reported on the Community Choice Energy program's power mix, on how the CCE program is meeting state renewable requirements well, and on factors impacting wholesale power costs.

The Directors discussed how regional and national, rather than global, energy issues such as Pacific Northwest precipitation and natural gas prices, affect RCEA's power procurement. Director Woo reported that the Board Finance Subcommittee examined program costs in detail as they reviewed the proposed budget and commended staff for preparing the budget document so the public can see what RCEA does.

Chair Winkler invited public comment. No one came forward to speak. Chair Winkler closed public comment.

M/S: Allison/Woo: Adopt the RCEA fiscal year 2019-2020 annual budget.

The motion passed on a unanimous voice vote. Ayes: Allison, Curran, Fennell, Miller, Smith, Wilson, Winkler, Woo. Noes: None. Absent: Glaser. Abstentions: None.

5.2 Comprehensive Action Plan for Energy Update

Executive Director Marshall presented a staff report on updating the 2012 Comprehensive Action Plan for Energy (CAPE), which will include the Board-approved 100% renewable electricity by 2025 goal, input received from current countywide Climate Action Plan (CAP) development and community outreach, and consolidation of qualitative and still-current quantitative strategies from RCEA's strategic planning documents. Findings from this update will inform the Community Choice Energy Program's next Integrated Resource Plan, which will be submitted to the CPUC by May 2020. Staff identified a need to refine high-level CAPE strategies, develop quantitative targets and milestones, determine targets for the power mix make up for the next ten years, and to work with the County to coordinate a community and stakeholder discussion around the many interconnections between forest lands and climate change mitigation.

The directors discussed how electric vehicle incentives are the only cap and trade auction proceeds to be distributed in Humboldt County to date, how the Board-approved goal of achieving 5% less greenhouse gas emissions than PG&E's power portfolio becomes moot when the program achieves 100% clean and renewable electricity in 2025, that building and transportation fuel switching can be included in the CAPE strategies and quantitative analyses; how PG&E's natural gas-powered Humboldt Bay power plant is the only back-up source of electricity during service interruptions to the transmission lines connecting the County to the rest of state grid at Cottonwood, the need for local renewable energy development given the restrictions of importing electricity on the Cottonwood lines, and the lack of non-fossil fuel-based local energy options other than wind and biomass.

Chair Winkler invited public comment.

Member of the public Scott Frazer stated that many local residents are producing more electricity than their homes require through solar panels, and that it is possible to produce a lot of energy locally on rooftops.

CCE customer and member of the public Diane Ryerson stated that she installed solar electric panels and a hot water thermal pump to stop using natural gas. Her definition of clean energy does not include biomass, which she stated produces carbon faster than can be sequestered. Ms. Ryerson would like to see alternate uses of forestry byproducts that keep carbon in the soil, a reduction in biomass energy and inclusion of offshore wind in the CCE power mix as soon as possible, and local energy storage. Given a choice between dirtier local or out-of-area clean energy, she prefers out-of-the-area clean energy.

Member of the public Walt Paniak of Arcata asked the directors to consider: health problems caused by emissions from diesel and natural gas cogeneration at the PG&E, Scotia and DG Fairhaven power plants; and the increasing cost of biomass as a fuel source as opposed to wind and solar, which are free.

Member of the public Dave Carter stated that the electric grid requires consistent 60hz frequency provided by large rotating machines with inertia in order to support wind and solar power. Both renewable energy sources lack this grid inertia and stable frequency. PG&E's Humboldt Bay Generating Station and the biomass plants provide these essential functions. Mr. Carter stated that while the local biomass plants are old and need upgrades to be cleaner, if the community moves away from biomass and loses the PG&E plant, there will be no grid inertia. With biomass, the community has a chance to regulate grid frequency locally without the PG&E plant.

Chair Winkler closed public comment.

5.3 Special District Risk Management Authority Board Election

Executive Director Marshall presented a staff report and recommendations to support the local candidate and the two incumbents.

The directors discussed the local candidate's qualifications, the possibility of assigning a director to research the candidates and the willingness to support the incumbents if they are performing well.

Chair Winkler invited public comment. No one came forward to speak. Chair Winkler closed public comment.

M/S: Allison, Smith: Defer consideration of the 2019 SDRMA Board of Directors election votes until the July 25 RCEA Board meeting.

The motion passed on a unanimous voice vote. Ayes: Allison, Curran, Fennell, Miller, Smith, Wilson, Winkler, Woo. Noes: None. Absent: Glaser. Abstentions: None.

COMMUNITY CHOICE ENERGY (CCE) BUSINESS

Chair Winkler stated that a quorum was present to conduct CCE business.

OLD CCE BUSINESS

7.1 Community Choice Energy Updates on Rate Change, Regulatory Compliance and Public Disclosure (Information only)

Account Services Manager Mahayla Slackerelli reported that PG&E was implementing its third and presumably final rate adjustment for the year on July 1, and that RCEA customers will receive a 1% discount on PG&E's generation rate. The power charge indifference adjustment (PCIA) is also changing. Overall, electricity rates will increase slightly.

Staff Manager Slackerelli clarified that PG&E charges Community Choice Aggregators in its service area the PCIA because PG&E was required by the CPUC to enter into high-priced energy contracts in the past. PG&E expected to serve its customers into the future but as they moved to CCAs, removing load, PG&E was left "holding the bag." The PCIA helps PG&E honor those legacy contracts.

Power Resources Director Richard Engel reported that the CPUC is scrutinizing CCAs more closely as they become a larger segment among load serving entities and staff is coordinating with other CCAs, The Energy Authority and energy legal counsel Braun Blaising Smith Wynne to fulfil the increased state renewable energy portfolio filing requirements in a consistent manner. In order to obtain a greenhouse gas emissions factor for the public to use to compare the CCE program's different electricity sources, RCEA enrolled with The Climate Registry (TCR) and will eventually perform a third-party verified audit on greenhouse gas emissions as part of its emissions disclosure practices through TCR.

Upon inquiry by member of the public Ellen Golla about the 12% biomass figure for the RePower+ portfolio, staff clarified that biomass constituted 12% of the total 2016 energy portfolio, a figure that was projected to increase to 24% with the addition of the DG Fairhaven procurement contract. However, in 2018 the plants' actual output was less that the full contract maximum so biomass' portfolio portion grew to only 20%. To keep the RePower+ power content mix consistent the amount of biomass in the RePower+ portfolio is being kept at 12%. Around 1% of RCEA customers have opted up to the RePower+ service, minimizing its impact on the total CCE program energy portfolio.

Chair Winkler closed public comment.

7.2 Energy Risk Management Plan Quarterly Report

The Energy Authority Client Services Specialist Jaclyn Harr reported on changes to the CCE program revenue and load forecasts since the last quarterly report in April. The current report incorporates more recent load forecast data and, with the adoption of a newer, more accurate method for assessing load, projects a 6.6% decrease in RCEA customer energy demand for 2019 and into the future, which will impact revenues.

Discussion ensued about how the PG&E rate changes have a positive influence on RCEA revenues and how summer weather projections, precipitation and hydropower availability affect electricity use and prices. Ms. Harr reviewed summer stress scenarios developed by CAISO, the organization that assesses whether California has sufficient energy resources to meet demand. Ms. Harr also reviewed California hydro conditions, their effect on power prices, and carbon-free power price increases due to a below-average hydropower year in the Pacific Northwest.

Chair Winkler invited public comment.

The directors discussed PG&E public safety power shutoffs and how they are more likely to affect customers in large electricity grid sections this summer during high winds, especially in central California, than system overload.

Chair Winkler closed public comment.

M/S: Fennell, Allison: Accept the Energy Risk Management Quarterly Report.

The motion passed on a unanimous voice vote. Ayes: Allison, Curran, Fennell, Miller, Smith, Wilson, Winkler. Noes: None. Absent: Glaser. Abstentions: Woo.

7.3 Renewable Power Request for Proposals Update

Director Woo recused herself from discussion of agenda item 7.3 due to a remote conflict of interest and left the dais at 5:14 p.m. Director Woo's conflict arises from her employment at SHN Engineers and Geologists, which performed work for Terra-Gen, of which Humboldt Wind, LLC is a subsidiary.

Power Resources Director Engel provided a staff report on the renewable energy request for proposals issued earlier this year which followed RCEA guiding document direction, specifically by the 2012 Comprehensive Action Plan for Energy, the RePower Humboldt strategic plan, and the CCE program's launch period guidelines, the latter of which set a

100% local renewable energy by 2030 goal, and the recent Board resolution revising the clean and renewable goal date to 2025. Director Engel described state mandates for renewable energy portfolio standards and long-term renewable energy contract duration, which also affect the CCE program's procurement. The request for proposal process, selection criteria, and reasons for selecting the finalists such as risk minimization based on projected prices, timing of other local power source availability and energy source diversification were described.

The directors discussed: how offshore wind, smaller scale feed-in tariff projects and biomass fit into RCEA's long-term procurement strategy; the standard industry practice of treating power purchase prices as proprietary information; how the combination of proposed power sources match fluctuating daily energy demands well; the portion of total projected load the proposed projects would meet until 2030; the limitations of total solar energy dependence; and the relative seasonal consistency of wind power.

Jaclyn Harr described in detail TEA's modeling and analysis of the different renewable energy proposals to determine the quantitative value of the projects and the different possible portfolio combinations. Ms. Harr stated that RCEA's financial outlook remains positive with the proposed power purchase agreements.

Upon inquiry by Director Miller, Ms. Harr stated that the projected cost savings from the three renewable energy contracts would result in net revenues increasing in future years as the projects come online, and the Board may choose to reduce customer electricity rates in the future.

The directors discussed concerns and potential benefits of locking in prices for long periods; how 15 to 20-year renewable energy contracts have become standard; high start-up costs for California energy projects due to environmental and permitting requirements; the difficulty for energy developers to get financing without longer term contracts; how the proposed contract prices are much lower than PG&E's long-term contracts with then-new technology renewable energy providers; and the state requirement to maintain a percentage of portfolio power purchase agreements of 10 years or longer to encourage new renewable energy development. The directors agreed to allow the finalist power producers a chance to speak.

Chair Winkler invited public comment.

Humboldt Wind Energy Project community liaison Natalynne DeLapp, speaking as a private citizen, stated that she was honored to work with the community on the Terra Gen project, that the wind project is evolving in response to community input to address cultural and biological impacts, and that she supports moving forward with this project which will provide tax revenue, new jobs and local renewable energy to meet greenhouse gas reduction goals.

Jim Zoellick, a Managing Research Engineer at the Schatz Energy Research Center who spoke as a private citizen, expressed support for the staff recommendation and stated that Humboldt County needs to develop local energy because the transmission system is inadequate to import enough electricity to meet the area's average, much less peak, needs. Mr. Zoellick outlined the technical and cost considerations making increased residential rooftop solar cost-prohibitive as a large-scale local renewable energy alternative. Mr. Zoellick stated his support for developing utility-scale wind energy with Terra-Gen at the proposed location and acknowledged that there will be project impacts which the company is doing a good job of working with the community to mitigate. He added that it will be up to the County whether the project is permitted and that the biggest impacts the community is facing are from climate change, which the Terra Gen project can help address in a short time frame.

Schatz Energy Research Center Managing Research Engineer Dave Carter, who also spoke as a private citizen, commended RCEA for its 100% clean and renewable electricity by 2025 goal and expressed the necessity of incorporating the Terra Gen wind project into the CCE power mix. Mr. Carter stated that it was difficult to express this support because the Wiyot Tribe has opposed the project, and that it was important for RCEA and CCE customers to acknowledge that they are asking, because of the climate crisis, to take something from the Wiyot Tribe after many other things have been taken from them.

An unidentified member of the public inquired whether it was possible for the public to know the cost of Terra Gen's wind power compared to solar and small hydropower and whether the Board was aware of the pricing. Staff responded that while biomass power purchase prices were made public previously, it was normal industry practice to treat pricing information as confidential; that an ad hoc Board subcommittee could be formed to analyze pricing information on behalf of the Board; that the proposed project contract prices are lower than what the CCE program is currently paying for other renewable energy; and that, not counting grid congestion, fluctuating time of day power and other risk factors, industrial-scale solar energy is cheapest, then wind, then other renewables.

Member of the public Ellen Golla strongly encouraged local wind development and expressed support for contract negotiations with Terra Gen. She urged RCEA to counteract misinformation circulating about the project and stated that the genuine environmental concerns being raised can be addressed.

Direct Miller requested that staff address the most frequently circulated rumors with accurate information that also explained the project's complexity and was informed that staff published a frequently asked questions section on the agency website's Power Procurement page. Director Miller further requested that RCEA consider compensating the Wiyot Tribe and the project neighbors for project impacts and expressed support for the staff recommendation.

Director Allison expressed support for the Terra Gen project and stated that while many of the project's negative commenters are older, younger generations must live with climate change repercussions. Director Allison stated the need to consider the bigger picture, the greatest means of benefitting the community, his hope that every community does all it can to reverse negative climate change impacts, and that there are community members supporting the project who are unable to participate in public meetings.

Director Fennell expressed support for negotiating with the three project finalists and stated that it is extremely important for supporters to present clear information in their public testimony to correct any misinformed narrative when the Humboldt County Planning Commission and Board of Supervisors consider the project permit, as other decision makers may not be as steeped in the climate crisis concept. Director Fennell stated that Terra Gen is trying to address the concerns that are being raised.

Director Wilson expressed support for moving forward with contract negotiations and agreement with staff's analysis. He stated that people need to consider what they will do if PG&E turns off the power and that the community must make trade-offs if it wants electricity.

Director Smith described the high level of unrest in the Ferndale community and stated that it is RCEA's responsibility to fully inform the public of the project's advantages and refute inaccurate statements with data.

Chair Winkler acknowledged concerns expressed by Mr. Carter and Directors Smith and Allison and stated that the majority of fossil fuel consumption in human history occurred during his lifetime, leaving his generation with a great responsibility. Chair Winkler expressed support for staff negotiation with the three companies, stated that the wind project presents an opportunity to keep energy dollars in the community, that impacts must be reduced until they are less than significant, and that if an onshore wind project is to be created in Humboldt County, there is no other location for it. For the longer term, Chair Winkler stated his desire to move away from reliance on outside companies for local renewable energy production.

Chair Winkler closed public comment.

M/S: Allison, Miller: Approve renewable energy RFP respondent short list of Terra-Gen LLC, Candela Renewables LLC, and Snow Mountain Hydro LLC and authorize staff to negotiate power purchase agreements to present to the Board for final approval.

The motion passed on a unanimous voice vote. Ayes: Allison, Curran, Fennell, Miller, Smith, Wilson, Winkler. Noes: None. Absent: Glaser. Abstentions: Woo.

Executive Director Marshall stated that public advocacy efforts were limited prior to Board approval and that staff resources could now be used to counter false energy-related information with factual information and engage the Ferndale and Scotia communities. Staff Director Marshall will contact Wiyot Tribe leaders directly to see if concerns can be mitigated.

Director Woo returned to the dais at 6:47 p.m.

Due to the late hour, the Board agreed to meet in closed session with legal counsel per Government Code Section 54956.9(d)(4), in re PG&E, Bankruptcy Court, 19-30088, Northern District of California, at the July 25 meeting.

Chair Winkler adjourned the meeting at 6:48 p.m.

Respectfully Submitted,

Lori Taketa
Clerk of the Board

Redwood Coast Energy Authority
Disbursements Report
As of May 31, 2019

Type	Date	Num	Name	Memo	Amount
Check	05/01/2019	9448	CoPower	June Premium	-341 90
Bill Pmt -Check	05/10/2019		Taketa, L.	Purchase reimburse - Calendars	-32 55
Liability Check	05/10/2019	E-pay	EDD	499-0864-3 QB Tracking # -2074404970	-3,865 51
Liability Check	05/10/2019	E-pay	Internal Revenue Service	74-3104616 QB Tracking # -2074399970	-19,323 68
Liability Check	05/10/2019	E-pay	EDD	499-0864-3 QB Tracking # -2074392970	-121 64
Paycheck	05/10/2019	9476	Paycheck	4/15-4/30/19 Payroll	-2,479 39
Bill Pmt -Check	05/10/2019	9477	Abbott, Stringham & Lynch	Professional Services - IT audit for CPUC	-13,500 00
Bill Pmt -Check	05/10/2019	9478	ABC Office Equipment	April print charges/service contract.	-322.75
Bill Pmt -Check	05/10/2019	9479	AESC	Professional Services through 4/30/19 - Scotia	-189 00
Bill Pmt -Check	05/10/2019	9480	Bob White Electric	Secutiry National. Audit #5138	-2,971 04
Bill Pmt -Check	05/10/2019	9481	Central Office	Printing/Copying services.	-177 90
Bill Pmt -Check	05/10/2019	9482	Chargepoint	Chargepoint Support	-1,931 00
Bill Pmt -Check	05/10/2019	9483	City of Eureka-Water	Water service, 3/26-4/25/19	-155 96
Bill Pmt -Check	05/10/2019	9484	Diamond, Nancy	Legal services	-6,956 00
Bill Pmt -Check	05/10/2019	9485	Enterprise	M. Slackerelli travel 04/20-4/22/19	-125 81
Bill Pmt -Check	05/10/2019	9486	Environmental Indicator Accounting Srvcs.	Services & support for climate action plan.	-1,520 00
Bill Pmt -Check	05/10/2019	9487	HireRight	Background Check: new hires	-171 52
Bill Pmt -Check	05/10/2019	9488	Humboldt Lighting, LLC.	Rosewood Body Shop self-install rebate/Audit 5715	-5,775.13
Bill Pmt -Check	05/10/2019	9489	Lost Coast Communications	Outreach Advertising	-400 00
Bill Pmt -Check	05/10/2019	9490	NGI, Inc.	Audit Rebates	-1,364 94
Bill Pmt -Check	05/10/2019	9491	North Coast Cleaning	Apr 2019 Cleaning Service	-438 00
Bill Pmt -Check	05/10/2019	9492	PG&E Utility Account	March utilities/lighting upgrade financing	-977.78
Bill Pmt -Check	05/10/2019	9493	PG&E EV Account	EV stations February	-344 06
Bill Pmt -Check	05/10/2019	9494	Recology	April garbage service	-90.72
Bill Pmt -Check	05/10/2019	9495	Sonoma County Office of Education	March 2019 Professional Services.	-390 00
Bill Pmt -Check	05/10/2019	9496	SDRMA Medical	June Premium	-22,766.40
Bill Pmt -Check	05/10/2019	9497	South River Technologies	Titan License Bundle	-1,949 95
Bill Pmt -Check	05/10/2019	9498	Suddenlink Communications	Internet access	-2,211.76
Bill Pmt -Check	05/10/2019	9499	The Energy Authority	Task Order 2: Offshore Wind Analysis	-3,802 50
Bill Pmt -Check	05/10/2019	9500	Verizon Wireless	April tablet/cell service for field staff/mobile broadban	-228 60
Check	05/10/2019	9503-9509	NEM Customer	NEM Closeouts	-309.79
Bill Pmt -Check	05/10/2019	9583	Fetters, Jake	April mileage reimbursement	-115 86
Bill Pmt -Check	05/10/2019	9585	Hilson, D.	April mileage reimbursement	-58.70
Bill Pmt -Check	05/10/2019	9587	McMahon, J.	April mileage reimbursements	-40.13
Bill Pmt -Check	05/10/2019	9588	McMahon, J.	April mileage reimbursements	-44 83
Bill Pmt -Check	05/10/2019	9590	Means, M.	April mileage	-95 99
Bill Pmt -Check	05/10/2019	9599	Terry, P.	April mileage reimbursement	-162 34
Paycheck	05/10/2019	5101901	Direct Deposit	4/15-4/30/19 Payroll	-47,935.78
Liability Check	05/23/2019	E-pay	EDD	499-0864-3 QB Tracking # -1789808970	-270.45
Liability Check	05/23/2019	E-pay	Internal Revenue Service	74-3104616 QB Tracking # -1789800970	-957 04
Liability Check	05/23/2019	E-pay	Internal Revenue Service	74-3104616 QB Tracking # -1789795970	-17,023.46
Liability Check	05/23/2019	E-pay	EDD	499-0864-3 QB Tracking # -1789787970	-3,277 87
Liability Check	05/23/2019	E-pay	EDD	499-0864-3 QB Tracking # -1789781970	-97 85
Liability Check	05/23/2019	E-pay	Internal Revenue Service	74-3104616 QB Tracking # -1789773970	-77 34
Paycheck	05/23/2019	9565	Paycheck	5/1-5/15-19 Payroll	-2,479 37
Liability Check	05/23/2019	9604	Umpqua Bank	HSA Contribution	-698.72
Bill Pmt -Check	05/24/2019	ACH	Humboldt Redwood Company	Humboldt Redwood CO. April 2019	-221,165.44
Bill Pmt -Check	05/24/2019	ACH	CalPine Corporation	Calpine April 2019 Costs	-73,348.15
Bill Pmt -Check	05/24/2019	ACH	DG Fairhaven	DG Fairhaven April 2019	-199,458 68
Check	05/24/2019	9510-9564	NEM Customers	NEM Account Annual True-up/Cash-outs	-13,805 62
Bill Pmt -Check	05/24/2019	9566	Avcollie, M.	April mileage reimbursement.	-279 56
Bill Pmt -Check	05/24/2019	9567	Bishop, M.	April mileage	-84 56
Bill Pmt -Check	05/24/2019	9568	Bishop, M.	Purchase reimbursement - utility cart.	-161.14
Bill Pmt -Check	05/24/2019	9569	Bithell, M.	Purchase reimbursement - Mailings.	-13 25
Bill Pmt -Check	05/24/2019	9570	Boudreau, D.	Purchase reimbursement: Station cleaning supplies	-13 99
Bill Pmt -Check	05/24/2019	9571	Boudreau, D.	Mileage reimbursement: REVNet	-54 81

Redwood Coast Energy Authority
Disbursements Report
As of May 31, 2019

Type	Date	Num	Name	Memo	Amount
Bill Pmt -Check	05/24/2019	9572	Campton Electric	Table rental for Lighting Fair.	-250 00
Bill Pmt -Check	05/24/2019	9573	Cissna, A.	Mileage reimbursement: REVNet	-9 66
Bill Pmt -Check	05/24/2019	9574	City of Arcata	April Utility User Tax	-7,424.46
Bill Pmt -Check	05/24/2019	9575	City of Arcata	April High Energy Use Tax	-1,569 81
Bill Pmt -Check	05/24/2019	9576	City of Blue Lake	April Utility User Tax	-1,187 03
Bill Pmt -Check	05/24/2019	9577	City of Eureka - permits	Alarm Service Permit Fee Jan 2019-Dec 2019	-20 00
Bill Pmt -Check	05/24/2019	9578	Developed Employment Services, LLC.	Facilities maintenance work	-29.40
Bill Pmt -Check	05/24/2019	9579	Engel, R.	R. Engel travel: 05/02-05/03/19 Renewable Energy P	-91 69
Bill Pmt -Check	05/24/2019	9580	Engel, R.	R. Engel travel: 04/30/19: Energy Summit Rancho Co	-11 39
Bill Pmt -Check	05/24/2019	9581	Eureka City Schools	Eureka High self-install rebate/Audit 5602.	-6,224.13
Bill Pmt -Check	05/24/2019	9582	Eureka City Schools	Eureka High self-install rebate/Audit 5812.	-1,141 68
Bill Pmt -Check	05/24/2019	9584	Gross Family, LLC.	VO D: Gross Family self-install rebate/Audit 5184.	0.00
Bill Pmt -Check	05/24/2019	9586	HBMWD	Reimbursement: Long distance phone calls.	-32.19
Bill Pmt -Check	05/24/2019	9589	Marshall, M.	Purchase reimbursement: 2019 Humboldt Bay Symp	-20 00
Bill Pmt -Check	05/24/2019	9591	Mission Uniform & Linen	May mat service, janitorial supplies	-60.14
Bill Pmt -Check	05/24/2019	9592	Morehead, M.	Purchase reimbursement: Northcoast Co-Op	-31 50
Bill Pmt -Check	05/24/2019	9593	North Coast Employer Advisory Council	Sexual Harassment Training - 10 participants	-400 00
Bill Pmt -Check	05/24/2019	9594	NYLEX.net, Inc.	Onsite network support services - June	-3,200 00
Bill Pmt -Check	05/24/2019	9595	PG&E CCA	April CCE Charges	-22,083 67
Bill Pmt -Check	05/24/2019	9596	SDRMA Dental	June Premium	-1,401 56
Bill Pmt -Check	05/24/2019	9597	SDRMA WC	Final Audited Premium FY 2018-19	-17,788 32
Bill Pmt -Check	05/24/2019	9598	Stephenson, Nancy	N. Stephenson travel: CalCCA meeting @ MCE, Cor	-84 80
Bill Pmt -Check	05/24/2019	9600	Terry, P.	P. Terry travel: PG&E Custom Projects Training	-415.78
Bill Pmt -Check	05/24/2019	9601	Times Printing Company	Miscellaneous printing & mailing service	-2,072 80
Bill Pmt -Check	05/24/2019	9602	WREGIS	Annual Fee - Generator Aggregators	-125 00
Liability Check	05/24/2019	9603	Calvert	S MPLE IRA: 74-3104616	-11,759.71
Check	05/24/2019	9725	NEM	VO D: NEM Account Closeout #[redacted]	0.00
Check	05/24/2019	9725	NEM	VO D: NEM Account Closeout #[redacted]	0.00
Check	05/24/2019	9725	NEM	VO D: NEM Account Closeout #[redacted]	0.00
Paycheck	05/24/2019	5241901	Direct Deposit	5/1-5/15-19 Payroll	-44,366.44
TOTAL					**-798,757.37**

Redwood Coast Energy Authority
Balance Sheet
As of May 31, 2019

	May 31, 19
ASSETS	
Current Assets	
Checking/Savings	
1010 · Petty Cash	414.35
1050 · GRANTS & DONATIONS 3840	15,204.58
1060 · Umpqua Checking Acct 0560	373,175.48
1070 · OLD Umpqua Dep Cntrl Acct 1687	80,790.73
1071 · Umpqua Deposit Cntrol Acct 8215	2,273,427.70
1075 · Umpqua Reserve Account 2300	3,250,000.00
8413 · COUNTY TREASURY 3839	5,065.52
Total Checking/Savings	5,998,078.36
Total Accounts Receivable	284,144.17
Other Current Assets	
1101 · Allowance for Doubtful Accounts	-283,678.54
1103 · Accounts Receivable-Other	5,810,811.22
1120 · Inventory Asset	21,715.00
1202 · Prepaid Expenses	-28,921.27
Total 1210 · Retentions Receivable	36,500.57
1499 · Undeposited Funds	49,800.75
Total Other Current Assets	5,606,227.73
Total Current Assets	11,888,450.26
Total Fixed Assets	151,725.39
Total Other Assets	4,100.00
TOTAL ASSETS	**12,044,275.65**
LIABILITIES & EQUITY	
Liabilities	
Current Liabilities	
Total Accounts Payable	2,043,846.32
Total Credit Cards	5,434.09
Other Current Liabilities	
2001 · Accounts Payable-Other	1,838,204.72
2012 · PG&E Deferred Revenue	-11,700.00
Total 2100 · Payroll Liabilities	120,869.79
Total 2210 · Retentions Payable	0.56
Total Other Current Liabilities	1,947,375.07
Total Current Liabilities	3,996,655.48
Total Long Term Liabilities	151,903.70
Total Liabilities	4,148,559.18
Equity	
2320 · Investment in Capital Assets	150,452.99
3900 · Fund Balance	8,364,861.93
Net Income	-619,598.45
Total Equity	7,895,716.47
TOTAL LIABILITIES & EQUITY	**12,044,275.65**

Redwood Coast Energy Authority
Profit & Loss Budget vs. Actual
July 2018 through May 2019

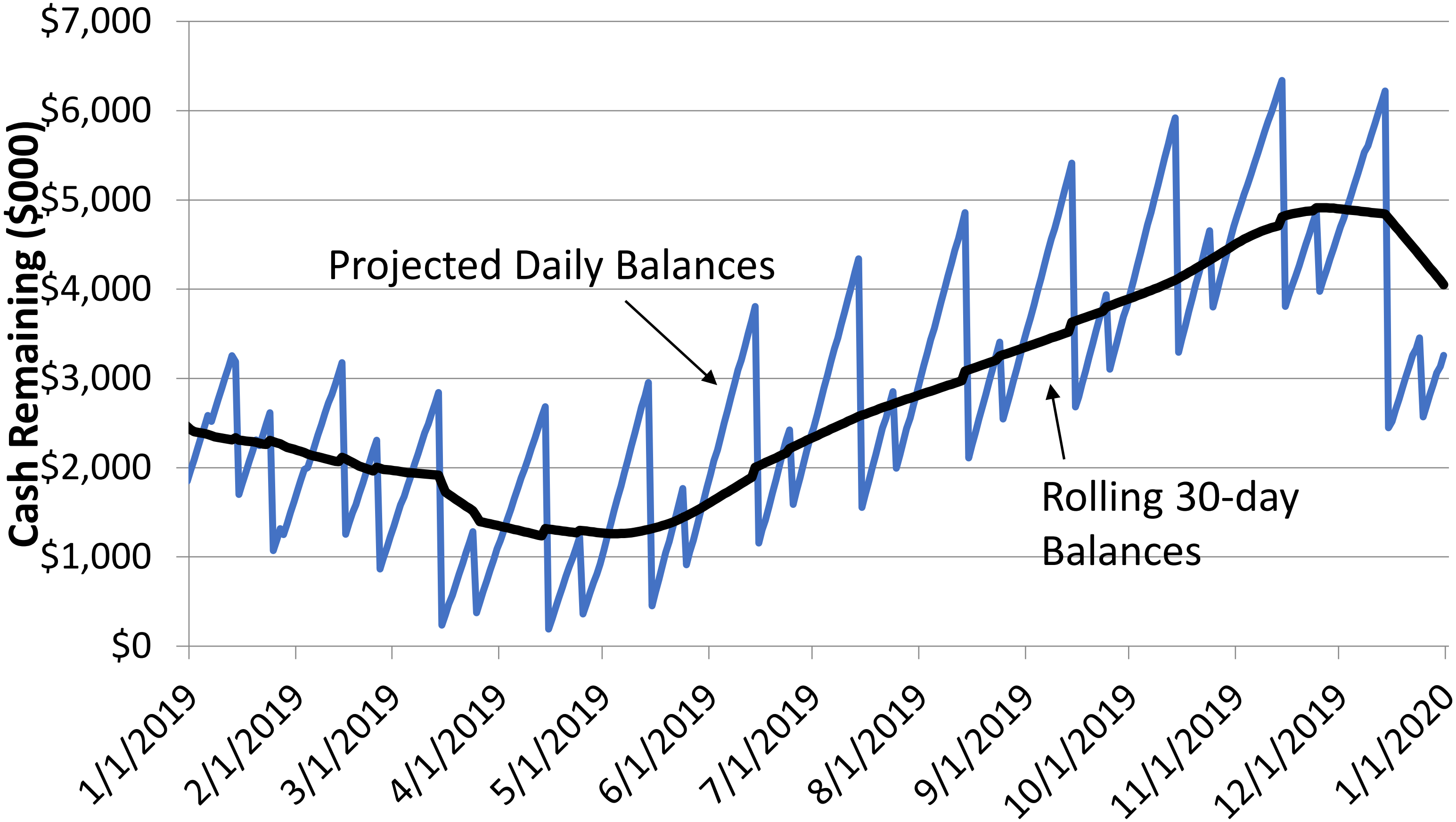
	Jul '18 - May 19	Budget	% of Budget
Ordinary Income/Expense			
Income			
5 REVENUE EARNED			
Total 5000 · Revenue - government agencies	114,362.32	111,600.00	102.48%
Total 5100 · Revenue - program related sales	10,308.22	18,000.00	57.27%
Total 5400 · Revenue-nongovernment agencies	1,991,327.64	2,048,527.00	97.21%
5500 · Revenue - Electricity Sales			
	41,670,200.63	51,940,000.00	80.23%
	-125,071.00	-160,000.00	78.17%
Total 5500 · Revenue - Electricity Sales	41,545,129.63	51,780,000.00	80.23%
Total 5 REVENUE EARNED	43,661,127.81	53,958,127.00	80.92%
Total Income	43,661,127.81	53,958,127.00	80.92%
Gross Profit	43,661,127.81	53,958,127.00	80.92%
Expense			
Total 6 WHOLESALE POWER SUPPLY	37,264,699.72	39,880,000.00	93.44%
Total 7 PERSONNEL EXPENSES	2,063,797.21	2,253,700.00	91.57%
Total 8.1 FACILITIES AND OPERATIONS	986,351.72	1,049,927.00	93.95%
Total 8.2 COMMUNICATIONS AND OUTREACH	83,119.45	108,200.00	76.82%
Total 8.3 TRAVEL AND MEETINGS	34,995.59	48,000.00	72.91%
8.4 PROFESSIONAL & PROGRAM SRVS			
8400 · Regulatory	97,500.53	94,600.00	103.07%
8410 · Contracts - Program Related Ser	229,833.75	362,200.00	63.46%
8420 · Accounting	18,804.00	55,000.00	34.19%
8430 · Legal	132,156.00	150,000.00	88.1%
8450 · Wholesale Services - TEA	534,905.25	585,000.00	91.44%
8460 · Procurement Credit - TEA	636,549.86	800,000.00	79.57%
8470 · Data Management - Calpine	802,985.20	1,100,000.00	73.0%
Total 8.4 PROFESSIONAL & PROGRAM SRVS	2,452,734.59	3,146,800.00	77.94%
Total 8.5 PROGRAM EXPENSES	534,662.34	1,268,000.00	42.17%
Total 8.6 INCENTIVES & REBATES	432,160.71	460,000.00	93.95%
Total 9 NON OPERATING COSTS	428,204.93	565,800.00	75.68%
Total Expense	44,280,726.26	48,780,427.00	90.78%
Net Ordinary Income	-619,598.45	5,177,700.00	-11.97%
Net Income	**-619,598.45**	**5,177,700.00**	**-11.97%**

Material received after agenda publication:
Powerpoint slides presented at the meeting
by Executive Director Matthew Marshall

Seasonal CCA Net Revenue Fluctuations

From TEA January 2019 Presentation to RCEA Board

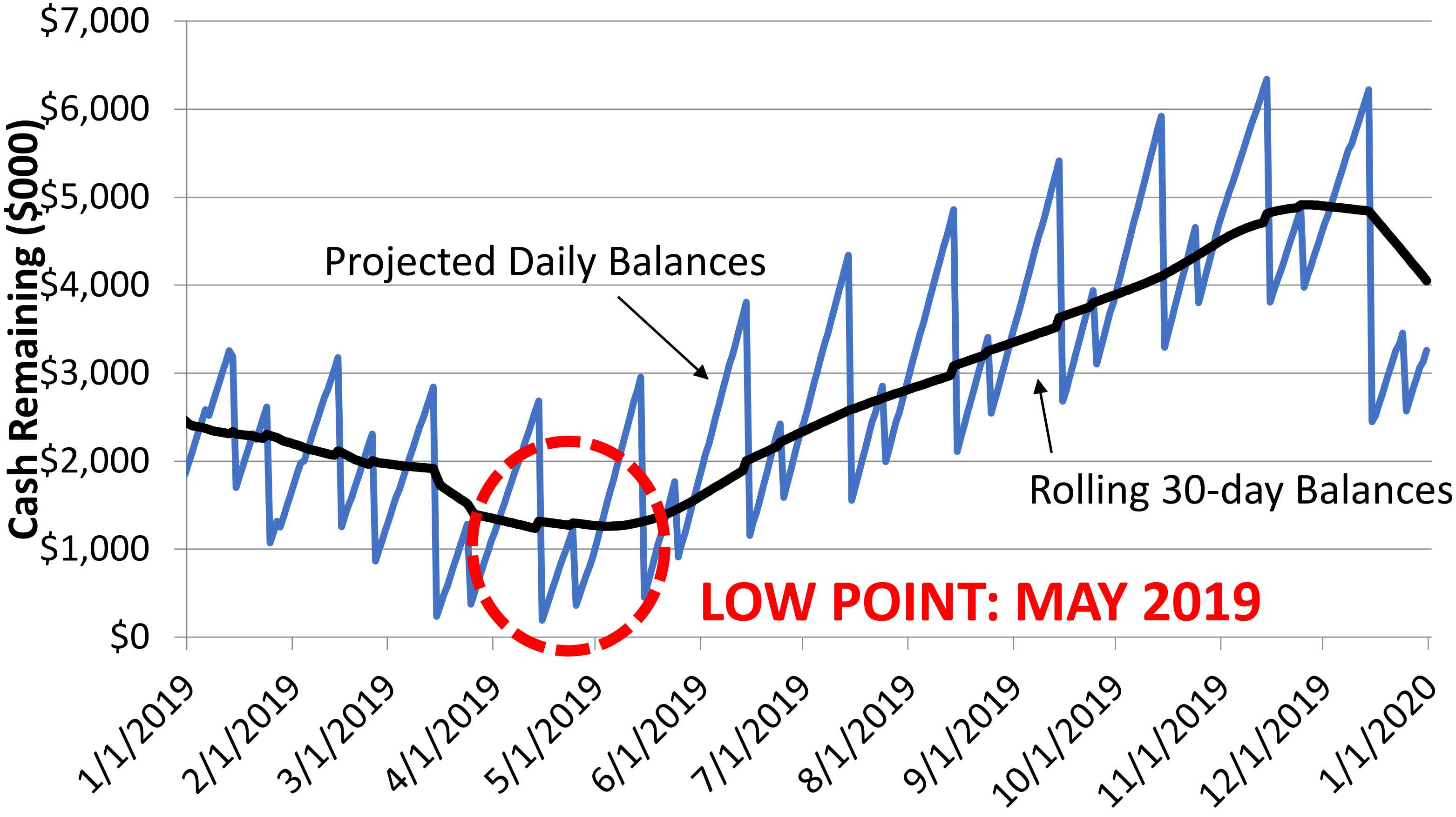
Projected Operating Account Cash Balance:



Reserve Fund Balance not included in this chart.

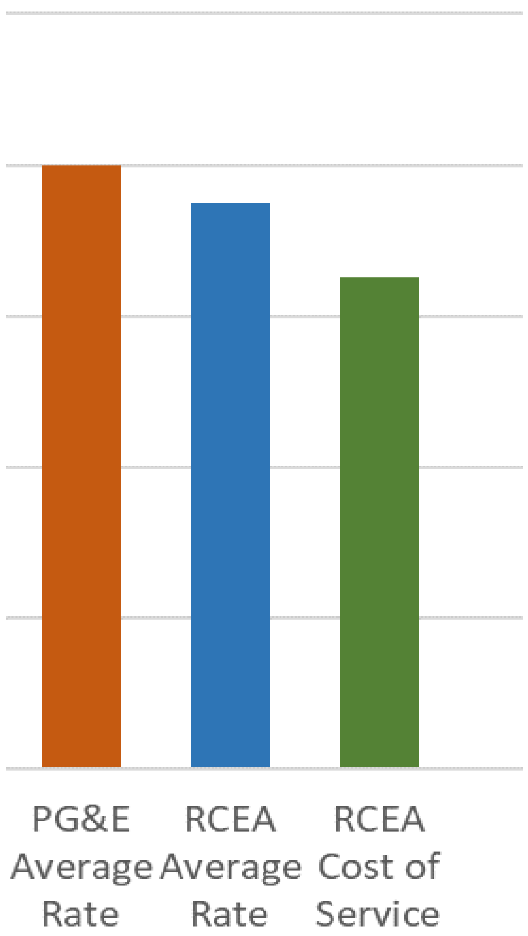
From TEA January 2019
Presentation to RCEA Board

Projected Operating Account Cash Balance:



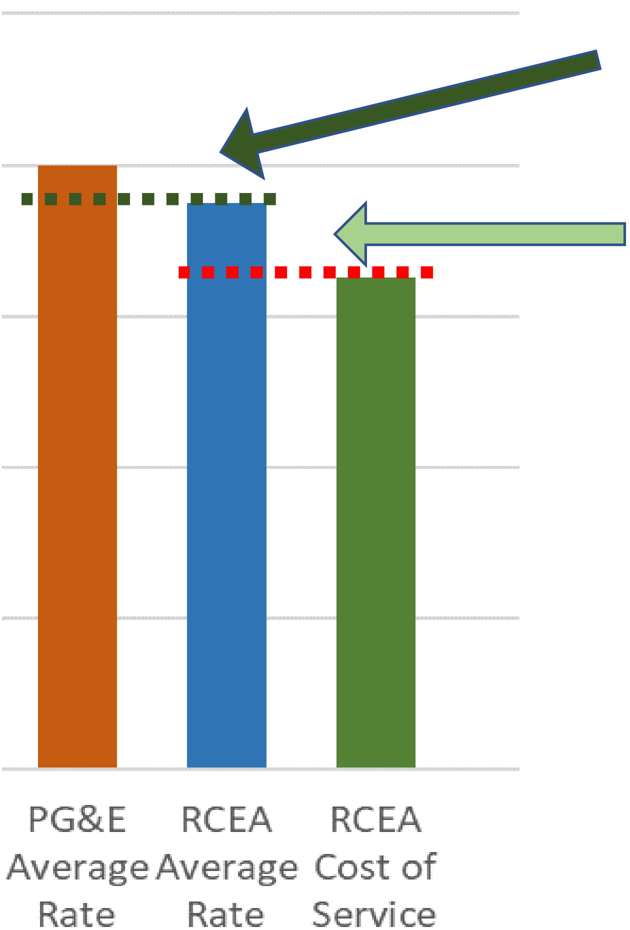
Reserve Fund Balance not included in this chart.

PG&E Rate structure impact on month-to-month net revenue



**Conceptual for purposes of illustration – not to scale*

PG&E Rate structure impact on month-to-month net revenue

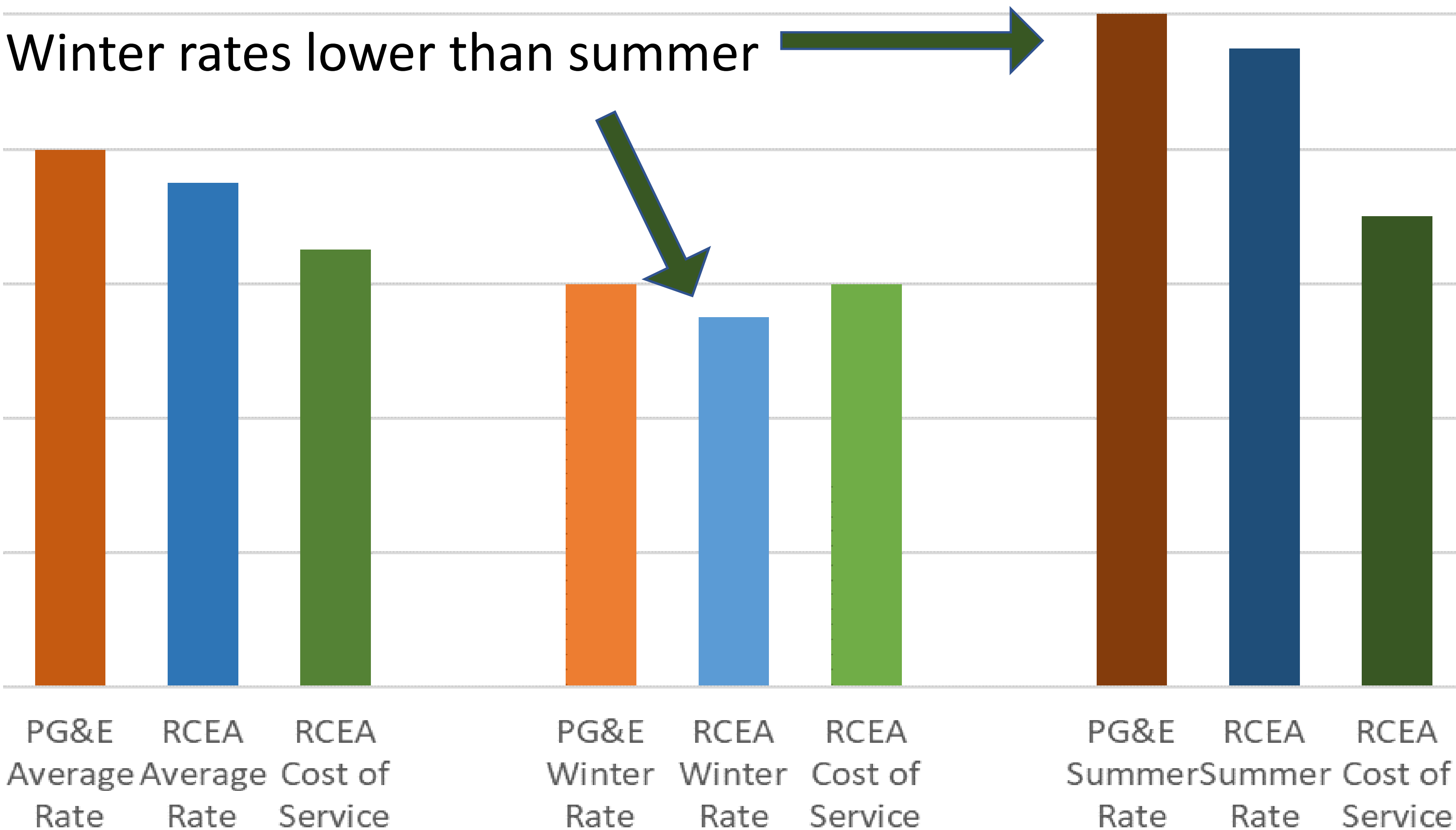


RCEA customer’s fixed discount % compared to PG&E

RCEA net revenue after costs

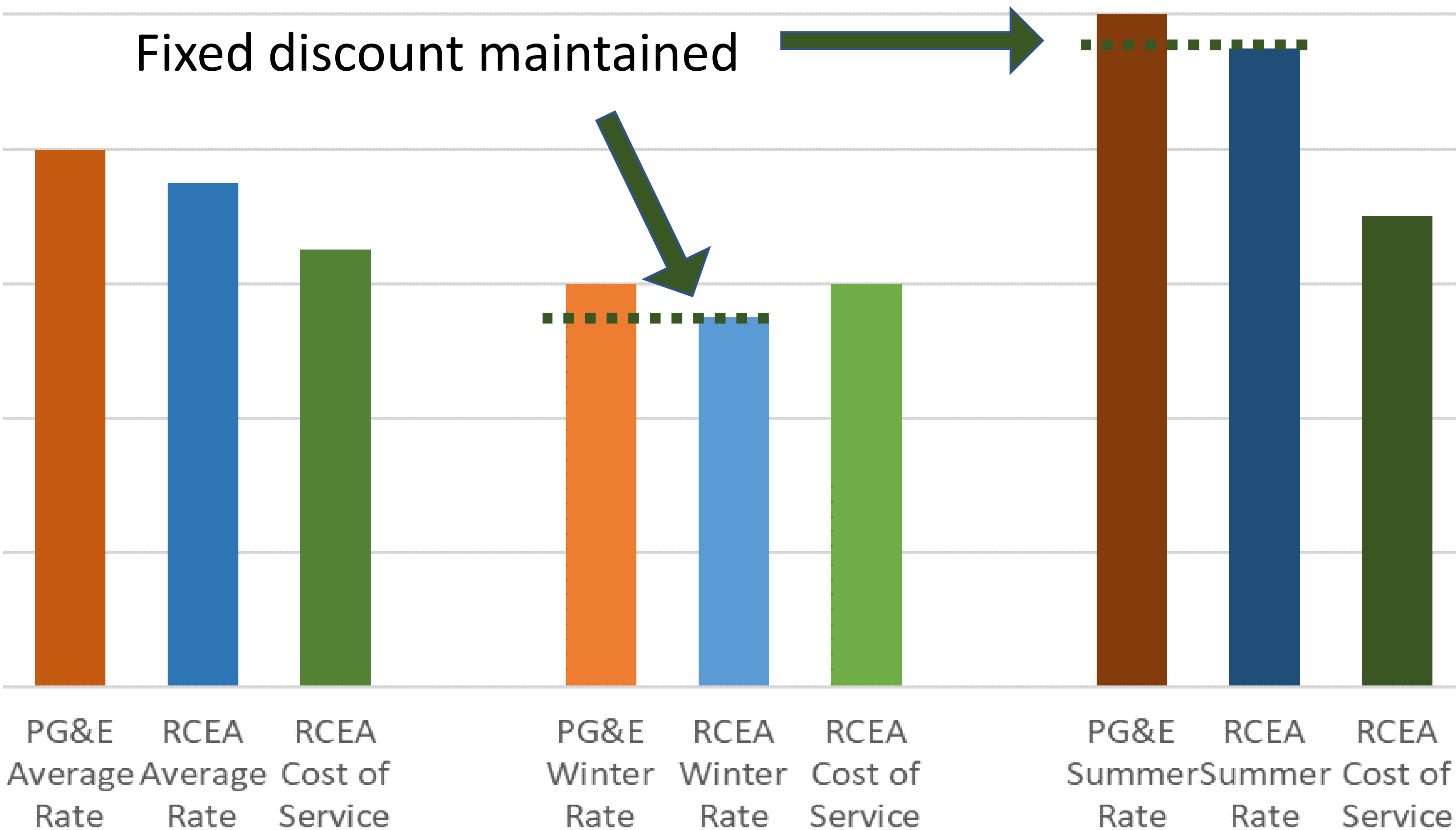
Conceptual for purposes of illustration – not to scale

PG&E Rate structure impact on month-to-month net revenue



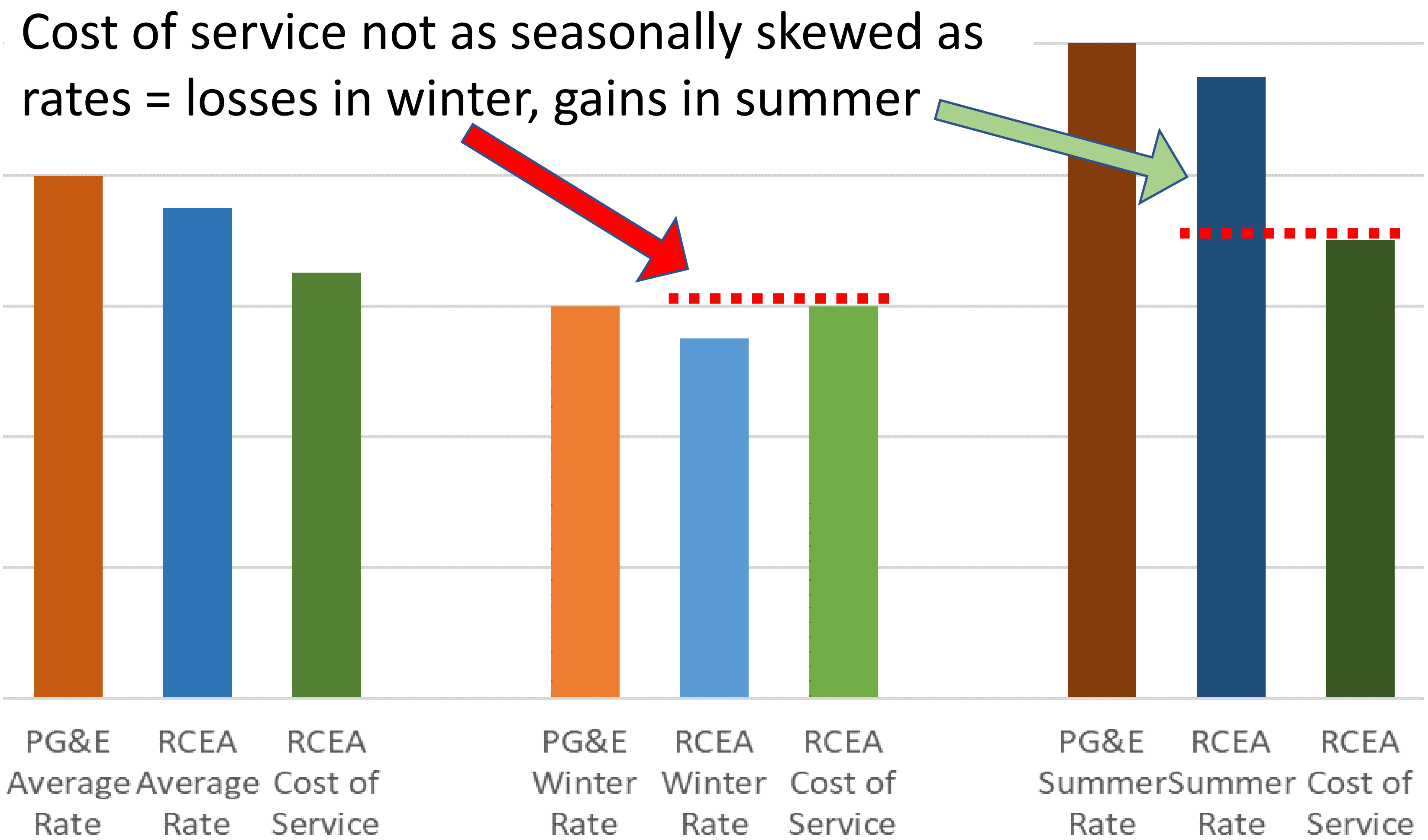
**Conceptual for purposes of illustration – not to scale*

PG&E Rate structure impact on month-to-month net revenue



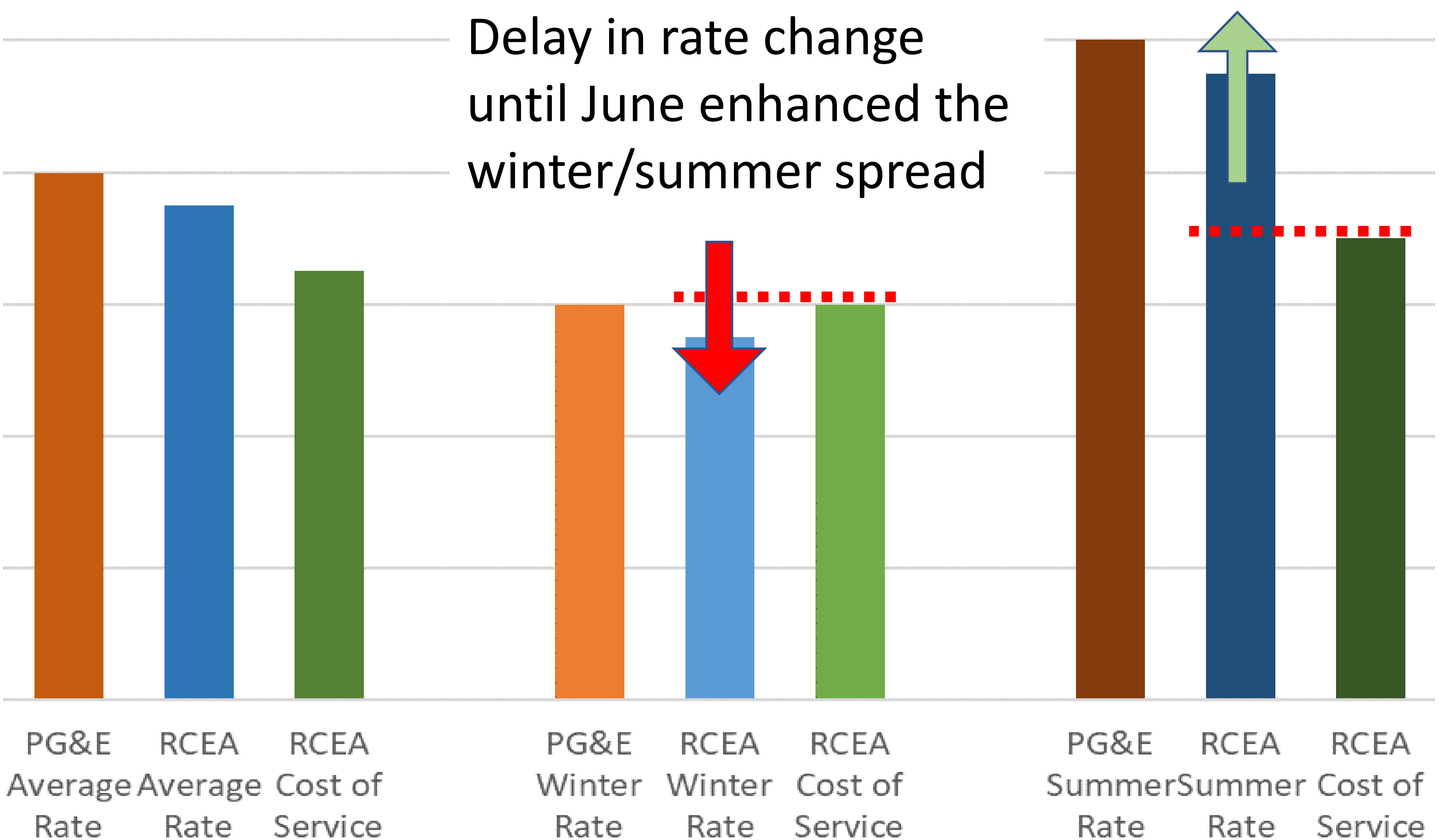
**Conceptual for purposes of illustration – not to scale*

PG&E Rate structure impact on month-to-month net revenue



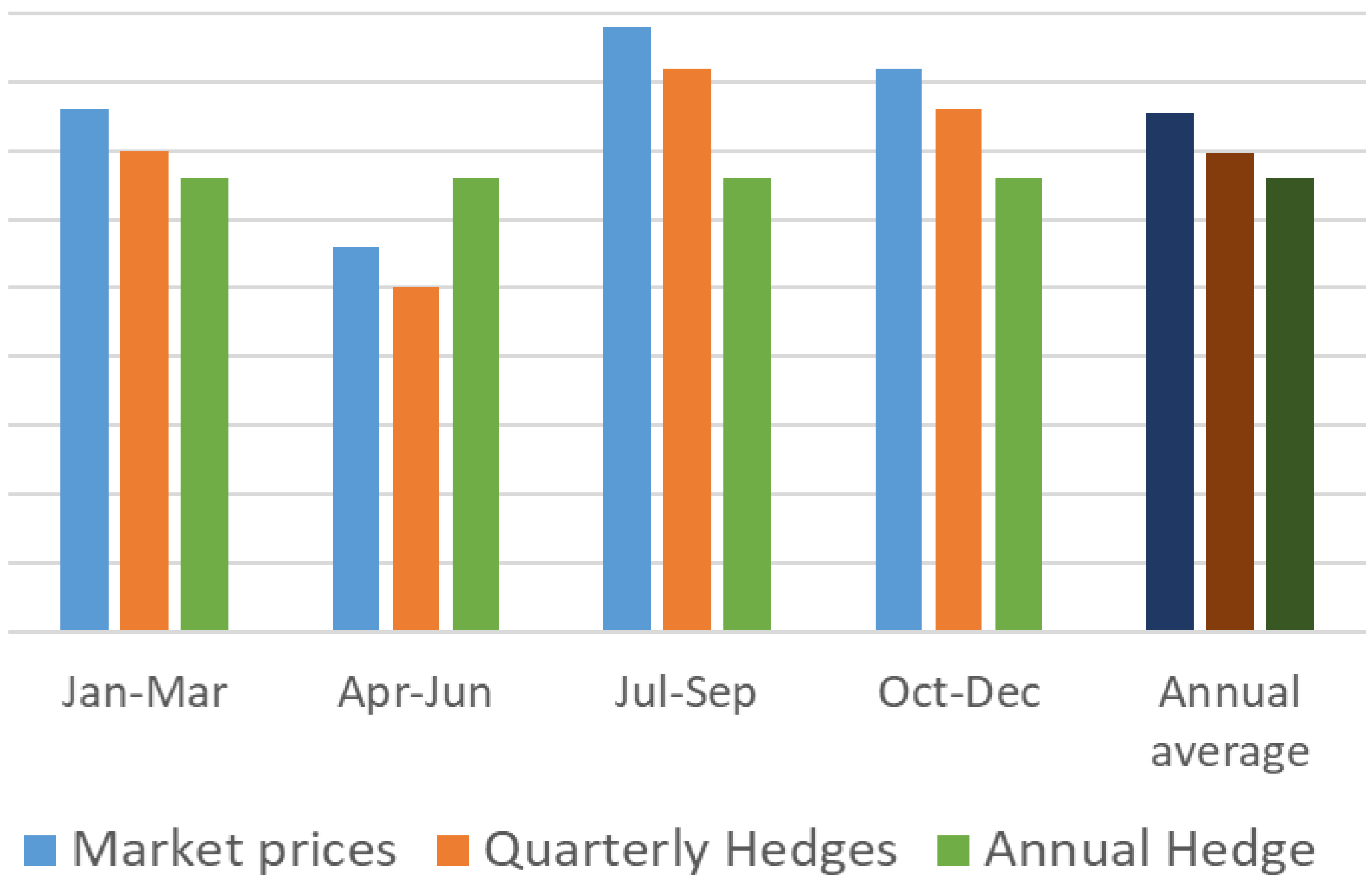
Conceptual for purposes of illustration – not to scale

PG&E Rate structure impact on month-to-month net revenue



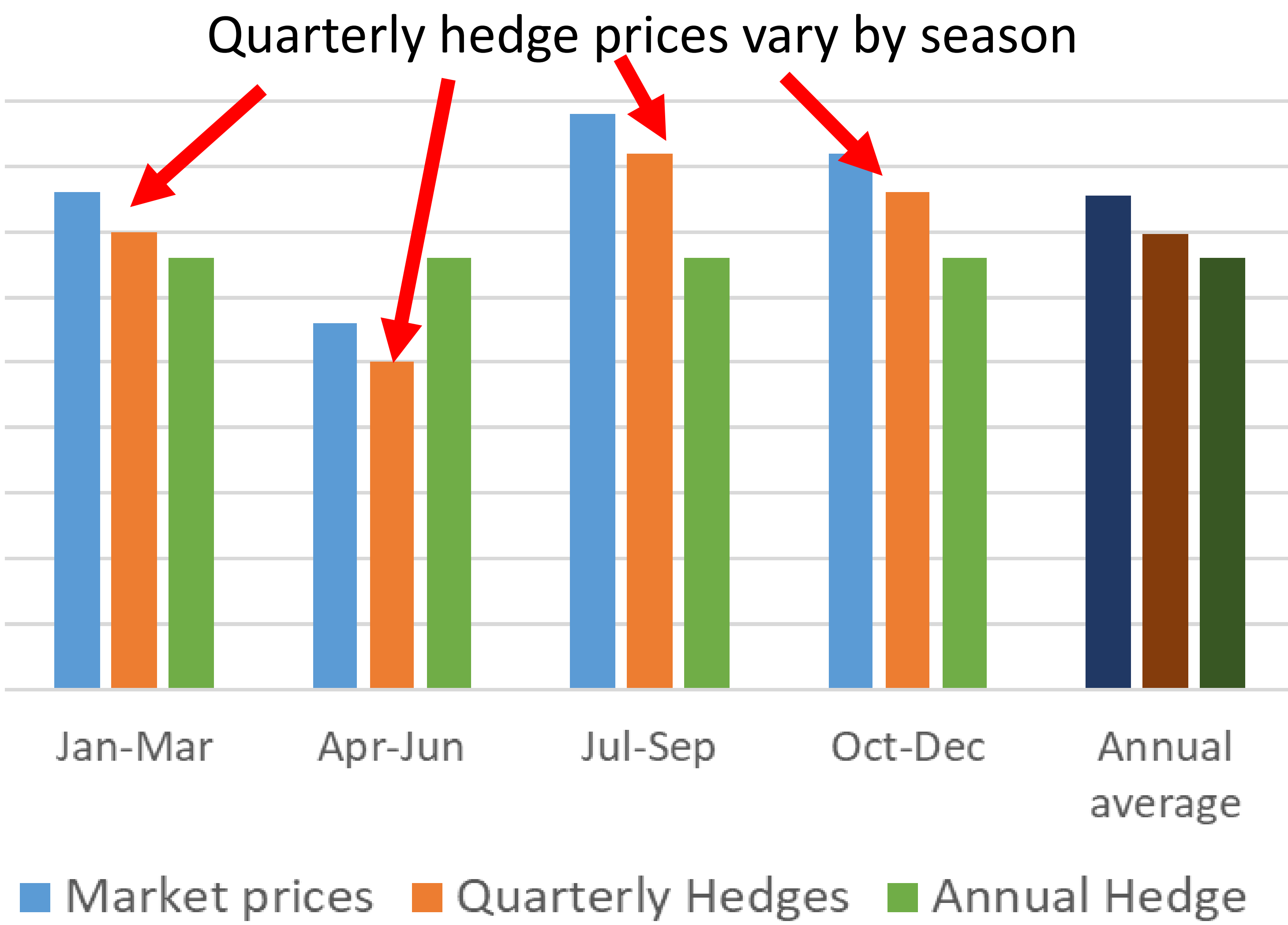
**Conceptual for purposes of illustration – not to scale*

Hedge strategy impact on month-to-month net revenue



**Conceptual for purposes of illustration – not to scale*

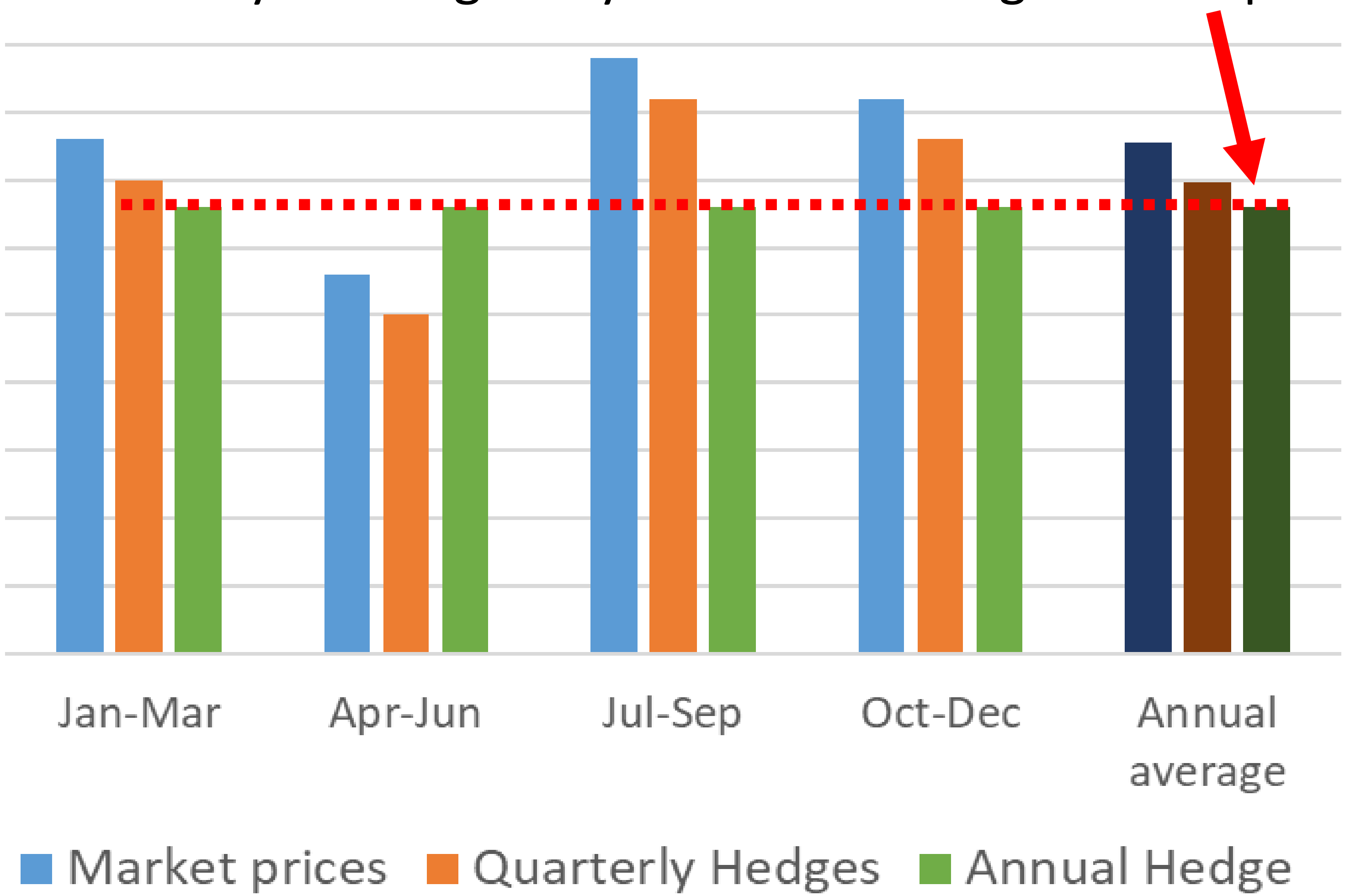
Hedge strategy impact on month-to-month net revenue



**Conceptual for purposes of illustration – not to scale*

Hedge strategy impact on month-to-month net revenue

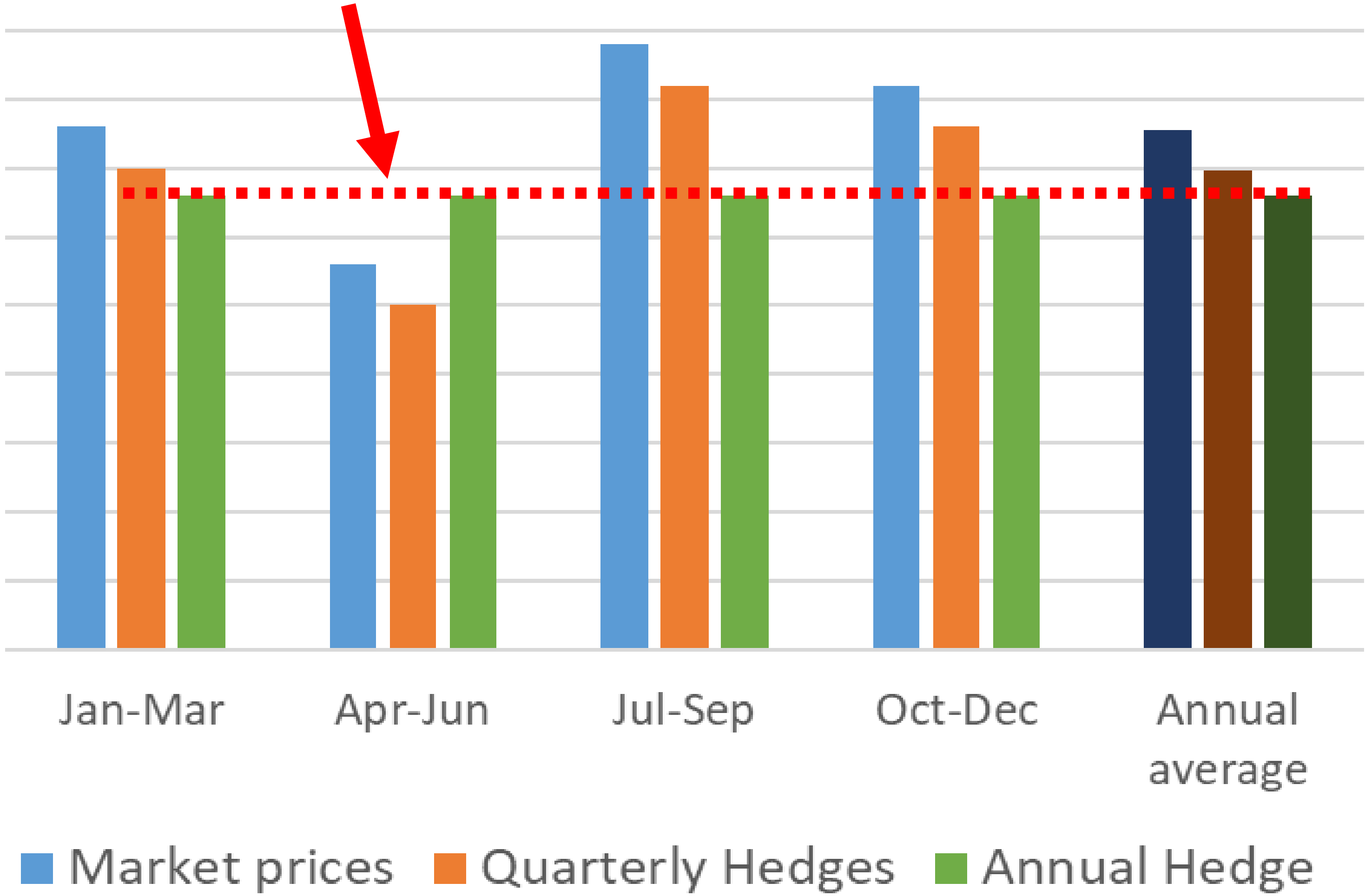
Calendar-year hedge may be better average annual price….



**Conceptual for purposes of illustration – not to scale*

Hedge strategy impact on month-to-month net revenue

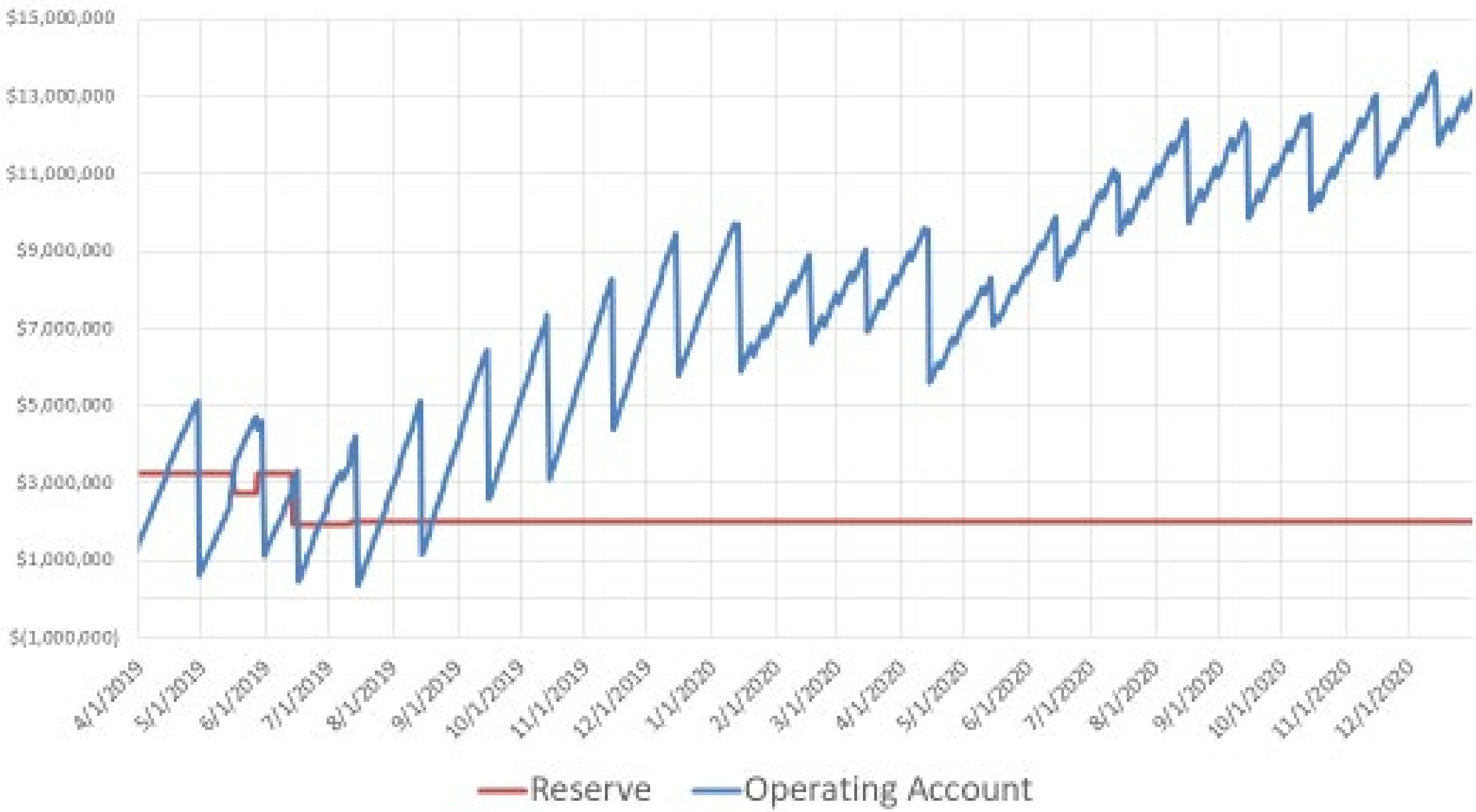
…but higher cost in low-price periods of the year.



**Conceptual for purposes of illustration – not to scale*

TEA risk management team
July 2019 update

Cash Position



REDWOOD COAST EnergyAuthority

STAFF REPORT

Agenda Item # 8.1

AGENDA DATE:	July 25, 2019
TO:	Board of Directors
PREPARED BY:	Lou Jacobson, Director of Demand-Side Management
SUBJECT:	Program Administrator Election

SUMMARY

During the April 25 meeting, staff were authorized to prepare an energy efficiency plan for Board approval and take all necessary actions to elect Program Administrator (PA) status. Electing PA status will allow RCEA to provide Community Choice Energy customers with non-duplicative energy saving services that meet specific criteria outlined in Public Utility Code Section 381.1(e)(f) and furthered through California Public Utility Commission (CPUC) decision 14-01-033.

RCEA proposes to offer all non-residential and residential customers products that are allowable and cost effective to the state. In addition, RCEA expects to enhance and expand these offerings through local funding. Provided services will include:

- No cost energy assessments
- Product procurement assistance
- Contracting assistance
- Project management support
- No and low-cost energy upgrades

Allowable energy upgrades will include but not be limited to:

- LED interior and exterior lighting
- Refrigeration
- Smart devices: thermostats, power strips and building energy management controls
- Flow restriction devices
- Space and domestic hot water heater replacements with electric impacts
- Variable frequency drives

The portfolio of offerings and associated cost-effectiveness sustains and grows existing services while leaving headroom for the incorporation of fuel substitution measures should the Proposed Decision Modifying the Energy Efficiency Three-Prong Test move forward and receive final CPUC approval as written.

Staff have completed the draft plan (attached) and have based it on Lancaster Choice Energy's approved submission.

To advance this effort the board must approve that the plan meets the following requirements:

- Substantiates funding levels
- Provides a program description
- Incorporates a cost-effectiveness analysis
- States the duration of the program
- Be consistent with the goals of the programs as established in Sections 381.1 and 399.4

- Accommodates statewide and regional programs
- Includes audit and reporting requirements consistent with the requirements established by the commission
- Includes evaluation, measurement and verification (EM&V) protocols
- Includes key performance metrics regarding the aggregator's achievements of the objectives listed above

Staff are confident that the plan currently meets all the requirements as laid out in 381.1(f)(1-6).

1. Funding Determination is presented on Page 22.
2. Non-Residential and Residential program descriptions are provided, see the table of contents.
3. Cost-effectiveness is presented under each program description and within the performance metrics section.
4. The recommended duration of the program is from July 1, 2020 to June 30, 2023.
5. The accommodation of statewide and regional programs is covered in a stand-alone section and is also noted in each program under collaboration.
6. EM&V is covered and can be found in the table of contents.

If the Board approves the proposed plan, staff will then present it to the California Energy Efficiency Coordinating Committee which was established by the CPUC as the forum for stakeholder input on the development of Program Administrators' energy efficiency implementation plans. RCEA's plan and final portfolio will be updated to address any input or feedback from the Coordinating Committee and will then be submitted to the CPUC for final approval.

Staff expect that some content, including mapped measures, will be updated and refined as the plan goes through subsequent steps of this process but that the fundamental elements that require the Board's approval, as necessary to meet 381.1(f), will not change.

FINANCIAL IMPACTS

Staff project that the successful submission of this plan will result in approximately $3,174,453 in state revenue from July 1, 2020 to June 30, 3023.

RECOMMENDED ACTIONS

<u>Per Public Utilities Code 381.1 (f), approve the enclosed energy efficiency and conservation program plan and authorize the Executive Director to submit the document to the California Public Utilities Commission and to make any edits and alterations necessary to address California Energy Efficiency Coordinating Committee (CAEECC) input and varying procedural and regulatory requirements.</u>

ATTACHMENT

- RCEA Draft Program Plan_2019-719

ATTACHMENT 1

REDWOOD COAST ENERGY AUTHORITY

ENERGY EFFICIENCY PROGRAM PLAN

Energy Efficiency Program Plan

Contents

INTRODUCTION

The Redwood Coast Energy Authority (RCEA) was formed in 2003 by the County of Humboldt and the Cities of Arcata, Blue Lake, Eureka, Ferndale, Fortuna, Rio Dell, and Trinidad, and the special district of the Humboldt Bay Municipal Water District to undertake a pilot project created and funded by the California Public Utilities Commission CPUC and the Local Government Commission, a California nonprofit membership organization, designed to encourage the formation of regional organizations to promote energy efficiency, conservation and increased local self-reliance. Through its activities since formation, RCEA has established Humboldt County and our communities as leaders in reducing energy demand, increasing energy efficiency, and advancing the use of clean, efficient and renewable local resources to increase regional self-reliance.

To further that purpose, RCEA works toward the following goals:

- To lead, coordinate and integrate regional efforts that advance secure, sustainable, clean and affordable energy resources,
- To develop a long-term sustainable energy strategy and implementation plan,
- To increase awareness of, and enhance access to, energy conservation, energy efficiency, and renewable energy opportunities available to the region,
- To add value to, but not duplicate, energy services offered by utilities and others serving the region,
- To keep key decision makers and stakeholders informed of policy, regulatory, and market changes that are likely to impact the region,
- To support research, development, demonstration, innovation, and commercialization of sustainable energy technologies by public and private entities operating in Humboldt County,
- To develop regional capabilities to respond to energy emergencies and short-term disruptions in energy supply, infrastructure, or markets that could adversely affect Humboldt residents and businesses,

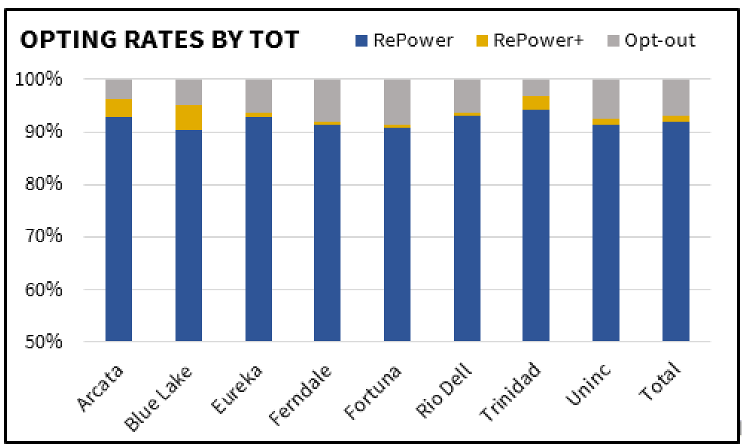
In 2012 RCEA adopted the Humboldt County Comprehensive Action Plan for Energy (CAPE) as the agencies primary guiding document. Expanding on the strategies outlined in the CAPE, RCEA initiated RePower Humboldt, a community-wide effort to define a vision and Strategic Plan for achieving energy independence and energy security in Humboldt County. With the support of the Humboldt State University Schatz Energy Research Center, the California Energy Commission, and many community stakeholders, this effort culminated in the development of the RePower Humboldt Strategic Plan which established the following 2030 vision:

In 2030 Humboldt County is no longer a net importer of energy. The county enjoys a high degree of energy independence through conscientious use of energy conservation and efficiency combined with locally produced and managed renewable energy generation. Significantly more of the money spent on energy stays in the county, supporting more local jobs. Citizens have a diversity of choices for meeting their energy needs and have more local control over energy prices. The county is a thriving research and development center and an incubator for energy technology and related industries. Because citizens, businesses and industries consume modest *quantities of energy derived from local renewable sources, life in the county is secure and prosperous.*

RCEA identified community choice aggregation as a critical mechanism to enable the implementation of the RePower Humboldt strategic plan and to realize the RePower Humbodlt 2030 vision and associated community benefits of that vision.

In September 2014, RCEA's Board approved Community Choice Aggregation (CCA) enabling revisions to the Joint Powers Agreement and directed staff to pursue and implement a local program. In June of 2015, the RCEA Board of Directors voted to proceed with developing a community choice program with the following core goal: maximize the use of local renewable energy while providing competitive rates to customers. In September 2016, RCEA's Board approved the CCA launch-period strategy and targets. In addition to this over-arching goal, the launch-period strategy and targets prioritized the following:

- Environmental Quality
- Local Control and the Ability to Pursue Local Priorities
- Economic Development
- Energy Independence
- Customer Rate-savings, Choice and Community Programs.



RCEA's Board approved CCA program launched in May of 2017. RCEA currently services 47,210 residential customers and 5,123 non-residential customers within Humboldt County California. RCEA is currently serving 93.2% of all eligible accounts (TOT).

RCEA has historically partnered with Pacific Gas and Electric Company (PG&E) to implement local energy efficiency programs targeting Hard to Reach (HTR) and non-HTR customers in Humboldt County across all sectors. RCEA is currently the local Regional Small Medium Business Program implementer (including Non-Residential Direct Install) as administered by PG&E under the auspices of the CPUC. PG&E's current products, offerings and program framing do not align with local needs and the 3rd party solicitation process has been deemed not in our customers best interest. Thus, RCEA is not responding to the 3rd party solicitation for resource-based programs. With the sunset of our historic partnership with PG&E slated for June 30th 2019, RCEA has determined that there will be a need for cost-effective energy efficiency programs for its customers.

RCEA has a deep understanding of the community it serves, has significant experience delivering resource-based energy efficiency programs and is well positioned to maximize local benefit and is therefore fully qualified to provide energy efficiency services to its customers. RCEA puts forth this energy efficiency program plan to deliver services to non-residential and residential ratepayers as approved by the Redwood Coast Energy Authority Governing Board pursuant to Public Utilities Code 381.1

> (e) The impartial process established by the commission shall allow a registered community choice aggregator, such as RCEA, to elect to become the administrator of funds collected from the aggregator's electric service customers and collected through a non-bypassable charge authorized by the commission, for cost-effective energy efficiency and conservation programs, except those funds collected for broader statewide and regional programs authorized by the commission.
>
> (f) A community choice aggregator electing to become an administrator shall submit a plan, approved by its governing board, to the commission for the administration of cost-effective energy efficiency and conservation programs for the aggregator's electric service customers that includes funding requirements, a program description, a cost-effectiveness analysis, and the duration of the program. The commission shall certify that the plan submitted does all of the following:
>
>> (1) Is consistent with the goals of the programs established pursuant to this section and Section 399.4.
>>
>> (2) Advances the public interest in maximizing cost-effective electricity savings and related benefits.
>>
>> (3) Accommodates the need for broader statewide or regional programs.
>>
>> (4) Includes audit and reporting requirements consistent with the audit and reporting requirements established by the commission pursuant to this section.
>>
>> (5) Includes evaluation, measurement, and verification protocols established by the community choice aggregator.
>>
>> (6) Includes performance metrics regarding the community choice aggregator's achievement of the objectives listed in paragraphs (1) to (5), inclusive, and in any previous plan.

NON-RESIDENTIAL DIRECT INSTALL

The Humboldt County non-residential market is largely comprised of small and geographically hard-to-reach customers. Table 1, below, categorizes RCEA's non-residential market based on annualized kWh. Table 1 shows that 76% of all RCEA accounts have an average annualized use of less than 25,000 kWh/yr but only account for 12.05% of all energy use. Table 1 also shows that those 24% of our customers account for 87.95% of all non-residential energy use.

Table 1: Non-Residential Annualized kWh/yr by Accounts

Annualized kWh Categories	% of Total Annualized kWh	% of Accounts
< 5,000	2.15%	44.14%
5,001-10,000	2.73%	14.66%
10,001-15,000	2.61%	8.15%
15,001-20,000	2.37%	5.37%
20,001-25,000	2.19%	3.71%
25,001-50,000	9.25%	10.00%
50,001-100,000	13.63%	7.40%
100,001-500,000	30.08%	5.73%
500,001-1,000,000	7.54%	0.43%
1,000,000+	27.44%	0.41%
	100.00%	100.00%

Humboldt is considered to be "Behind the Redwood Curtain." This phrase represents the literal challenge of getting to or out of the area. RCEA's office is approximately 5 hours and 279 miles away from 242 Market Street, San Francisco. Eastern routes to the 5 on highway 199, 299 or 36 are slow and dangerous throughout the year. And in some cases, residents in Humboldt have been completely land-locked by landslides. Lastly, Humboldt County's fog, small regional airport and limited flight offerings, traveling by plane is often economically unrealistic or plagued with delays. Our geographical remoteness, environmental hazards and limited infrastructure supporting travel increase the incremental costs of travel to or from Humboldt County.

The incremental service cost to savings potential ratio create unique barriers to cost-effectively serving our Community Choice Aggregation non-residential HTR and non-HTR customers. RCEA puts forth a program plan that will deliver cost-effective direct install energy efficiency services to RCEA's customers while prioritizing existing and forecasted regional and statewide programs administered by PG&E and third parties.

RCEA's proposed non-residential program will replace PG&E's Regional Small and Medium Business program partnership with RCEA (including Direct Install) and gap fill where existing and forecasted regional third-party providers fail to serve Humboldt's geographically constrained

HTR and non-HTR customers. Redwood Coast Energy Authority's Non-Residential Direct Install Program will prioritize cost-effective energy efficiency services to:

- RCEA non-residential hard-to-reach customers regardless of demand or annualized kWh
- All public sector market actors including member agencies, k12 and special districts,
- All non-hard-to-reach customers who show an intent to participate in a PG&E third party program but do not receive timely service.

As Isaac Newton wrote in a letter to Robert Hooke in 1676, "If I have seen further, it is by standing upon the shoulders of giants." RCEA's vision is one that does not toss out the last decade of implementation and innovation but rather one that builds on it to maximize ratepayer benefit in Humboldt County. RCEA has been the Direct Install Implementer in Humboldt County since 2006 and have consistently observed that the key barriers to localized energy efficiency adoption are money, time and knowledge. Our program plan is built around creating drivers to overcome each noted barrier to action.

<u>Non-Residential Program Process</u>

RCEA expects that the regulatory framework that empowers action will change over time. Staff have and will continue to ensure that program design is adaptive and nimble. Staff expects that program processes and services will have to be adjusted based on current working groups, expected resolutions, and proposed decisions as associated with R.13-11-005. The following tasks outline current and expected program processes.

Task 1—Data Driven Marketing, Outreach and Education: RCEA has 13 years of marketing collateral, documentation, direct install resource-based implementation data, advanced metering infrastructure data and built environment data we will use this information to make our program generally available to our customers while executing highly targeted campaigns.

RCEA will use data driven mass-market approaches such as but not limited to:

- Community based outreach that collaboration with member agencies, community service districts and community-based organizations to leverage trusting relationships while maximizing opinion leadership.
- Leverage opinion leaders in our community such as our member agencies and those who serve on our community advisory committee.
- Provide program presentations within our community and maximize social marketing benefits including earned and paid media exposure.

Targeted strategies will use tactics that allow us to focus on identifying the most cost-effective building types, projects and customers with the propensity to act. Examples include:

- In-person targeted canvassing using geo-spatial analysis.
- Calling campaigns with RCEA's account services team.
- Engaging customers who have taken action in the past.

RCEA will update all marketing materials to effectively describe the program while ensuring that the brand is unique and separate from PG&E programs. Marketing materials will include but not be limited to:

- An updated website to afford customers an opportunity to learn about the program. The website will provide general information about the program, the program service flyer, application and site access agreement, frequently asked questions and participant case studies.
- Hard copies of the noted resources above.
- Bill inserts that can be sent through our member or partner agency's water/waste billing mechanisms.
- Videos showcasing opinion leaders sharing the benefits of participating in the program.
- Scripts for paid and earned radio spots.

Task 2—Prequalification. Our prequalification process has increased project conversion rates from approximately 33% to 61% over the last two years. This has significantly reduced implementation costs per completed project while also increasing our ability to engage with varying local, state and federal programs. Prequalification allows our operations specialist to quickly verify program eligibility and guide customers through resource programs' varying requirements. This process will be adapted and expanded to better track customers and ensure RCEA maximizes the value of local, regional and statewide programs while also ensuring clear branding of our services.

Task 3—Turn-Key Assessments and Account Services: Project technicians and managers will double as Account Managers. They are trained and competent at providing no-cost non-residential energy efficiency assessments that look at a variety of energy saving opportunities. RCEA staff will deliver a report that includes all recommended measures, financial analysis and next steps. In addition, RCEA project technicians and managers will provide account services that facilitate project success by providing integrated demand side management services aligned to D.07-10-032. RCEA account services provide a non-biased and trusted opinion on project recommendations.

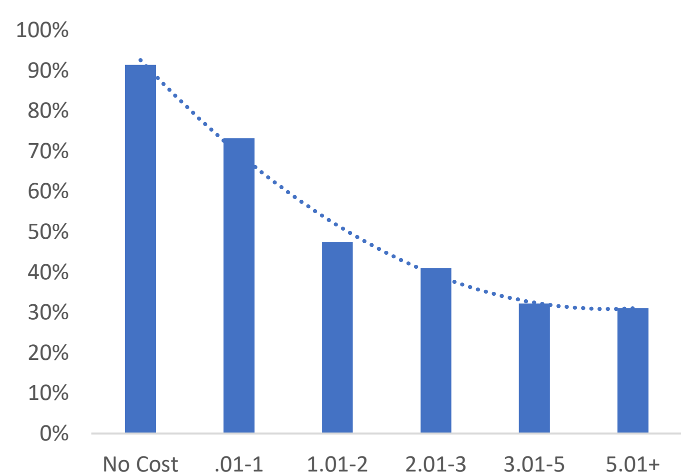


Figure 1: 2007-18 RCEA Project Acceptance Rates by Simple Payback in Years

Task 4—Incentives: RCEA will use a dynamic and targeted retrofit incentive kicker or TRIK, that will objectively set incentive based on measurable and verifiable metrics. TRIK begins with set per unit incentives. However, specific triggers will initiate incentive kickers to optimize program production. When triggered, incentives will be increased but never decreased. This will maximize project acceptance rates while minimizing implementation costs and customer confusion. Optimizing project acceptance rates and disbursed incentives will reduce direct install non-incentives to incentive ratios while maximizing delivered savings to the portfolio for the lowest dollar value possible.

Figure 1 shows the association between simple payback and project acceptance rates where a co-pay was required. The following provides an operationalization of TRIK as associated with Figure 1. If a project has a payback of 1.01 years and requires an additional $500 to reduce the payback to .75 years thus increasing the probability of the project converting from 48% to 73%.

Task 5.a—Procurement: RCEA maintains a list of qualified installing contractors. Once a customer enrolls in our program, Project technicians or managers will trigger a competitive bidding process.

- The assessment, scoping document and estimated project costs including incremental are sent to all qualified contractors.
- A job site walk is scheduled; depending on project scope, complexity and location, some walks may be mandatory others will not be.
- Contractors are given the opportunity to comment on scope and request addendums.
- All contractors are given equal information.
- Bids are accepted by RCEA staff and presented to the participating customer.
- The customer selects the contractor.

RCEA has a proven track record that this process increases customer capacity to act, reduces customer costs and increases contractor satisfaction with the program design.

Task 5.b—Public Agency Procurement. RCEA staff provide direct procurement support to public agencies. A variety of strategies can be used to reduce public agency participant costs. Strategies vary based on each public agency's specific, and adopted, procurement guidelines.

Strategies include but will not be limited to:

- The use of government code (GC) 4217 to streamline procurement,
- Facilitating and managing the bid cycle, and
- Supporting engagement with the Department of Industrial Relations.

Task 6— Installation: Once a contractor is selected, an installation agreement will be executed with RCEA, the contractor and the customer. This will set expectations and clearly state program requirements such as but not limited to:

- Eligibility
- Estimated energy savings and incentives
- Roles of RCEA, customer and contractors
- Access Agreement

- Code Compliance
- Double Dipping
- Life of Product

Task 7.a—Commercial Project Management: RCEA will provide no-cost project management support to ensure projects are installed to spec, on-time and on budget.

Task 7.b—Public Agency Project Management: RCEA will provide a variety of project management support activities ranging from ensuring all required Department of Industrial relations requirements are met to direct procurement support as described above.

Task 8—Reporting: Where applicable, RCEA will support all required reporting to ensure that the opportunity cost of participating is reduced. Additional reporting will occur to RCEA's board and to the CPUC as required.

<u>Deliverables</u>

The Non-Residential Direct Install Program will provide no and low-cost installations of prescribed measures tailored to the Humboldt County market. This will allow for a more effective alignment of offered products and services to opportunity. Unlike other Direct Install programs, RCEA will utilize a competitive bid process to ensure costs representative of a fair market value. RCEA has previously used job order contracting or fixed pricing. We learned that this does not facilitate reduced participant costs, increased program cost-effectiveness nor the rapid response to changes in market valuation of a product service or product that are necessary to stay viable.

RCEA proposes, but will not be limited to the installation of the following measures:

- LED Interior Lighting
- LED Exterior Lighting
- Refrigeration
- LED Signs
- Occupancy Sensors
- Smart Power Strips
- Programmable Thermostats

RCEA strives to secure flexible, adaptive and innovative program design as we intend to explore and incorporate new offerings over time that will advance and be consistent with state goals while aligning to and supporting new local emerging markets such as:

- Fuel substitution measures
- Normalized Metered Energy Consumption program designs
- Localized behavioral, retro-commissioning and operational measures
- Communicative advanced controls.

Commencement Date

The program will begin July 1st 2020, following CPUC approval and will run for 3 years.

Cost-Effectiveness Analysis

RCEA has performed a cost-effectiveness analysis for the non-residential program to the best of our ability. Staff have taken steps to ensure the effort was advanced in accordance with the methodologies included in the California Standard Practices manual. Labor and material costs were estimates based on RCEA's internal data and Marin, Lancaster and PG&E's 2019 CEDAR filings.

The initial program Total Resource Cost (TRC) is 1.40 with a Program Administrator Cost of 1.51. The full results of the Calculation can be found in Appendix A RCEA Cost Effectiveness Test inputs and outputs. Appendix B combines and truncates the information from the embedded input and output Excel workbooks.

Demand Reduction, Energy Savings, and Other Measures of Success

RCEA expects that first-year gross energy savings for the program will be 1,674,463.40 kWh with 460.55 kW. Additional measures of success will include but not be limited to: services to HTR customers exceed 85% of all rendered services; project conversation rates are sustained at or above 50%; number of value stacked distributed energy resource services.

Budget

The three-year program budget for Non-Residential Direct Install is $1,351,500 prior to incentives. The budget breakdown can be found in the following table.

	Year 1	Year 2	Year 3	Totals
Administration	$ 30,500.00	$ 30,500.00	$ 30,500.00	$ 91,500.00
Marketing and Outreach	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 60,000.00
Direct Implementation Non-Incentive	$ 400,000.00	$400,000.00	$400,000.00	$ 1,200,000.00
Total Budget	$ 450,500.00	$450,500.00	$450,500.00	$ 1,351,500.00

Collaboration

RCEA has a long history of collaborating and partnering with PG&E. RCEA will make every effort to differentiate our locally-administered programs from PG&E's. In addition, RCEA will continue to work to bring regional and statewide programs to Humboldt County as historic and publicly available data shows that regional and statewide program penetration rates in Humboldt are low.

RCEA will provide program delivery information to PG&E through the assigned PG&E representative. RCEA will also provide PG&E all necessary information regarding locally funded programs and statewide and regional program referrals. RCEA hopes that by continuing to maintain a strong partnership with PG&E we will be able to collectively direct customers to the very best service, while reducing confusion at every step.

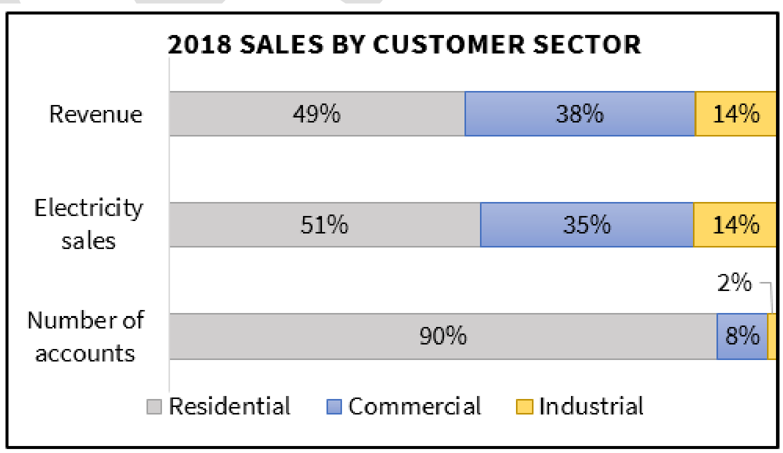
RESIDENTIAL DIRECT INSTALL

RCEA provided Residential Direct Install services from 2006 to early 2018 in partnership with PG&E. In 2018 PG&E requested that RCEA halt all residential services. RCEA complied but requested an opportunity to work with PG&E's Moderate-Income Direct Install and Mobile Home Direct Install programs to ensure that RCEA customers received a proportionate level of service. This has not occurred.

RCEA's Residential Direct Install program will provide programmatic offerings to residents that are not being served by regional and state-wide programs and will therefore be non-duplicative. In recent years, Humboldt County residents have been able to access income-based programs and the Home Upgrade program (with support from RCEA). Other regional and state-wide programs (such as Moderate-Income Direct Install and the Mobile Home program) have not been providing significant numbers of services to Humboldt County residents. RCEA's Residential Direct Install program is intended to address the large service gap that currently exists between services available to Humboldt County residents.

As a Participating Rater for the Home Upgrade program for the last 6 years, RCEA has observed Home Upgrade project costs range from $7,000 to $25,000. The majority of residents have told us that an investment of this level is beyond their means and they are unable to participate. RCEA's Residential Direct Install program will target households whose income is too high to qualify for income-based services and for which Home Upgrade is also out of reach. RCEA's Residential Direct Install program will also gap fill where existing and forecasted regional third-party providers fail to serve Humboldt's geographically constrained customers.

2018 sales data, made available through RCEA's Community Choice program, shows that the residential sector accounts for 51% of all electricity sales, 90% of all accounts and 49% of CCA revenue. It is imperative that RCEA's residential customers have access to energy saving services.



In addition, peak demand has shifted towards the evening hours and time of use rates are changing. This increases the importance of energy efficiency and integrated demand response in the residential sector.

<u>Residential Program Process</u>

RCEA expects that the regulatory framework that empowers action within the residential space will change over time. Staff have and will continue to ensure that program design is adaptive and nimble. Staff are eager and excited to explore localized energy reports, communicative energy saving devices and fuel substitution measures. RCEA understands that program processes and services will have to be adjusted in the future to align with R.13-11-005 outputs including the proposed decision on the Three Prong Test. The following tasks outline current and expected program processes.

Task 1—Data Driven Marketing, Outreach and Education: RCEA has been providing residential energy efficiency services since 2006. We have years of marketing collateral, documentation, Residential Direct Install resource-based implementation data, advanced metering infrastructure data and over 6 years of built environment data to draw from. We will use this information to make our program generally available to our customers while custom tailoring messaging, products and services to known opportunities that exist in our community.

RCEA does not expect the program to be a cost-effective as a stand-alone effort and thus will have to limit and scale efforts to ensure the entire portfolio is balanced. The need to balance the portfolio, to ensure that we deliver a forecasted TRC greater than 1.0, will inform marketing over time. Based on historic service request volume, we do not expect that we will have to aggressively market the offerings and that passive interest will drive service.

RCEA will update all marketing materials to effectively describe the program while ensuring that the brand is unique and separate from PG&E programs. Marketing materials will include but not be limited to:

- An updated website to afford customers an opportunity to learn about the program. The website will provide general information about the program, the program service flyer, application and site access agreement, frequently asked questions and participant case studies.
- Hard copies of the noted resources above.
- Bill inserts that can be sent through our member or partner agency's water/waste billing mechanisms.
- Videos showcasing opinion leaders.
- Scripts for paid and earned radio spots.

Task 2—Prequalification. Much like non-residential, RCEA has a prequalification process that is used to guide referrals to locally funded, regional, statewide and federal pogroms. Prequalification allows our operations specialist to quickly verify program eligibility and guide customers through resource programs' varying requirements. This process will be adapted and expanded to better track customers and ensure RCEA maximizes the value of local, regional and statewide programs while also ensuring clear branding of our services. When the customer's needs are best met by another regional or state-wide program, the customer will be connected to the applicable program. We intend to continue to prequalify to ensure that the customer is tracked to the program that can provide the most comprehensive, cost-effective service possible.

Task 3—Turn-Key Assessments and No-Cost Direct Installation: RCEA Building Performance Institute Certified Professional Project Technicians will provide no-cost in home assessments to customers requesting service. Based on the assessment, customers will receive a customized report with behavior change opportunities, an itemized list of installed measures including location and quantity, low-cost opportunities and investment opportunities including integrated demand response, and referrals to applicable programs. RCEA has an existing database that makes implementing this program element turn-key.

Task 4—No-Cost Installation: Staff will verify eligibility and will install, as a best practice, no-cost and low-cost offerings during the first visit. When necessary, staff will schedule a follow-up appointment to install. After the customer agrees to the recommended measures, an installation agreement will be executed with RCEA. This will set expectations and clearly state program requirements such as but not limited to:

- Eligibility
- Estimated Energy Savings and Incentives
- Roles of RCEA, customer and contractors
- Access Agreement
- Code Compliance
- Double Dipping
- Life of product

Task 5—Incentives: Incentives will match the installed cost of technologies to ensure that the project is no-cost to the customer. Incentive levels will change as cost of technologies shift. The customer and installer will certify that all T24 requirements were met on completion of the project.

Task 6—Reporting: Where applicable, RCEA will support all required reporting to ensure that the opportunity cost of participating is reduced. Additional reporting will occur to RCEA's board and to the CPUC as required.

<u>Deliverables</u>

The Residential Direct Install Program will provide no-cost installations of prescribed measures tailored to the Humboldt County market. This will allow for a more effective alignment of offered products and services to opportunity.

RCEA proposes, but will not be limited to the installation of the following measures:

- Smart Thermostats
- LED Reflector/ Parabolic Lamps
- LED Globes
- Faucet Aerators and low flow showerheads

RCEA strives to secure flexible, adaptive and innovative program design as we intend to explore and incorporate new offerings over time that will advance and be consistent with state goals while aligning to and supporting new local emerging markets such as:

- Fuel substitution measures
- Communicative advanced controls.

Commencement Date

The program will begin July 1st 2020, following CPUC approval and will run for 3 years.

Cost-Effectiveness Analysis

RCEA has performed a cost-effectiveness analysis for the non-residential program to the best of our ability. Staff have taken steps to ensure the effort was advanced in accordance with the methodologies included in the California Standard Practices manual. Labor and material costs were estimates based on RCEA's internal data and Marin, Lancaster and PG&E's 2019 CEDAR filings.

The initial program Total Resource Cost (TRC) is 0.49 with a Program Administrator Cost of 0.5. The full results of the Calculation can be found in Appendix A RCEA Cost Effectiveness Test inputs and outputs. Appendix B combines and truncates the information from the embedded input and output Excel workbooks.

Demand Reduction, Energy Savings, and Other Measures of Success

The residential program has limited offerings and will only deliver 34,182 gross kWh and a demand reduction of 1.86. The residential program is not intended to be initially cost-effective so other measures of success are critical.

- Number of residents served.
- Number of behavioral recommendations made.
- Internalization of fuel substitution measures.

Budget

The three-year program budget for Residential Direct Install is $412,500.00 prior to incentives. The budget breakdown can be found in the following table.

	Year 1	Year 2	Year 3	Totals
Administration	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 37,500.00
Marketing and Outreach	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 45,000.00
Direct Implementation Non-Incentive	$ 110,000.00	$110,000.00	$110,000.00	$ 330,000.00
Total Budget	$ 137,500.00	$137,500.00	$137,500.00	$ 412,500.00

Collaboration

RCEA has a long history of collaborating and partnering with PG&E. RCEA will provide program delivery information to PG&E through the assigned PG&E representative. RCEA will also provide PG&E all necessary information regarding locally funded programs and statewide and regional program referrals. RCEA hopes that by continuing to maintain a strong partnership with PG&E we will be able to collectively direct customers to the very best service, while reducing confusion at every step. RCEA knows that a strong, collaborative, and open relationship with PG&E will benefit the customer while maximizing programmatic cost-effectiveness for all.

EXPERIENCE

RCEA has provided energy efficiency, conservation and integrated demand side management services since 2003-2004. RCEA sees demand-side services as necessary to achieve the aggressive organizational goals as specified in the CAPE and RePower documents. RCEA has a long history of implementing applicable programs. For example:

Resource Center

The Resource Center is RCEA's longest running program offering to the public. Launched in 2004, the Resource Center offers information and education to the public and emerging energy professionals, an energy answer line, and tools and books for checkout. This one-stop shop for information has become a staple in the local community. The Resource Center provides easy to access in-person services right here in our geographically hard-to-reach community. The Resource Center has evolved over time hosting workshops; housing interactive efficiency displays built by Humboldt State University Engineering students; and providing a public meeting space for energy-related forums, free checkout of energy tools for both residents and home performance contractors, and school kits with curriculum for teachers.

Redwood Coast Energy Watch and Local Government Partnership

RCEA launched the Redwood Coast Energy Watch (RCEW) Local Government program partnership with Pacific Gas and Electric Company in 2006. RCEW brought direct install energy services to Humboldt County that previously had not reached our rural community. RCEW has been RCEA's flagship program since its launch. RCEA migrated the resource center effort into Energy Watch in 2006. The Energy Watch program has historically provided both resource and non-resource services to non-residential small-and medium businesses, public sector and residential ratepayers.

Energy Efficiency Conservation Block Grants (EECBG)

RCEA provided EECBG project management support services to member agencies, Trinity County, Etna and Point Arena from 2010-2012. Where allowable, EECBG was integrated into our existing non-residential efficiency services supported by our RCEW program. EECBG coupled with RCEW provided an opportunity to build significant capacity as relating to the administration of efficiency projects in the public sphere.

Proposition 39 Energy Management Services

RCEA's Proposition 39 program currently supports Local Educational Agencies (LEAs) with energy management services, project management and assistance with navigating the California Energy Commissions application and reporting process to access funding. The program leverages the Redwood Coast Energy Watch non-residential program, providing basic benchmarking, walkthrough energy assessments and incentives through Direct Install and Deemed Downstream. RCEA Prop 39 project managers have become trusted energy advisors and continue to assist LEAs with additional efficiency projects, electrification, EV buses, demand response, on-site generation and storage.

Public Agency Solar Program

RCEA's Public Agency Solar Program (PASP) provides a "no-cost" service to local public agencies to reduce the institutional barriers that public agencies face to entering the solar marketplace. The PASP has been integrated into RCEA's 2018-19 Energy Watch services. The integration of local funding (PASP) and efficiency funding (RCEW) allows RCEA staff to offer a comprehensive service to public agencies that adheres to California's energy loading order—efficiency first! PASP services include but are not limited to: electric load analysis, benchmarking, energy efficiency upgrade options, project feasibility studies, financing and public works procurement process support that align to the agency's adopted standards.

Redwood Neighborhood Energy Challenge

The Redwood Neighborhood Energy Challenge program was implemented by RCEA and funded by a PG&E's Innovator Pilot Grant. The purpose of the pilot was to use community-based social marketing and friendly competition to encourage residents to save energy as well as educate them on energy efficiency, renewable energy and applicable services. The Challenge engaged neighborhoods and individuals by having them reduce energy use in their home on behalf of a local school of their choice. Participants received in-home assessments, efficiency upgrades through our Direct Install program, education about technologies and financing and referrals to applicable programs. The winning school secured a large cash prize towards an energy upgrade.

No-Cost Homeowner Assessments and Energy Saver Assessments

RCEA offered No-Cost Homeowner Assessments for homeowners and Energy Saver Assessments for renters. The program leveraged the tools and resources developed for the Redwood Neighborhood Energy Challenge. Along with a walk-through assessment and report, residents received Direct Install measures. Homeowners that were deemed a good fit were encouraged to pursue Rater Services and invest in deeper retrofits.

Rater Services

In 2014, RCEA launched Rater Services to support the development of a residential home performance marketplace in Humboldt County. In order to promote deeper retrofits and move residents toward zero net energy homes, we provided education and services to both residents and contractors. We supported customers through a stepped process starting with a no-cost assessment and moving them all the way through the completion of an Advanced Home Upgrade project. We enrolled as a Participating Home Upgrade Rater to fill service gaps and act as an independent trusted energy advisor. We even provided home performance workforce education training for dozens of local contractors, thus greatly increasing local capacity.

Residential Energy Consultations & Efficiency Kits

Residential energy consultation and efficiency kit services were launched in 2018 as a gap filling program. The reduction of residential RCEW funding resulted in no program services for middle income Humboldt County residents. There is a large sector of residential customers in Humboldt County that fall between low-income program services and Home Upgrade program services. RCEA used local funding leveraged against PG&E foundation funding to provide no-cost phone-based energy consultations and efficiency kits to residents.

Consultations aim to address customer inquiries and cover a wide range of activities such as: identifying the best program to serve their specific needs, referrals to programs and resources, electric rate analysis, home performance questions, behavioral recommendations, and vendor referrals. The efficiency kit is custom built for the customer based on their needs and shipped to their home. The efficiency kit includes $75 of do-it-yourself type efficiency measures and safety measures such as LED bulbs, low-flow showerheads, faucet aerators, switch plate gaskets, and carbon monoxide alarms.

Property Assessed Clean Energy

RCEA led the charge to educate the county's tax collector and city/ county officials about PACE. RCEA leveraged its position as a Joint Powers Authority to encourage and support each member jurisdiction to adopt the required ordinance allowing for PACE implementation. PACE is now available to residents throughout Humboldt County with new providers being added.

ACV Airport Microgrid Project

The ACV Airport Microgrid project will install a 2 MWDC PV array–coupled to a 2 MW/8MWh battery energy storage system, a 250 kWAC net metered PV array and a variety of distributed energy resources including electric vehicle chargers and advanced lighting and lighting controls. The objectives are to deploy the first front-of-the-meter, multi-customer microgrid in the PG&E service territory; increase the resilience of two critical emergency facilities (Humboldt County's main, commercial airport and a U.S. Coast Guard Air Station); integrate a community-scale, direct DC-coupled PV array and battery storage system with PG&E's electric grid; demonstrate use of CCA-owned renewable generation as an asset for wholesale CAISO market participation while grid-connected and as a microgrid power supply when islanded and to provide a demonstration site that will be used to develop the agreements, operating procedures, tariffs, interconnection and safety protocols that will support future multi-customer microgrids.

ACCOMODATION OF STATEWIDE AND REGIONAL PROGRAMS

RCEA intends to continue to provide services to our geographically hard-to-reach ratepayers. RCEA will make every effort to comply with 381.1(f)(3) and D.14-01-033. RCEA has developed a strong brand as the electricity provider devoted to local decision making on power generation, energy conservation, and sustainability throughout Humboldt County. We have clearly branded our efforts as unique from the existing electric utility and we are generally well known to our constituents. The energy efficiency programs that RCEA intends to elect to administer will be clearly distinguished as unique programs offered exclusively to RCEA customers by RCEA. Program marketing will be targeted to RCEA customers as well as clearly describing which ratepayers will be eligible to participate.

RCEA is in a strong position to provide energy efficiency programs to its constituents. With oversight from our Board, who represent the seven cities, the County and our Municipal Water District, RCEA is held to a level of accountability and transparency that will benefit all. Because of this very close link between elected officials, RCEA staff and customers, RCEA understands its customers' needs better than an investor owned utility or out of area third party that must spread its attention across a much larger population and territory. To that end, we will provide direct install services to hard-to-reach qualified customers, public sector customers and to those non-hard-to-reach customers that have no other service options.

We expect that all programs administered through PG&E will be branded appropriately and that will support differentiation. RCEA intends to continue to work with PG&E through their Lead Local Partner solicitation. This effort will be branded as a direct partnership with PG&E administered under the auspices of the CPUC. RCEA's intent is to support implementers while maximizing the delivery of viable regional and statewide programs that provide cost-effective services that RCEA cannot. For example, RCEA can't scale a waste water treatment program for our member agencies but I suspect other may be able to either at the regional or statewide level. It is our intent to clearly brand our service while marketing, promoting and otherwise accommodating value additive regional and statewide programs.

RCEA will consistently recommend leveraging statewide and regional programs when and where they are staged to provide the best service to our customer base. Statewide and regional program qualification will be made part of prequalification process. This will ensure that customers are channeled to the appropriate service. In addition, RCEA will effectively communicate who the pertinent program implementers are to customers and will coordinate with PG&E to ensure that RCEA customers have the most accurate, up-to-date materials on available programs.

CONSISTENCY WITH CPUC GOALS

RCEA's non-residential and residential programs will deliver cost-effective energy savings to customers of Redwood Coast Energy Authority while remaining consistent with CPUC goals, supporting and aligning to RCEA's 2030 RePower Vision, and advancing CAPE.

RCEA has and will continue to prioritize advancing the public interest as aligned with 399.4 and 381.1. RCEA programs are consistent with broader regional or statewide energy efficiency program and are designed to integrate demand side management activities in a way that will value stack the deployment of distributed energy resources. This will also support relevant rulings and decisions such as but not limited to D.07-10-032 and D.12-11-015.

RCEA complies with the mandate set forth in Section 399.4(d)(2)—that the CPUC authorize the following types of programs: market transformation, pay for performance, and programs that achieve savings through operational, behavioral, and retro commissioning activities—by prioritizing the value stacking of available programs while ensuring effective branding. Compliance with Section 399.4(d)(2) will also support the goals noted in D.07-10-032.

RCEA will comply with Section 399.4(b)(1) by requiring all installing contractors or non-residential and residential customers who are the recipient of a rebate or incentive to certify that they have complied with Title 24.

RCEA's plan will show that it is custom tailored to meet Section 399.4(c) which states " the commission, in evaluating energy efficiency investments under its statutory authority, shall also ensure that local and regional interests, multifamily dwellings, and energy service industry capabilities are incorporated into program portfolio design and that local governments, community-based organizations, and energy efficiency service providers are encouraged to participate in program implementation where appropriate."

RCEA is submitting a plan that complies with Section 399.4(c) but is also advancing additional statewide goals. For example, RCEA is submitting a plan that presents a Total Resource Cost test that exceeds what it's been able to deliver through its historic relationship with PG&E. This is attributed to our ability to better align offerings and products to local opportunities in the non-residential hard-to-reach market space

RCEA programs will fulfill the Public Utility Codes Section 399.4 requirement that incentives be based on values and methodology stated in customer agreements and derived from measured results. RCEA is proposing an innovative approach to incentive disbursement and believes that the alterations noted in the Targeted Retrofit Incentive Kicker model are still compliant, measurable and transparent. RCEA understands that cost-effectiveness calculations require specific inputs—costs (project costs and incentives) and benefits (energy savings)—thus RCEA is committed to accurately forecast portfolio averaged incentive values to ensure cost-effectiveness calculations are accurate, achievable and based on realistic and timebound values.

LCE's programs will fully follow Section 399.4 requirements that participants comply with applicable permitting requirements. Participating contractors will be required to pull permits as required by code.

By acting as point of contact for RCEA customer energy efficiency programs, RCEA will simplify the goals set forth in Section 381.1 ensuring that local and statewide goals are met—such as those associated with SB350.

AUDITING AND REPORTING

RCEA performs annual financial audits using generally accepted accounting principles specific to government entities. These reports are publicly available and will be provided to the CPUC on request. As a CCA, once RCEA's energy efficiency plan is certified and programs begin, current auditing procedures will be extended to include energy efficiency program administration data. This will ensure appropriate accounting controls for energy efficiency program funds.

Per requirement of the Governmental Accounting Standards Board Statement No. 34, the management's discussion and analysis will be included to supplement the basic financial statements. To evaluate the effective use of resources and management procedures, RCEA will also complete all regulatory filings and reports as directed by CPUC staff. These documents will provide the results of program efforts that can be evaluated against the performance metrics identified by RCEA, including adherence to cost- effectiveness requirements.

RCEA will take all necessary actions to remain compliant with additional auditing and reporting requirements.

EVALUATION, MEASUREMENT AND VERFICATION PROTOCOLS

RCEA will contract with an independent third-party to perform process evaluations or market studies to determine the effectiveness and needs for the successful implementation of programs. RCEA-led studies will be performed according to the process of Commission oversight of IOU Evaluation Measurement and Verification (EM&V) projects as detailed in the Energy Efficiency EM&V Plan. RCEA will be subject to the same protocol as investor owned utilities for CPUC-directed impact evaluations to determine actual energy savings, benefits, costs, and goal achievement as directed in D.05-01-055. RCEA expects to dedicate no more than 4% of total program budget during the three-year program to evaluate the program and market.

RCEA directed evaluations will explore market conditions and needs, identify any weaknesses in the program and the reasons for their existence, and viable solutions to address those issues. The effects of the program will be measured in indirect program impact (i.e., behavioral changes), and impacts to the market that resulted in induced market changes (i.e., job creation), while direct program impact (i.e., energy savings) will be measured by CPUC-directed impact evaluations. RCEA will refer to existing EM&V led by IOUs and CPUC to avoid duplication and expand on existing efforts.

The EM&V effort will draw upon data from program databases, program descriptions, implementation plans, surveys and actual energy savings at the meter, interviews, marketing collateral, and work papers developed for or used during program implementation. Objectives include, but will not be limited to:

- Compare program efforts in Humboldt County to efforts for other programs serving rural and geographically remote regions of the state.
- Evaluate the successes, failures, and replicability of programs.
- Evaluate the differences and unique qualities within RCEA and determine how best to respond.
- Do they match original data collection and estimates prior to program launch?

PERFORMANCE METRICS

The following Performance Metrics will indicate progress toward meeting the goals and objectives of the CPUC Energy Efficiency Strategic Plan and RCEA's service goals.

- Progress toward becoming achieving RCEA's 2025 goal of 100% Clean and Renewable power using the Clean Net Short methodology—energy efficiency is a critical aspect of balancing demand to supply.
- Program energy savings.
- Tracking and serving hard-to-reach customers.
- Cost-effectiveness calculations.
- Percentage of customers audited who install at least one program measure.
- Percentage of recommended measures installed by customers.
- Evaluation, Measurement, and Verification process, tracking, and incorporation into program design.

Within this section RCEA would also like to summarize the specific metrics identified for both programs to use as targets against which to measure program performance. The table below presents portfolio level metrics that will be managed.

Program	Metric	Year 1	Year 2[1]	Year 3[1]	Metric Totals	Program Cost
Non-Res	Admin Costs	$ 30,500.00	$ 30,500.00	$ 30,500.00	$ 91,500.00	$ 2,651,421.60
	Marketing Costs	$ 20,000.00	$ 20,000.00	$ 20,000.00	$ 60,000.00	
	DINI	$ 400,000.00	$ 400,000.00	$ 400,000.00	$ 1,200,000.00	
	Incentives	$ 433,307.20	$ 433,307.20	$ 433,307.20	$ 1,299,921.60	
	Gross kWh	1,674,463.40	1,674,463.40	1,674,463.40	5,023,390.20	
	Gross kW	460.55	460.55	460.55	1,381.65	
Res	Admin Costs	$ 12,500.00	$ 12,500.00	$ 12,500.00	$ 37,500.00	$ 523,031.49
	Marketing Costs	$ 15,000.00	$ 15,000.00	$ 15,000.00	$ 45,000.00	
	DINI	$ 110,000.00	$ 110,000.00	$ 110,000.00	$ 330,000.00	
	Incentives	$ 36,843.83	$ 36,843.83	$ 36,843.83	$ 110,531.49	
	Gross kWh	34182.00	34182.00	34182.00	102546.00	
	Gross kW	1.86	1.86	1.86	5.58	

1: Program year 2 and 3 are speculative. Costs, savings and incnetives will be determined with subsequent filings.

FUNDING DETERMINATION

Resolution E-4518 states that “funding collection and program periods do not always correspond” and that there is no statutory requirement for funding collection to begin subsequent to Commission certification of the plan. MEA (now named Marin Clean Energy) was provided a collection period beginning with the original draft submittal date. Based on this precedent, RCEA finds it reasonable to request the CPUC to direct transfer of energy efficiency funds collected from RCEA’s customers beginning on August 30th 2019, the date of filing for RCEA’s Advice Letter.

The Commission must establish whether the funding requested in the CCA’s proposed plan is within the forecasted maximum amount of funds the CCA would be eligible to collect. Commission staff must determine the actual and forecasted amounts of non-bypassable charges likely to be collected from the CCA’s customers over a reasonable collection period to fund energy efficiency programs. The commission is to use the following formula:

> CCA maximum funding = Total electricity energy efficiency nonbypassable charge collections from the CCA’s customers – (total electricity EE nonbypassable charge collections from the CCA’s customers * % of the applicable IOU portfolio budget that was dedicated to statewide and regional programs in the most recently authorized program cycle).

RCEA staff have determined:

- Total CCA non-bypassable funds collected = $9,761,576.18.
- 88% of collected funds are currently dedicated to statewide and regional programs.
- Total funding to statewide and regional programs = $8,590,187.04
- RCEA’s first year not-to-exceed value = Total non-bypassable funds collected by CCA customers less statewide and regional programs = $1,171,389.41
- The three year not-to-exceed value equals $3,514,168.23

Redwood_Elect_CCA_Funding_Analysis

APPENDIX A: COST EFFECTIVENESS INPUT and OUTPUT

CET_Inputs_20190719.xlsx

CET_Outputs_20190719.xlsx

APPENDIX B: RCEA COST EFFECTIVENESS TEST RESULTS

CET_ID	MeasDescription	GrossKWh	GrossKW	GrossThm	TRCRatio	PACRatio
RCEA-2020-01	Setback Programmable Thermostat Control	15573.6	0	4654.44	2.3185077	2.3408293
RCEA-2020-02	Setback Programmable Thermostat Control	42876	-1.485	4244.4	2.1271431	2.1544597
RCEA-2020-03	Setback Programmable Thermostat Control	47578.5	-0.99	20138.4	2.6574908	2.6680769
RCEA-2020-04	Setback Programmable Thermostat Control	17851.5	-0.63	14033.475	2.7010494	2.7098625
RCEA-2020-05	Setback Programmable Thermostat Control	7785.45	-2.2545	1445.715	2.2761603	2.2996893
RCEA-2020-06	Setback Programmable Thermostat Control	7523.1	-1.701	495	2.2433772	2.267801
RCEA-2020-07	Setback Programmable Thermostat Control	30448.44	-2.376	7471.332	2.6664018	2.6766302
RCEA-2020-08	Setback Programmable Thermostat Control	8899.2	0	2659.68	2.3393393	2.3610458
RCEA-2020-09	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	38250	7.9356846	-431.71558	1.0525126	1.1052576
RCEA-2020-10	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	32625	6.7686722	-368.22799	1.0525126	1.1052576
RCEA-2020-11	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	16875	3.5010373	-190.46275	1.0525126	1.1052576
RCEA-2020-12	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	24750	5.1348548	-279.34537	1.0525126	1.1052576
RCEA-2020-13	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	14625	3.0342324	-165.06772	1.0525126	1.1052576
RCEA-2020-14	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	12375	2.5674274	-139.67269	1.0525126	1.1052576
RCEA-2020-15	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	16875	3.5010373	-190.46275	1.0525126	1.1052576
RCEA-2020-16	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	7875	1.6338174	-88.882619	1.0525126	1.1052576
RCEA-2020-17	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	10125	2.1006224	-114.27765	1.0543483	1.1071301
RCEA-2020-18	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	4950	1.026971	-55.869074	1.0543483	1.1071301
RCEA-2020-19	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	3375	0.7002075	-38.092551	1.0543483	1.1071301
RCEA-2020-20	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	12375	2.5674274	-139.67269	1.0543483	1.1071301
RCEA-2020-21	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	7875	1.6338174	-88.882619	1.0543483	1.1071301
RCEA-2020-22	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	5625	1.1670124	-63.487585	1.0543483	1.1071301
RCEA-2020-23	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	12375	2.5674274	-139.67269	1.0543483	1.1071301
RCEA-2020-24	LIGHTING RETROFIT/NEW-INT-LED-REPLACEMENT LAMPS, EXTENDED (>=5 YR) LIFE	4050	0.840249	-45.711061	1.0543483	1.1071301
RCEA-2020-25	Vending Machine Controller	44514.9	0	0	0.8467572	0.8762975
RCEA-2020-26	Main Freezer Door Auto Closer	170040	52.5336	-11.16	0.8021094	0.8307132
RCEA-2020-27	Main Cooler Door Auto Closer	215880	122.4	72.84	0.9512601	0.9827005
RCEA-2020-28	Main Cooler Auto Closer	53967.9	19.32	-18.21	0.912415	1.1308975
RCEA-2020-29	Main Freezer Auto Closer	103949.25	31.9632	-2.709	1.3950843	1.7139098
RCEA-2020-30	Cooler AntiSweat Heater equal toASHequal to Controls	13088.969	1.177	-172.71	1.4375839	1.6920552
RCEA-2020-31	Shaded Pole to ECM in Refrigerated Display Cases	24780	3.122	0	1.3957243	1.6795075
RCEA-2020-32	Low ASH Display Doors	28350	5	-172	1.3429541	1.5355149
RCEA-2020-33	Cooler AntiSweat Heater equal to ASH equal to Controls	19633.454	1.7655	-259.065	1.4376094	1.69208
RCEA-2020-34	Shaded Pole to ECM in Refrigerated Display Cases	70800	8.92	0	1.3957537	1.6795362
RCEA-2020-35	Low ASH Display Doors	42525	7.5	-258	1.3429987	1.5355595
RCEA-2020-36	Residential Smart Communicating Thermostat	5200	0	9800	0.5315495	0.5434101
RCEA-2020-37	Residential Smart Communicating Thermostat	11175	0	2325	0.537381	0.5486761
RCEA-2020-38	LED High/Low Bay: 110 LPW to less than130 LPW, 48 to less than71 W	338.944	0.075688	-2.21088	0.0816508	0.1602807
RCEA-2020-39	LED High/Low Bay: 110 LPW to less than130 LPW, 71 to less than90 W	522.4	0.116656	-3.4058	0.1237865	0.2392143
RCEA-2020-40	LED High/Low Bay: 120 LPW to less than130 LPW, 90 to less than125 W	595.6	0.132984	-3.88284	0.1402147	0.2693282
RCEA-2020-41	LED High/Low Bay: 120 LPW to less than130 LPW, 125 to less than153 W	802.16	0.17908	-5.23004	0.1854377	0.3503802
RCEA-2020-42	LED High/Low Bay: 125 LPW to less than135 LPW, 153 to less than187 W	1248.24	0.27868	-8.14036	0.277745	0.5078721
RCEA-2020-43	LED High/Low Bay: 125 LPW to less than135 LPW, 246 to less than283 W	689.84	0.15404	-4.49948	0.1610445	0.3069917
RCEA-2020-44	LED High/Low Bay: 110 LPW to less than130 LPW, 48 to less than71 W	1694.72	0.37844	-11.0544	0.0816568	0.1602923
RCEA-2020-45	LED High/Low Bay: 110 LPW to less than130 LPW, 71 to less than90 W	1828.4	0.408296	-11.9203	0.1237955	0.239231
RCEA-2020-46	LED High/Low Bay: 120 LPW to less than130 LPW, 90 to less than125 W	2382.4	0.531936	-15.53136	0.1402248	0.2693467
RCEA-2020-47	LED High/Low Bay: 120 LPW to less than130 LPW, 125 to less than153 W	4010.8	0.8954	-26.1502	0.1854509	0.3504036
RCEA-2020-48	LED High/Low Bay: 125 LPW to less than135 LPW, 153 to less than187 W	4368.84	0.97538	-28.49126	0.2777641	0.5079039
RCEA-2020-49	LED High/Low Bay: 125 LPW to less than135 LPW, 246 to less than283 W	2759.36	0.61616	-17.99792	0.161056	0.3070125
RCEA-2020-50	LED RBR: less than11 Watts	34640	8.24	-225.6	1.1189338	1.1505352
RCEA-2020-51	LED RBR: 11 less than 14 Watts	17160	4.05	-111.3	1.1396129	1.1713595
RCEA-2020-52	LED RBR: 14 less than equal to 22 Watts	18870	4.47	-122.4	1.1401312	1.1718809
RCEA-2020-53	Low Flow Showerhead (1.6 GPM Electric WH)	5354	0.5385	0	0.4381192	0.4446657
RCEA-2020-54	Low Flow Showerhead (1.6 GPM Electric WH)	5354	0.5385	0	0.4365517	0.4431277
RCEA-2020-55	Faucet Aerator 1.0GPM (Electric WH)	153	0.0155	0	0.1959058	0.2025723
RCEA-2020-56	Faucet Aerator 0.5GPM (Electric WH)	506	0.051	0	0.3782884	0.3856995
RCEA-2020-57	LED Candelabra 3 to 5	2895	0.32	-55.5	0.3218181	0.3278785
RCEA-2020-58	LED PAR20: <= 11 Watts	3545	0.395	-68	0.2582895	0.2647039
RCEA-2020-59	Process Fan VSD: greater than 5 HP less than 75 HP	3736.4375	2.154875	0	1.0219122	1.2951719
RCEA-2020-60	LIGHTING RETROFIT/NEW-EXT-LED-WALL MOUNTED	56250	0	0	1.6349322	2.3473821
RCEA-2020-61	VFDs for HVAC Fans	232000	137.5	-1075	0.5725359	0.5949566
RCEA-2020-62	VFDs for HVAC Fans	99500	8.45	-1155	1.3324784	1.362945

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Materials Received After Agenda Publication

Energy Efficiency Program Plan

Election of Program Administrator Status

July 25th 2019

2020 Options Compared (February 2019)

Table 1: Programmatic Factors Across CPUC Funding Channels

	PG&E 3rd Party Solicitations	Elect PA Status	Apply for PA Status	R-REN Formation
Ready by January 1st 2020	X/?	?		
Ready by July 1st 2020	**X**	X		?
Ready by January 1st 2021		X	?	?
Exploration	X	X		X
General Programmatic Stability	?	X	X	X
Total Resource Cost Requirements	?	X	X	
Non-Duplicative	X	X		X
Must pass Threshold for Review Tests				X
Contracted Directly with PG&E	X			
PG&E as Fiscal Agent		X	X	
IOU as Fiscal Agent				X

During the April 25 meeting, staff were authorized to prepare an energy efficiency plan for Board approval and take all necessary actions to elect Program Administrator (PA) status.

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Board Action

- Per Public Utilities Code 381.1 (f), approve the enclosed energy efficiency and conservation program plan and

- Authorize the Executive Director to submit the document to the California Public Utilities Commission and

- To make any edits and alterations necessary to address California Energy Efficiency Coordinating Committee (CAEECC) input and varying procedural and regulatory requirements.

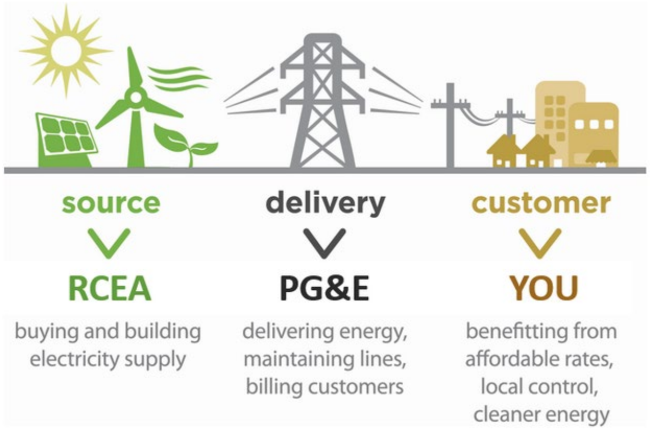
REDWOOD COAST
EnergyAuthority

Public Utilities Code 381.1 (f)

The Community Choice Aggregator shall…submit a plan, approved by its governing board, to the commission for the administration of cost-effective energy efficiency and conservation programs for the aggregator's electric service customers…

That includes:

- The duration of the program
- A program description
- A cost effectiveness analysis



Commencement Date: July 1st 2020

Plan Sunset: June 30th 2023

Non-Residential Program Description

As Isaac Newton wrote in a letter to Robert Hooke in 1676,

“If I have seen further, it is by standing upon the shoulders of giants.”

1. Data driven marketing, outreach and education
2. Prequalification
3. Turn-Key Energy Assessments and Account Services
4. Dynamic Incentives
5. Procurement
6. Installation
7. Project Management Support
8. Reporting

REDWOOD COAST EnergyAuthority

Non-Residential Initial and Expected Products

Initial Products

- LED Interior Lighting
- LED Exterior Lighting
- Refrigeration
- LED Signs
- Occupancy Sensors
- Smart Power Strips
- Programmable Thermostats

Expected Products

- Air Source Heat Pumps (Fuel Substitution)
- Behind the Meter Performance Based Behavior, Retro-commissioning, and Operational services
- Communicating advanced controls and products

Residential Program Description

As Isaac Newton wrote in a letter to Robert Hooke in 1676,

“If I have seen further, it is by standing upon the shoulders of giants.”

1. Data driven marketing, outreach and education
2. Prequalification
3. Turn-Key Energy Assessments and Account Services
4. No-Cost Installations

REpower+ 100% renewable

Non-Residential Initial and Expected Products

Initial Products

- LED Interior Lighting
- LED Exterior Lighting
- Refrigeration
- LED Signs
- Occupancy Sensors
- Smart Power Strips
- Programmable Thermostats

Expected Products

- Air Source Heat Pumps (Fuel Substitution)
- Behind the Meter Performance Based Behavior, Retro-commissioning, and Operational services
- Communicating advanced controls and products

REDWOOD COAST EnergyAuthority

Cost Effectiveness, Total Resource Cost and Program Design

$$\frac{\textit{Benefits}}{\textit{Costs}} \geq 1$$

What counts as a "*Benefit*"?

What counts as a "*Cost*"?

Who is receiving the costs & benefits?

$$\text{TRC} = \frac{\text{(Avoided Cost Benefits) x NTG}}{\text{(NonIncentive Costs) + (Measure Costs) x NTG + (Incentives) x (1-NTG)}} = \frac{\text{TRC Benefits}}{\text{TRC Costs}}$$

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Cost Effectiveness Analysis

1. Expect changes based on final offerings, non-res to res balance and 2020 measure level updates.

2. TRC threshold will not drop below 1.0.

Portfolio Filing Summary

Download This Data

Primary Sector	TRC	PAC	TRC (no admin)	PAC (no admin)	RIM	Budget	Gross kWh	Gross kW	Gross Therm	Net kWh	Net kW	Net Therm
Uncategorized	1.25	1.34	2.75	3.23	0.49	1,081,671	1,708,645	462	60,956	1,380,747	363	51,740
Portfolio (all Sectors)	**1.25**	**1.34**	**2.75**	**3.23**	**0.49**	**1,081,671**	**1,708,645**	**462**	**60,956**	**1,380,747**	**363**	**51,740**

Programs in This CET Run

Download This Data

PrgID	Primary Sector	TRC	PAC	TRC no admin	PAC no admin	RIM	Budget	Gross kWh	Gross kW	Gross Therm	Net kWh	Net kW	Net Therm
RCEA_Non Res	Uncategorized	1.40	1.51	2.79	3.28	0.49	901,827	1,674,463.40	460.55	48,954.11	1,357,919.69	361.14	44,583.63
RCEA_Res	Uncategorized	0.49	0.50	2.35	2.61	0.41	179,844	34,182.00	1.86	12,001.50	22,827.60	1.37	7,156.44

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381.1 (f)(1-6): Commission Certification

The commission shall certify:

(1) Is consistent with the goals of the programs established pursuant to this section and Section 399.4.

(2) Advances the public interest in maximizing cost-effective electricity savings and related benefits.

(3) **Accommodates the need for broader statewide or regional programs.**

(4) Includes audit and reporting requirements consistent with the audit and reporting requirements established by the commission pursuant to this section.

(5) Includes evaluation, measurement, and verification protocols established by the community choice aggregator.

(6) Includes performance metrics regarding the community choice aggregator’s achievement of the objectives listed in paragraphs (1) to (5), inclusive, and in any previous plan.

What is Section 399.4

- **399.4(a)** = Cost effectiveness compliance, TRC
- **399.4(b)(1)** = Title 24 compliance as applicable
- **399.4(c)** = Community focused plan (climate zone, socioeconomic characteristics, opportunity)
- **399.4(d)(2)** = Support the prioritization of market transformation, pay for performance, and behavioral, retro-commission and operational programs.

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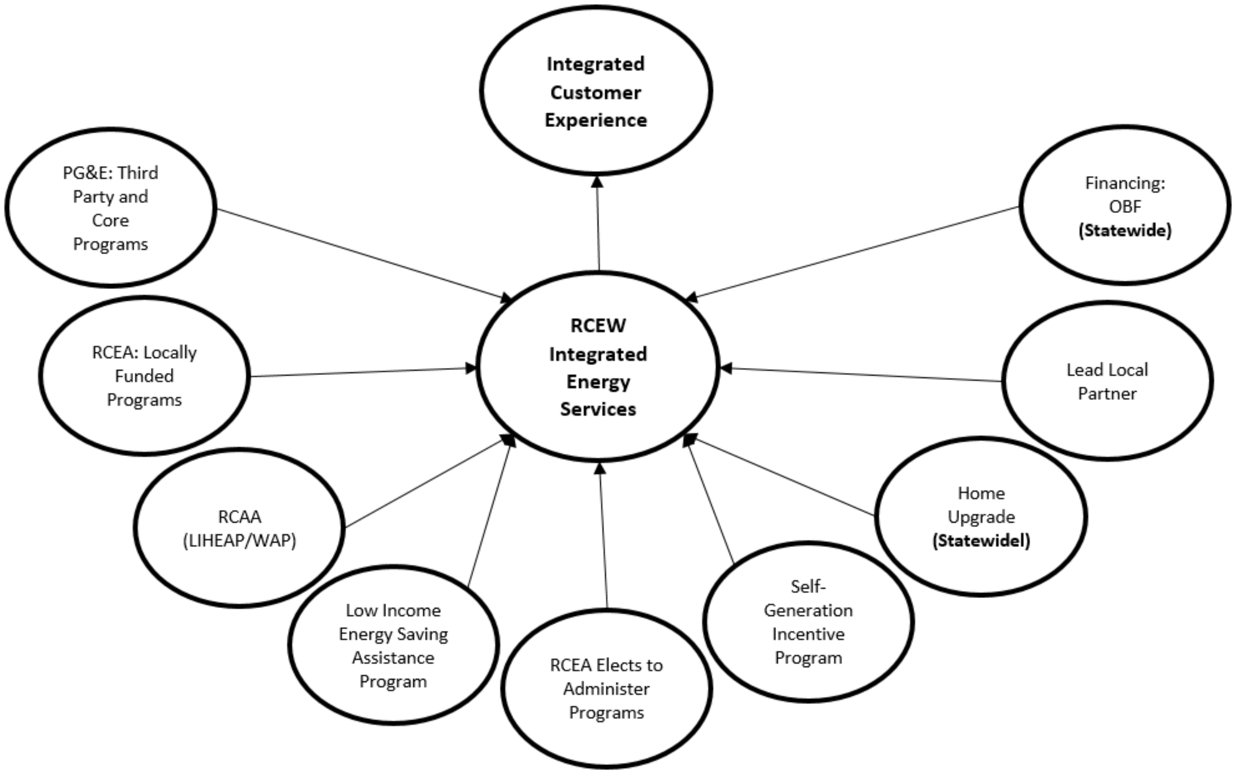
Accommodation of Regional and Statewide Programs

Figure 1: Integrated Energy Services Model



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Performance Metrics

- Progress towards achieving RCEA’s 2025 goal of 100% Clean and Renewable power using the Clean Net Short methodology—energy efficiency is a critical aspect of balancing demand to supply.
- Program energy savings.
- Tracking and serving hard-to-reach customers.
- Cost-effectiveness calculations.
- Percentage of customers audited who install at least one program measure.
- Percentage of recommended measures installed by customers.
- Evaluation, Measurement, and Verification process, tracking, and incorporation into program design.

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Next Steps Over Time

ACTIVITY TIMELINE

	2019									2020						
	August				September				December	January	February	March	April	May	June	July
Activity (week/month)	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**								
Finalize Tier 3 advice letter																
Socialize with IOUs/CAEECC/CPUC Staff																
Update CEDARS CET run and plan based on stakeholder feedback																
Submit plan to CPUC Energy Division Staff																
Provide and support Energy Division Staff with any information needed to resolve advice letter and/or resubmit as required																
Launch new services																X

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EnergyAuthority

Questions?

Lou Jacobson
Director of Demand Side Management | Redwood Coast Energy Authority
(707) 269-1700 x 304 |www.redwoodenergy.org

Board Action

- Per Public Utilities Code 381.1 (f), approve the enclosed energy efficiency and conservation program plan and

- Authorize the Executive Director to submit the document to the California Public Utilities Commission and

- To make any edits and alterations necessary to address California Energy Efficiency Coordinating Committee (CAEECC) input and varying procedural and regulatory requirements.

STAFF REPORT
Agenda Item # 8.2

AGENDA DATE:	July 25, 2019
TO:	Board of Directors
PREPARED BY:	Matthew Marshall, Executive Director Richard Engel, Director of Power Resources
SUBJECT:	Comprehensive Action Plan for Energy Update

SUMMARY

As presented to the Board last month, staff is at work on updating RCEA's guiding strategic document, the Comprehensive Action Plan for Energy (CAPE). Public input and support are essential to the update process. At the RCEA Community Advisory Committee's (CAC) July 9 meeting, staff presented a proposed process and timeline for public engagement to the Committee. CAC members provided useful suggestions that were incorporated into a process and timeline diagram (attached).

In addition, the CAC proposed the following actions be included in the public engagement component of the CAPE update process:

- A written public comment period open through October 26, including adequate time for a phase of public comment on any revised or new quantitative CAPE goals and milestones
- Convening of targeted stakeholder groups to provide input on CAPE
- An education campaign on what RCEA is doing to accomplish CAPE goals.

One significant change has taken place since the overall CAPE update process was presented to the Board last month. Staff had originally intended to align the CAPE update and public engagement process closely with the countywide Climate Action Plan (CAP) process also currently underway. This would have provided an opportunity to maximize public participation in these two interrelated planning processes. However, it now appears the main CAP public meeting will be delayed. In order to keep the CAPE process on track for November adoption by the Board, we propose to hold more stand-alone CAPE meetings, though we still plan to participate in the CAP meeting when it occurs and to also hold a joint CAPE/CAP public workshop on the topic of forest lands and climate change, which will include discussion of the place of biomass power in RCEA's energy portfolio.

FINANCIAL IMPACTS

There will be some nominal costs associated with the CAPE update, including facility rental, hiring a professional event facilitator, event advertising, printing, and staff time. These costs were factored into the annual communications and outreach budget.

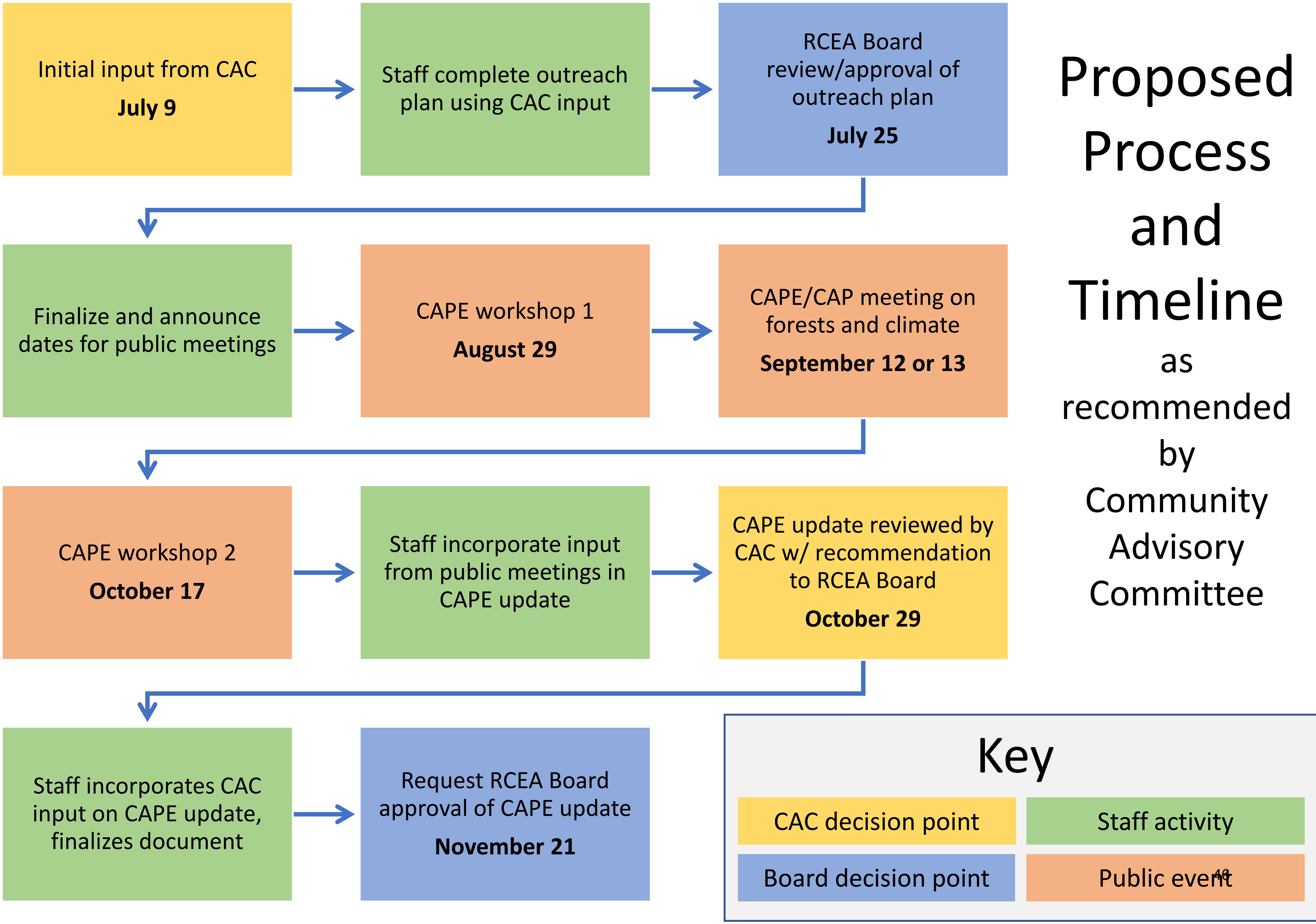
RECOMMENDED ACTIONS

<u>Approve the CAPE public engagement plan and timeline recommended by the Community Advisory Committee.</u>

ATTACHMENT

Public engagement process and timeline diagram

Attachment A - CAPE Community Engagement



REDWOOD COAST EnergyAuthority

STAFF REPORT

Agenda Item # 8.3

AGENDA DATE:	July 25, 2019
TO:	Board of Directors
PREPARED BY:	Richard Engel, Director of Power Resources
SUBJECT:	Power Purchase Agreement with Snow Mountain Hydro, LLC

SUMMARY

In its June 2019 meeting, the RCEA Board directed staff to negotiate power purchase agreements with three companies that responded to RCEA's February 2019 request for proposals (RFP) for long-term renewable energy contracts. Negotiations have been successfully completed with Snow Mountain Hydro, LLC (SMH) for a 15-year contract to purchase the full output from the company's existing 5.5 MW run-of-the-river Cove hydropower plant. The facility is located on Hatchet Creek, a tributary to the Pit River located northeast of Redding in Shasta County. The project lies within the preferred northwest California area identified in RCEA's RFP.

This facility is an eligible producer under California's Renewable Portfolio Standard. Under the proposed power purchase agreement, RCEA is expected to receive approximately 15,000 MWh of renewable electricity in a normal precipitation year. The contract includes provisions to allow for the seasonal and annual variations in production typical of a run-of-the-river hydropower project. This type of hydropower project does not impound the creek and has minimal environmental impact. Energy deliveries are proposed to begin in February 2020.

SMH has applied to the California Independent System Operator (CAISO) to adjust the project's nominal capacity upward from 5.5 MW to 5.6 MW. CAISO's decision on this matter is currently pending. Staff ask the Board to approve the agreement with permission for RCEA's executive director to adjust the Contract Capacity up to 5.6 MW and adjust associated financial terms of the agreement accordingly prior to contract execution, should CAISO approve the capacity adjustment.

FINANCIAL IMPACTS

The proposed agreement would provide a relatively small amount of energy, about 2% of RCEA's overall portfolio in a normal precipitation year. While more expensive than solar energy on a price per MWh basis, the price is competitive with other non-solar offers RCEA received under its RFP. As previously discussed with the Board, procurement of renewable energy from sources such as small hydropower helps RCEA to manage price risk during times of day and times of year when solar energy is not available. In keeping with normal practice of CCAs and municipal utilities participating in competitive power markets, we are not disclosing pricing details for this proposed agreement.

RECOMMENDED ACTIONS

Approve a 15-year power purchase agreement with Snow Mountain Hydro, LLC for the full capacity of its Cove Hydro project up to 5.6 MW, and authorize RCEA's executive director to execute all applicable documents and adjust the contract terms as needed to reflect the nominal capacity, as approved by the California Independent System Operator.

ATTACHMENTS

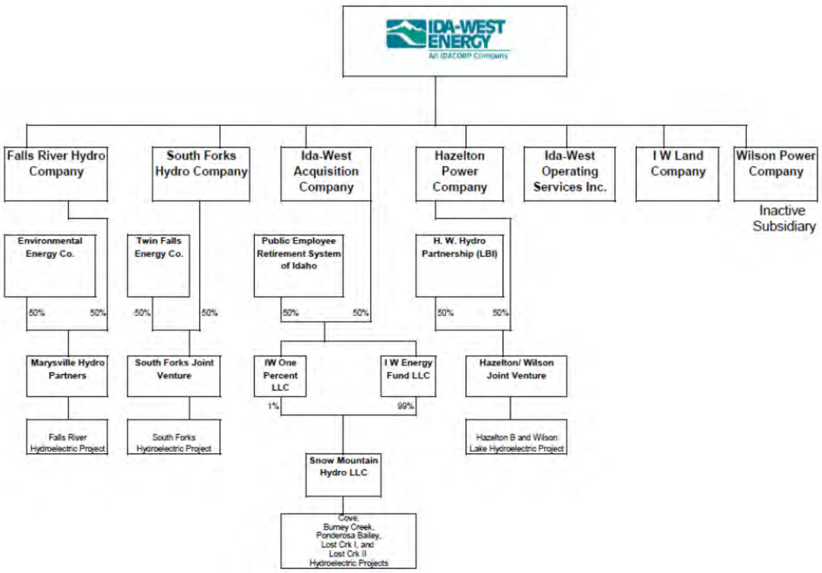
Attachment A: Organization Chart of Ida-West Energy, Including Snow Mountain Hydro, LLC

Attachment B: Location Map of Cove Hydro Project in Shasta County, CA

Attachment C: Project Photos

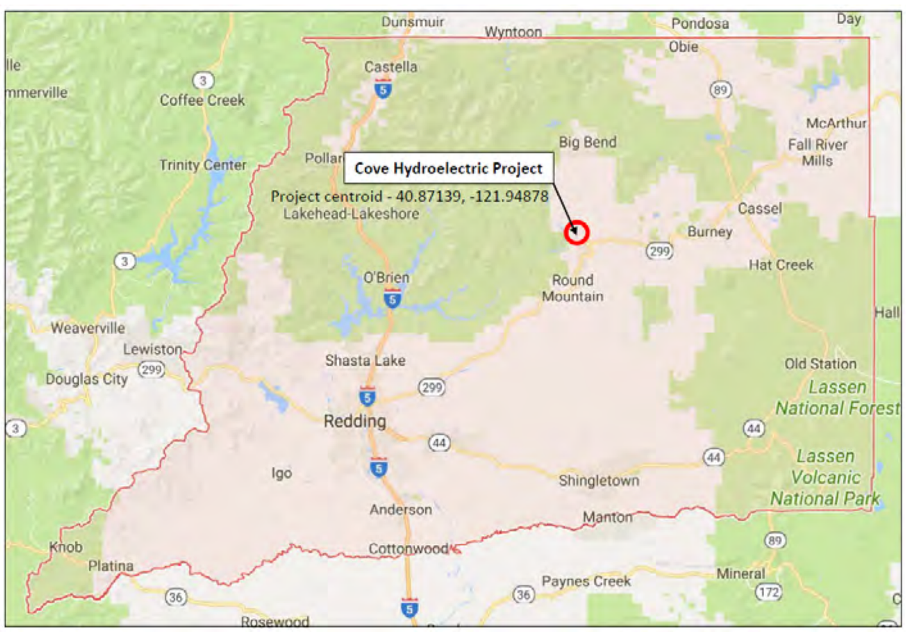
Attachment D: Power Purchase Agreement Between Redwood Coast Energy Authority and Snow Mountain Hydro, LLC (redacted)

Attachment A – Organization Chart of Ida-West Energy, Including Snow Mountain Hydro, LLC



1

Attachment B – Location Map of Cove Hydro Project in Shasta County, CA



2

Attachment C – Project Photos

3

Attachment C – Project Photos (Continued)

Turbine Generator

Runner

4

POWER PURCHASE AGREEMENT

Between

Redwood Coast Energy Authority
(as "Buyer")

and

Snow Mountain Hydro, LLC
(as "Seller")

POWER PURCHASE AGREEMENT

TABLE OF CONTENTS

PREAMBLE

GENERAL TERMS AND CONDITIONS

APPENDICES

The following Appendices constitute a part of this Agreement and are incorporated into this Agreement by reference:

Appendix I	Form of Letter of Credit
Appendix II	Initial Energy Delivery Date Confirmation Letter
Appendix III	Not Used
Appendix IV	Not Used
Appendix V	GEP Damages Calculation
Appendix VI	Notification Requirements for Available Capacity and Project Outages
Appendix VII	Form of Consent to Assignment
Appendix VIII	Seller Documentation Condition Precedent
Appendix IX	Not Used
Appendix X	Telemetry Parameters for Wind or Solar Facility
Appendix XI	Not Used
Appendix XII	Project Specifications and Contract Capacity Calculation
Appendix XIII	Section 3.3(e) Liquidated Damages Calculation

POWER PURCHASE AGREEMENT

COVER SHEET

This Power Purchase Agreement ("Agreement") is entered into between Redwood Coast Energy Authority, a California joint powers authority ("Buyer" or "RCEA"), and __Snow Mountain Hydro LLC__ , an ___Idaho limited liability company___ ("Seller"), as of the Execution Date. The information contained in this Cover Sheet shall be completed by Seller and incorporated into the Agreement.

A. Transaction Type

Seller may not modify the Transaction Type designated in this Part A of the Cover Sheet at any time after the Execution Date.

Product:
- ☒ As-Available
- ☐ Baseload

Portfolio Content Category:

- ☒ Portfolio Content Category 1

Deliverability:

- ☐ Energy Only Status
- ☐ Partial Capacity Deliverability Status ("PCDS")
  - a) If PCDS is selected, provide the Expected PCDS Date, or the date the Project received a PCDS finding if already received: ________________________ (mm/dd/yyyy);
  - b) The Partial Capacity Deliverability Status Amount the Project will obtain is ___________________MW.
- ☒ Full Capacity Deliverability Status ("FCDS")
  - a) If FCDS is selected, provide the Expected FCDS Date, or the date the Project received a unique FCDS finding if already received: ____01/01/2018___ (mm/dd/yyyy).

Seller shall elect one of the following types of transactions pursuant to Section 3.1(b) of the Agreement:

- ☒ Full Buy/Sell
- ☐ Excess Sale

Seller shall elect one of the following Delivery Terms:

- ☐ ten (10) Contract Years
- ☒ fifteen (15) Contract Years

☐ twenty (20) Contract Years

B. Project Description Including Description of Site

Contract Capacity: 5.5 MW

(i) Project Development:

(a) The Project is an:

☒ Existing Project

☐ New Project

(1) If the Project is a New Project:

(A) The date on which the Commercial Operation Date of the Project is expected (must be no later than the Guaranteed Commercial Operation Date):

(B) The Expected Construction Start Date of the Project:

(2) If the Project is an Existing Project:

(A) The Expected Initial Energy Delivery Date (which shall be no later than the Guaranteed Commercial Operation Date) is: 02/20/2020

(b) Project development Milestone schedule:

Identify Milestone	Date for Completion
Secure new QF conversion 3 party GIA	[redacted]
Completion of CAISO New Resource Implementation Process	[redacted]

C. Contract Price

The Contract Price for each MWh of Product as measured by Delivered Energy in the initial Contract Year shall be $[redacted]. In each succeeding Contract Year, the Contract Price shall be adjusted by multiplying the prior year's Contract Price by [redacted].

D. Delivery Term Contract Quantity Schedule

Length of Delivery Term (in Contract Years):

Contract Year	Contract Quantity (MWh)
1	[redacted]
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	n/a
17	n/a
18	n/a
19	n/a
20	n/a

E. Collateral

- Pre-Delivery Term Security (provide dollar amount)

  Dollar Amount: $[redacted]

  - Cash,
  - Letter of Credit, or
  - Guaranty

- Delivery Term Security (provide dollar amount)

  Dollar Amount: $ [redacted]

  - Cash,
  - Letter of Credit, or
  - Guaranty

F. Buyer Bid Curtailment and Buyer Curtailment Orders.

Operational characteristics of the Project for Buyer Bid Curtailment and Buyer Curtailment Orders are listed below. Buyer, as the Scheduling Coordinator, may request that CAISO modify the Master File for the Project to reflect the findings of a CAISO audit of the Project. In addition, Seller agrees to coordinate with Buyer or Third-Party SC, as applicable, to ensure all information provided to the CAISO regarding the operational and technical constraints in the Master File for the Project are accurate and are based on the true physical characteristics of the resource.

- PMax of the Project: _5.5_ MW
- Minimum operating capacity: _0.3_ MW
- Ramp Rate: _0.5_ MW/Minute
- Advance notification required for Buyer Bid Curtailment and Buyer Curtailment Order: Not greater than the shortest Dispatch Interval in the Real-Time Market (as defined in the CAISO Tariff).
- Maximum number of Start-ups per calendar day (if any such operational limitations exist): ___5____

Other Requirements:

- Maximum number of hours annually for Buyer Curtailment Periods: unlimited hours
- The Project will be capable of receiving and responding to all Dispatch Instruction in accordance with Section 3.1(q).
- Start-Up Time (if applicable): __10__ Minutes
- Minimum Run Time after Start-Up (if applicable): __n/a__ Minutes
- Minimum Down Time after Shut-Down (if applicable):__n/a__ Minutes

Note: Sellers should enter the maximum flexibility the Project can offer given the operational constraints of the technology.

G. Damage Payment (as described under Damage Payment definition in Section 1.53)

☐ Ten (10) year Delivery Term. Dollar amount: $__________

☒ Fifteen (15) year Delivery Term. Dollar amount: $__[redacted]_

☐ Twenty (20) year Delivery Term. Dollar amount: $__________

H. Notices List

Name: Snow Mountain Hydro, an Idaho limited liability company ("Seller") All Notices:	Name: Redwood Coast Energy Authority, ("Buyer" or "RCEA") All Notices:
Delivery Address: PO Box 7867, Boise, ID 83707	Delivery Address:
Street: 205 N. 10th Str, STE 510 Boise, ID 83702	633 3rd St, Eureka, CA 95501
Mail Address: (if different from above)	Mail Address:
Attn: [redacted]	Attn: [redacted]
Phone: [redacted]	Phone: [redacted]

Email: [redacted]

DUNS: [redacted]
Federal Tax ID Number: [redacted]

Invoices:
Attn: [redacted]
Phone: [redacted]
Facsimile: [redacted]
Email: [redacted]

Scheduling:
Attn: [redacted]
Phone: [redacted]
Facsimile: [redacted]
Email: [redacted]

Payments:
Attn: [redacted]

Phone: [redacted]
Facsimile: [redacted]
Email: [redacted]

Wire Transfer:
BNK: [redacted]
ABA: [redacted]
ACCT: [redacted]

Credit and Collections:
Attn: [redacted]

Phone: [redacted]
Email: [redacted]

Notices of an Event of Default to :

Attn: [redacted]

Phone: [redacted]
Facsimile: [redacted]
Email:

With additional Notices of an Event of Default to:

Ida-West Energy Co General Counsel
[redacted]

Email: [redacted]

DUNS: [redacted]
Federal Tax ID Number: [redacted]

Invoices:
Attn: [redacted]
Phone: [redacted]
Facsimile: [redacted]
Email: [redacted]

Scheduling:
Attn: [redacted]
Real Time Desk Phone: [redacted]
Facsimile: [redacted]

Payments:
Attn: [redacted]

Phone: [redacted]
Facsimile: [redacted]
Email: [redacted]

Wire Transfer:
BNK: [redacted]
ABA: [redacted]
ACCT: [redacted]

Credit and Collections:
Attn: [redacted]

Phone: [redacted]
Email [redacted]

Attn: [redacted]

Phone: [redacted]
Facsimile: [redacted]
Email [redacted]

RCEA General Counsel
[redacted]

PREAMBLE

This Power Purchase Agreement, together with the Cover Sheet, appendices and any other attachments referenced herein, is made and entered into between RCEA and Seller, as of the Execution Date set forth in the Cover Sheet. Buyer and Seller hereby agree to the following:

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 Omitted.

1.2 "Additional Extension" has the meaning set forth in Section 3.1(c)(ii).

1.3 "Affiliate" means, with respect to any person or entity, any other person or entity (other than an individual) that (a) directly or indirectly, through one or more intermediaries, controls, or is controlled by such person or entity or (b) is under common control with such person or entity. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

1.4 "Agreement" means this Power Purchase Agreement between Buyer and Seller, which is comprised of the Cover Sheet, Preamble, these General Terms and Conditions, and all appendices, schedules and any written supplements attached hereto and incorporated herein by references, as well as all written and signed amendments and modifications thereto. For purposes of Section 10.10, the word "agreement" shall have the meaning set forth in this definition. For purposes of Section 3.1(k)(viii), the word "contract" shall have the meaning set forth in this definition.

1.5 "Ancillary Services" has the meaning set forth in the CAISO Tariff.

1.6 "As-Available Product" means an Energy Product with a Capacity Factor of eighty percent (80%) or less.

1.7 "Availability Workbook" has the meaning set forth in Appendix IX.

1.8 "Available Capacity" means the capacity from the Project, expressed in whole megawatts, that is available to generate Product.

1.9 "Balancing Authority" has the meaning set forth in the CAISO Tariff.

1.10 "Bankrupt" means with respect to any entity, such entity that (a) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar Law, or has any such petition filed or commenced against it and such case filed against it is not dismissed in ninety (90) days, (b) makes an assignment or any general arrangement for the benefit of creditors, (c) otherwise becomes bankrupt or insolvent (however evidenced), (d) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (e) is generally unable to pay its debts as they fall due.

1.11 "Baseload" means an Energy Product with a Capacity Factor greater than or equal to eighty percent (80%).

1.12 "Bid" has the meaning set forth in the CAISO Tariff.

1.13 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday and shall be between the hours of 8:00 a.m. and 5:00 p.m. local time for the relevant Party's principal place of business where the relevant Party, in each instance unless otherwise specified, shall be the Party from whom the Notice, payment or delivery is being sent and by whom the Notice or payment or delivery is to be received.

1.14 "Buyer" has the meaning set forth in the Cover Sheet.

1.15 "Buyer Bid Curtailment" means Buyer as SC or through its Third-Party SC communicates a curtailment instruction to the Seller, requiring Seller to produce less Energy from the Project than the CAISO final market forecast amount to be produced from the Project for a period of time, and Buyer as the SC or through its Third-Party SC either (a) submitted a CAISO final market Energy Supply Bid and such curtailment is solely a result of the CAISO implementing the Energy Supply Bid; or (b) submitted a CAISO final market Self-Schedule for less than the amount of the final-market Energy forecasted to be produced from the Project. However, if the Project is subject to a Planned Outage, Forced Outage, Force Majeure and/or a Curtailment Period during the same period of time, then Buyer Bid Curtailment shall not include any Energy that is subject to such Planned Outage, Forced Outage, Force Majeure or Curtailment Period.

1.16 "Buyer Curtailment Order" means the instruction from Buyer or through its Third-Party SC to Seller to reduce generation from the Project by the amount, and for the period of time set forth in such order, for reasons unrelated to a Planned Outage, Forced Outage, Force Majeure and/or Curtailment Order.

1.17 "Buyer Curtailment Period" means the period of time, as measured using current Settlement Intervals, during which Seller reduces generation from the Project pursuant to (a) Buyer Bid Curtailment or (b) a Buyer Curtailment Order. The Buyer Curtailment Period shall be inclusive of the time required for the Project to ramp down and ramp up; provided that such time periods to ramp down and ramp up shall be consistent with the Ramp Rate designated in the Cover Sheet.

1.18 "Buyer's Notice of First Offer Acceptance" has the meaning set forth Section 11.1(b)(ii), as applicable.

1.19 "Buyer's WREGIS Account" has the meaning set forth in Section 3.1(k)(i).

1.20 "CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

1.21 "CAISO Global Resource ID" means the number or name assigned by the CAISO to the Project.

1.22 "CAISO Grid" has the same meaning as "CAISO Controlled Grid" as defined in the CAISO Tariff.

1.23 "CAISO Penalties" means any fees, liabilities, assessments, or similar charges assessed by the CAISO for (a) violation of the CAISO Tariff and all applicable protocols, WECC rules or CAISO operating instructions or orders or (b) as a result of a Party's failure to follow Good Utility Practices. In either case, "CAISO Penalties" do not include the costs and charges related to scheduling and Imbalance Energy as addressed in Section 4.6(b) of this Agreement.

1.24 “CAISO Tariff” means the California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff), as it may be amended, supplemented or replaced (in whole or in part) from time to time.

1.25 “California Renewables Portfolio Standard” or “RPS” means the renewable energy program and policies established by the California Legislature and codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

1.26 “Capacity Attributes” means any current or future defined characteristic (including the ability to generate at a given capacity level, provide Ancillary Services, and ramp up or ramp down at a given rate), certificate, tag, credit, flexibility, or dispatchability attribute, whether general in nature or specific as to the location or any other attribute of the Project, intended to value any aspect of the capacity of the Project to produce any and all Product, including any accounting construct so that the maximum amount of Contract Capacity of the Project may be counted toward a Resource Adequacy Requirement or any other measure by the CPUC, the CAISO, the FERC, or any other entity invested with the authority under federal or state Law, to require Buyer to procure, or to procure at Buyer’s expense, Resource Adequacy or other such products.

1.27 “Capacity Factor” has the meaning set forth in Section 4.3.

1.28 Omitted.

1.29 “CEC” means the California Energy Commission or its successor agency.

1.30 “CEC Certification and Verification” means that the CEC has certified (or, with respect to periods before the Project has commenced commercial operation (as such term is defined by and according to the CEC), that the CEC has pre-certified) that the Project is an ERR for purposes of the California Renewables Portfolio Standard and that all Energy produced by the Project qualifies as generation from an ERR for purposes of the Project.

1.31 “Claims” means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys’ fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination or expiration of this Agreement.

1.32 “Commercial Operation” means the Project is operating and able to produce and deliver the Product to Buyer pursuant to the terms of this Agreement.

1.33 Omitted.

1.34 “Compliance Costs” means all reasonable out-of-pocket costs and expenses incurred by Seller and paid directly to third parties in connection with any of the obligations under Sections 3.1(j) (Greenhouse Gas Emissions Reporting), 3.1(k) (WREGIS), 3.1(n) (Obtaining and Maintaining CEC Certification and Verification), 3.3 (Resource Adequacy), and 10.1(b) (ERR), including registration fees, volumetric fees, license renewal fees, external consultant fees and capital costs necessary for compliance, but excluding Seller's internal administrative and staffing costs, due to a change, amendment, enactment or repeal of Law after the Execution Date which requires Seller to incur additional costs and expenses in connection with any of such obligations, in excess of the costs and expenses incurred for such obligations under the Law in effect as of the Execution Date. Compliance Costs do not include any amounts designated in the Project's full capacity deliverability study to obtain FCDS nor any costs and expenses incurred by Seller for FCDS studies.

1.35 "Condition Precedent" means each of, or one of, the conditions set forth in Section 2.4(a)(i) through (ii) and "Conditions Precedent" shall refer to all of the conditions set forth in Section 2.4(a)(i) through (ii).

1.36 "Confidential Information" has the meaning set forth in Section 10.6(a)

1.37 "Construction Start Date" means the later to occur of the date on which Seller delivers to Buyer (a) a copy of the Notice to Proceed that Seller has delivered to the EPC Contractor for the Project, and (b) a written Certification substantially in the form attached hereto as Appendix IV-1.

1.38 "Contract Capacity" has the meaning set forth in Section 3.1(f).

1.39 "Contract Capacity Commitment" means the amount of the Contract Capacity that may be constructed pursuant to the Governmental Approvals received or obtained by Seller as of the Expected Initial Energy Delivery Date specified on the Cover Sheet.

1.40 "Contract Price" means the price in United States dollars ($U.S.) (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Cover Sheet.

1.41 "Contract Quantity" means the quantity of Delivered Energy expected to be delivered by Seller during each Contract Year as set forth in Section 3.1(e) and Cover Sheet Section D.

1.42 "Contract Year" means a period of twelve (12) consecutive months. The first Contract Year shall commence on the Initial Energy Delivery Date and each subsequent Contract Year shall commence on the anniversary of the Initial Energy Delivery Date.

1.43 "Cost Responsibility Surcharge" means the charges identified in PG&E Electric Rate Schedule CCA-CRS, and further set forth in each PG&E rate schedule, as may be amended, supplemented, or replaced (in whole or in part) from time to time.

1.44 "Costs" means, with respect to the Non-Defaulting Party, (a) brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or in entering into new arrangements which replace the Terminated Transaction; and (b) all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of the Transaction.

1.45 "Cover Sheet" means the cover sheet to this Agreement, completed by Seller and incorporated into the Agreement.

1.46 "CPUC" or "Commission" means the California Public Utilities Commission, or successor entity.

1.47 "Credit Rating" means, with respect to any entity, (a) the rating then assigned to such entity's unsecured senior long-term debt obligations (not supported by third party credit enhancements) or (b) if such entity does not have a rating for its unsecured senior long-term debt obligations, then the rating assigned to such entity as an issuer rating by S&P and/or Moody's. If the entity is rated by both S&P and Moody's and such ratings are not equivalent, the lower of the two ratings shall determine the Credit

Rating. If the entity is rated by either S&P or Moody's, but not both, then the available rating shall determine the Credit Rating.

1.48 "Cure" has the meaning set forth in Section 8.5(b).

1.49 "Cured Performance Measurement Period" has the meaning set forth in Section 3.1(e)(ii)(C).

1.50 "Cure Payment Period" has the meaning set forth in Section 3.1(e)(ii)(C)(III).

1.51 "Curtailment Order" means any of the following:

(a) the CAISO, Reliability Coordinator, Balancing Authority or any other entity having similar authority or performing similar functions during the Delivery Term, orders, directs, alerts, or communicates via any means, to a Party to curtail Energy deliveries, which may come in the form of a request to return to Schedule consistent with the CAISO Tariff, for reasons including, (i) any System Emergency, (ii) any warning of an anticipated System Emergency, or warning of an imminent condition or situation, which jeopardizes the CAISO's electric system integrity or the integrity of other systems to which the CAISO is connected, or (iii) any warning, forecast, or anticipated over-generation conditions, including a request from CAISO to manage over-generation conditions, provided that this subsection (a)(iii) shall not include Buyer Bid Curtailment;

(b) a curtailment ordered by the Participating Transmission Owner, distribution operator (if interconnected to distribution or sub-transmission system), or any other entity having similar authority or performing similar functions during the Delivery Term, for reasons including (i) any situation that affects normal function of the electric system including any abnormal condition that requires action to prevent circumstances such as equipment damage, loss of load, or abnormal voltage conditions, or (ii) any warning, forecast or anticipation of conditions or situations that jeopardize the Participating Transmission Owner's electric system integrity or the integrity of other systems to which the Participating Transmission Owner is connected;

(c) scheduled or unscheduled maintenance or construction on the Participating Transmission Owner's or distribution operator's transmission or distribution facilities that prevents (i) Buyer from receiving or (ii) Seller from delivering Delivered Energy at the Delivery Point; or

(d) a curtailment in accordance with Seller's obligations under its Generator Interconnection Agreement with the Participating Transmission Owner or distribution operator.

For the avoidance of doubt, if Buyer or Third-Party SC submitted a Self-Schedule and/or an Energy Supply Bid that clears, in full, the applicable CAISO market for the full amount of Energy forecasted to be produced from the Project for any time period, any notice from the CAISO having the effect of requiring a reduction during the same time period is a Curtailment Order, not a Buyer Bid Curtailment.

1.52 "Curtailment Period" means the period of time during which Seller reduces generation from the Project, pursuant to a Curtailment Order. The Curtailment Period shall be inclusive of the time required for the Project to ramp down and ramp up; provided that such time periods to ramp down and ramp up shall be consistent with the Ramp Rate designated in the Cover Sheet.

1.53 "Damage Payment" means for a fifteen year Delivery Term the dollar amount that equals [redacted]% of the minimum expected annual revenue of the Project based on the Contract Quantity, as set forth in Section 3.1(e) and Cover Sheet Section D, and the estimated average TOD-adjusted Contract Price, which will be calculated prior to the Execution Date.

1.54 "DA Price" means the resource specific locational marginal price ("LMP") applied to the PNode applicable to the Project in the CAISO Day-Ahead Market.

1.55 "DA Scheduled Energy" means the Day-Ahead Scheduled Energy as defined in the CAISO Tariff.

1.56 "Day-Ahead Availability Notice" has the meaning set forth in Section 3.4(b)(iii)(C).

1.57 "Day-Ahead Market" has the meaning set forth in the CAISO Tariff.

1.58 "Deemed Delivered Energy" means the amount of Energy, expressed in MWh, that the Project would have produced and delivered to the Delivery Point, but that is not produced by the Project and delivered to the Delivery Point during a Buyer Curtailment Period, which amount shall be equal to (a) the seller curtailed production calculation ("Seller Curtailed Production Calculation"), expressed in MWh, applicable to the Buyer Curtailment Period, less (b) the amount of Delivered Energy delivered to the Delivery Point during the Buyer Curtailment Period. Seller Curtailed Production Calculation and procedures are described in Section 4.5. If the applicable Deemed Delivered Energy calculated is negative, the Deemed Delivered Energy shall be zero (0).

1.59 "Defaulting Party" means the Party that is subject to an Event of Default.

1.60 "Deficient Month" has the meaning set forth in Section 3.1(k)(v).

1.61 "Deliverability Assessment" has the meaning set forth in the CAISO Tariff.

1.62 "Deliverability Finding Deadline" shall be two (2) calendar years after the RA Start Date. The Deliverability Finding Deadline shall be no later than December 31, 2027.

1.63 "Delivered Energy" means the lesser of either (i) the Contract Capacity, expressed in MW, multiplied by the duration of the Settlement Interval, expressed in hours, or (ii) the Energy produced from the Project during the Settlement Interval as measured in MWh at the CAISO revenue meter of the Project and in accordance with the CAISO Tariff, which shall include any applicable adjustments for power factor and Electrical Losses.

1.64 "Delivery Month" means a period of one month

1.65 "Delivery Network Upgrade" has the meaning set forth in the CAISO Tariff.

1.66 "Delivery Point" means the point at which Buyer receives Seller's Product, as identified in Section 3.1(d).

1.67 "Delivery Term" has the meaning set forth in Section 3.1(c)(i) and shall be of the length specified in the Cover Sheet.

1.68 "Delivery Term Security" means the Performance Assurance that Seller is required to maintain, as specified in Article Eight, to secure performance of its obligations during the Delivery Term.

1.69 "Dispatch Instruction" has the meaning set forth in the CAISO Tariff.

1.70 “Dispatch Interval” has the meaning set forth in the CAISO Tariff.

1.71 “Distribution Loss Factor” is a multiplier factor that reduces the amount of Delivered Energy produced by a Project connecting to a distribution system to account for the electrical distribution losses, including those related to distribution and transformation, occurring between the point of interconnection, where the Participating Transmission Owner’s meter is physically located, and the first Point of Interconnection, as defined in the CAISO Tariff, with the CAISO Grid.

1.72 “Distribution Upgrades” has the meaning set forth in the CAISO Tariff.

1.73 “DUNS” means the Data Universal Numbering System, which is a unique nine character identification number provided by Dun & Bradstreet, Inc.

1.74 “Early Termination Date” has the meaning set forth in Section 5.2.

1.75 “Effective Date” means the date on which all of the Conditions Precedent set forth in Section 2.4(a) have been satisfied or waived in writing by both Parties.

1.76 “Effective FCDS Date” means the date on which Seller provides Buyer Notice and documentation from CAISO that the Project has attained Full Capacity Deliverability Status, which Buyer subsequently finds, in its reasonable discretion, to be adequate evidence that the Project has attained Full Capacity Deliverability Status.

1.77 “Effective PCDS Date” means the date on which Seller provides Buyer Notice and documentation from CAISO that the Project has attained Partial Capacity Deliverability Status, which Buyer subsequently finds, in its reasonable discretion, to be adequate evidence that the Project has attained Partial Capacity Deliverability Status.

1.78 “EIRP Forecast” means the final forecast of the Energy to be produced by EIRP eligible projects prepared by the CAISO in accordance with the Eligible Intermittent Resources Protocol and communicated to buyers or Third-Party SCs for use in submitting schedules for the output of projects in the Real-Time Market.

1.79 “Electrical Losses” means all applicable losses, including the following: (a) any transmission or transformation losses between the CAISO revenue meter(s) and the Delivery Point; and (b) the Distribution Loss Factor, if applicable.

1.80 “Electric System Upgrades” means any Network Upgrades, Distribution Upgrades, or Interconnection Facilities that are determined to be necessary by the CAISO or Participating Transmission Owner, as applicable, to physically and electrically interconnect the Project to the Participating Transmission Owner’s electric system for receipt of Energy at the Point of Interconnection (as defined in the CAISO Tariff) if connecting to the CAISO Grid, or the Interconnection Point, if connecting to a part of the Participating TO’s electric system that is not part of the CAISO Grid.

1.81 “Electrician” means any person responsible for placing, installing, erecting, or connecting any electrical wires, fixtures, appliances, apparatus, raceways, conduits, solar photovoltaic cells or any part thereof, which generate, transmit, transform or utilize energy in any form or for any purpose.

1.82 “Eligible Intermittent Resources Protocol” or “EIRP” means the Eligible Intermittent Resource Protocol, as may be amended from time to time, as set forth in the CAISO Tariff.

1.83 "Eligible LC Bank" means either a U.S. commercial bank, or a foreign bank issuing a Letter of Credit through its U.S. branch; and in each case the issuing U.S. commercial bank or foreign bank must be acceptable to Buyer in its sole discretion and such bank must have a Credit Rating of at least: (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the Letter of Credit but ceases to be rated by either, but not both of those ratings agencies.

1.84 "Eligible Renewable Energy Resource" or "ERR" has the meaning set forth in California Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision is amended or supplemented from time to time.

1.85 "Energy" means three-phase, 60-cycle alternating current electric energy measured in MWh and net of auxiliary loads and station electrical uses (unless otherwise specified).

1.86 "Energy Deviation(s)" means the absolute value of the difference, in MWh, in any Settlement Interval between (a) the final accepted Bid submitted for the Project; and (b) Delivered Energy.

1.87 "Energy Only Status Seller" or "EOS Seller" means a Seller that has selected Energy Only Status in the Cover Sheet. For avoidance of doubt, an EOS Seller does not have an obligation to have or obtain a Full Capacity Deliverability Status Finding.

1.88 "Energy Supply Bid" has the meaning set forth in the CAISO Tariff.

1.89 "EPC Contract" means the Seller's engineering, procurement and construction contract with the EPC Contractor.

1.90 "EPC Contractor" means an engineering, procurement, and construction contractor, or if not utilizing an engineering, procurement and construction contractor, the entity having lead responsibility for the management of overall construction activities, selected by Seller, with substantial experience in the engineering, procurement, and construction of power plants of the same type of facility as the Seller's; provided, however, that the Seller or the Seller's Affiliate(s) may serve as the EPC Contractor.

1.91 "Equitable Defenses" means any bankruptcy, insolvency, reorganization or other Laws affecting creditors' rights generally and, with regard to equitable remedies, the discretion of the court before which proceedings may be pending to obtain same.

1.92 "Event of Default" has the meaning set forth in Section 5.1.

1.93 "Excess Deemed Delivered Energy" has the meaning set forth in Section 4.4(a)(i).

1.94 "Excess Deemed Delivered Energy Price" has the meaning set forth in Section 4.3(a)(ii)(B).

1.95 "Excess Delivered Energy" has the meaning set forth in Section 4.4(a)(i).

1.96 "Excess Delivered Energy Price" has the meaning set forth in Section 4.4(a)(ii)(A).

1.97 "Excess Energy" has the meaning set forth in Section 4.4(a)(i).

1.98 "Excess Sale" means the type of transaction described in Section 3.1(b)(ii).

1.99 "Exclusivity Period" has the meaning set forth in Section 11.1(b)(i), as applicable.

1.100 "Execution Date" means the latest signature date found on the signature page of this Agreement.

1.101 "Exempt Wholesale Generator" has the meaning provided in 18 C.F.R. Section 366.1.

1.102 "Existing Project" is a Project that has achieved Commercial Operation on or prior to the Execution Date.

1.103 "Expected FCDS Date" means the date set forth in Section A of the Cover Sheet which is the date the Project is expected to achieve Full Capacity Deliverability Status or began receiving a unique Net Qualifying Capacity value reflecting the Project's Full Capacity Deliverability Status.

1.104 "Expected PCDS Date" means the date set forth in Section A of the Cover Sheet which is the date the Project is expected to achieve Partial Capacity Deliverability Status.

1.105 "Expected Initial Energy Delivery Date" is the date specified on the Cover Sheet for an Existing Project.

1.106 "Expected Net Qualifying Capacity" means an estimate of the amount of Net Qualifying Capacity the Project would have received had it obtained deliverability according to the deliverability type selected in Section A of the Cover Sheet, as determined in accordance with Appendix VIII.

1.107 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

1.108 "Final True-Up" means the final payment made pursuant to this Agreement settling all invoices by the Party with an outstanding net amount due to the other Party for Product delivered prior to the end of the Delivery Term or other amounts due pursuant to this Agreement incurred prior to the end of the Delivery Term.

1.109 "First Offer" has the meaning set forth in Section 11.1(b)(i).

1.110 "Force Majeure" means any event or circumstance which wholly or partly prevents or delays the performance of any material obligation arising under this Agreement, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party seeking to have its performance obligation(s) excused thereby, (ii) the Party seeking to have its performance obligation(s) excused thereby has taken all reasonable precautions and measures in order to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations under this Agreement and which by the exercise of due diligence such Party could not reasonably have been expected to avoid and which by the exercise of due diligence it has been unable to overcome, and (iii) such event is not the direct or indirect result of the negligence or the failure of, or caused by, the Party seeking to have its performance obligations excused thereby.

(a) Subject to the foregoing, events that could qualify as Force Majeure include the following:

(i) flooding, lightning, landslide, earthquake, fire, drought, explosion, epidemic, quarantine, storm, hurricane, tornado, volcanic eruption, other natural disaster or unusual or extreme adverse weather-related events;

(ii) war (declared or undeclared), riot or similar civil disturbance, acts of the public enemy (including acts of terrorism), sabotage, blockade, insurrection, revolution, expropriation or confiscation;

(iii) except as set forth in subsection (b)(viii) below, strikes, work stoppage or other labor disputes (in which case the affected Party shall have no obligation to settle the strike or labor dispute on terms it deems unreasonable); or

(iv) emergencies declared by the Transmission Provider or any other authorized successor or regional transmission organization or any state or federal regulator or legislature requiring a forced curtailment of the Project or making it impossible for the Transmission Provider to transmit Energy, including Energy to be delivered pursuant to this Agreement; provided that, if a curtailment of the Project pursuant to this subsection (a)(iv) would also meet the definition of a Curtailment Period, then it shall be treated as a Curtailment Period for purposes of Section 3.1(p).

(b) Force Majeure shall not be based on:

(i) Buyer's inability economically to use or resell the Product purchased hereunder;

(ii) Seller's ability to sell the Product at a price greater than the price set forth in this Agreement;

(iii) Seller's inability to obtain permits or approvals of any type for the construction, operation, or maintenance of the Project, including a delay that could constitute a Permitting Delay unless caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(v) Seller's inability to obtain sufficient fuel, power or materials to operate the Project, except if Seller's inability to obtain sufficient fuel, power or materials is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(vi) Seller's failure to obtain additional funds, including funds authorized by a state or the federal government or agencies thereof, to supplement the payments made by Buyer pursuant to this Agreement;

(vii) a Forced Outage except where such Forced Outage is caused by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above;

(viii) a strike, work stoppage or labor dispute limited only to any one or more of Seller, Seller's Affiliates, the EPC Contractor or subcontractors thereof or any other third party employed by Seller to work on the Project;

(ix) any equipment failure except if such equipment failure is caused solely by an event of Force Majeure of the specific type described in any of subsections (a)(i) through (a)(iv) above; or

(x) a Party's inability to pay amounts due to the other Party under this Agreement, except if such inability is caused solely by a Force Majeure event that disables physical or electronic facilities necessary to transfer funds to the payee Party.

1.111 "Force Majeure Failure" has the meaning set forth in Section 11.1(a).

1.112 "Forced Outage" means any unplanned reduction or suspension of the electrical output from the Project or unavailability of the Product in whole or in part from a Unit in response to any control system trip or operator-initiated trip in response to an alarm or equipment malfunction; or any other unavailability of the Project or a Unit for operation, in whole or in part, for maintenance or repair that is not a Planned Outage and not the result of Force Majeure.

1.113 "Forecasting Penalty" has the meaning set forth in Section 4.4(c)(iii), and "Forecasting Penalties" means more than one Forecasting Penalty.

1.114 "Full Buy/Sell" is the type of transaction described in Section 3.1(b)(i).

1.115 "Full Capacity Deliverability Status" or "FCDS" has the meaning set forth in the CAISO Tariff except that it applies to any Generating Facility (as defined in the CAISO Tariff).

1.116 "Full Capacity Deliverability Status Finding" or "FCDS Finding" means a written confirmation from the CAISO that the Project is eligible for FCDS.

1.117 "Full Capacity Deliverability Status Seller" or "FCDS Seller" means a Seller that selected Full Capacity Deliverability Status in the Cover Sheet and either has previously obtained, or is obligated to obtain per the terms of the Agreement, a Full Capacity Deliverability Status Finding.

1.118 "Future Environmental Attributes" shall mean any and all generation attributes (other than Green Attributes or Renewable Energy Incentives) under the RPS regulations and/or under any and all other international, federal, regional, state or other law, rule, regulation, bylaw, treaty or other intergovernmental compact, decision, administrative decision, program (including any voluntary compliance or membership program), competitive market or business method (including all credits, certificates, benefits, and emission measurements, reductions, offsets and allowances related thereto) that are attributable, now, or in the future, to the generation of electrical energy by the Facility.

1.119 "Gains" means with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of the Transaction, determined in a commercially reasonable manner, subject to Section 5.3 hereof. Factors used in determining economic benefit may include reference to information either available to it internally or supplied by one or more third parties, including quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets, market price referent, market prices for a comparable transaction, forward price curves based on economic analysis of the relevant markets, settlement prices for a comparable transaction at liquid trading platforms (e.g., NYMEX), all of which should be calculated for the remaining Delivery Term to determine the value of the Product.

1.120 "Generally Accepted Accounting Principles" means the standards for accounting and preparation of financial statements established by the Federal Accounting Standards Advisory Board (or its successor agency) or any successor standards adopted pursuant to relevant SEC rule.

1.121 "Generator Interconnection Agreement" or "GIA" means, for Projects interconnecting at the transmission level, the agreement and associated documents (or any successor agreement and associated documentation approved by FERC) by and among Seller, the Participating Transmission Owner, and the CAISO governing the terms and conditions of Seller's interconnection with the CAISO Grid, including any description of the plan for interconnecting to the CAISO Grid. For Projects interconnecting at the distribution level, it means the agreement and associated documents (or any successor agreement and associated documentation) by and between Seller and the Participating Transmission Owner governing the terms and conditions of Seller's interconnection with the Participating TO's distribution system, including any description of the plan for interconnecting to Participating TO's distribution system.

1.122 "Generator Interconnection Process" or "GIP" means the Generator Interconnection Procedures set forth in the CAISO Tariff or Participating TO's tariff, as applicable, and associated documents; provided that if the GIP is replaced by such other successor procedures governing interconnection (a) to the CAISO Grid or Participating TO's distribution system, as applicable, or (b) of generating facilities with an expected net capacity equal to or greater than the Project's Contract Capacity, the term "GIP" shall then apply to such successor procedure.

1.123 "GEP Cure" has the meaning set forth in Section 3.1(e)(ii)(C).

1.124 "GEP Damages" has the meaning set forth in Appendix V.

1.125 "GEP Failure" means Seller's failure to produce Delivered Energy plus Deemed Delivered Energy in an amount equal to or greater than the Guaranteed Energy Production amount for the applicable Performance Measurement Period.

1.126 "GEP Shortfall" means the amount in MWh by which Seller failed to achieve the Guaranteed Energy Production in the applicable Performance Measurement Period.

1.127 "Good Utility Practice" has the meaning provided in the CAISO Tariff.

1.128 "Governmental Approval" means all authorizations, consents, approvals, waivers, exceptions, variances, filings, permits, orders, licenses, exemptions and declarations of or with any governmental entity and shall include those siting and operating permits and licenses, and any of the foregoing under any applicable environmental Law, that are required for the construction, use and operation of the Project.

1.129 "Governmental Authority" means any federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

1.130 "Governmental Charges" has the meaning set forth in Section 9.2.

1.131 "Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (a) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by Law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere;[1] (c) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state Law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local Law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. Green Attributes do not include (i) any Energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project.

1.132 Omitted.

1.133 "Guaranteed Energy Production" or "GEP" has the meaning set forth in Section 3.1(e)(ii).

1.134 "Guaranty" means a guaranty issued by an entity and in a form acceptable to Buyer in Buyer's sole discretion.

1.135 "Imbalance Energy" has the meaning set forth in the CAISO Tariff.

1.136 "Initial Energy Delivery Date" has the meaning set forth in Section 3.1(c)(i).

1.137 "Initial Extension" has the meaning set forth in Section 3.1(c)(ii).

1.138 "Interconnection Customer's Interconnection Facilities" has the meaning set forth in the CAISO Tariff or Participating TO's tariff, as applicable.

1.139 "Interconnection Facilities" has the meaning set forth in the CAISO Tariff.

1.140 "Interconnection Point" means the physical interconnection point of the Project as identified by Seller in the Cover Sheet.

1.141 "Interconnection Study" means any of the studies defined in the CAISO Tariff or, if applicable, any distribution provider's tariff that reflect the methodology and costs to interconnect the Project to the Participating Transmission Owner's electric grid.

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[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

1.142 "Integrated Forward Market" has the meaning set forth in the CAISO Tariff.

1.143 "Interest Amount" means, with respect to an Interest Period, the amount of interest calculated as follows: (a) the sum of (i) the principal amount of Performance Assurance in the form of cash held by Buyer during that Interest Period, and (ii) the sum of all accrued and unpaid Interest Amounts accumulated prior to such Interest Period; (b) multiplied by the Interest Rate in effect for that Interest Period; (c) multiplied by the number of days in that Interest Period; (d) divided by 360.

1.144 "Interest Payment Date" means the date of returning unused Performance Assurance held in the form of cash.

1.145 "Interest Period" means the monthly period beginning on the first day of each month and ending on the last day of each month.

1.146 "Interest Rate" means the rate per annum equal to the "Monthly" Federal Funds Rate (as reset on a monthly basis based on the latest month for which such rate is available) as reported in Federal Reserve Bank Publication H.15(519), or its successor publication.

1.147 "JAMS" means JAMS, Inc. or its successor entity, a judicial arbitration and mediation service.

1.148 "Law" means any statute, law, treaty, rule, regulation, CEC guidance document, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective after the Execution Date; or any binding interpretation of the foregoing. For purposes of 10.1(b), "Seller Representations and Warranties" and 10.9 "Governing Law", the term "law" shall have the meaning set forth in this definition.

1.149 "Letter of Credit" means an irrevocable, non-transferable standby letter of credit, the form of which must be substantially as contained in Appendix I to this Agreement; provided, that, if the issuer is a U.S. branch of a foreign commercial bank, Buyer may require changes to such form; the issuer must be an Eligible LC Bank on the date of Transfer.

1.150 "Licensed Professional Engineer" means a person acceptable to Buyer in its reasonable judgment who (a) is licensed to practice engineering in California, (b) has training and experience in the power industry specific to the technology of the Project, (c) has no economic relationship, association, or nexus with Seller or Buyer, other than to meet the obligations of Seller pursuant to this Agreement, (d) is not a representative of a consultant, engineer, contractor, designer or other individual involved in the development of the Project or of a manufacturer or supplier of any equipment installed at the Project, and (e) is licensed in an appropriate engineering discipline for the required certification being made.

1.151 "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from the termination of the Transaction, determined in a commercially reasonable manner, subject to Section 5.3 hereof. Factors used in determining the loss of economic benefit may include reference to information either available to it internally or supplied by one or more third parties including quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets, market price referent, market prices for a comparable transaction, forward price curves based on economic analysis of the relevant markets, settlement prices for a comparable transaction at liquid trading platforms (e.g. NYMEX), all of which should be calculated for the remaining term of the Transaction to determine the value of the Product.

1.152 "Master File" has the meaning set forth in the CAISO Tariff.

1.153 "Milestone(s)" means the key development activities required for the construction and operation of the Project, as set forth in Section B(i)(b) of the Cover Sheet.

1.154 "Minimum Load" has the meaning set forth in the CAISO Tariff.

1.155 "Minimum Down Time" has the meaning set forth in the CAISO Tariff.

1.156 "Monthly Payment for Excess Energy" has the meaning set forth in Section 4.4(b).

1.157 "Monthly Period" has the meaning set forth in Section 4.2.

1.158 "Moody's" means Moody's Investors Service, Inc., or its successor.

1.159 "MW" means megawatt in alternating current or AC.

1.160 "MWh" means megawatt-hour.

1.161 "NERC" means the North American Electric Reliability Corporation or a successor organization that is responsible for establishing reliability criteria and protocols.

1.162 "Net Qualifying Capacity" has the meaning set forth in the CAISO Tariff.

1.163 "Network Upgrades" has the meaning set forth in the CAISO Tariff or the Participating TO's tariff, as applicable.

1.164 "New Project" is a Project that has not achieved Commercial Operation on or prior to the Execution Date.

1.165 "Non-Bypassable Charges" means all charges that are collected by PG&E from the customers of Buyer, including all applicable charges for transmission, transmission rate adjustments, reliability services, distribution, conservation incentive adjustment, public purpose programs, nuclear decommissioning, the franchise fee surcharge, new system generation charges, and the Cost Responsibility Surcharge.

1.166 "Non-Defaulting Party" has the meaning set forth in Section 5.2.

1.167 "Notice," unless otherwise specified in the Agreement, means written communications by a Party to be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). The Cover Sheet contains the names and addresses to be used for Notices.

1.168 "Notice to Proceed" means the full notice to proceed, provided by Seller to the EPC Contractor following execution of the EPC Contract between Seller and such EPC Contractor and satisfaction of all conditions to performance of such contract, by which Seller authorizes such EPC Contractor to begin mobilization and construction of the Project without any delay or waiting periods.

1.169 "Operational Deliverability Assessment" has the meaning set forth in the CAISO Tariff.

1.170 "Outage Notification Procedures" means the procedures specified in Appendix VI, attached hereto. RCEA reserves the right to revise or change the procedures upon written Notice to Seller.

1.171 "Partial Capacity Deliverability Status" or "PCDS" has the meaning set forth in the CAISO Tariff.

1.172 "Partial Capacity Deliverability Status Amount" means the number of MW that the Project will obtain, as stated in the Deliverability type selected in Section A of the Cover Sheet.

1.173 "Partial Capacity Deliverability Status Finding" or "PCDS Finding" means a written confirmation from the CAISO that the Project is eligible for PCDS.

1.174 "Participating Intermittent Resource" or "PIRP" has the meaning set forth in the CAISO Tariff.

1.175 "Participating Transmission Owner" or "Participating TO" means an entity that (a) owns, operates and maintains transmission lines and associated facilities and/or has entitlements to use certain transmission lines and associated facilities and (b) has transferred to the CAISO operational control of such facilities and/or entitlements to be made part of the CAISO Grid.

1.176 "Party" means the Buyer or Seller individually, and "Parties" means both collectively. For purposes of Section 10.9, Governing Law, the word "party" or "parties" shall have the meaning set forth in this definition.

1.177 "Performance Assurance" means collateral provided by Seller to Buyer to secure Seller's obligations hereunder and includes Pre-Delivery Term Security and Delivery Term Security, as applicable. Acceptable forms of collateral are cash, a Letter of Credit, or Guaranty as designated in Section E of the Cover Sheet. The required form of Letter of Credit is attached hereto in Appendix I.

1.178 "Performance Measurement Period" has the meaning set forth in Section 3.1(e)(ii).

1.179 "Performance Tolerance Band" shall be calculated as set forth in Section 4.4(c)(ii).

1.180 "Permit Failure" has the meaning set forth in Section 3.9(d). ***[For New Projects only]***

1.181 "Permitting Delay" has the meaning set forth in Section 3.9(c)(ii)(A).

1.182 Omitted.

1.183 "Planned Outage" means the removal of equipment from service availability for inspection and/or general overhaul of one or more major equipment groups. To qualify as a Planned Outage, the maintenance (a) must actually be conducted during the Planned Outage, and in Seller's sole discretion must be of the type that is necessary to reliably maintain the Project, (b) cannot be reasonably conducted during Project operations, and (c) causes the generation level of the Project to be reduced by at least ten percent (10%) of the Contract Capacity.

1.184 "PMax" has the meaning set forth in the CAISO Tariff.

1.185 "PNode" has the meaning set forth in the CAISO Tariff.

1.186 "Portfolio Content Category 1" means any Renewable Energy Credit associated with the generation of electricity from an Eligible Renewable Energy Resource consisting of the portfolio content set forth in California Public Utilities Code Section 399.16(b)(1), as may be amended from time to time or as further defined or supplemented by Law.

1.187 "Preamble" means the paragraph that precedes Article One: General Definitions to this Agreement.

1.188 "Preschedule Day" has the meaning set forth in Section 3.4(b)(iii)(C).

1.189 "Product" means the Energy, capacity, Ancillary Services, and all products, services and/or attributes similar to the foregoing which are or can be produced by or associated with the Project and which is specified by Seller in the Cover Sheet and thereby committed to Seller by this Agreement, including renewable attributes, Renewable Energy Credits, Capacity Attributes and Green Attributes.

1.190 "Production Tax Credit" or "PTC" means the tax credit for electricity produced from certain renewable generation resources described in Section 45 of the Internal Revenue Code of 1986, as it may be amended or supplemented from time to time.

1.191 Omitted.

1.192 "Project" means all of the Unit(s) and the Site at which the generating facility is located and the other assets, tangible and intangible, that compose the generation facility, including the assets used to connect the Unit(s) to the Interconnection Point, as more particularly described in the Cover Sheet.

1.193 "Pre-Delivery Term Security" is the collateral required of Seller, as specified and referred to in Section 8.3(a).

1.194 "Project Specifications" has the meaning set forth in Appendix XII.

1.195 "Prolonged Outage" is any period of more than thirty (30) consecutive days during which the Project is or will be unable, for whatever reason, to provide at least sixty percent (60%) of the Contract Capacity.

1.196 "Qualifying Facility" has the meaning provided in the Public Utility Regulatory Policies Act ("PURPA") and in regulations of the FERC at 18 C.F.R. §§ 292.201 through 292.207.

1.197 "RA Deficiency Amount" means the liquidated damages payment that Seller shall pay to Buyer for an applicable RA Shortfall Month as calculated in accordance with Section 3.3(e)(ii).

1.198 "RA Shortfall Period" means the period of consecutive calendar months that starts with the calendar month in which the RA Start Date occurs and concludes with the second calendar month following the calendar month in which the Effective FCDS Date or Effective PCDS Date occurs. The RA Shortfall Period shall not exceed twenty-six (26) months.

1.199 "RA Shortfall Month" means the applicable calendar month within the RA Shortfall Period for purposes of calculating an RA Deficiency Amount under Section 3.3(e)(ii).

1.200 "RA Start Date" shall be the later of the Initial Energy Delivery Date or the Expected PCDS Date or FCDS Date according to the deliverability type selected in Section A of the Cover Sheet.

1.201 “RA Value” means the value in U.S. dollars per MW of Expected Net Qualifying Capacity for each RA Shortfall Month, as set forth in Appendix XIII.

1.202 “Ramp Rate” has the meaning set forth in the CAISO Tariff.

1.203 “Real-Time Market” means any existing or future intra-day market conducted by the CAISO occurring after the Day-Ahead Market.

1.204 “Real-Time Price” means the Resource-Specific Settlement Interval LMP as defined in the CAISO Tariff. If there is more than one applicable Real-Time Price for the same period of time, Real-Time Price shall mean the price associated with the smallest time interval.

1.205 “Reductions” has the meaning set forth in Section 4.7(b).

1.206 “Reliability Coordinator” has the meaning set forth in the CAISO Tariff.

1.207 “Reliability Must-Run Contract” has the meaning set forth in the CAISO Tariff. “Reliability Network Upgrade” has the meaning set forth in the CAISO Tariff. ***[For Baseload Product only]***

1.208 “Reliability Network Upgrade” has the meaning set forth in the CAISO Tariff.

1.209 “Renewable Energy Credit” has the meaning set forth in California Public Utilities Code Section 399.12(h) and CPUC Decision 08-08-028, as may be amended from time to time or as further defined or supplemented by Law.

1.210 “Replacement Capacity Rules” means the replacement requirement for Resource Adequacy Capacity (as defined in the CAISO Tariff) associated with a Planned Outage as set forth in the CAISO Tariff or successor replacement requirements as prescribed by the CPUC, CAISO and/or other regional entity.

1.211 “Resource Adequacy” means the procurement obligation of load serving entities, including Buyer, as such obligations are described in CPUC Decisions D.04-01-050, 04-10-035 and 05-10-042, 06-04-040, 06-06-064, 06-07-031, 07-06-029, 08-06-031, 09-06-028, 10-06-036, 11-06-022, 12-06-025, 13-06-024, 15-06-063, 16-06-045, 17-06-027, 18-06-030, 18-06-031 and any other existing or subsequent decisions, resolutions or rulings addressing Resource Adequacy issues, as those obligations may be altered from time to time in the CPUC Resource Adequacy Rulemakings (R.) 04-04-003, 05-12-013, 14-10-10, and 17-09-020 or by any successor proceeding, and all other Resource Adequacy obligations established by any other entity, including the CAISO.

1.212 “Resource Adequacy Plan” has the meaning set forth in the CAISO Tariff.

1.213 “Resource Adequacy Requirements” has the meaning set forth in Section 3.3.

1.214 “Resource Adequacy Standards” means (a) the Program set forth in Section 40.9 of the CAISO Tariff and (b) any future program or provision under the CAISO Tariff providing for availability standards or similar standards with respect to any flexible Resource Adequacy resource, product, or procurement obligation; in the case of (a) or (b), as any such program or provision may be amended, supplemented, or replaced (in whole or in part) from time to time, setting forth certain standards regarding the desired level of availability for Resource Adequacy resources and possible changes and incentive payments for performance thereunder.

1.215 "Resource-Specific Settlement Interval LMP" has the meaning set forth in the CAISO Tariff.

1.216 "Retained Revenues" has the meaning set forth in Section 4.6(c).

1.217 "Revised Offer" has the meaning set forth in Section 11.1(b)(iii), as applicable.

1.218 "S&P" means the Standard & Poor's Financial Services, LLC (a subsidiary of The McGraw-Hill Companies, Inc.) or its successor.

1.219 "Satisfaction Date" has the meaning set forth in Section 2.5.

1.220 "Schedule" has the meaning set forth in the CAISO Tariff.

1.221 "Scheduling Coordinator" or "SC" means an entity certified by the CAISO as qualifying as a Scheduling Coordinator pursuant to the CAISO Tariff, for the purposes of undertaking the functions specified in "Responsibilities of a Scheduling Coordinator" of the CAISO Tariff, as amended from time to time.

1.222 "SEC" means the U.S. Securities and Exchange Commission.

1.223 "Self-Schedule" has the meaning set forth in the CAISO Tariff.

1.224 "Seller" has the meaning set forth in the Cover Sheet.

1.225 "Seller Excuse Hours" means those hours during which Seller is unable to deliver Delivered Energy to Buyer as a result of (a) a Force Majeure event, (b) Buyer's failure to perform, or (c) Curtailment Period.

1.226 "Seller's WREGIS Account" has the meaning set forth in Section 3.1(k)(i).

1.227 "Settlement Amount" means the amount in US dollars equal to the sum of Losses, Gains, and Costs, which the Non-Defaulting Party incurs as a result of the termination of this Agreement.

1.228 "Settlement Interval" has the meaning set forth in the CAISO Tariff.

1.229 Omitted.

1.230 "Shared Contract Year" has the meaning set forth in section 3.1(e)(ii)(C)(I).

1.231 "Site" means the location of the Project as described in Appendix VIII.

1.232 "Start-up" means the action of bringing a Unit from non-operation to operation at or above the Unit's Minimum Load, or with positive generation output if Minimum Load is zero.

1.233 "Station Use" means all energy consumption necessary for the generation of electricity that can be supplied by the Project itself while it is generating electricity, and any loads not separately metered from any station use load. For a biomass facility, the energy demand to transport the biomass material that has undergone all processing necessary for consumption in the biomass boiler into the boiler, using stationary equipment (or at least stationary while operating) is considered station use.

1.234 "Surplus Delivered Energy" means, in any Settlement Interval, the Energy produced from the Project as measured in MWh at the CAISO revenue meter of the Project and in accordance with the CAISO Tariff, including any applicable adjustments for power factor and Electrical Losses, that exceeds the product of [redacted] percent ([redacted]%) of Contract Capacity multiplied by the duration of the Settlement Interval.

1.235 "Supply Plan" has the meaning set forth in the CAISO Tariff.

1.236 "System Emergency" has the meaning set forth in the CAISO Tariff.

1.237 "Term" has the meaning provided in Section 2.5.

1.238 "Terminated Transaction" means the Transaction terminated in accordance with Section 5.2 of this Agreement.

1.239 "Termination Payment" means the payment amount equal to the sum of (a) and (b), where (a) is the Settlement Amount and (b) is the sum of all amounts owed by the Defaulting Party to the Non-Defaulting Party under this Agreement, less any amounts owed by the Non-Defaulting Party to the Defaulting Party determined as of the Early Termination Date.

1.240 "Test Period" means the period of not more than ninety (90) consecutive days, as extended by the Initial Extension and Additional Extension according to Section 3.1(c)(ii), as applicable, which period shall commence upon the first date that the following have occurred (a) the CAISO informs Seller in writing that Seller may deliver Energy from the Project to the CAISO Grid, and (b) the items in Section 3.4(a)(i)(E) have been fulfilled and implemented, and shall end upon the Initial Energy Delivery Date.

1.241 "Third-Party SC" means a qualified third party designated by Buyer to provide the Scheduling Coordinator functions for the Project pursuant to this Agreement. For purposes of this Agreement, and subject to replacement as provided in Section 3(4)(i)(B), Buyer has designated The Energy Authority ("TEA") to act as its Third-Party SC. All references and provisions in this Agreement to Buyer acting in its capacity as Scheduling Coordinator shall mean and include the designated Third-Party SC regardless of whether the reference or provision in this Agreement expressly states "Third-Party SC."

1.242 "Transaction" means the particular transaction described in its entirety in Section 3.1(b) of this Agreement.

1.243 "Transfer" with respect to Letters of Credit means the delivery of the Letter of Credit conforming to the requirements of this Agreement, by Seller or an Eligible LC Bank to Buyer or delivery of an executed amendment to such Letter of Credit (extending the term or varying the amount available to Buyer thereunder, if acceptable to Buyer) by Seller or Eligible LC Bank to Buyer.

1.244 "Transmission Delay" has the meaning set forth in Section 3.9(c)(ii)(B).

1.245 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point.

1.246 "Uninstructed Imbalance Energy" shall have the meaning set forth in the CAISO Tariff.

1.247 “Unit” means the technology used to produce the Products, which are identified in the Cover Sheet for the Transaction entered into under this Agreement.

1.248 “Variation(s)” means the absolute value of the difference, in MWh, in any Settlement Interval between (a) DA Scheduled Energy; and (b) Delivered Energy for the Settlement Interval. ***[For Baseload Product only]***

1.249 “WECC” means the Western Electricity Coordinating Council or successor agency.

1.250 “Work” means (a) work or operations performed by a Party or on a Party’s behalf, and (b) materials, parts or equipment furnished in connection with such work or operations, including (i) warranties or representations made at any time with respect to the fitness, quality, durability, performance or use of “a Party’s work”, and (ii) the providing of or failure to provide warnings or instructions.

1.251 “WREGIS” means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

1.252 “WREGIS Certificate Deficit” has the meaning set forth in Section 3.1(k)(v).

1.253 “WREGIS Certificates” has the same meaning as “Certificate” as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

1.254 “WREGIS Operating Rules” means those operating rules and requirements adopted by WREGIS as of May 1, 2018, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

ARTICLE TWO: GOVERNING TERMS AND TERM

2.1 Entire Agreement. This Agreement, together with the Cover Sheet, Preamble and each and every appendix, attachment, amendment, schedule and any written supplements hereto, if any, between the Parties constitutes the entire, integrated agreement between the Parties.

2.2 Interpretation. The following rules of interpretation shall apply in addition to those set forth in Section 10.10:

(a) The term "month" or "Month" shall mean a calendar month unless otherwise indicated, and a "day" shall be a 24-hour period beginning at 12:00:01 a.m. Pacific Prevailing Time and ending at 12:00:00 midnight Pacific Prevailing Time; provided that a "day" may be 23 or 25 hours on those days on which daylight savings time begins and ends.

(b) Unless otherwise specified herein, all references herein to any agreement or other document of any description shall be construed to give effect to amendments, supplements, modifications or any superseding agreement or document as then existing at the applicable time to which such construction applies.

(c) Capitalized terms used in this Agreement, including the appendices hereto, shall have the meaning set forth in Article One, unless otherwise specified.

(d) Unless otherwise specified herein, references in the singular shall include references in the plural and vice versa, pronouns having masculine or feminine gender will be deemed to include the other, and words denoting natural persons shall include partnerships, firms, companies, corporations, joint ventures, trusts, associations, organizations or other entities (whether or not having a separate legal personality). Other grammatical forms of defined words or phrases have corresponding meanings.

(e) References to a particular article, section, subsection, paragraph, subparagraph, appendix or attachment shall, unless specified otherwise, be a reference to that article, section, subsection, paragraph, subparagraph, appendix or attachment in or to this Agreement.

(f) Any reference in this Agreement to any natural person, Governmental Authority, corporation, partnership or other legal entity includes its permitted successors and assigns or any natural person, Governmental Authority, corporation, partnership or other legal entity succeeding to its functions.

(g) All references to dollars are to U.S. dollars.

(h) The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation.

2.3 Authorized Representatives. Each Party shall provide Notice to the other Party of the persons authorized to nominate and/or agree to a Schedule or dispatch order for the delivery or acceptance of the Product or make other Notices on behalf of such Party and specify the scope of their individual authority and responsibilities, and may change its designation of such persons from time to time in its sole discretion by providing Notice.

2.4 Conditions Precedent.

(a) Conditions Precedent. Subject to Section 2.4 hereof, the Term shall not commence until the occurrence of all of the following:

(i) this Agreement has been duly executed by the authorized representatives of each of Buyer and Seller; and

(ii) Buyer receives from Seller the documentation listed in Appendix VIII (Seller Documentation Condition Precedent).

(b) Failure to Meet All Conditions Precedent. If the Condition Precedent set forth in Section 2.4(a)(ii) is waived by Buyer prior to or at execution of this Agreement but is not satisfied or further waived in writing by Buyer on or before one hundred and eighty (180) days from the execution date of this Agreement, then either Party may terminate this Agreement effective upon receipt of Notice by Seller. Neither Party shall have any obligation or liability to the other, including for a Termination Payment or otherwise, by reason of such termination.

2.5 Term.

(a) The term shall commence upon the satisfaction of the Conditions Precedent set forth in Section 2.4(a) of this Agreement and shall remain in effect until the conclusion of the Delivery Term unless terminated sooner pursuant to Section 2.4(b), Section 5.2 or Section 11.1 of this Agreement (the "Term"); provided that this Agreement shall thereafter remain in effect (i) until the Parties have fulfilled all obligations with respect to the Transaction, including payment in full of amounts due pursuant to the Final True-Up, the Settlement Amount, or other damages (whether directly or indirectly such as through set-off or netting) and the undrawn portion of the Pre-Delivery Term Security or Delivery Term Security, is released and/or returned as applicable (the "Satisfaction Date") or (ii) in accordance with the survival provisions set forth in subpart (b) below.

(b) Notwithstanding anything to the contrary in this Agreement, (i) all rights under Section 10.4 ("Indemnities") and any other indemnity rights shall survive the Satisfaction Date or the end of the Term (whichever is later) for an additional twelve (12) months; (ii) all rights and obligations under Section 10.6 ("Confidentiality") shall survive the Satisfaction Date or the end of the Term (whichever is later) for an additional two (2) years; and (iii) the right of first offer in Section 11.1(b) shall survive the Satisfaction Date for three (3) years.

2.6 Omitted.

2.7 Binding Nature.

(a) Upon Execution Date. This Agreement shall be effective and binding as of the Execution Date only to the extent required to give full effect to, and enforce, the rights and obligations of the Parties under:

(i) Sections 5.1(a)(iv), 5.1(a)(v), 5.1(b)(ii), and 5.1(b)(vii);

(ii) Section 5.1(a)(ii) only with respect to Section 10.1, and Section 5.1(a)(iii) only with respect to the Sections identified in this Section 2.7;

(iii) Sections 5.2 through 5.7;

(iv) Sections 8.2, 8.3(a)(i), 8.3(b), and 8.4;

(v) Sections 10.1, 10.5 through 10.6, and Sections 10.10 through 10.13; and

(vi) Articles One, Two, Seven, Twelve and Thirteen.

(b) Upon Effective Date. This Agreement shall be in full force and effect, enforceable and binding in all respects, upon occurrence of the Effective Date.

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations.

(a) Product. The Product to be delivered and sold by Seller and received and purchased by Buyer under this Agreement is set forth in the Cover Sheet.

(b) Transaction. Unless specifically excused by the terms of this Agreement during the Delivery Term, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Product at the Delivery Point, pursuant to Seller's election in the Cover Sheet of a Full Buy/Sell or Excess Sale arrangement as described in paragraphs 3.1(b)(i) and 3.1(b)(ii) below. Buyer shall pay Seller the Contract Price in accordance with the terms of this Agreement. In no event shall Seller have the right to procure any element of the Product from sources other than the Project for sale or delivery to Buyer under this Agreement except with respect to Energy delivered to Buyer in connection with Energy Deviations or Variations, as applicable. Buyer shall have no obligation to receive or purchase Product from Seller prior to or after the Delivery Term. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product after its receipt at and from the Delivery Point. Each Party agrees to act in good faith in the performance of its obligations under this Agreement.

(i) Full Buy/Sell. If "Full Buy/Sell" is elected on the Cover Sheet, Seller agrees to sell to Buyer the Project's gross output of Product measured in kilowatt-hours, net of Station Use and transformation and transmission losses to and at the Delivery Point. Seller shall purchase all Energy required to serve the Project's on-site load, net of station use, from Buyer or applicable retail service provider pursuant to its applicable retail rate schedule.

(ii) Excess Sale. If "Excess Sale" is selected on the Cover Sheet, Seller agrees to sell to Buyer the Project's gross output of Product as measured in kilowatt-hours, net of station Use, any on-site load and transformation and transmission losses to the Delivery Point. Seller agrees to convey to Buyer all elements of Product associated with the Energy sold to Buyer.

(c) Delivery Term.

(i) Delivery Term and Initial Energy Delivery Date. As used herein, "Delivery Term" shall mean the period of Contract Years specified on the Cover Sheet, beginning on the first date that Buyer accepts delivery of the Product from the Project in connection with this Agreement following Seller's demonstration of satisfaction of the items listed below in this Section 3.1(c)(i) ("Initial Energy Delivery Date") and continuing until the end of the tenth, fifteenth, or twentieth Contract Year (as applicable, based on the Cover Sheet election) unless terminated pursuant to the terms of this Agreement; provided that the Expected Initial Energy Delivery Date may be extended pursuant to Section 3.1(c)(ii). The Initial Energy Delivery Date shall be the later of the (A) date that the Buyer receives the "Initial Energy Delivery Date Confirmation Letter" attached hereto as Appendix II and (B) the date listed as the Initial Energy Delivery Date on the Initial Energy Delivery Date Confirmation Letter. The Initial Energy

Delivery Date shall occur as soon as practicable once all of the following have been satisfied: (I) Seller notifies Buyer that Commercial Operation has occurred; (II) Buyer shall have received and accepted the Pre-Delivery Term Security or Delivery Term Security, as applicable, in accordance with the relevant provisions of Article Eight of the Agreement, as applicable; (III) Seller shall have obtained the requisite CEC Certification and Verification for the Project (IV) all of the applicable Conditions Precedent in Section 2.4(a) have been satisfied or waived in writing; (V) for resources that are already under a contract as of the Execution Date, that existing contract must have expired by its own terms before the Initial Energy Delivery Date; (VI) Seller shall have demonstrated satisfaction of Seller's other obligations in this Agreement that commence prior to or as of the Delivery Term; and (VII) unless Seller has been directed by Buyer to not participate in the Participating Intermittent Resource Program, Buyer shall have received written notice from the CAISO that the Project is certified as a Participating Intermittent Resource to the extent the Participating Intermittent Resource Program exists for the Project's technology type at such time as the conditions in subsections (I) through (VI) of this Section 3.1(c)(i) are satisfied.

(ii) Extensions of Test Period and Initial Energy Delivery Date. In the event that Seller cannot satisfy the requirements for the Initial Energy Delivery Date by the Expected Initial Energy Delivery Date, as set forth in Section 3.1(c)(i), then Seller may provide Buyer with a one-time Notice of a thirty (30) day extension of the Test Period and Expected Initial Energy Delivery Date ("Initial Extension") along with a written explanation of the basis for the extension, no later than five (5) Business Days prior to the Expected Initial Energy Delivery Date. In the event that Seller requires an additional extension of the Test Period and Expected Initial Energy Delivery Date beyond the Initial Extension, Seller may request a further extension of the Test Period and Expected Initial Energy Delivery Date from Buyer no later than ten (10) days prior to the expiration of the Initial Extension of up to sixty (60) days by providing Notice to Buyer along with a detailed written explanation of the basis for such request ("Additional Extension"). Buyer shall provide Seller with Notice of Buyer's acceptance or rejection, in its sole discretion, of such Notice of Additional Extension within ten (10) days of receipt of Seller's Notice of Additional Extension. If Buyer fails to provide a Notice of Buyer's acceptance or rejection, then Seller's Notice of Additional Extension shall be deemed accepted. If Buyer provides Seller with Notice of Buyer's rejection of the Additional Extension, then Seller may be subject to an Event of Default. As evidence of the Initial Energy Delivery Date, the Parties shall execute and exchange the "Initial Energy Delivery Date Confirmation Letter," attached hereto as Appendix II, on the Initial Energy Delivery Date.

(d) Delivery Point. The Delivery Point shall be the PNode designated by the CAISO for the Project.

(e) Contract Quantity and Guaranteed Energy Production.

(i) Contract Quantity. The Contract Quantity during each Contract Year is the amount set forth in the applicable Contract Year in Section D of the Cover Sheet ("Delivery Term Contract Quantity Schedule"), which amount is inclusive of outages.

(ii) Guaranteed Energy Production.

(A) Throughout the Delivery Term, Seller shall be required to provide to Buyer an amount of Delivered Energy plus Deemed Delivered Energy, if any, no less than the Guaranteed Energy Production over [redacted] consecutive Contract Years during the Delivery Term ("Performance Measurement Period"). "Guaranteed Energy Production" is equal to the product of (x) and (y), where (x) is [redacted] percent ([redacted]%) of the average of the Contract Quantities applicable to the [redacted] Contract Years comprising the Performance Measurement Period, and (y) is the difference between (I) and (II), with the resulting difference divided by (I), where (I) is the number of hours in the applicable Performance Measurement Period and (II) is the aggregate number of Seller Excuse Hours in the applicable Performance Measurement Period. Guaranteed Energy Production is described by the following formula:

Guaranteed Energy Production = ([redacted]% × average of the Contract Quantities in MWh in Performance Measurement Period) × [(Hrs in Performance Measurement Period – Seller Excuse Hrs in Performance Measurement Period) / Hrs in Performance Measurement Period]

(B) In no event shall any amount of Delivered Energy plus Deemed Delivered Energy in any Settlement Interval that exceeds the Contract Capacity be credited toward or added to Seller's Guaranteed Energy Production requirement.

(C) <u>GEP Failure, Cure, Damages</u>.

(I) If Seller has a GEP Failure, then within forty-five (45) days after the last day of the last month of such Performance Measurement Period, Buyer shall promptly provide Notice to Seller of such failure, provided that Buyer's failure to provide Notice shall not constitute as a waiver of Buyer's rights to collect GEP damages. Seller may cure the GEP Failure by providing to Buyer an amount of Delivered Energy plus Deemed Delivered Energy, if any, that is no less than [redacted] percent ([redacted]%) of the Contract Quantity, subject to adjustment for Seller Excuse Hours over the next following Contract Year, as set forth in the formula below ("GEP Cure").

GEP Cure = [redacted]% × Contract Quantity in MWh) × [(Hrs in next following Contract Year – Seller Excuse Hrs in next following Contract Year) / Hrs in next following Contract Year]

If Seller fails to provide sufficient Delivered Energy plus Deemed Delivered Energy, if any, as adjusted by Seller Excuse Hours, to qualify for the GEP Cure for a given Performance Measurement Period, Seller shall pay GEP Damages, calculated pursuant to <u>Appendix V</u> ("GEP Damages Calculation"). If Seller provides a GEP Cure or pays GEP Damages for the Contract Years in a particular Performance Measurement Period ("Cured Performance Measurement Period"), then for purposes of calculating the Guaranteed Energy Production in the following Performance Measurement Period, the amount of Delivered Energy plus Deemed Delivered Energy in the [redacted] Contract Years of the Cured Performance Measurement Period, which are also the [redacted] Contract Years of the following Performance Measurement Period ("Shared Contract Years"), shall be deemed equal to the greater of (X) the Delivered Energy plus Deemed Delivered Energy, if any, for the Shared Contract Years, subject to adjustment for Seller Excuse Hours, or (Y) [redacted] percent ([redacted]%) of Contract Quantity in the Shared Contract Years, where X and Y are calculated as follows:

X = (Delivered Energy + Deemed Delivered Energy in Shared Contract Years) × [Hrs in Shared Contract Years / (Hrs in Shared Contract Years – Seller Excuse Hours in Shared Contract Years)] or;

Y = [redacted]% × Contract Quantities in Shared Contract Years

For the avoidance of doubt, the calculation set forth above for the amount of Delivered Energy plus Deemed Delivered Energy for the Shared Contract Years shall not apply to the cumulative GEP Shortfall under Section 5.1(b)(vi)(B).

(II) The Parties agree that the damages sustained by Buyer associated with Seller's failure to achieve the Guaranteed Energy Production requirement would be difficult or impossible to determine, or that obtaining an adequate remedy would be unreasonably time consuming or expensive and therefore agree that Seller shall pay the GEP Damages to Buyer as liquidated damages. In no event shall Buyer be obligated to pay GEP Damages.

(III) After the GEP Cure period has run, if Seller has not achieved the GEP Cure, Buyer shall have forty-five (45) days to notify Seller of such failure. Within forty-five (45) days of the end of the GEP Cure period, Buyer shall provide Notice to Seller in writing of the amount of the GEP Damages, if any, which Seller shall pay within sixty (60) days of receipt of the Notice (the "Cure Payment Period"). If Seller does not pay the GEP Damages within the Cure Payment Period, then Buyer may, at its option, declare an Event of Default pursuant to Section 5.1(b)(vi)(A) within ninety (90) days following the Cure Payment Period. If Seller has failed to pay the GEP Damages, and Buyer does not (1) notify Seller of the GEP Failure or (2) declare an Event of Default pursuant to Section 5.1(b)(vi) within the ninety (90) day period, then Buyer shall be deemed to have waived its right to declare an Event of Default based on Seller's failure with respect to the Performance Measurement Period which served as the basis for the notice of GEP Failure, GEP Damages, or default, subject to the limitations set forth in Section 5.1(b)(vi)(B).

(f) Contract Capacity. The generation capability designated for the Project shall be the contract capacity in MW designated in the Cover Sheet, (the "Contract Capacity"), which shall be equal to the result of the Contract Capacity calculation performed in accordance with Section II of Appendix XII. Throughout the Delivery Term, Seller shall sell and deliver all Product produced by the Project solely to Buyer. In no event shall Buyer be obligated to receive, in any Settlement Interval, any Surplus Delivered Energy. Seller shall not receive payment for any Surplus Delivered Energy. To the extent Seller delivers Surplus Delivered Energy to the Delivery Point in a Settlement Interval in which the Real-Time Price for the applicable PNode is negative, Seller shall pay Buyer an amount equal to the Surplus Delivered Energy (in MWh) during such Settlement Interval, multiplied by the absolute value of the Real-Time Price per MWh for such Settlement Interval.

(g) Project.

(i) All Product provided by Seller pursuant to this Agreement shall be supplied from the Project only. Seller shall not make any alteration or modification to the Project which results in a change to the Contract Capacity or the anticipated output of the Project without Buyer's prior written consent. The Project is further described in Appendix XII.

(ii) Seller shall not relinquish its possession or demonstrable exclusive right to control the Project without the prior written consent of Buyer, except under circumstances provided in Section 10.5.

(h) Interconnection Facilities.

(i) Seller Obligations. Seller shall (A) arrange and pay independently for any and all necessary costs under any Generator Interconnection Agreement with the Participating Transmission Owner; (B) cause the Interconnection Customer's Interconnection Facilities, including metering facilities, to be maintained; and (C) comply with the procedures set forth in the GIP and applicable agreements or procedures provided under the GIP in order to obtain the applicable Electric System Upgrades and (D) obtain Electric System Upgrades, as needed, in order to ensure the safe and reliable delivery of Energy from the Project up to and including quantities that can be produced utilizing all of the Contract Capacity of the Project.

(ii) Coordination with Buyer.

(A) Seller shall (I) provide to Buyer copies of all material correspondence related thereto; and (II) provide Buyer with written reports of the status of the GIA on a monthly basis. The foregoing shall not preclude Seller from executing a GIA that it reasonably determines allows it to comply with its obligations under this Agreement and applicable Law.

(i) Performance Excuses.

(i) Seller Excuse. For Seller selling As-Available Product, Seller shall be excused from achieving the Guaranteed Energy Production only for the applicable time period during Seller Excuse Hours.

(ii) Buyer Excuses. Buyer shall be excused from (A) receiving and paying for the Product only (I) during periods of Force Majeure, (II) by Seller's failure to perform, (III) during Curtailment Periods and (B) receiving Product during Buyer Curtailment Periods.

(iii) Curtailment. Notwithstanding Section 3.1(b) and this Section 3.1(i), Seller shall reduce output from the Project during any Curtailment Period or Buyer Curtailment Period.

(j) Greenhouse Gas Emissions Reporting. During the Term, Seller acknowledges that a Governmental Authority may require Buyer to take certain actions with respect to greenhouse gas emissions attributable to the generation of Energy, including reporting, registering, tracking, allocating for or accounting for such emissions. Promptly following Buyer's written request, Seller agrees to take all commercially reasonable actions and execute or provide any and all documents, information or instruments with respect to generation by the Project reasonably necessary to permit Buyer to comply with such requirements, if any. Nothing in this Section 3.1(j) shall cause Buyer to assume any liability or obligation with respect to Seller's compliance obligations with respect to the Project under any new or existing Laws, rules, or regulations.

(k) WREGIS. Seller shall, at its sole expense, take all actions and execute all documents or instruments necessary to ensure that all WREGIS Certificates associated with all Renewable Energy Credits corresponding to all Delivered Energy and Surplus Delivered Energy are issued and tracked for purposes of satisfying the requirements of the California Renewables Portfolio Standard and transferred in a timely manner to Buyer for Buyer's sole benefit. Seller shall comply with all Laws, including the WREGIS Operating Rules, regarding the certification and transfer of such WREGIS Certificates to Buyer and Buyer shall be given sole title to all such WREGIS Certificates. Seller shall be deemed to have satisfied the warranty in Section 3.1(k)(viii), provided that Seller fulfills its obligations under Sections 3.1(k)(i) through (vii) below. In addition:

(i) Prior to the Initial Energy Delivery Date, Seller shall register the Project with WREGIS and establish an account with WREGIS ("Seller's WREGIS Account"), which Seller shall maintain until the end of the Delivery Term. Seller shall transfer the WREGIS Certificates using "Forward Certificate Transfers" (as described in the WREGIS Operating Rules) from Seller's WREGIS Account to the WREGIS account(s) of Buyer or the account(s) of a designee that Buyer identifies by Notice to Seller ("Buyer's WREGIS Account"). Seller shall be responsible for all expenses associated with registering the Project with WREGIS, establishing and maintaining Seller's WREGIS Account, paying WREGIS Certificate issuance and transfer fees, and transferring WREGIS Certificates from Seller's WREGIS Account to Buyer's WREGIS Account.

(ii) Seller shall cause Forward Certificate Transfers to occur on a monthly basis in accordance with the certification procedure established by the WREGIS Operating Rules. Since WREGIS Certificates will only be created for whole MWh amounts of Energy generated, any fractional MWh amounts (i.e., kWh) will be carried forward until sufficient generation is accumulated for the creation of a WREGIS Certificate.

(iii) Seller shall, at its sole expense, ensure that the WREGIS Certificates for a given calendar month correspond with the Delivered Energy for such calendar month as evidenced by the Project's metered data.

(iv) Due to the ninety (90) day delay in the creation of WREGIS Certificates relative to the timing of invoice payment under Article 6, Buyer shall make an invoice payment for a given month in accordance with Article 6 before the WREGIS Certificates for such month are formally transferred to Buyer in accordance with the WREGIS Operating Rules and this Section 3.1(k). Notwithstanding this delay, Buyer shall have all right and title to all such WREGIS Certificates upon payment to Seller in accordance with Article 6.

(v) A "WREGIS Certificate Deficit" means any deficit or shortfall in WREGIS Certificates delivered to Buyer for a calendar month as compared to the Delivered Energy for the same calendar month ("Deficient Month"). If any WREGIS Certificate Deficit is caused, or the result of any action or inaction, by Seller, then the amount of Delivered Energy in the Deficient Month shall be reduced by the amount of the WREGIS Certificate Deficit for the purposes of calculating Buyer's payment(s) to Seller under Article 6 and the Guaranteed Energy Production for the applicable Performance Measurement Period. Any amount owed by Seller to Buyer because of a WREGIS Certificate Deficit shall be made as an adjustment to Seller's next monthly invoice to Buyer in accordance with Article 6, and Buyer shall net such amount against Buyer's subsequent payment(s) to Seller pursuant to Article 6.

(vi) Without limiting Seller's obligations under this Section 3.1(k), if a WREGIS Certificate Deficit is caused solely by an error or omission of WREGIS, the Parties shall cooperate in good faith to cause WREGIS to correct its error or omission.

(vii) If WREGIS changes the WREGIS Operating Rules after the Execution Date or applies the WREGIS Operating Rules in a manner inconsistent with this Section 3.1(k) after the Execution Date, the Parties promptly shall modify this Section 3.1(k) as reasonably required to cause and enable Seller to transfer to Buyer's WREGIS Account a quantity of WREGIS Certificates for each given calendar month that corresponds to the Delivered Energy in the same calendar month.

(viii) Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(l) <u>Access to Data</u>

(i) Commencing on the first date on which the Project generates Product to be delivered to the CAISO Grid or the Delivery Point, if different, and continuing throughout the Term, Seller shall provide to Buyer, in a form reasonably acceptable to Buyer, the data set forth below on a real-time basis; provided that Seller shall agree to make and bear the cost of changes to any of the data delivery provisions below, as requested by Buyer, throughout the Term, which changes Buyer determines are necessary to forecast output from the Project, and/or comply with Law:

(A) read-only access to meteorological measurements, and transformer availability, any other facility availability information, if available;

(B) read-only access to energy output information collected by the supervisory control and data acquisition (SCADA) system for the Project;

(C) read-only access to the Project's CAISO revenue meter and all Project meter data at the Site;

(D) full, real-time access to the Project's Scheduling and Logging for the CAISO' Outage Management System (OMS) client application, or its successor system;

(E) net plant electrical output at the CAISO revenue meter.

(ii) Seller shall maintain at least a minimum of one hundred twenty (120) days' historical data for all data required pursuant to Section 3.1(l)(i), which shall be available on a minimum time interval of one hour basis or an hourly average basis. Seller shall provide such data to Buyer within five (5) Business Days of Buyer's request.

(iii) Installation, Maintenance and Repair.

(A) Seller, at its own expense, shall install and maintain a secure communication link in order to provide Buyer with access to the data required in Section 3.1(l)(i) of this Agreement.

(B) Seller shall maintain the telecommunications path, hardware, and software required in Section 3.1(l)(i) to provide accurate data to Buyer or Third-Party SC (as applicable) to enable Buyer or the Third-Party SC to meet current CAISO scheduling requirements. Seller shall promptly repair and replace as necessary such telecommunications path, hardware and software and shall notify Buyer as soon as Seller learns that any such telecommunications paths, hardware and software are providing faulty or incorrect data.

(C) If Buyer notifies Seller of the need for maintenance, repair or replacement of the telecommunications path, hardware or software, Seller shall maintain, repair or replace such equipment as necessary within seven (7) days of receipt of such Notice.

(D) For any occurrence in which Seller's telecommunications system is not available or does not provide quality data and Buyer notifies Seller of the deficiency or Seller becomes aware of the occurrence, Seller shall transmit data to Buyer through any alternate means of verbal or written communication, including cellular communications from onsite personnel, facsimile, blackberry or equivalent mobile e-mail, or other method mutually agreed upon by the Parties, until the telecommunications link is re-established.

(iv) Seller agrees and acknowledges that Buyer may seek from third parties any information relevant to its duties as SC for Seller, including from the Participating Transmission Operator. Seller hereby voluntarily consents to allow the Participating Transmission Operator to share Seller's information with Buyer in furtherance of Buyer's duties as SC for Seller, and agrees to provide the Participating Transmission Owner with written confirmation of such voluntary consent at least ninety (90) days prior to the Initial Energy Delivery Date.

(m) Obtaining and Maintaining CEC Certification and Verification. Seller shall take all necessary steps including making or supporting timely filings with the CEC to obtain and maintain CEC Certification and Verification throughout the Term.

(n) Curtailment Requirements.

(i) Order. Seller shall reduce generation from the Project as required pursuant to a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order, provided that (A) a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order shall be consistent with the operational characteristics set forth in Section F of the Cover Sheet; (B) the Buyer Curtailment Period shall be for unlimited hours during the Delivery Term and (C) Buyer shall pay Seller for Deemed Delivered Energy associated with a Buyer Curtailment Period pursuant to Article 4. Seller agrees to reduce the Project's generation by the amount and for the period set forth in the Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order.

(ii) Failure to Comply. If Seller fails to comply with a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order provided in compliance with Section 3.1(p)(i), then, for each MWh of Delivered Energy that the Project generated in contradiction to the Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order, Seller shall pay Buyer for each such MWh at an amount equal to the sum of (A) + (B) + (C), where: (A) is the amount, if any, paid to Seller by Buyer for delivery of such MWh (for example, the Contract Price) and, (B) is the absolute value of the Real-Time Price for the applicable PNode, if such price is negative, for the Buyer Curtailment Period or Curtailment Period and, (C) is any penalties or other charges resulting from Seller's failure to comply with the Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order.

(o) Seller Equipment Required for Curtailment Instruction Communications. Seller shall acquire, install, and maintain such facilities, communications links and other equipment, and implement such protocols and practices, as necessary to respond and follow instructions, including an electronic signal conveying real time and intra-day instructions, to operate the Units as directed by the Buyer and/or a Governmental Authority, including to implement a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order in accordance with the then-current methodology used to transmit such instructions as it may change from time to time. If at any time during the Delivery Term Seller's facilities, communications links or other equipment, protocols or practices are not in compliance with then-current methodologies, Seller shall take the steps necessary to become compliant as soon as commercially reasonably possible. Seller shall be liable pursuant to Section 3.1(p)(ii) for failure to comply with a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order, during the time that Seller's facilities, communications links or other equipment, protocols or practices are not in compliance with then-current methodologies. For the avoidance of doubt, a Buyer Curtailment Order, Buyer Bid Curtailment or Curtailment Order communication via such systems and facilities shall have the same force and effect on Seller as any other form of communication.

3.2 Green Attributes.

(a) Seller hereby provides and conveys all Green Attributes associated with all Delivered Energy and Surplus Delivered Energy from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project. Notwithstanding the foregoing, Seller shall not be obligated to convey to Buyer any Green Attributes associated with Excess Energy, and may convey any Green Attributes Associated with Excess Energy to a third party.

(b) Future Environmental Attributes.

(i) The Parties acknowledge and agree that as of the Effective Date, environmental attributes sold under this Agreement are restricted to Green Attributes; however, Future Environmental Attributes may be created by a Governmental Authority through Laws enacted after the Effective Date. In such event, Buyer shall bear all costs associated with the transfer, qualification, verification, registration and ongoing compliance for such Future Environmental Attributes, but there shall be no increase in the Contract Price. Upon Seller's receipt of Notice from Buyer of Buyer's intent to claim such Future Environmental Attributes, the Parties shall determine the necessary actions and additional costs associated such Future Environmental Attributes. Seller shall have no obligation to alter the Facility unless the Parties have agreed on all necessary terms and conditions relating to such alteration and Buyer has agreed to reimburse Seller for all costs associated with such alteration.

(ii) If Buyer elects to receive Future Environmental Attributes pursuant to Section 3.2, the Parties agree to negotiate in good faith with respect to the development of further agreements and documentation necessary to effectuate the transfer of such Future Environmental Attributes, including agreement with respect to (i) appropriate transfer, delivery and risk of loss mechanisms, and (ii) appropriate allocation of any additional costs, as set forth above; *provided*, that the Parties acknowledge and agree that such terms are not intended to alter the other material terms of this Agreement.

3.3 Resource Adequacy.

(a) During the Delivery Term, Seller grants, pledges, assigns and otherwise commits to Buyer all of the Capacity Attributes from the Project, to enable Buyer to meet its Resource Adequacy or successor program requirements, as the CPUC, CAISO and/or other regional entity may prescribe, including submission of a Supply Plan or Resource Adequacy Plan ("Resource Adequacy Requirements"). From the Execution Date, and for the duration of the Delivery Term, Seller shall take all commercially reasonable actions, including complying with all applicable registration and reporting requirements, and execute any and all documents or instruments necessary to enable Buyer to use all of the capacity of the Project, including Capacity Attributes, to be committed by Seller to Buyer pursuant to this Agreement to meet Buyer's Resource Adequacy Requirements during the Delivery Term.

(b) Seller shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from Resource Adequacy Standards, if applicable, and Seller shall be entitled to retain all credits, payments, and revenues, if any, resulting from Seller achieving or exceeding Resource Adequacy Standards, if applicable.

(c) Buyer shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from the Replacement Capacity Rules, if applicable, provided that Seller has given Buyer Notice of the outages subject to the Replacement Capacity Rules by the earlier of ninety (90) days before the first day of the month for which the outage will occur or forty-five (45) days before Buyer's monthly Resource Adequacy capacity showing in accordance with the CAISO Tariff or decision of the CPUC. If Seller fails to provide such Notice, then Seller shall be responsible for all costs, charges, expenses, penalties, and obligations resulting from the Replacement Capacity Rules for such outage.

(d) To the extent Seller has an exemption from the Resource Adequacy Standards or the Replacement Capacity Rules under the CAISO Tariff, Sections 3.3(b) and 3.3(c) above shall not apply. If Seller would like to request an exemption for this Agreement from the CAISO, Seller shall provide to Buyer, as Seller's Scheduling Coordinator, Notice specifically requesting that Buyer seek certification or approval of this Agreement as an exempt contract pursuant to the CAISO Tariff; provided that Buyer's failure to obtain such exemption shall not be an Event of Default and Buyer shall not have any liability to Seller for such failure.

(e) Resource Adequacy Failure.

(i) RA Deficiency Determination. Notwithstanding Seller's obligations set forth in Section 3.4(a)(i)(A) or anything to the contrary herein, the Parties acknowledge and agree that:

(A) if Seller is unable to obtain the deliverability type selected in Section A of the Cover Page by the RA Start Date, then Seller shall pay to Buyer the RA Deficiency Amount for each RA Shortfall Month as liquidated damages due to Buyer for the Capacity Attributes that Seller failed to convey to Buyer; and

(B) if Seller is unable to obtain the deliverability type selected in Section A of the Cover Page by the Deliverability Finding Deadline, then Seller shall be in breach of this Agreement and subject to an Event of Default under Sections 5.1(b)(v) - (vi), regardless of Seller's payment of any RA Deficiency Amount hereunder.

(ii) RA Deficiency Amount Calculation.

(A) Buyer shall calculate the RA Deficiency Amount for each RA Shortfall Month using the formula set forth in Section 3.3(e)(ii)(B). Buyer shall notify Seller of the RA Deficiency Amount for a given RA Shortfall Month no later than the last day of that RA Shortfall Month. The Parties agree that these liquidated damages shall be paid to Buyer for each RA Shortfall Month and constitute a reasonable approximation of the harm or loss suffered by Buyer. The Parties further agree that Buyer may use such liquidated damages for any purpose in its sole discretion. Seller shall pay the RA Deficiency Amount for a given RA Shortfall Month in the form of a deduction from the amount invoiced by Seller in such month pursuant to Section 6.1. In the event that the RA Deficiency Amount for a given RA Shortfall Month exceeds the amount invoiced pursuant to Section 6.1, Buyer shall make no payment to Seller for that month, and the difference between the invoiced amount and the RA Deficiency Amount shall be deducted from the amount(s) invoiced in the succeeding month(s) until all of the RA Deficiency Amount for such RA Shortfall Month has been deducted. Any dispute regarding Buyer's calculation of any RA Deficiency Amount shall be resolved in accordance with Article Twelve.

(B) The RA Deficiency Amount for a given RA Shortfall Month shall be equal to the product of the RA Value and the Expected Net Qualifying Capacity, as calculated in accordance with Appendix XIII. The RA Deficiency Amount is represented by the following equation:

RA Deficiency Amount ($/Month) = RA Value ($/MW/Month) × Expected Net Qualifying Capacity (MW)

To the extent the Project obtains Net Qualifying Capacity that Seller applies towards its obligations under Section 3.3(a) before the Project obtains the deliverability type selected in Section A of the Cover Page (e.g., through the CAISO's Operational Deliverability Assessment), then the RA Deficiency Amount calculated above for a given RA Shortfall Month shall be reduced accordingly (e.g. the RA Deficiency Amount would equal the product of (x) the RA Value and (y) the difference between the Expected Net Qualifying Capacity and the actual Net Qualifying Capacity):

RA Deficiency Amount ($/Month) = RA Value ($/MW/Month) × [Expected Net Qualifying Capacity (MW) – actual Net Qualifying Capacity (MW)].

(f) Central Buyer and/or Central Procurement Entity Bid Requirements. If the CPUC adopts regulations authorizing a central buyer, central procurement entity, or other similar entity to procure Resource Adequacy on behalf of Buyer, then Seller shall take all reasonable actions to assist Buyer in maximizing the economic value associated with the Capacity Attributes of the Product.

3.4 Transmission and Scheduling.

(a) Transmission.

(i) Seller's Transmission Service Obligations. Throughout the Term, and consistent with the terms of this Agreement, Seller shall:

(A) arrange and pay independently for any and all necessary electrical interconnection, distribution and/or transmission (and any regulatory approvals required for the foregoing), sufficient to allow Seller to deliver the Product to the Delivery Point for sale pursuant to the terms of this Agreement. Seller's interconnection, distribution and/or transmission arrangements shall provide for the deliverability type selected in Section A of the Cover Sheet as of the RA Start Date and throughout the Delivery Term.

(B) If Seller has elected Energy Only Status on the Cover Sheet, this Section 3.4(a)(i)(B) is not applicable. An FCDS or PCDS Seller shall have either previously obtained, or is obligated to obtain per the terms of the Agreement, a FCDS or PCDS Finding. If Seller's Project has not attained Full Capacity Deliverability Status or Partial Capacity Deliverability Status prior to the Execution Date, Seller shall take all actions necessary or appropriate to cause the Delivery Network Upgrades necessary for it to obtain Full Capacity Deliverability Status or Partial Capacity Deliverability Status to be constructed and placed into service. The cost of each Deliverability Assessment and any necessary Delivery Network Upgrades to ensure Full Capacity Deliverability Status or Partial Capacity Deliverability Status shall be borne solely by Seller. When the CAISO advises Seller that the Project has Full Capacity Deliverability Status or Partial Capacity Deliverability Status, Seller shall Notify Buyer of such status within five (5) Business Days of the date it receives notification from the CAISO of such status by providing Buyer documentation from the CAISO. The Effective FCDS Date or Effective PCDS Date must occur on or before the Deliverability Finding Deadline; a failure to do so shall constitute an Event of Default under Section 5.1(a)(iii). The Termination Payment for an Event of Default caused by Seller's failure to achieve the Effective FCDS Date or Effective PCDS Date on or before the Deliverability Finding Deadline shall be capped at the amount of Seller's Delivery Term Security or Term Security obligation under Section 8.3(a)(ii) or (iii), as applicable.

(C) if the Project has or obtains FCDS, Seller shall Notify Buyer of such status as of the Execution Date, if applicable, or within five (5) Business Days of the date it receives notification from the CAISO of such status by providing Buyer documentation from the CAISO.

(D) bear all risks and costs associated with such transmission service, including any transmission outages or curtailment to the Delivery Point.

(E) fulfill all contractual, metering and applicable interconnection requirements, including those set forth in the Participating Transmission Owner's applicable tariffs, the CAISO Tariff and implementing CAISO standards and requirements, so as to be able to deliver Energy from the Project according to the terms of this Agreement.

(ii) Buyer's Transmission Service Obligations. During the Delivery Term,

(A) Buyer shall arrange and be responsible for transmission service at and from the Delivery Point.

(B) Buyer shall bear all risks and costs associated with such transmission service, including any transmission outages or curtailment from the Delivery Point.

(C) Buyer shall schedule or arrange for Scheduling Coordinator services with its Transmission Providers to receive the Product at the Delivery Point.

(D) Buyer shall be responsible for all CAISO costs and charges, electric transmission losses and congestion at and from the Delivery Point.

(b) Scheduling Coordinator. Buyer, or Buyer's designated Third-Party SC, shall act as the Scheduling Coordinator for the Project. In that regard, Buyer and Seller shall agree to the following:

(i) Designation as Scheduling Coordinator.

(A) At least ninety (90) days before the beginning of the Delivery Term, Seller shall take all actions and execute and deliver to Buyer all documents necessary to authorize or designate Buyer's Third-Party SC as Seller's Scheduling Coordinator, and the Third-Party SC will take all actions and execute and deliver to Seller or CAISO all documents necessary to become and act as Seller's Scheduling Coordinator. If Buyer replaces its designated Third-Party SC, then Buyer shall give Seller Notice of such designation at least ninety (90) Business Days before the successor Third-Party SC assumes Scheduling Coordinator duties hereunder, and Seller shall be entitled to rely on such designation until it is revoked or a new Third-Party SC is appointed by Buyer upon similar Notice. Buyer shall be fully responsible for all acts and omissions of Third-Party SC and for all cost, charges and liabilities incurred by Third-Party SC to the same extent that Buyer would be responsible under this Agreement for such acts, omissions, costs, charges and liabilities if taken, omitted or incurred by Buyer directly.

(B) Seller shall not authorize or designate any other party to act as Scheduling Coordinator, nor shall Seller perform, for its own benefit, the duties of Scheduling Coordinator during the Delivery Term.

(ii) Buyer's Responsibilities as Scheduling Coordinator. Buyer or Third-Party SC shall comply with all obligations as Seller's Scheduling Coordinator under the CAISO Tariff and shall conduct all scheduling in full compliance with the terms and conditions of this Agreement, the CAISO Tariff, and all requirements of EIRP (if applicable).

(iii) Available Capacity Forecasting. Seller shall provide the Available Capacity forecasts described below. To avoid Forecasting Penalties set forth in Section 4.7(c)(iii), Seller shall use commercially reasonable efforts to forecast the Available Capacity of the Project accurately and to transmit such information in a format reasonably acceptable to Buyer. Buyer and Seller shall agree upon reasonable changes to the requirements and procedures set forth below from time-to-time, as necessary to comply with CAISO Tariff changes, accommodate changes to their respective generation technology and organizational structure and address changes in the operating and Scheduling procedures of Buyer, Third-Party SC (if applicable) and the CAISO, including automated forecast and outage submissions.

(A) Annual Forecast of Available Capacity. No later than (I) the earlier of July 1 of the first calendar year following the Execution Date or one hundred and eighty (180) days before the first day of the first Contract Year of the Delivery Term ("First Annual Forecast Date"), and (II) on or before July 1 for each calendar year from the First Annual Forecast Date for every subsequent Contract Year during the Delivery Term, Seller shall provide to Buyer and Third-Party SC (if applicable) a non-binding forecast of the hourly Available Capacity for each day in each month of the following calendar year in a form reasonably acceptable to Buyer.

(B) Monthly Forecast of Available Capacity. Seller shall provide to Buyer and Third-Party SC (if applicable), pursuant to subsections (I) and (II) below, a non-binding forecast of the hourly Available Capacity for each day of the following month in a form reasonably acceptable to Buyer:

(I) by forty-five (45) days before Buyer's monthly Resource Adequacy capacity showing in accordance with the CAISO Tariff or decision of the CPUC, and

(II) throughout the Delivery Term, by the earlier of ninety (90) days before the beginning of each month or forty-five (45) days before Buyer's monthly Resource Adequacy capacity showing must be completed in accordance with the CAISO Tariff or decision of the CPUC.

(C) Daily Forecast of Available Capacity. During the Delivery Term, Seller or Seller's agent shall provide a binding day ahead forecast of Available Capacity (the "Day-Ahead Availability Notice") to Buyer or Third-Party SC (as applicable) at [redacted] or backup phone [redacted] and send an email to [redacted], as provided in Appendix VI, for each day no later than fourteen (14) hours before the beginning of the "Preschedule Day" (as defined by the WECC) for such day. The current industry standard Preschedule Day timetable in the WECC is as follows:

(1) Monday – Preschedule Day for Tuesday
(2) Tuesday – Preschedule Day for Wednesday
(3) Wednesday – Preschedule Day for Thursday
(4) Thursday – Preschedule Day for Friday and Saturday
(5) Friday – Preschedule Day for Sunday and Monday

Exceptions to this standard Monday through Friday Preschedule Day timetable are presently set forth by the WECC in order to accommodate holidays, monthly transitions and other events. Exceptions are posted on the WECC website (www.wecc.biz) under the document title, "Preschedule Calendar." Each Day-Ahead Availability Notice shall clearly identify, for each hour, Seller's forecast of all amounts of Available Capacity pursuant to this Agreement. If the Available Capacity changes by at least one (1) MW as of a time that is less than fourteen (14) hours prior to the Preschedule Day but prior to the CAISO deadline for submittal of Schedules into the Day-Ahead Market then Seller must notify Buyer of such change by telephone and shall send a revised notice to [redacted] or backup phone [redacted] and send an email to [redacted] as set forth in Appendix VI. Such Notices shall contain information regarding the beginning date and time of the event resulting in the change in Available Capacity, the expected end date and time of such event, the expected Available Capacity in MW, and any other necessary information.

If Seller fails to provide the Third-Party SC with a Day-Ahead Availability Notice as required herein, then, until Seller provides a Day-Ahead Availability Notice, the Third-Party SC may rely on the most recent Day-Ahead Forecast of Available Capacity submitted by Seller to Third-Party SC to the extent Seller's failure contributes to Imbalance Energy, Seller shall be subject to the Forecasting Penalties set forth in Section 4.6(c).

(D) Real-Time Available Capacity. During the Delivery Term, Seller shall notify Third-Party SC of any changes in Available Capacity of one (1) MW or more, whether due to Forced Outage, Force Majeure or other cause, as soon as reasonably possible, but no later than one (1) hour prior to the deadline for submitting Schedules to the CAISO in accordance with the CAISO rules for participation in the Real-Time Market. If the Available Capacity changes by at least one (1) MW as of a time that is less than one (1) hour prior to the Real-Time Market deadline, but before such deadline, then Seller must likewise notify Third-Party SC. Such Notices shall contain information regarding the beginning date and time of the event resulting in the change in Available Capacity, the expected end date and time of such event, the expected Available Capacity in MW, and any other information required by the CAISO or reasonably requested by Third-Party SC. With respect to any Forced Outage, Seller shall use commercially reasonable efforts to notify Third-Party SC of such outage within fifteen (15) minutes of the commencement of the Forced Outage. Seller shall inform Third-Party SC of any developments that will affect either the duration of such event or the availability of the Project during or after the end of such event. These notices and changes to Available Capacity shall be communicated in a method acceptable to Third-Party SC; provided that Third-Party SC specifies the method no later than 60 days prior to the effective date of such requirement. In the event Third-Party SC fails to provide Notice of an acceptable method for communications under this Section 3.4(b)(iii)(D), then Seller shall send such communications by telephone to Third-Party SC's Real-Time Desk and via email to [redacted] as set forth in Appendix VI.

(E) To the extent that Seller obtains, in the normal course of business, other forecasts of energy production at the Project not otherwise specified in this Section 3.4, then Seller shall grant Buyer read-only access to such forecasts.

(iv) Replacement of Scheduling Coordinator.

(A) At least ninety (90) days prior to the end of the Delivery Term, or as soon as practicable before the date of any termination of this Agreement prior to the end of the Delivery Term, Seller shall take all actions necessary to terminate the designation of Buyer or the Third-Party SC, as applicable, as Seller's SC. These actions include (I) submitting to the CAISO a designation of a new SC for Seller to replace Buyer or the Third-Party SC (as applicable); (II) causing the newly-designated SC to submit a letter to the CAISO accepting the designation; and (III) informing Buyer and the Third-Party SC (if applicable) of the last date on which Buyer or the Third-Party SC (as applicable) will be Seller's SC.

(B) Buyer shall submit, or if applicable cause the Third-Party SC to submit, a letter to the CAISO identifying the date on which Buyer (or Third-Party SC, as applicable) resigns as Seller's SC on the first to occur of either (I) thirty (30) days prior to the end of the Delivery Term or (II) the date of any early termination of this Agreement.

3.5 Standards of Care.

(a) General Operation. Seller shall comply with all applicable requirements of Law, the CAISO, NERC and WECC relating to the Project (including those related to construction, safety, ownership and/or operation of the Project). In the event Seller requires any data or information from Buyer in order to comply with any applicable requirements of Law, including the requirements of CAISO, NERC and WECC, relating to the Project (including those related to construction, safety, ownership and/or operation of the Project), then Seller shall request in writing such data from Buyer no less than forty-five (45) calendar days prior to Seller's requested date of Buyer's response; provided that if Seller has less than forty-five (45) calendar days prior notice of the need for such data, Seller shall request in writing such data from Buyer as soon as reasonably practicable. Buyer shall make a good faith effort to provide such data and/or information within the timeframe specified in writing by Seller or as soon thereafter as reasonably practicable.

(b) CAISO and WECC Standards. Each Party shall perform all generation, scheduling and transmission services in compliance with all applicable (i) operating policies, criteria, rules, guidelines, tariffs and protocols of the CAISO, (ii) WECC scheduling practices and (iii) Good Utility Practices.

(c) Reliability Standard. Seller agrees to abide by (i) CPUC General Order No. 167, "Enforcement of Maintenance and Operation Standards for Electric Generating Facilities", and (ii) all applicable requirements regarding interconnection of the Project, including the requirements of the interconnected Participating Transmission Owner.

3.6 Metering. All output from the Project must be delivered through a single CAISO revenue meter located on the high-voltage side of the Project's final step-up transformer (which must be dedicated solely to the Project) nearest to the Interconnection Point that exclusively measures output for the Project described herein. All Delivered Energy purchased under this Agreement must be measured by the Project's CAISO revenue meter to be eligible for payment under this Agreement. Seller shall bear all costs relating to all metering equipment installed to accommodate the Project. In addition, Seller hereby agrees to provide all meter data to Buyer in a form acceptable to Buyer, and consents to Buyer obtaining from the CAISO the CAISO meter data applicable to the Project and all inspection, testing and calibration data and reports. Seller shall grant Buyer the right to retrieve the meter reads from the CAISO Operational Meter Analysis and Reporting ("OMAR") web and/or directly from the CAISO meter(s) at the Project site. If the CAISO makes any adjustment to any CAISO meter data for a given time period, Seller agrees that it shall submit revised monthly invoices, pursuant to Section 6.2, covering the entire applicable time period in order to conform fully such adjustments to the meter data. Seller shall submit any such revised invoice no later than thirty (30) days from the date on which the CAISO provides to Seller such binding adjustment to the meter data.

3.7 Outage Notification.

(a) CAISO Approval of Outage(s). Buyer, acting through its Third-Party SC, is responsible for securing CAISO approvals for Project outages, including securing changes in its outage schedules when CAISO disapproves Buyer's schedules or cancels previously approved outages and for entering Project outages in the Scheduling and Logging system for the CAISO ("SLIC") or successor system. Through its Third-Party SC, Buyer shall put forth commercially reasonable efforts to secure and communicate CAISO approvals for Project outages in a timely manner to Seller.

(b) Planned Outages. During the Delivery Term, Seller shall notify Buyer of its proposed Planned Outage schedule for the Project for the following calendar year by complying with Section 3.4(b)(iii)(A), ("Annual Forecast of Available Capacity") and Section 3.4(b)(iii)(B), (Monthly Forecast of Available Capacity") and implementing the notification procedures set forth in Appendix VI no later than July 1st of each year during the Delivery Term. Seller shall also notify Buyer of the proposed Planned Outage schedule for the Project by the earlier of ninety (90) days before the beginning of each month or forty-five (45) days before Buyer's monthly Resource Adequacy capacity showing must be completed in accordance with the CAISO Tariff or decision of the CPUC. The Planned Outage schedule is subject to Buyer's approval, which approval may not be unreasonably withheld or conditioned. Seller shall also confirm or provide updates to Buyer regarding the Planned Outage by the earlier of fourteen (14) days prior to each Planned Outage or two (2) Business Days prior to the CAISO deadline for submitting Planned Outages. Seller shall not conduct Planned Outages during the months of January, May through September, and December. During all other months, Seller shall not schedule

Planned Outages without the prior written consent of Buyer, which consent may not be unreasonably withheld or conditioned. Seller shall contact Buyer with any requested changes to the Planned Outage schedule if Seller believes the Project must be shut down to conduct maintenance that cannot be delayed until the next scheduled Planned Outage consistent with Good Utility Practices. Seller shall not change its Planned Outage schedule without Buyer's approval, not to be unreasonably withheld or conditioned. Subject to Section 3.7(a), after any Planned Outage has been scheduled, at any time up to the commencement of work for the Planned Outage, Buyer may direct that Seller change its outage schedule as ordered by CAISO. For non-CAISO ordered changes to a Planned Outage schedule requested by Buyer, Seller shall notify Buyer of any incremental costs associated with such schedule change and an alternative schedule change, if any, that would entail lower incremental costs. If Buyer agrees to pay the incremental costs, Seller shall use commercially reasonable efforts to accommodate Buyer's request.

(c) Forced Outages. Seller shall notify Buyer and the Third-Party SC of a Forced Outage as promptly as possible, but no later than fifteen (15) minutes after the commencement of the Forced Outage and in accordance with the notification procedures set forth in Appendix VI. Buyer shall put forth commercially reasonable efforts to submit such outages to CAISO.

(d) Prolonged Outages. Seller shall notify Buyer and the Third-Party SC of a Prolonged Outage as soon as practicable in accordance with the notification provisions in Appendix VI. Seller shall notify Buyer in writing when the Project is again capable of meeting its Contract Quantity on a *pro rata* basis also in accordance with the notification provisions in Appendix VI.

(e) Force Majeure. Within two (2) Business Days of commencement of an event of Force Majeure, the non-performing Party shall provide the other Party with oral notice of the event of Force Majeure, and within two (2) weeks of the commencement of an event of Force Majeure the non-performing Party shall provide the other Party with Notice in the form of a letter describing in detail the particulars of the occurrence giving rise to the Force Majeure claim. Failure to provide timely Notice constitutes a waiver of a Force Majeure claim. The suspension of performance due to a claim of Force Majeure must be of no greater scope and of no longer duration than is required by the Force Majeure. Buyer shall not be required to make any payments for any Products that Seller fails to deliver or provide as a result of Force Majeure during the term of a Force Majeure.

(f) Communications with CAISO. Buyer, through its Third-Party SC, shall be responsible for all outage coordination communications with CAISO outage coordination personnel and CAISO operations management, including submission to CAISO of updates of outage plans, submission of clearance requests, and all other outage-related communications.

(g) Changes to Operating Procedures. Notwithstanding any language to the contrary contained in Sections 3.4, 3.6, 3.7, 3.8, or 10.13, or Appendix VI, and consistent with Section 3.5, Seller understands and acknowledges that the specified access to data and installation and maintenance of weather stations, transmission and scheduling mechanisms, metering requirements, Outage Notification Procedures and scheduling, forecast, bidding, notification and operating procedures described in the above-referenced sections are subject to change. If such changes are provided by (i) Notice from Buyer, then Seller shall implement any such changes as reasonably deemed necessary by Buyer; provided that such change does not result in an increased cost of performance to Seller hereunder other than *de minimis* amounts, or (ii) Law, then the Parties shall implement such changes as necessary for Seller and Buyer to perform their respective rights and obligations in accordance with the Law.

3.8 Operations Logs and Access Rights.

(a) Operations Logs. Seller shall maintain a complete and accurate log of all material operations and maintenance information on a daily basis. Such log shall include information on power production, efficiency, availability, maintenance performed, outages, results of inspections, manufacturer recommended services, replacements, electrical characteristics of the generators, control settings or adjustments of equipment and protective devices. Seller shall provide this information electronically to Buyer within thirty (30) days of Buyer's request.

(b) Access Rights. Buyer, its authorized agents, employees and inspectors may, on reasonable advance notice (which no case shall be less than three (3) Business Days) visit the Project during normal business hours for purposes reasonably connected with this Agreement or the exercise of any and all rights secured to Buyer by Law, or its tariff schedules, PG&E Interconnection Handbook, Electric Rule 21, and rules on file with the CPUC. In connection with the foregoing, Buyer, its authorized agents, employees and inspectors must (i) at all times adhere to all safety and security procedures as may be required by Seller; (ii) not interfere with the operation of the Project; and (iii) unless waived in writing by Seller, be escorted by a representative of Seller. Buyer shall make reasonable efforts to coordinate its emergency activities with the Safety and Security Departments, if any, of the Project operator. Seller shall keep Buyer advised of current procedures for contacting the Project operator's Safety and Security Departments.

3.9 Omitted.

ARTICLE FOUR: COMPENSATION; MONTHLY PAYMENTS

4.1 Price.

(a) Contract Price. The Contract Price for each MWh of Product as measured by Delivered Energy in each Delivery Period is set forth in Section C of the Cover Sheet.

For the avoidance of doubt, Seller shall not be compensated for any Surplus Delivered Energy.

(b) Test Period Payments. During the Test Period, Seller's full compensation for Product sold to Buyer shall be the CAISO Revenues for the Delivered Energy, which revenues Buyer shall forward to Seller in accordance with the schedule described in Section 6.1.

(c) Applicability of Full Capacity Deliverability Status to Contract Price. This Section 4.1(b) only applies to Sellers that elected to be FCDS Sellers in the Cover Sheet. If Seller has not achieved FCDS on or prior to the expected full capacity delivery date set forth in the Cover Sheet , the Contract Price shall be reduced by $[redacted]/MWh between the period beginning on such date until the first day of the calendar month immediately following the date that is forty-five (45) calendar days from the Effective FCDS Date.

4.2 Monthly Payment. Except as otherwise provided in this Article 4, for each Delivery Month, Buyer shall pay Seller, or cause to be paid to Seller, for all Delivered Energy and Deemed Delivered Energy ("Monthly Payment") in an amount equal to (A) the Contract Price multiplied by (B) the sum of (i) for each hour in the month, the Delivered Energy (exclusive of Surplus Delivered Energy) during the hour plus (ii) for each hour in the month, the amount of Deemed Delivered Energy during the hour:

Monthly Payment ={sum over all hours} [Contract Price $ × (Delivered Energy MWh_{hour} + *Deemed Delivered Energy* MWh_{hour})

For the avoidance of doubt, Excess Energy shall be compensated as set forth in Section 4.4 and shall not be included in the determination of payment set forth above; and "Delivered Energy" as used in the formula above excludes Surplus Delivered Energy, for which Seller will receive no compensation.

4.3 Capacity Factor. The Capacity Factor shall be calculated and defined as the percentage amount resulting from Delivered Energy plus Deemed Delivered Energy, if any, per Contract Year divided by the product resulting from multiplying the Contract Capacity times the number of hours in the applicable Contract Year minus Seller Excuse Hours ("Capacity Factor"):

Capacity Factor = (Delivered Energy + Deemed Delivered Energy) / (Contract Capacity × (Hours in Contract Year minus Seller Excuse Hours)).

4.4 Excess Delivered and Deemed Delivered Energy.

(a) Excess Energy Price. If, at any point in any Contract Year, the amount of Delivered Energy (exclusive of Surplus Delivered Energy) plus the amount of Deemed Delivered Energy exceeds [redacted] percent ([redacted]%) of the annual Contract Quantity amount, then:

(i) each MWh of additional Delivered Energy during such Contract Year shall be deemed "Excess Delivered Energy" and each MWh of additional Deemed Delivered Energy during such Contract Year shall be deemed "Excess Deemed Delivered Energy" (Excess Delivered Energy and Excess Deemed Delivered Energy, cumulatively, "Excess Energy"); and

(ii) for the remainder of such Contract Year:

(A) for every MWh of Excess Delivered Energy, the price paid to Seller shall be the hourly DA Price at the Delivery Point (the "Excess Delivered Energy Price"); and

(B) for every MWh of Excess Deemed Delivered Energy the price paid to Seller shall be the hourly DA Price at the Delivery Point (the "Excess Deemed Delivered Energy Price").

$Excess\ Delivered\ Energy\ Price_{hour} = (DA\ Price_{hour})$

$Excess\ Deemed\ Delivered\ Energy\ Price_{hour} = (DA\ Price_{hour})$

For the avoidance of doubt, Excess Energy shall not include any Surplus Delivered Energy.

(b) Monthly Payment for Excess Energy. Buyer shall pay Seller for Excess Energy in each hour ("Monthly Payment for Excess Energy") the amount resulting from (i) multiplying the Excess Delivered Energy Price applicable to that hour times the Excess Delivered Energy for such hour plus (ii) the Excess Deemed Delivered Energy Price applicable to that hour times the amount of Excess Deemed Delivered Energy for such hour:

$Monthly\ Payment\ for\ Excess\ Energy = \{sum\ over\ all\ hours\}\ (Excess\ Delivered\ Energy\ Price_{hour} \times Excess\ Delivered\ Energy\ MWh_{hour}) + (Excess\ Deemed\ Delivered\ Energy\ Price_{hour} \times Excess\ Deemed\ Delivered\ Energy\ MWh_{hour})$

4.5 Seller Curtailed Production Calculation. No later than fifteen (15) days after the end of a calendar month in which a Buyer Curtailment Period occurred, Seller will prepare and provide to Buyer a Seller Curtailed Production Calculation, as described in Section 1.58, for the previous month that calculates the Deemed Delivered Energy using relevant Project availability, weather, water flow, and other pertinent data for the period of time during the Buyer Curtailment Period. Upon Buyer's request, Seller shall promptly provide to Buyer any additional and supporting documentation necessary for Buyer to audit and verify any matters set forth in the Seller Curtailed Production Calculation.

4.6 CAISO Charges.

(a) Seller shall assume all liability and reimburse Buyer for any and all CAISO Penalties incurred by Buyer because of Seller's failure to perform any covenant or obligation set forth in this Agreement. Buyer shall assume all liability and reimburse Seller for any and all CAISO Penalties incurred by Seller as a result of Buyer's actions, including those resulting in a Buyer Curtailment Period.

(b) Buyer, acting through its Third-Party SC, shall (i) be responsible for all costs and charges assessed by the CAISO with respect to scheduling and Imbalance Energy, subject to Sections 4.6(a) and (c) and (ii) retain the credits and other payments received as a result of Energy from the Project delivered to the Integrated Forward Market or Real-Time Market, including revenues associated with CAISO dispatches. Seller and Buyer shall cooperate to minimize such charges and Uninstructed Imbalance Energy to the extent possible. Seller shall use commercially reasonable efforts to monitor imbalances and shall promptly notify Buyer as soon as possible after it becomes aware of any material imbalance that is occurring or has occurred. Such notification shall not alter Seller's and Buyer's respective responsibilities for payment for Imbalance Energy and costs and CAISO Penalties under this Agreement. Throughout the Delivery Term, Buyer shall be entitled to all Integrated Forward Market Load Uplift Obligation credits (as defined or required for MRTU under the CAISO Tariff) associated with the Energy generated from the Project.

(c) Forecasting Penalties.

(i) Subject to Force Majeure, in the event Seller does not in a given hour either (A) provide the access and information required in Section 3.1(l)(i); (B) comply with the installation, maintenance and repair requirements of Section 3.1(l)(iv); or (C) provide the forecast of Available Capacity required in Section 3.4(b)(iii), and the sum of Energy Deviations for each of the Settlement Intervals in the given hour exceeded the Performance Tolerance Band defined below, then Seller will be responsible for Forecasting Penalties as set forth below.

(ii) The Performance Tolerance Band is [redacted] percent [redacted]%) multiplied by Contract Capacity multiplied by one (1) hour.

(iii) Forecasting Penalties. The Forecasting Penalty shall be equal to the greater of (A) [redacted] percent ([redacted]%) of the Contract Price or (B) the absolute value of the Real-Time Price, in each case for each MWh of Energy Deviation outside the Performance Tolerance Band, or any portion thereof, in every hour for which Seller fails to meet the requirements in Section 4.6(c)(i). Settlement of Forecasting Penalties shall occur as set forth in Section 6.1 of this Agreement.

4.7 Additional Compensation.

(a) To the extent not otherwise provided for in this Agreement, in the event that Seller is compensated by a third party for any Products produced by the Project, including compensation for Resource Adequacy or Green Attributes, Seller shall remit all such compensation directly to Buyer; provided that for avoidance of doubt, nothing herein precludes Seller from retaining credits related to Electric System Upgrades contemplated in Section 3.1(h)(i).

(b) To the extent that during the Delivery Term Seller (at a nominal or no cost to Seller) is exempt from, reimbursed for or receives any refunds, credits or benefits from CAISO for congestion charges or Congestion Revenue Rights (as defined in the CAISO Tariff), whether due to any adjustments in Congestion Revenue Rights or any Locational Marginal Price (as defined in the CAISO Tariff), market adjustments, invoice adjustments, or any other hedging instruments associated with the Product (collectively, any such refunds, credits or benefits are referred to as "Reductions"), then, at Buyer's option, either (i) Seller shall transfer any such Reductions and their related rights to Buyer less any costs incurred by Seller in connection with such Reductions; or (ii) Buyer shall reduce payments due to Seller under this Agreement in amounts equal to the Reductions less any costs incurred by Seller in connection with such Reduction and Seller shall retain the Reductions.

ARTICLE FIVE: EVENTS OF DEFAULT; PERFORMANCE REQUIREMENT; REMEDIES

5.1 Events of Default. An "Event of Default" shall mean,

(a) with respect to a Party that is subject to the Event of Default, the occurrence of any of the following:

(i) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within five (5) Business Days after written Notice is received by the Party failing to make such payment;

(ii) any representation or warranty made by such Party herein (A) is false or misleading in any material respect when made or (B) with respect to Section 10.1(b), becomes false or misleading in any material respect during the Delivery Term; provided that, if a change in Law occurs after the Execution Date that causes the representation and warranty made by Seller in Section 10.1(b) to be materially false or misleading, such breach of the representation or warranty in Section 10.1(b) shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in Law during the Delivery Term in order to make the representation and warranty no longer false or misleading;

(iii) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default), if such failure is not remedied within forty-five (45) days after Notice from the Non-Defaulting Party, which time period shall be extended if the Defaulting Party is making diligent efforts to cure such failure to perform, provided that such extended period shall not exceed forty-five (45) additional days;

(iv) such Party becomes Bankrupt; or

(v) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of Law or pursuant to an agreement reasonably satisfactory to the other Party.

(b) with respect to Seller as the Defaulting Party, the occurrence of any of the following:

(i) if at any time during the Term of this Agreement, Seller delivers or attempts to deliver to the Delivery Point for sale under this Agreement Energy that was not generated by the Project;

(ii) failure by Seller to satisfy the creditworthiness/collateral requirements agreed to pursuant to Sections 8.2, 8.3, or 8.4 of this Agreement and such failure is not cured within any applicable cure period;

(iii) if Seller has provided and Buyer has accepted, a Guaranty to satisfy the collateral obligations under this Agreement, then with respect to such guarantor or the Guaranty, if Seller had not replaced the Guaranty in accordance with Section 8.6 within five (5) Business Days following Buyer's Notice of a request for replacement;

(iv) failure by Seller to achieve the Guaranteed Energy Production requirement as set forth in Section 3.1(e)(ii) of this Agreement as follows:

(A) after the one (1) year GEP Cure period Seller has failed to cure the GEP Failure and has failed to pay GEP Damages in the time period set forth in Section 3.1(e)(ii); or

(B) if, after any Performance Measurement Period the cumulative GEP Shortfall for all preceding Performance Measurement Periods occurring during the Delivery Term equals or exceeds two times the Contract Quantity (as may be adjusted pursuant to Section 3.1(e)(ii)); provided, however, that if all or a portion of the GEP Shortfall during an applicable Performance Measurement Period is principally caused by a non-Force Majeure major equipment malfunction, breakdown, or failure resulting in a reduction of Energy production of the Project by at least fifty percent (50%) of the Contract Quantity in one or both years of the Performance Measurement Period, as applicable, and such malfunction, breakdown, or failure was not caused by Seller and could not have been avoided through the exercise of Good Utility Practice, such failure shall be excluded from the calculation of the cumulative GEP Shortfall for purposes of this subsection;

(v) Seller has not obtained the deliverability type selected in Section A (FCDS or PCDS) of the Cover Sheet by the Deliverability Finding Deadline; or

(vi) Seller has not obtained the Partial Capacity Deliverability Status Amount identified in Section A of the Cover Sheet by the Deliverability Finding Deadline.

(vii) Seller's failure to operate the Project in compliance with all applicable Laws as determined by the Governmental Authority charged with implementation and/or enforcement of the specific Law at issue.

5.2 Remedies. If an Event of Default with respect to a Defaulting Party shall have occurred and is continuing, the other Party ("Non-Defaulting Party") shall have the following rights:

(a) send Notice, designating a day, no earlier than the day such Notice is deemed to be received and no later than twenty (20) days after such Notice is deemed to be received, as an early termination date of this Agreement ("Early Termination Date") on which to (i) collect the Damage Payment (in the case of any Event of Default of Seller that arose at any time prior to the commencement of the Delivery Term), or (ii) collect the Termination Payment (in the case of any Event of Default of Seller that arose during the Delivery Term or in the case of any Event of Default of Buyer at any time);

(b) accelerate all amounts owing between the Parties, terminate the Transaction and end the Delivery Term effective as of the Early Termination Date;

(c) collect the Termination Payment or Damage Payment, as applicable;

(d) withhold any payments due to the Defaulting Party under this Agreement;

(e) suspend performance;

(f) exercise its rights pursuant to Section 8.2 to draw upon and retain Performance Assurance;

(g) demand payment for damages due to Buyer's unexcused failure to take delivery or pay for Product; and

(h) exercise any other rights or remedies available at Law or in equity (including the collection of monetary damages) to the extent otherwise permitted under this Agreement.

Notwithstanding anything to the contrary contained herein, Seller may exercise the rights or remedies set forth in Sections 5.2(e), (g), and (h) without terminating this Agreement.

5.3 Calculation of Termination Payment.

(a) In the case where the Non-Defaulting Party is entitled to collect the Termination Payment pursuant to Section 5.2(a), the Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for the Terminated Transaction as of the Early Termination Date. Third parties supplying information for purposes of the calculation of Gains or Losses may include dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information. If the Non-Defaulting Party uses the market price for a comparable transaction to determine the Gains or Losses, such price should be determined by using the average of market quotations provided by three (3) or more bona fide unaffiliated market participants. If the number of available quotes is three, then the average of the three quotes shall be deemed to be the market price. Where a quote is in the form of bid and ask prices, the price that is to be used in the averaging is the midpoint between the bid and ask price. The quotes shall be obtained in a commercially reasonable manner and shall be: (i) for a like amount, (ii) of the same Product, (iii) at the same Delivery Point, and (iv) for the remaining Delivery Term. Regardless of the method chosen by the Non-Defaulting Party to calculate the Settlement Amount, the Settlement Amount must still be reasonable under the circumstances.

(b) If the Non-Defaulting Party's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of the Terminated Transaction, the Settlement Amount shall be zero.

(c) The Non-Defaulting Party shall not have to enter into replacement transactions to establish a Settlement Amount.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, Notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to the Non-Defaulting Party. The Notice shall include a written statement explaining in reasonable detail the calculation of such amount and the sources for such calculation. The Termination Payment shall be made to the Non-Defaulting Party, as applicable, within ten (10) Business Days after such Notice is effective.

5.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within ten (10) Business Days of receipt of the Non-Defaulting Party's calculation of the

Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute. Disputes regarding the Termination Payment shall be determined in accordance with Article Twelve.

5.6 Rights And Remedies Are Cumulative. The rights and remedies of a Party pursuant to this Article Five shall be cumulative and in addition to the rights of the Parties otherwise provided in this Agreement.

5.7 Duty to Mitigate. Buyer and Seller shall each have a duty to mitigate damages pursuant to this Agreement, and each shall use reasonable efforts to minimize any damages it may incur as a result of the other Party's non-performance of this Agreement, including with respect to termination of this Agreement.

ARTICLE SIX: PAYMENT

6.1 Billing and Payment; Remedies. On or about the tenth (10th) day of each month beginning with the second month of the first Contract Year, and every month thereafter, and continuing through and including the first month following the end of the Delivery Term, Seller shall provide to Buyer: (a) records of metered data, including CAISO metering and transaction data sufficient to document and verify the generation of Product by the Project for any CAISO settlement time interval during the preceding months; (b) access to any records, including invoices or settlement data from the CAISO, necessary to verify the accuracy or amount of any Reductions; and (c) an invoice, in the format specified by Buyer, covering the services provided in the preceding month determined in accordance with the applicable provisions of Article Four. Seller shall continue to provide to Buyer an invoice of CAISO charges, net any sums Buyer owes Seller under this Agreement, on or about the tenth (10th) day of each month until the date of the Final True-Up. Buyer shall pay the undisputed amount of such invoices less the amount of any RA Deficiency Amount and the amount of any Forecasting Penalties, as applicable on or before the later of the twenty-fifth (25th) day of each month and fifteen (15) days after receipt of the invoice. If either the invoice date or payment date is not a Business Day, then such invoice or payment shall be provided on the next following Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any undisputed amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full. Invoices may be sent by facsimile or e-mail.

6.2 Disputes and Adjustments of Invoices. In the event an invoice or portion thereof or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with Notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Subject to Section 3.6, in the event adjustments to payments are required as a result of inaccurate meter(s), Buyer shall use corrected measurements to recompute the amount due from Buyer to Seller for the Product delivered under the Transaction during the period of inaccuracy. The Parties agree to use good faith efforts to resolve the dispute or identify the adjustment as soon as possible. Upon resolution of the dispute or calculation of the adjustment, any required payment shall be made within fifteen (15) days of such resolution along with interest accrued at the Interest Rate from and including the due date, but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment, but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.2 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made; provided that, such waiver shall not apply to any adjustment or dispute related to Seller's performance under any applicable RMR Contract; and provided further that, any disputes with respect to a statement of CAISO Revenues is waived unless Seller notifies Buyer in accordance with this Section 6.2 within one (1) month after the last statement of CAISO Revenues is provided. If an invoice is not rendered within twelve (12) months after the close of the month during which performance under the Transaction occurred, the right to payment for such performance is waived.

ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS MAY OTHERWISE BE EXPRESSLY PROVIDED IN THIS AGREEMENT, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED UNLESS EXPRESSLY HEREIN PROVIDED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 10.4 ("INDEMNITIES"), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF.

TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Seller Financial Information. If requested by Buyer, Seller shall deliver to Buyer (a) within one hundred twenty (120) days following the end of each of Seller's fiscal years, a copy of Seller's or Seller's guarantor's, if applicable, annual report containing unaudited consolidated financial statements for such fiscal year (or audited consolidated financial statements for such fiscal year if otherwise available) and (b) within sixty (60) days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with Generally Accepted Accounting Principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as such Party diligently pursues the preparation, certification and delivery of the statements.

8.2 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent Seller delivers the Pre-Delivery Term Security, or Delivery Term Security, as applicable hereunder, Seller hereby grants to Buyer, as the secured party, a first priority security interest in, and lien on (and right of setoff against), and assignment of, all such Performance Assurance posted with Buyer in the form of cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, Buyer. Within thirty (30) days of the delivery of the Pre-Delivery Term Security or Delivery Term Security as applicable, Seller agrees to take such action as Buyer reasonably requires in order to perfect a first-priority security interest in, and lien on (and right of setoff against), such Performance Assurance and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, Buyer, as the Non-Defaulting Party, may do any one or more of the following: (a) exercise any of the rights and remedies of a secured party with respect to all Pre-Delivery Term Security or Delivery Term Security, as applicable, including any such rights and remedies under the Law then in effect; (b) exercise its rights of setoff against any and all property of Seller, as the Defaulting Party, in the possession of the Buyer or Buyer's agent; (c) draw on any outstanding Letter of Credit issued for its benefit; and (d) liquidate all Pre-Delivery Term Security or Delivery Term Security, as applicable, then held by or for the benefit of Buyer free from any claim or right of any nature whatsoever of Seller, including any equity or right of purchase or redemption by Seller. Buyer shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce Seller's obligations under the Agreement (Seller remaining liable for any amounts owing to Buyer after such application), subject to the Buyer's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

8.3 Performance Assurance.

(a) Security. Seller agrees to deliver to Buyer collateral to secure its obligations under this Agreement, which Seller shall maintain in full force and effect for the period posted with Buyer, as follows:

(i) Pre-Delivery Term Security pursuant to this Section 8.3(a)(i) in the amount of $[redacted]/kW for As-Available resources or [redacted]/kW for Baseload resources multiplied by the capacity of the Project as reflected in Section B of the Cover Sheet, within fifteen (15) Business Days following the Effective Date of this Agreement until Seller posts Delivery Term Security pursuant to Section 8.3(a)(ii) below with Buyer.

(ii) Delivery Term Security pursuant to this Section 8.3(a)(ii) in the amount equal to the Damage Payment from the date required pursuant to Section 3.1(c)(i) as a condition precedent to the Initial Energy Delivery Date until the end of the Term; provided that, with Buyer's consent, Seller may elect to apply the Pre-Delivery Term Security posted pursuant to Section 8.3(a)(i) toward the Delivery Term Security posted pursuant to this Section 8.3(a)(ii).

The amount of Performance Assurance required under this Agreement shall not be deemed a limitation of damages. Except as specifically provided for in this Section 8.3(a), Buyer acknowledges that Seller shall not be required to post any additional security.

(b) Use of Pre-Delivery Term Security or Term Security. Buyer shall be entitled to draw upon the Pre-Delivery Term Security or Term Security for any damages arising upon Buyer's declaration of an Early Termination Date.

(c) Termination of Pre-Delivery Term Security. If after the Initial Energy Delivery Date no damages are due and owing to Buyer under this Agreement, then Seller shall no longer be required to maintain the Pre-Delivery Term Security, and Buyer shall return to Seller the Pre-Delivery Term Security, less the amounts drawn in accordance with Section 8.3(b). The Pre-Delivery Term Security (or portion thereof) due to Seller shall be returned to Seller within five (5) Business Days of

Seller's provision of the Delivery Term Security, as applicable unless, with Buyer's consent, Seller elects to apply the Pre-Delivery Term Security posted pursuant to Section 8.3(a)(i) toward the Delivery Term Security posted pursuant to Section 8.3(a)(ii), as applicable.

(d) Payment and Transfer of Interest. Buyer shall pay interest on cash held as Pre-Delivery Term Security, Delivery Term Security or Term Security, as applicable, at the Interest Rate; provided that, the interest on Pre-Delivery Term Security shall be retained by Buyer until Seller posts the Delivery Term Security pursuant to Section 8.3(a)(ii). Upon Seller's posting of the Delivery Term Security, all accrued interest on the unused portion of Pre-Delivery Term Security shall be transferred from Buyer to Seller in the form of cash by wire transfer to the bank account specified under "Wire Transfer" in the Cover Sheet (Notices List). After Seller posts the Delivery Term Security or Term Security, Buyer shall transfer (as described in the preceding sentence) on or before each Interest Payment Date the Interest Amount due to Seller for such Delivery Term Security or Term Security.

(e) Return of Performance Assurance. Buyer shall return the unused portion of Pre-Delivery Term Security, Delivery Term Security or Term Security, as applicable, including the payment of any interest due thereon, pursuant to Section 8.3(d) above, to Seller promptly after the following has occurred: (i) the Term of the Agreement has ended, or subject to Section 8.2, an Early Termination Date has occurred, as applicable; and (ii) all payment obligations of the Seller arising under this Agreement, including payments pursuant to Section 4.6 ("CAISO Charges"), Termination Payment, indemnification payments or other damages are paid in full (whether directly or indirectly such as through set-off or netting).

8.4 Letter of Credit. Performance Assurance provided in the form of a Letter of Credit shall be subject to the following provisions:

(a) If Seller has provided a Letter of Credit pursuant to any of the applicable provisions in this Article Eight, then Seller shall renew or cause the renewal of each outstanding Letter of Credit on a timely basis in accordance with this Agreement.

(b) In the event the issuer of such Letter of Credit at any time (i) fails to maintain the requirements of an Eligible LC Bank or Letter of Credit, (ii) indicates its intent not to renew such Letter of Credit, or (iii) fails to honor Buyer's properly documented request to draw on such Letter of Credit, Seller shall cure such occurrence by complying with either (A) or (B) below in an amount equal to the outstanding Letter of Credit, and by completing the action within five (5) Business Days after the date of Buyer's Notice to Seller of an occurrence listed in this subsection (Seller's compliance with either (A) or (B) below is considered the "Cure"):

(A) providing a substitute Letter of Credit that is issued by an Eligible LC Bank, other than the bank which is the subject of Buyer's Notice to Seller in Section 8.5(b) above; or

(B) posting cash.

If Seller fails to Cure or if such Letter of Credit expires or terminates without a full draw thereon by Buyer, or fails or ceases to be in full force and effect at any time that such Letter of Credit is required pursuant to the terms of this Agreement, then Seller shall have failed to meet the creditworthiness or collateral requirements of Article Eight.

(c) Notwithstanding the foregoing in Section 8.4(b), if, at any time, the issuer of such Letter of Credit has a Credit Rating on "credit watch" negative or developing by S&P, or is on

Moody's "watch list" under review for downgrade or uncertain ratings action (either a "Watch"), then Buyer may make a demand to Seller by Notice ("LC Notice") to provide a substitute Letter of Credit that is issued by an Eligible LC Bank, other than the bank on a Watch ("Substitute Letter of Credit"). The Parties shall have thirty (30) Business Days from the LC Notice to negotiate a Substitute Letter of Credit ("Substitute Bank Period").

(i) If the Parties do not agree to a Substitute Letter of Credit by the end of the Substitute Bank Period, then Buyer shall provide Seller with Notice within five (5) Business Days following the expiration of the Substitute Bank Period ("Ineligible LC Bank Notice Period") that either:

(A) Buyer agrees to continue accepting the then currently outstanding Letter of Credit from the bank that is the subject of the LC Notice, but such bank shall no longer be an Eligible LC Bank ("Ineligible LC Bank") and Buyer will not accept future or renewals of Letters of Credit from the Ineligible LC Bank; or

(B) the bank that is the subject of the LC Notice is an Ineligible LC Bank and Seller shall then have thirty (30) days from the date of Buyer's Notice to Cure pursuant to Section 8.5(b) and, if Seller fails to Cure, then the last paragraph in Section 8.4(b) shall apply to Seller.

(ii) If the Parties have not agreed to a Substitute Letter of Credit and Buyer fails to provide a Notice during the Ineligible LC Bank Notice Period above, then Seller may continue providing the Letter of Credit posted immediately prior to the LC Notice.

(d) In all cases, the reasonable costs and expenses of establishing, renewing, substituting, canceling, increasing, reducing, or otherwise administering the Letter of Credit shall be borne by Seller.

8.5 Guaranty. If at any time Seller's guarantor or Guaranty is no longer acceptable to Buyer in its sole discretion, Seller shall replace the Guaranty with Performance Assurance as provided herein. Within five (5) Business Days following Buyer's written request for replacement of the Guaranty, Seller shall deliver to Buyer replacement Performance Assurance in the form of a replacement Guaranty, Letter of Credit or cash in an amount equal to the applicable amount of the Guaranty issued pursuant to this Agreement. In the event Seller shall fail to provide replacement Performance Assurance to Buyer as required in the preceding sentence, then Buyer may declare an Event of Default pursuant to Section 5.1(b)(iii) by providing Notice thereof to Seller in accordance with Section 5.2.

ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the Parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

9.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any Governmental Authority ("Governmental Charges") on or with respect to the Product or the Transaction arising at the Delivery Point, including ad valorem taxes and other taxes attributable to the Project, land, land rights or interests in land for the Project. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or the Transaction from the Delivery Point. In the event Seller is required by Law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by Law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct such amounts from payments to Seller with respect to payments under the Agreement;

if Buyer elects not to deduct such amounts from Seller's payments, Seller shall promptly reimburse Buyer for such amounts upon request. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the Law. A Party that is exempt at any time and for any reason from one or more Governmental Charges bears the risk that such exemption shall be lost or the benefit of such exemption reduced; and thus, in the event a Party's exemption is lost or reduced, each Party's responsibility with respect to such Governmental Charge shall be in accordance with the first four sentences of this Section.

ARTICLE TEN: MISCELLANEOUS

10.1 Representations and Warranties.

(a) General Representations and Warranties. On the Execution Date, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the Laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to perform its obligations under this Agreement;

(iii) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code (as in effect as of the Execution Date of this Agreement);

(iv) the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any Laws applicable to it;

(v) this Agreement and each other document executed and delivered in accordance with this Agreement constitute legally valid and binding obligations enforceable against it in accordance with its terms, subject to any Equitable Defenses;

(vi) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vii) there is not pending or, to its knowledge, threatened against it or any of its Affiliates, any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement;

(viii) no Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement;

(ix) it is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Agreement; and

(x) it has entered into this Agreement in connection with the conduct of its business and it has the capacity or the ability to make or take delivery of the Product as provided in this Agreement.

(b) Seller Representations and Warranties.

(i) Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; (ii) the Product meets the RPS compliance requirements for Portfolio Content Category 1 as set forth in California Public Utilities Code Section 399.16(b)(1)(A) in a manner consistent with Commission Decision 11-12-052, as it may be subsequently revised; and (iii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to become materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(ii) Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(iii) Seller, and, if applicable, its successors, represents and warrants that beginning with the Execution Date and throughout the Delivery Term of this Agreement, the Project is operated in compliance with all applicable Laws as determined by the Governmental Authority charged with implementation and/or enforcement of the specific Law at issue.

10.2 Covenants.

(a) General Covenants. Each Party covenants that throughout the Delivery Term:

(i) it shall continue to be duly organized, validly existing and in good standing under the Laws of the jurisdiction of its formation;

(ii) it shall maintain (or obtain from time to time as required, including through renewal, as applicable) all regulatory authorizations necessary for it to legally perform its obligations under this Agreement and the Transaction; and

(iii) it shall perform its obligations under this Agreement and the Transaction in a manner that does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any Law, rule, regulation, order or the like applicable to it.

(b) Seller Covenants.

(i) Seller covenants throughout the Delivery Term that it will take no action or permit any other person or entity (other than Buyer) to take any action that would impair in any way Buyer's ability to rely on the Project in order to satisfy its Resource Adequacy Requirements; and

(ii) Seller covenants that it shall comply with all CAISO Tariff requirements and/or Participating TO tariff requirements, as applicable, that are applicable to an Interconnection Customer (as defined in the CAISO Tariff or Participating TO's tariff, as applicable) and shall take any other necessary action, including payment of fees and submission of requests, applications or other documentation, to promote the completion of the Electric System Upgrades prior to the RA Start Date.

(iii) Seller covenants that the Initial Energy Delivery Date shall occur no later than the Expected Initial Energy Delivery Date specified in Section B of the Cover Sheet.

10.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Product free and clear of all liens, security interests, Claims and encumbrances or any interest therein or thereto by any person or entity arising prior to or at the Delivery Point.

10.4 Indemnities.

(a) Indemnity by Seller. Seller shall release, indemnify and hold harmless Buyer or Buyers' respective directors, officers, agents, and representatives against and from any and all loss, Claims, actions or suits, including costs and attorney's fees resulting from, or arising out of or in any way connected with (i) the Product delivered under this Agreement to the Delivery Point, or (ii) Seller's operation and/or maintenance of the Project, including any loss, Claim, action or suit, for or on account of injury to, bodily or otherwise, or death of persons, or for damage to or destruction of property belonging to Buyer, Seller, or others, excepting only such loss, Claim, action or suit as may be caused solely by the willful misconduct or gross negligence of Buyer, its Affiliates, or Buyers' and Affiliates' respective agents, employees, directors, or officers.

(b) Indemnity by Buyer. Buyer shall release, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, Claims, actions or suits, including costs and attorney's fees resulting from, or arising out of or in any way connected with the Product delivered by Seller under this Agreement after the Delivery Point, including any loss, Claim, action or suit, for or on account of injury to, bodily or otherwise, or death of persons, or for damage to or destruction of property belonging to Buyer, Seller, or others, excepting only such loss, Claim, action or suit as may be caused solely by the willful misconduct or gross negligence of Seller, its Affiliates, or Seller's and Affiliates' respective agents, employees, directors or officers.

(c) No Dedication. Without limitation of each Party's obligations under Sections 10.5(a) and 10.5(b) herein, nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person or entity not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or the public, nor affect the status of Buyer as an independent public utility corporation or Seller as an independent individual or entity.

10.5 Assignment.

(a) General Assignment. Except as provided in Sections 10.5 (b) and (c), neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld so long as among other things (i) the assignee assumes the transferring Party's payment and performance obligations under this Agreement, (ii) the assignee agrees in writing to be bound by the terms and conditions hereof, (iii) the transferring Party delivers evidence satisfactory to the non-transferring Party of the proposed assignee's technical and financial capability to fulfill the assigning Party's obligations hereunder and (iv) the transferring Party delivers such tax and enforceability assurance as the other Party may reasonably request. Notwithstanding the foregoing and except as provided in Section 10.5(b), consent shall not be required for an assignment of this Agreement where the assigning Party remains subject to liability or obligation under this Agreement, provided that (i) the assignee assumes the assigning Party's payment and performance obligations under this Agreement, (ii) the assignee agrees in writing to be bound by the terms and conditions hereof, and (iii) the assigning Party provides the other Party hereto with at least thirty (30) days' prior written notice of the assignment.

(b) Assignment to Financing Providers. Seller shall be permitted to assign this Agreement as collateral for any financing or refinancing of the Project with the prior written consent of the Buyer, which consent shall not be unreasonably withheld. If Buyer gives its consent, then such consent shall be in a form substantially similar to the Form of Consent to Assignment attached hereto as Appendix VII provided that (i) Buyer shall not be required to consent to any additional terms or conditions beyond those contained in Appendix VII, including extension of any cure periods or additional remedies for financing providers, and (ii) Seller shall be responsible at Buyer's request for Buyer's reasonable costs associated with the review, negotiation, execution and delivery of documents in connection with such assignment, attorneys' fees.

(c) Notice of Change in Control. Except in connection with public market transactions of the equity interests or capital stock of Seller or Seller's Affiliates', Seller shall provide Buyer notice of any direct change of control of Seller (whether voluntary or by operation of Law).

(d) Unauthorized Assignment. Any assignment or purported assignment in violation of this Section 10.5 is void.

10.6 Confidentiality.

(a) Each Party agrees, and shall use reasonable efforts to cause its parent, subsidiary and Affiliates, and its and their respective directors, officers, employees and representatives, as a condition to receiving confidential information hereunder, to keep confidential, except as required by Law, including without limitation the California Public Records Act (Government Code §§ 6250 et seq, "CPRA"), all documents, data (including operating data provided in connection with the scheduling of energy or otherwise pursuant to this Agreement), drawings, studies, projections, plans and other written information that relate to economic benefits to, or amounts payable by, any Party under this Agreement, and with respect to documents that are clearly marked "Confidential" at the time a Party shares such information with the other Party ("Confidential Information"). The provisions of this Section 10.6 shall survive and shall continue to be binding upon the Parties for a period of one (1) year following the date of termination or expiration of this Agreement. Notwithstanding the foregoing, information shall not be considered Confidential Information if such information (i) is disclosed with the prior written consent of the originating Party, (ii) was in the public domain prior to disclosure or is or becomes publicly known or available other than through the action of the receiving Party in violation of this Agreement, (iii) was lawfully in a Party's possession or acquired by a Party outside of this Agreement, which acquisition was not known by the receiving Party to be in breach of any confidentiality obligation, or (iv) is developed independently by a Party based solely on information that is not considered confidential under this Agreement.

(b) Subject to the CPRA, either Party may, without violating this Section 10.6, disclose matters that are made confidential by this Agreement:

(i) to its counsel, accountants, auditors, advisors, other professional consultants, credit rating agencies, actual or prospective, co-owners, investors, purchasers, lenders, underwriters, contractors, suppliers, and others involved in construction, operation, and financing transactions and arrangements for a Party or its subsidiaries or Affiliates;

(ii) to governmental officials and parties involved in any proceeding in which a Party is seeking a Permit, certificate, or other regulatory approval or order necessary or appropriate to carry out this Agreement; and

(iii) to governmental officials or the public as required by any law, regulation, order, rule, order, ruling or other Requirement of Law, including oral questions, discovery requests, subpoenas, civil investigations or similar processes and laws or regulations requiring disclosure of financial information, information material to financial matters, and filing of financial reports.

(c) If a Party is requested or required, pursuant to any applicable Law, regulation, order, rule, or ruling, discovery request, subpoena, civil investigation or similar process to disclose any of the Confidential Information, such Party shall provide prompt written notice to the other Party of such request or requirement so that at such other Party's expense, such other Party can seek a protective order or other appropriate remedy concerning such disclosure.

(d) Notwithstanding the foregoing or any other provision of this Agreement, Seller acknowledges that Buyer is subject to disclosure as required by CPRA. Confidential Information of Seller provided to Buyer pursuant to this Agreement shall become the property of Buyer, and Seller acknowledges that Buyer shall not be in breach of this Agreement or have any liability whatsoever under this Agreement or otherwise for any claims or causes of action whatsoever resulting from or arising out of Buyer copying or releasing to a third party any of the Confidential Information of Seller pursuant to CPRA; *provided* that Seller shall (i) provide notice to Seller prior to any such disclosure in accordance with Section 10.6(c) endeavor, in good faith, not to disclose any of Seller's "trade secrets" as consistent with the CPRA and (iii) support, to the extent in compliance with Buyer's rights and obligations under applicable laws, Seller in its efforts to obtain a protective order or other appropriate remedy with respect to the disclosure of operating data from the Project or any engineering drawings, project plans, technical specifications or other similar information regarding the Project.

(e) Notwithstanding the foregoing or any other provision of this Agreement, Buyer may record, register, deliver and file all such notices, statements, instruments and other documents as may be necessary or advisable to render fully valid, perfected and enforceable under all applicable law the credit support contemplated by this Agreement, and the rights, Liens and priorities of Buyer with respect to such credit support.

(f) If Buyer receives a CPRA request for Confidential Information of Seller, and Buyer determines that such Confidential Information is subject to disclosure under CPRA, then Buyer shall notify the other Buyer and Seller of the request and its intent to disclose the documents. Buyer, as required by CPRA, shall release such documents unless Seller timely obtains a court order prohibiting such release. If Seller, at its sole expense, chooses to seek a court order prohibiting the release of Confidential Information pursuant to a CPRA request, then Seller undertakes and agrees to defend, indemnify and hold harmless Buyer and the Indemnitees from and against all suits, claims, and causes of action brought against Buyer or any Indemnitees for Buyer's refusal to disclose Confidential Information of Seller to any person making a request pursuant to CPRA. Seller's indemnity obligations shall include, but are not limited to, all actual costs incurred by Buyer and any Indemnitees, and specifically including costs of experts and consultants, as well as all damages or liability of any nature whatsoever arising out of any suits, claims, and causes of action brought against Buyer or any Indemnitees, through and including any appellate proceedings. Seller's obligations to Buyer and all Indemnitees under this indemnification provision shall be due and payable on a Monthly, on-going basis within thirty (30) days after each submission to Seller of Buyer' invoices for all fees and costs incurred by Buyer and all Indemnitees, as well as all damages or liability of any nature.

(g) Each Party acknowledges that any disclosure or misappropriation of Confidential Information by such Party in violation of this Agreement could cause the other Party or their Affiliates irreparable harm, the amount of which may be extremely difficult to estimate, thus making any remedy at law or in damages inadequate. Therefore each Party agrees that the non-breaching Party shall have the right to apply to any court of competent jurisdiction for a restraining order or an injunction restraining or enjoining any breach or threatened breach of this Agreement and for any other equitable relief that such non-breaching Party deems appropriate. This right shall be in addition to any other remedy available to the Parties in law or equity, subject to the limitations set forth in Section 7.1.

10.7 Audit. Each Party has the right, at its sole expense and during normal working hours, after reasonable Notice, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement including amounts of Delivered Energy. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

10.8 Insurance. Throughout the Term, Seller shall, at its sole cost and expense, obtain and maintain the following insurance coverages and be responsible for its subcontractors, including Seller's EPC Contractors, maintaining sufficient limits of the appropriate insurance coverage. The obligations of the Seller in this Section 10.10 constitute material obligations of the Agreement.

(a) Workers' Compensation and Employers' Liability.

(i) Workers' Compensation insurance indicating compliance with any applicable labor codes, acts, Laws or statutes, state or federal, where Seller performs Work.

(ii) Employers' Liability insurance shall not be less than one million dollars ($1,000,000.00) for injury or death occurring as a result of each accident.

(b) Commercial General Liability.

(i) Coverage shall be at least as broad as the Insurance Services Office Commercial General Liability Coverage "occurrence" form, with no alterations to the coverage form.

(ii) The limit shall not be less than three million dollars ($3,000,000.00) each occurrence for bodily injury, property damage, personal injury and products/completed operations. Defense costs shall be provided as an additional benefit and not included within the limits of liability. Coverage limits may be satisfied using an umbrella or excess liability policy or an Owners Contractors Protective (OPC) policy. Limits shall be on a per project basis.

(iii) Coverage shall:

(A) by “Additional Insured” endorsement add as insureds RCEA, its directors, officers, agents and employees with respect to liability arising out of the Work performed by or for the Seller. In the event the Commercial General Liability policy includes a “blanket endorsement by contract,” the following language added to the certificate of insurance will satisfy Buyer’s requirement: “RCEA, its directors, officers, agents and employees with respect to liability arising out of the Work performed by or for the Seller has been endorsed by blanket endorsement;”

(B) be endorsed (blanket or otherwise) to specify that the Seller's insurance is primary and that any insurance or self-insurance maintained by RCEA shall not contribute with it; and

(C) include a severability of interest clause.

(c) Business Auto.

(i) Coverage shall be at least as broad as the Insurance Services Office Business Auto Coverage form covering Automobile Liability, code 1 “any auto”.

(ii) The limit shall not be less than one million dollars ($1,000,000.00) each accident for bodily injury and property damage.

(iii) If scope of Work involves hauling hazardous materials, coverage shall be endorsed in accordance with Section 30 of the Motor Carrier Act of 1980 (Category 2) and the CA 99 48 endorsement.

(d) Additional Insurance Requirements.

(i) Before commencing performance of the Work, Seller shall furnish Buyer with certificates of insurance and endorsements of all required insurance for Seller.

(ii) The documentation shall state that coverage shall not be cancelled except after thirty (30) days prior written Notice has been given to Buyer.

(iii) Certificates of insurance and endorsements shall be signed and submitted by a person authorized by that insurer to issue certificates of insurance and endorsements on its behalf, and shall be Noticed and delivered to Buyer’s authorized representative.

(iv) Reviews of such insurance may be conducted by Buyer on an annual basis.

(v) Upon request, Seller shall furnish Buyer evidence of insurance for its subcontractors.

(e) Form And Content.

All policies or binders with respect to insurance maintained by Seller shall waive any right of subrogation of the insurers hereunder against Buyer, its officers, directors, employees, agents and representatives of each of them, and any right of the insurers to any setoff or counterclaim or any other deduction, whether by attachment or otherwise, in respect of any liability of any such person insured under such policy.

10.9 Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

10.10 General. Except to the extent provided for, no amendment or modification to this Agreement shall be enforceable unless reduced to writing and executed by both Parties. The Parties acknowledge and agree that this Agreement is a "forward contract" (within the meaning of the Bankruptcy Code, as in effect as of the Execution Date). This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The headings used herein are for convenience and reference purposes only. Facsimile or PDF transmission will be the same as delivery of an original document; provided that at the request of either Party, the other Party will confirm facsimile or PDF signatures by signing and delivering an original document; provided, however, that the execution and delivery of this Agreement and its counterparts shall be subject to Section 10.12. This Agreement shall be binding on each Party's successors and permitted assigns.

10.11 Severability. If any provision in this Agreement is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties.

10.12 Counterparts. This Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Agreement. Delivery of an executed counterpart of this Agreement by fax will be deemed as effective as delivery of an originally executed counterpart. Any Party delivering an executed counterpart of this Agreement by facsimile will also deliver an originally executed counterpart, but the failure of any Party to deliver an originally executed counterpart of this Agreement will not affect the validity or effectiveness of this Agreement.

10.13 Mobile Sierra. Notwithstanding any provision of this Agreement, neither Party shall seek, nor shall they support any third party seeking, to prospectively or retroactively revise the rates, terms or conditions of service of this Agreement through application or complaint to the FERC pursuant to the provisions of the Federal Power Act, absent prior written agreement of the Parties. Further, absent the prior written agreement in writing by both Parties, the standard of review for changes to the rates, terms or conditions of service of this Agreement proposed by a Party, a non-Party, or the FERC acting *sua sponte* shall be the "public interest" standard of review set forth in *United States Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956).*

10.14. Public Announcements. Seller shall make no public announcement regarding any aspect of this Agreement or the role of Seller in regards to the development or operation of the Project without the prior written consent of Buyer, which consent shall not be unreasonably withheld. Any public announcement by Seller must comply with California Business and Professions Code § 17580.5 and with the *Guides for the Use of Environmental Marketing Claims*, published by the FTC, as it may be updated from time to time.

ARTICLE ELEVEN: TERMINATION EVENT

11.1 Force Majeure Termination Event.

(a) Force Majeure Failure. Buyer shall have the right, but not the obligation, to terminate this Agreement after the occurrence of any of the following: (each constituting a "Force Majeure Failure"):

(i) If during the Delivery Term:

(A) the Project fails to deliver at least forty percent (40%) of the Contract Quantity to the Delivery Point for a period of twelve (12) consecutive rolling months following a Force Majeure event that materially and adversely impacts the Project and Buyer has provided Notice to Seller of such failure; provided that, if Seller within forty-five (45) days of receipt of Notice from Buyer, presents Buyer with a plan for mitigation of the effect of the Force Majeure within a period not to exceed six (6) months from the above-mentioned Notice date, which plan is commercially reasonable and satisfactory to Buyer, as evidenced by Buyer's written acknowledgement of such plan, then Buyer shall not have the right to terminate this Agreement pursuant to this Section 11.1(a) until the expiration of the mitigation period deemed necessary by Seller to repair the Project (which shall not exceed six (6) months); provided that Seller diligently pursues such mitigation plan throughout the mitigation period, and after which time Buyer may terminate this Agreement unless the Project has been repaired, and the Seller has resumed and is satisfying all of its obligations under this Agreement; or

(B) the Project is destroyed or rendered inoperable by a Force Majeure event caused by a catastrophic natural disaster; provided that Seller shall have up to ninety (90) days following such Force Majeure event to obtain a report from an independent, third party engineer stating whether the Project is capable of being repaired or replaced no later than twenty-four (24) months from the date of the report and Seller shall provide Buyer with a copy of the engineer's report, at no cost to Buyer; provided further that if such engineer's report concludes that the Project is capable of being repaired or replaced within such twenty-four (24) month period and Seller undertakes and continues such repair or replacement with due diligence, then Buyer shall not have the right to terminate this Agreement pursuant to this Section 11.1(a) until the expiration of the period deemed necessary by the engineer's report (which shall not exceed twenty-four (24) months), after which time, Buyer may terminate this Agreement unless the Project has been repaired or replaced, as applicable, and the Seller has resumed and is satisfying all of its obligations under this Agreement.

(b) Termination and Right of First Offer.

(i) If Buyer exercises its termination right in connection with the Force Majeure Failure, then the Agreement shall terminate without further liability of either Party to the other, effective upon the date set forth in Buyer's Notice of termination, subject to each Party's satisfaction of all of the final payment and survival obligations set forth in Sections 2.5(a) and (b). The Parties agree that for a period of three (3) years from the date on which Buyer Notifies Seller of termination due to the Force Majeure Failure ("Exclusivity Period"), neither Seller, its successors and assigns, nor its Affiliates shall enter into an obligation or agreement to sell or otherwise transfer any Products from the Project to any third party, unless Seller first offers, in writing, to sell to Buyer such Products from the Project on the same terms and conditions as this Agreement, subject to permitted modifications identified in subpart (ii) below, (the "First Offer") and Buyer either accepts or rejects such First Offer in accordance with the provisions herein.

(ii) If Buyer accepts the First Offer, Buyer shall Notify Seller within thirty (30) days of receipt of the First Offer subject to Buyer's governing board approval ("Buyer's Notice of First Offer Acceptance"), and then the Parties shall have not more than ninety (90) days from the date of Buyer's Notice of First Offer Acceptance to enter into a new power purchase agreement, in substantially the same form as this Agreement, or amend this Agreement, if necessary; provided that the Contract Price may only be increased to reflect Seller's documented incremental costs in overcoming the Force Majeure event.

(iii) If Buyer rejects or fails to accept Seller's First Offer within thirty (30) days of receipt of such offer, Seller shall thereafter be free to sell or otherwise transfer, and to enter into agreements to sell or otherwise transfer, any Products from the Project to any third party, so long as the material terms and conditions of such sale or transfer are not more favorable to the third party than those of the First Offer to Buyer. If, during the Exclusivity Period, Seller desires to enter into an obligation or agreement with a third party, Seller shall deliver to Buyer a certificate of an authorized officer of Seller (A) summarizing the material terms and conditions of such agreement and (B) certifying that the proposed agreement with the third party will not provide Seller with a lower rate of return than that offered in the First Offer to Buyer. If Seller is unable to deliver such a certificate to Buyer, then Seller may not sell or otherwise transfer, or enter into an agreement to sell or otherwise transfer, the Products from the Project without first offering to sell or otherwise transfer such Products to Buyer on such more favorable terms and conditions (the "Revised Offer") in accordance with subpart (ii) above. If within thirty (30) days of receipt of Seller's Revised Offer the Buyer rejects, or fails to accept by Notice to Seller, the Revised Offer, then Seller will thereafter be free to sell or otherwise transfer, and to enter into agreements to sell or otherwise transfer, such Products from the Project to any third party on such terms and conditions as set forth in the certificate.

ARTICLE TWELVE: DISPUTE RESOLUTION

12.1 Dispute Resolution.

(a) In the event of any claim, controversy or dispute between the Parties arising out of or relating to or in connection with this Agreement (including any dispute concerning the validity of this Agreement or the scope and interpretation of this Section 12.1) (a "Dispute"), any Party (the "Notifying Party") may deliver to the other Parties (the "Recipient Party") notice of the Dispute with a detailed description of the underlying circumstances of such Dispute (a "Dispute Notice"). The Dispute Notice shall include a schedule of the availability of the Notifying Party's senior officers (having a title of senior vice president (or its equivalent) or higher) duly authorized to settle the Dispute during the thirty (30) day period following the delivery of the Dispute Notice.

(b) The Recipient Party shall, within five (5) Business Days following receipt of the Dispute Notice, provide to the Notifying Party a brief summary of the Recipient Party's position on the Dispute and a parallel schedule of availability of the Recipient Party's senior officers (having a title of senior vice president (or its equivalent) or higher) duly authorized to settle the Dispute. Following delivery of the respective senior officers' schedules of availability, the senior officers of the Parties shall meet and confer as often as they deem reasonably necessary during the remainder of the thirty (30) day period in good faith negotiations to resolve the Dispute to the satisfaction of each Party.

(c) In the event a Dispute is not resolved pursuant to the procedures set forth in Sections 12.1(a) and (b) by the expiration of the thirty (30) day period set forth in Section 12.1(b), then a Party may pursue any legal remedy available to it in accordance with this Agreement.

ARTICLE THIRTEEN: NOTICES

Whenever this Agreement requires or permits delivery of a "Notice" (or requires a Party to "notify"), the Party with such right or obligation shall provide a written communication in the manner specified herein; provided, however, that notices of Outages or other Scheduling or dispatch information or requests, as provided in Appendix VI, shall be provided in accordance with the terms set forth in the relevant section of this Agreement. Notices may be sent by facsimile or e-mail. A Notice sent by facsimile transmission or e-mail will be recognized and shall be deemed received on the Business Day on which such Notice was transmitted if received before 5:00 p.m. (and if received after 5:00 p.m., on the next Business Day) and a Notice of overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent or such earlier time as is confirmed by the receiving Party. Either Party may periodically change any address, phone number, e-mail, website, or contact, including such information in Appendix VI and the "Notices List" in the Cover Sheet, to which Notice is to be given it by providing Notice of such change to the other Party.

SIGNATURES

Agreement Execution

In WITNESS WHEREOF, each Party has caused this Agreement to be duly executed by its authorized representative as of the dates provided below:

SNOW MOUNTAIN HYDRO LLC, an Idaho limited liability company	**REDWOOD COAST ENERGY AUTHORITY, a California joint powers authority**
Signature: ______________________	Signature: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

APPENDIX I

FORM OF LETTER OF CREDIT

Issuing Bank Letterhead and Address

STANDBY LETTER OF CREDIT NO. XXXXXXXX

Date: [insert issue date]

Beneficiary: Redwood Coast Energy Authority

633 3rd St,
Eureka, CA 95501

Attention:

Applicant: [Insert name and address of Applicant]

Letter of Credit Amount: [insert amount]

Expiry Date: [insert expiry date]

Ladies and Gentlemen:

By order of **[insert name of Applicant]** ("Applicant"), we hereby issue in favor of Redwood Coast Energy Authority (the "Beneficiary") our irrevocable standby letter of credit No. **[insert number of letter of credit]** ("Letter of Credit"), for the account of Applicant, for drawings up to but not to exceed the aggregate sum of U.S. $ **[insert amount in figures followed by (amount in words)]** ("Letter of Credit Amount"). This Letter of Credit is available with **[insert name of issuing bank, and the city and state in which it is located]** by sight payment, at our offices located at the address stated below, effective immediately, and it will expire at our close of business on **[insert expiry date]** (the "Expiry Date").

Funds under this Letter of Credit are available to the Beneficiary against presentation of the following documents:

1. Beneficiary's signed and dated sight draft in the form of Exhibit A hereto, referencing this Letter of Credit No. **[insert number]** and stating the amount of the demand; and

2. One of the following statements signed by an authorized representative or officer of Beneficiary:

    A. "Pursuant to the terms of that certain **[insert name of the agreement]** (the "Agreement"), dated **[insert date of the Agreement]**, between Beneficiary and **[insert name of Seller under the Agreement],** Beneficiary is entitled to draw under Letter of Credit No. **[insert number]** amounts owed by **[insert name of Seller under the Agreement]** under the Agreement; or

    B. "Letter of Credit No. **[insert number]** will expire in thirty (30) days or less and **[insert name of Seller under the Agreement]** has not provided replacement security acceptable to Beneficiary.

Special Conditions:

1. Partial and multiple drawings under this Letter of Credit are allowed;
2. All banking charges associated with this Letter of Credit are for the account of the Applicant;
3. This Letter of Credit is not transferable; and
4. The Expiry Date of this Letter of Credit shall be automatically extended without a written amendment for a period of one year and on each successive Expiry Date, unless at least sixty (60) days before the then current Expiry Date, we notify you by registered mail or courier that we elect not to extend the Expiry Date of this Letter of Credit for such additional period.

We engage with you that drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored upon presentation, on or before the Expiry Date (or after the Expiry Date as provided below), at our offices at **[insert issuing bank's address for drawings]**.

All demands for payment shall be made by presentation of originals or copies of documents; or by facsimile transmission of documents to **[insert fax number]**, Attention: **[insert name of issuing bank's receiving department]**, with originals or copies of documents to follow by overnight mail. If presentation is made by facsimile transmission, you may contact us at **[insert phone number]** to confirm our receipt of the transmission. Your failure to seek such a telephone confirmation does not affect our obligation to honor such a presentation.

Our payments against complying presentations under this Letter of Credit will be made no later than on the sixth (6th) banking day following a complying presentation.

Except as stated herein, this Letter of Credit is not subject to any condition or qualification. It is our individual obligation, which is not contingent upon reimbursement and is not affected by any agreement, document, or instrument between us and the Applicant or between the Beneficiary and the Applicant or any other party.

Except as otherwise specifically stated herein, this Letter of Credit is subject to and governed by the *Uniform Customs and Practice for Documentary Credits, 2007 Revision,* International Chamber of Commerce (ICC) Publication No. 600 (the "UCP 600"); provided that, if this Letter of Credit expires during an interruption of our business as described in Article 36 of the UCP 600, we will honor drafts presented in compliance with this Letter of Credit within thirty (30) days after the resumption of our business and effect payment accordingly.

The law of the State of California shall apply to any matters not covered by the UCP 600.

For telephone assistance regarding this Letter of Credit, please contact us at **[insert number and any other necessary details]**.

Very truly yours,

[insert name of issuing bank]

By: ______________________________
Authorized Signature

Name: ______**[print or type name]**______

Title: ______________________________

Exhibit A SIGHT DRAFT

TO
[INSERT NAME AND ADDRESS OF PAYING BANK]

AMOUNT: $________________________ DATE: __________________________

AT SIGHT OF THIS DEMAND PAY TO THE ORDER OF REDWOOD COAST ENERGY AUTHORITY THE AMOUNT OF U.S.$________(______________ U.S. DOLLARS)

DRAWN UNDER [INSERT NAME OF ISSUING BANK] LETTER OF CREDIT NO. XXXXXX.

REMIT FUNDS AS FOLLOWS:

[INSERT PAYMENT INSTRUCTIONS]

DRAWER

BY: ________________________________
NAME AND TITLE

APPENDIX II

INITIAL ENERGY DELIVERY DATE CONFIRMATION LETTER

In accordance with the terms of that certain Power Purchase Agreement dated _______ ("Agreement") by and between ___________("Buyer") and ________________ ("Seller"), this letter ("Initial Energy Delivery Date Confirmation Letter") serves to document the Parties' further agreement that (i) the Conditions Precedent to the occurrence of the Initial Energy Delivery Date have been satisfied, and (ii) Buyer has accepted delivery of the Product, as specified in the Agreement, as of this _____ day of ______, ______ (the "Initial Energy Delivery Date"). All capitalized terms not defined herein shall have the meaning set forth in the Agreement.

Seller represents to Buyer that it has been granted status as an [Exempt Wholesale Generator] [Qualifying Facility]. Additionally Seller provides the following FERC Tariff information for reference purposes only:

Tariff: Dated: Docket Number:

IN WITNESS WHEREOF, each Party has caused this Initial Energy Delivery Date Confirmation Letter to be duly executed by its authorized representative as of the date of last signature provided below:

SNOW MOUNTAIN HYDRO LLC		**REDWOOD COAST ENERGY AUTHORITY**	
Signature:	______________________	Signature:	______________________
Name:	______________________	Name:	______________________
Title:	______________________	Title:	______________________
Date:	______________________	Date:	______________________

[APPENDIX III NOT USED]

[APPENDIX IV NOT USED]

APPENDIX V

GEP DAMAGES CALCULATION

In accordance with the provisions in Section 3.1(e)(ii), GEP Damages means the liquidated damages payment due by Seller to Buyer, calculated as follows:

[(A-B) x (C-D)]

Where:

A = the Guaranteed Energy Production for the Performance Measurement Period, in MWh

B = Sum of Delivered Energy plus Deemed Delivered Energy, if any, over the Performance Measurement Period, in MWh

C= Replacement price for the Performance Measurement Period, in $/MWh, which is the sum of (a) the simple average of the Integrated Forward Market hourly price for all the hours in the Performance Measurement Period, as published by the CAISO, for the Existing Zone Generation Trading Hub (as defined in the CAISO Tariff), in which the PNode resides, plus (b) $[redacted]/MWh

D = the unweighted Contract Price specified in the Cover Sheet for the Performance Measurement Period, in $/MWh

The Parties agree that in the above calculation of GEP Damages, if the result of "(C-D)" is less than $[redacted]/MWh, the "(C-D)" will be replaced with $[redacted]/MWh. The Parties also agree that in the above calculation of GEP Damages, if the result of "(C-D)" is more than $[redacted]/MWh, the "(C-D)" will be replaced with $[redacted]/MWh.

APPENDIX VI

NOTIFICATION REQUIREMENTS FOR AVAILABLE CAPACITY AND PROJECT OUTAGES

A. NOTIFICATION REQUIREMENTS FOR ROUTINE START-UP AND SHUTDOWNS

Prior to paralleling or after disconnecting from the electric system, ALWAYS follow your balancing authority rules and notify the applicable Participating Transmission Owner's (PTO) switching center

- Call the applicable Participating Transmission Owner's (PTO) switching center and TEA's Real-Time Desk to advise of the intent to parallel before any Start-up.
- Call the applicable Participating Transmission Owner's (PTO) switching center and TEA's Real-Time Desk after the unit has been paralleled and report the parallel time and intended unit output.
- Call the applicable Participating Transmission Owner's (PTO) switching center and TEA's Real-Time Desk after any routine separation and report the separation time as well as the date and time estimate for return to service.

B. SUBMISSION OF AVAILABLE CAPACITY AND PLANNED OUTAGES

1. Implement the procedures set forth below:

   a. For all email correspondence, enter the following in the email subject field: Delivery Date Range, Company Name, Contract Name, Email Purpose, Date Range (For example: "dd/mm/yyyy through dd/mm/yyyy, XYZ Company Project #2, Daily Forecast of Available Capacity,")

   b. For Annual Forecasts of Available Capacity, email to For Monthly and Daily Forecasts of Available Capacity, email to CAISOAdmin@teainc.org.

   c. For Daily Forecasts of Available Capacity after fourteen (14) hours before the WECC Preschedule Day, but before the CAISO deadline for submitting Schedules into the Day-Ahead Market, call primary phone [redacted] or backup phone [redacted]. Also send email to [redacted].

   d. For Hourly Forecasts of Available Capacity, call TEA's Real Time Desk at [redacted] and email to [redacted].

   e. For Planned Outages and Prolonged Outages, complete the specifics below and submit by email to [redacted].

      i. *Email subject field*: Company Name, Contract Name, Email Purpose, Date Range (For example: "dd/mm/yyyy through dd/mm/yyyy, XYZ Company Project #2, Daily Forecast of Available Capacity")

      ii. Email body:

1. Type of Outage: Planned Outage or Prolonged Outage

2. Start Date and Start Time

3. Estimated or Actual End Date and End Time for Outage

4. Date and time when reported to TEA and name(s) of TEA representative(s) contacted

5. Text description of additional information as needed, including, but not limited to, changes to a Planned Outage or Prolonged Outage.

6. Contact name: first and last name of the individual at the Unit to contact regarding the outage(s) at issue in the email.

C. FORCED OUTAGE REPORTING

1. Forced Outages – Seller shall notify TEA's Real Time Desk verbally at [redacted] within fifteen (15) minutes of event or as soon as reasonably possible, after the safety of all personnel and securing of all facility equipment.

   a. Verbal notification shall include time of forced outage, cause, current availability and estimated return date and time.

   b. After verbally notifying TEA's Real Time Desk of the forced outage, Seller shall also submit the following information via email to [redacted].

      i. *Email subject field*: Company Name, Contract Name, Email Purpose, Date Range (For example: "dd/mm/yyyy through dd/mm/yyyy, XYZ Company Project #2, Daily Forecast of Available Capacity")

      ii. Email body:

         1. Type of Outage: Forced Outage

         2. Start Date and Start Time

         3. Estimated or Actual End Date and End Time

         4. Date and time when reported to TEA and name(s) of TEA representative(s) contacted.

         5. Text description of additional information as needed.

         6. Primary and secondary causes of Forced Outage, including a detailed description of specific equipment involved and the nature of the problem or condition.

         7. Equipment description and nature of work being performed. For generation outages, include NERC Generation Availability Data System (GADS) numbers (as available) that identify the specific equipment and

type of work that affect restrictions. Include additional equipment designations as available.

8. Text description of additional information as needed, including, but not limited to, changes to a previously scheduled Outage, links/cross-references to related outage cards and log entries, outage classifications per the CAISO Tariff, etc.

9. Associated events, e.g. operation of Special Protection Schemes.

10. Impact on CAISO-controlled Grid.

APPENDIX VII

FORM OF CONSENT TO ASSIGNMENT

CONSENT AND AGREEMENT

This CONSENT AND AGREEMENT ("Consent and Agreement") is entered into as of **[_______ __, 2___]**, between REDWOOD COAST ENERGY AUTHORITY ("RCEA"), and **[_________________]** , as collateral agent (in such capacity, "Financing Provider"), for the benefit of various financial institutions (collectively, the "Secured Parties") providing financing to [_______] ("Seller"). RCEA, Seller, and the Financing Provider shall each individually be referred to as a "Party" and collectively as the "Parties".

Recitals

A. Pursuant to that certain Power Purchase Agreement dated as of _____________, 2___ (as amended, modified, supplemented or restated from time to time, as including all related agreements, instruments and documents, collectively, the "Assigned Agreement") between RCEA and Seller, RCEA has agreed to purchase energy from Seller.

B. The Secured Parties have provided, or have agreed to provide, to Seller financing (including a financing lease) pursuant to one or more agreements (the "Financing Documents"), and require that Financing Provider be provided certain rights with respect to the "Assigned Agreement" and the "Assigned Agreement Accounts," each as defined below, in connection with such financing.

C. In consideration for the execution and delivery of the Assigned Agreement, RCEA has agreed to enter into this Consent and Agreement for the benefit of Seller.

Agreement

1. <u>Definitions</u>. Any capitalized term used but not defined herein shall have the meaning specified for such term in the Assigned Agreement.

2. <u>Consent</u>. Subject to the terms and conditions below, RCEA consents to and approves the pledge and assignment by Seller to Financing Provider pursuant to the Loan Agreement and/or Security Agreement of (a) the Assigned Agreement, and (b) the accounts, revenues and proceeds of the Assigned Agreement (collectively, the "Assigned Agreement Accounts").

3. <u>Limitations on Assignment</u>. Financing Provider acknowledges and confirms that, notwithstanding any provision to the contrary under applicable law or in any Financing Document executed by Seller, Financing Provider shall not assume, sell or otherwise dispose of the Assigned Agreement (whether by foreclosure sale, conveyance in lieu of foreclosure or otherwise) unless, on or before the date of any such assumption, sale or disposition, Financing Provider or any third party, as the case may be, assuming, purchasing or otherwise acquiring the Assigned Agreement (a) cures any and all defaults of Seller under the Assigned Agreement which are capable of being cured and which are not personal to the Seller, (b) executes and delivers to RCEA a written assumption of all of Seller's rights and obligations under the Assigned Agreement in form and substance reasonably satisfactory to RCEA, (c) otherwise satisfies and complies with all requirements of the Assigned Agreement, (d) provides such tax and enforceability assurance as RCEA may reasonably request, and (e) is a Permitted Transferee (as defined below). Financing Provider further acknowledges that the assignment of the Assigned Agreement and the Assigned Agreement Accounts is for security purposes only and that Financing Provider has no

rights under the Assigned Agreement or the Assigned Agreement Accounts to enforce the provisions of the Assigned Agreement or the Assigned Agreement Accounts unless and until an event of default has occurred and is continuing under the Financing Documents between Seller and Financing Provider (a "Financing Default"), in which case Financing Provider shall be entitled to all of the rights and benefits and subject to all of the obligations which Seller then has or may have under the Assigned Agreement to the same extent and in the same manner as if Financing Provider were an original party to the Assigned Agreement.

"Permitted Transferee" means any person or entity who is reasonably acceptable to RCEA. Financing Provider may from time to time, following the occurrence of a Financing Default, notify RCEA in writing of the identity of a proposed transferee of the Assigned Agreement, which proposed transferee may include Financing Provider, in connection with the enforcement of Financing Provider's rights under the Financing Documents, and RCEA shall, within thirty (30) business days of its receipt of such written notice, confirm to Financing Provider whether or not such proposed transferee is a "Permitted Transferee" (together with a written statement of the reason(s) for any negative determination) it being understood that if RCEA shall fail to so respond within such thirty (30) business day period such proposed transferee shall be deemed to be a "Permitted Transferee".

4. Cure Rights.

(a) Notice to Financing Provider by RCEA. RCEA shall, concurrently with the delivery of any notice of an event of default under the Assigned Agreement (each, an "Event of Default") to Seller (a "Default Notice"), provide a copy of such Default Notice to Financing Provider pursuant to Section 9(a) of this Consent and Agreement. In addition, Seller shall provide a copy of the Default Notice to Financing Provider the next business day after receipt from RCEA, independent of any agreement of RCEA to deliver such Default Notice.

(b) Cure Period Available to Financing Provider Prior to Any Termination by RCEA. Upon the occurrence of an Event of Default, subject to (i) the expiration of the relevant cure periods provided to Seller under the Assigned Agreement, and (ii) Section 4(a) above, RCEA shall not terminate the Assigned Agreement unless it or Seller provides Financing Provider with notice of the Event of Default and affords Financing Provider an Additional Cure Period (as defined below) to cure such Event of Default. For purposes of this Agreement "Additional Cure Period" means (i) with respect to a monetary default, ten (10) days in addition to the cure period (if any) provided to Seller in the Assigned Agreement, and (ii) with respect to a non-monetary default, thirty (30) days in addition to the cure period (if any) provided to Seller in the Assigned Agreement.

(c) Failure by RCEA to Deliver Default Notice. If neither RCEA nor Seller delivers a Default Notice to Financing Provider as provided in Section 4(a), the Financing Provider's applicable cure period shall begin on the date on which notice of an Event of Default is delivered to Financing Provider by either RCEA or Seller. Except for a delay in the commencement of the cure period for Financing Provider and a delay in RCEA's ability to terminate the Assigned Agreement (in each case only if both RCEA and Seller fail to deliver notice of an Event of Default to Financing Provider), failure of RCEA to deliver any Default Notice shall not waive RCEA's right to take any action under the Assigned Agreement and will not subject RCEA to any damages or liability for failure to provide such notice.

(d) Extension for Foreclosure Proceedings. If possession of the Project (as defined in the Assigned Agreement) is necessary for Financing Provider to cure an Event of Default and Financing Provider commences foreclosure proceedings against Seller within thirty (30) days of receiving notice of an Event of Default from RCEA or Seller, whichever is received first, Financing Provider shall be allowed a reasonable additional period to complete such foreclosure proceedings, such period not to exceed ninety (90) days; provided, however, that Financing Provider shall provide a written notice to RCEA that it intends to commence foreclosure proceedings with respect to Seller within ten (10) business days of receiving a notice of such Event of Default from RCEA or Seller, whichever is received first. In the event Financing Provider succeeds to Seller's interest in the Project as a result of foreclosure proceedings, the Financing Provider or a purchaser or grantee pursuant to such foreclosure shall be subject to the requirements of Section 3 of this Consent and Agreement.

5. Setoffs and Deductions. Each of Seller and Financing Provider agrees that RCEA shall have the right to set off or deduct from payments due to Seller each and every amount due RCEA from Seller whether or not arising out of or in connection with the Assigned Agreement. Financing Provider further agrees that it takes the assignment for security purposes of the Assigned Agreement and the Assigned Agreement Accounts subject to any defenses or causes of action RCEA may have against Seller.

6. No Representation or Warranty. Seller and Financing Provider each recognizes and acknowledges that RCEA makes no representation or warranty, express or implied, that Seller has any right, title, or interest in the Assigned Agreement or as to the priority of the assignment for security purposes of the Assigned Agreement or the Assigned Agreement Accounts. Financing Provider is responsible for satisfying itself as to the existence and extent of Seller's right, title, and interest in the Assigned Agreement, and Financing Provider releases RCEA from any liability resulting from the assignment for security purposes of the Assigned Agreement and the Assigned Agreement Accounts.

7. Amendment to Assigned Agreement. Financing Provider acknowledges and agrees that RCEA may agree with Seller to modify or amend the Assigned Agreement, and that RCEA is not obligated to notify Financing Provider of any such amendment or modification to the Assigned Agreement. Financing Provider hereby releases RCEARCEA from all liability arising out of or in connection with the making of any amendment or modification to the Assigned Agreement.

8. Payments under Assigned Agreement. RCEA shall make all payments due to Seller under the Assigned Agreement from and after the date hereof to [__________], as depositary agent, to ABA No. [__________], Account No. [__________], and Seller hereby irrevocably consents to any and all such payments being made in such manner. Each of Seller, RCEA and Financing Provider agrees that each such payment by RCEA to such depositary agent of amounts due to Seller from RCEA under the Assigned Agreement shall satisfy RCEA's corresponding payment obligation under the Assigned Agreement.

9. Miscellaneous.

(a) Notices. All notices hereunder shall be in writing and shall be deemed received (i) at the close of business of the date of receipt, if delivered by hand or by facsimile or other electronic means, or (ii) when signed for by recipient, if sent registered or certified mail, postage prepaid, provided such notice was properly addressed to the appropriate address indicated on the signature page hereof or to such other address as a party may designate by prior written notice to the other parties, at the address set forth below:

If to Financing Provider:	
Name:	
Address:	
Attn:	
Telephone:	
Facsimile:	
Email:	

If to RCEA:	
Name:	
Address:	
Attn:	
Telephone:	
Facsimile:	
Email:	

(b) No Assignment. This Consent and Agreement shall be binding upon and shall inure to the benefit of the successors and assigns of RCEA, and shall be binding on and inure to the benefit of the Financing Provider, the Secured Parties and their respective successors and permitted transferees and assigns under the loan agreement and/or security agreement.

(c) No Modification. This Consent and Agreement is neither a modification of nor an amendment to the Assigned Agreement.

(d) Choice of Law. The parties hereto agree that this Consent and Agreement shall be construed and interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

(e) No Waiver. No term, covenant or condition hereof shall be deemed waived and no breach excused unless such waiver or excuse shall be in writing and signed by the party claimed to have so waived or excused.

(f) Counterparts. This Consent and Agreement may be executed in one or more duplicate counterparts, and when executed and delivered by all the parties listed below, shall constitute a single binding agreement.

(g) No Third Party Beneficiaries. There are no third party beneficiaries to this Consent and Agreement.

(h) Severability. The invalidity or unenforceability of any provision of this Consent and Agreement shall not affect the validity or enforceability of any other provision of this Consent and Agreement, which shall remain in full force and effect.

(i) Amendments. This Consent and Agreement may be modified, amended, or rescinded only by writing expressly referring to this Consent and Agreement and signed by all parties hereto.

IN WITNESS WHEREOF, each of RCEA and Financing Provider has duly executed this Consent and Agreement as of the date first written above.

Redwood Coast Energy Authority (RCEA)

By: ________________________________
Name: ______________________________
Title: ______________________________

[____________________________________]
(Financing Provider), as collateral agent

By: ________________________________
Name: ______________________________
Title: ______________________________

ACKNOWLEDGEMENT

The undersigned hereby acknowledges the Consent and Agreement set forth above, makes the agreements set forth therein as applicable to Seller, including the obligation of Seller to provide a copy of any Default Notice it receives from RCEA to Financing Provider the next business day after receipt by Seller, and confirms that the Financing Provider identified above and the Secured Parties have provided or are providing financing to the undersigned.

Snow Mountain Hydro LLC

By: ________________________________
Name: ______________________________
Title: ______________________________

APPENDIX VIII

SELLER DOCUMENTATION CONDITION PRECEDENT

Seller shall provide to Buyer all of the following documentation prior to the Execution Date:

1. A copy of each of (A) the articles of incorporation, certificate of incorporation, operating agreement or similar applicable organizational document of Seller and (B) the by-laws or other similar document of Seller (collectively, "Charter Documents") as in effect, or anticipated to be in effect, on the Execution Date.

2. A certificate signed by an authorized officer of Seller (who must be a different person than the officers listed in clause (C) below), dated no earlier than ten (10) Business Days prior to the Execution Date, certifying (A) that attached thereto is a true and complete copy of the Charter Documents of the Seller, as in effect at all times from the date on which the resolutions referred to in clause (B) below were adopted to and including the date of such certificate; (B) that attached thereto is a true and complete copy of resolutions duly adopted by the board of directors (or other equivalent body) or evidence of all corporate or limited liability company action, as the case may be, of Seller, authorizing the execution, delivery and performance of this Agreement, and that such resolutions have not been modified, rescinded or amended and are in full force and effect, and (C) as to the name, incumbency and specimen signature of each officer of Seller executing this Agreement.

3. A certificate from the jurisdiction of Seller's incorporation or organization certifying that Seller is duly organized, validly existing and in good standing under the laws of such jurisdiction.

4. Evidence of Site control (e.g., lease with redacted price terms) satisfactory to Buyer.

5. Evidence of CEC Certification and Verification (pre-certification) satisfactory to Buyer.

6. A copy of the most recent financial statements (which may be unaudited) from Seller together with a certificate from the Chief Financial or equivalent officer of Seller, dated no earlier than ten (10) Business Days prior to the Execution Date, to the effect that, to the best of such officer's knowledge, (A) such financial statements are true, complete and correct in all material respects and (B) there has been no material adverse change in the financial condition, operations, Properties, business or prospects of Seller since the date of such financial statements.

7. A document that includes the following information: (A) a description of each Milestone listed in the Cover Sheet, plus any additional significant milestones related to the Project; (B) the status and progress of each Milestone; (C) the date of completion of completed Milestone(s) and the expected date of completion of uncompleted Milestone(s); (D) potential delays that could result in the Milestone not being completed by the Milestone date; and (E) the remedial actions that Seller plans to take for each for each Milestone, if that Milestone is not completed by the Milestone Date.

[APPENDIX IX NOT USED]

APPENDIX X

TELEMETRY PARAMETERS FOR WIND OR SOLAR FACILITY

Technology Type	Telemetry Parameters	Units
Solar Photovoltaic	Back Panel Temperature	˚C
	Global Horizontal Irradiance	W/m²
	Plane of Array Irradiance (If PV is fixed) Direct Normal Irradiance (If PV is Tracking)	W/m²
	Wind Speed	m/s
	Peak Wind Speed (Within 1 minute)	m/s
	Wind Direction	Degrees
	Ambient Air Temperature	˚C
	Dewpoint Air Temperature or Relative Humidity	˚C
	Horizontal Visibility	m
	Precipitation (Rain Rate)	mm/hr
	Precipitation (Running 30 day total)	mm
	Barometric Pressure	Millibars or Hecto Pascals (HPa)
Solar Thermal or Solar Trough	Global Horizontal Irradiance	W/m²
	Plane of Array Irradiance (If PV is fixed) Direct Normal Irradiance (If PV is Tracking)	W/m²
	Wind Speed	m/s
	Peak Wind Speed (Within 1 minute)	m/s
	Wind Direction	Degrees
	Ambient Air Temperature	˚C
	Dewpoint Air Temperature or Relative Humidity	˚C
	Horizontal Visibility	m
	Precipitation (Rain Rate)	mm/hr
	Precipitation (Running 30 day total)	mm
	Barometric Pressure	Millibars or Hecto Pascals (HPa)
	Individual Tracking Assembly Angle Set Points (Solar Trackers Only)	Degrees
	Actual Tracking Assembly Angles (Solar Trackers Only)	Degrees
Wind	Wind Speed (measured at hub height)	m/s
	Peak Wind Speed (Within 1 minute, measured at hub height)	m/s
	Wind Direction	Degrees
	Wind Speed Standard Deviation	--
	Wind Direction Standard Deviation	--
	Barometric Pressure (measured at hub height)	Millibars or Hecto Pascals (HPa)
	Ambient Temperature (measured at hub height)	˚C

[APPENDIX XI NOT USED]

APPENDIX XII
PROJECT SPECIFICATIONS AND CONTRACT CAPACITY CALCULATION

I. PROJECT SPECIFICATIONS

"MVA" means megavolt ampere, the unit of apparent power.

"Nameplate Rated Output" means, with respect to an inverter or electric generator, the MVA that the manufacturer of the inverter or generator has designed such equipment to produce under normal operating conditions as specified by such manufacturer.

"Designated Power Factor" means, with respect to an inverter or electric generator, the power factor required to satisfy the portion of the Project's reactive power requirements that are specified in ***[please identify the applicable source, such as the PTO's Interconnection Handbook, the CAISO's Phase II Study, or the Generator Interconnection Agreement for the Project]*** and are not being satisfied by other sources of reactive power within the Project.

"Nameplate Rated Power" means, with respect to an inverter or electric generator, the multiplication product of the Nameplate Rated Output and the Designated Power Factor for such inverter or generator, in MWs.

The project specifications shall consist of the following eleven (11) items (each item of which shall be a "Project Specification"). As provided in Section 3.1(g), Seller shall not make any change or modification to any Project Specification without Buyer's prior written consent.

1. Project name:

2. Project Site name:

3. Project physical address:

4. Total number of Units at the Project:

5. Technology Type:

6. Interconnection Point of Project:

7. Service Territory of Project:

8. Substation:

9. Description of Units:

    a. For each steam turbine, specify the rated conditions (MW rating, steam inlet temperature, steam inlet pressure, condensing temperature, mass flow rate):

    b. For each electric generator, specify the Nameplate Rated Output, Designated Power Factor and Nameplate Rated Power:

10. Description of Land:

    The Site contains the following Assessor Parcel Numbers upon which the Project is located and as identified on the topographical map included in this <u>Appendix XII</u>: [Insert Map]

11. Description of Interconnection Facilities and metering:

The Project will use the following Interconnection Facilities and metering configuration as identified in this one-line diagram included in this Appendix XII:

[Insert One-Line Diagram for Interconnection Facilities and Metering]

12. Maps: The Site is identified in the following topographical map:

[INSERT MAP]

II. CONTRACT CAPACITY CALCULATION

The Contract Capacity specified in Section B of the Cover Sheet shall be the factor (A) minus each of the factors (B) through (E) provided below:

A	Sum of the Nameplate Rated Power of all inverters/generators	________ MW
B	Calculated electrical losses from inverter/generator output terminals to Delivery Point (with all inverters/generators operating at Nameplate Rated Outputs)	________ MW
C	Electrical Losses	________ MW
D	Auxiliary and station loads coincident with inverters/generators operating at Nameplate Rated Outputs	________ MW
E	Other factors (explain below)	________ MW
F	Contract Capacity at the Delivery Point (F = A – B – C – D – E), which shall be the same as the MW amount specified for the Contract Capacity in Section B of the Cover Sheet	________ MW

Inputs for the Nameplate Rated Power calculation:

Designated Power Factor:

	Leading	Lagging
Project power factor requirements	_______	_______
Seller's Designated Power Factor for inverters/generators	_______	_______

Power factor requirement is measured at (check one):

□ inverter/generator terminals; □ Point of Interconnection; □ Other:_____________

APPENDIX XIII

SECTION 3.3(e) LIQUIDATED DAMAGES CALCULATION

I. <u>Equation and Formulas for Calculating RA Deficiency Amount</u>

As provided in Section 3.3(e)(ii)(B), the formula for calculating the RA Deficiency Amount in a given RA Shortfall Month is:

RA Deficiency Amount (\$/Month) = RA Value (\$/MW/Month) × Expected Net Qualifying Capacity (MW)

Where the:

A. RA Value shall be $[redacted]/MW/Month in calendar year 2016 and shall escalate at [redacted]% per year for each succeeding calendar year; and

B. Expected Net Qualifying Capacity for projects that selected Full Capacity Deliverability Status shall be the product of the Contract Capacity and the applicable monthly Qualifying Capacity factor in the table below; or

C. Expected Net Qualifying Capacity for Projects seeking Partial Capacity Deliverability Status shall be the minimum of (a) the Expected Net Qualifying Capacity values as calculated in Section B above; or, (b) the product of the Contract Capacity and the Partial Capacity Deliverability Status Amount.

Table XIV-1 Monthly Qualifying Capacity Factor

Month	Biomass	Geothermal	Solar	Wind
Jan	90%	95%	0.0%	11.3%
Feb	93%	94%	2.4%	17.3%
March	87%	93%	10.4%	18.3%
April	76%	91%	33.2%	31.4%
May	88%	87%	30.5%	30.6%
June	94%	79%	44.8%	47.5%
July	93%	81%	41.7%	29.7%
Aug	94%	83%	41.0%	26.5%
Sept	92%	81%	33.4%	26.5%
Oct	86%	90%	29.4%	8.8%
Nov	88%	94%	4.1%	8.4%
Dec	91%	93%	0.0%	15.2%

II. <u>Example of Calculation of the RA Deficiency Amount (for illustrative purposes only) if</u>:

- RA Shortfall Month is June 2019
- Project is a solar system
- Contract Capacity is 20 MW
- RA Start Date is based on the Expected FCDS Date, which is January 1, 2019
- FCDS is achieved on August 14, 2019

RA Value ($/MW/Month) = $[redacted] escalated at [redacted]% per year for 3 years, from 2016 to 2019

$[redacted] × (1.025)^3 = [redacted] /MW/Month.

Monthly Qualifying Capacity factor for a solar project in June is 44.8% (from table above).

Expected Net Qualifying Capacity =

Contract Capacity (MW) × monthly Qualifying Capacity factor =

20 MW × 44.8% = 8.96 MW

RA Deficiency Amount ($/Month) =

RA Value ($/MW/Month) × Expected Net Qualifying Capacity (MW) =

$[redacted]/MW/Month × 8.96 MW = $[redacted]

In this example, the RA Shortfall Period is from January through October 2019. The calculations above would be performed and the result applied for each month in this RA Shortfall Period.

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REDWOOD COAST EnergyAuthority

STAFF REPORT

Agenda Item # 8.4

AGENDA DATE:	July 25, 2019
TO:	Board of Directors
PREPARED BY:	Matthew Marshall, Executive Director
SUBJECT:	SDRMA Board Election

BACKGROUND

RCEA is a member of the Special District Risk Management Authority (SDRMA), which provides RCEA with insurance, training resources and other risk-management services. Attached are the election ballot for SDRMA's Board of Directors and the candidates' statements. The Board may choose to cast RCEA's vote for up to three candidates.

At June's RCEA Board meeting, the directors decided to defer voting until this meeting. The ballot is due by August 21.

POTENTIAL BOARD ACTIONS

1. <u>Approve the official 2019 SDRMA Board of Directors election ballot casting RCEA's vote for up to three of the five candidates for a four-year term.</u>

Or, alternatively, the Board could:

2. Choose not to vote in the current election if the Board has no preferences amongst the candidates.

ATTACHMENTS:

1. 2019 SDRMA Board of Directors Election Ballot
2. 2019 SDRMA Board Candidates' Statements

SDRMA
SPECIAL DISTRICT RISK MANAGEMENT AUTHORITY

OFFICIAL 2019 ELECTION BALLOT
SPECIAL DISTRICT RISK MANAGEMENT AUTHORITY
BOARD OF DIRECTORS

VOTE FOR ONLY THREE (3) CANDIDATES

Mark each selection directly onto the ballot, voting for no more than three (3) candidates. Each candidate may receive only one (1) vote per ballot. A ballot received with more than three (3) candidates selected will be considered invalid and not counted. All ballots must be sealed and received by mail or hand delivery in the enclosed self-addressed, stamped envelope at SDRMA on or before 4:30 p.m., Wednesday, August 21, 2019. Faxes or electronic transmissions are NOT acceptable.

- ☐ **BOB SWAN** (INCUMBENT)
  Board Member, Groveland Community Services District
- ☐ **JESSE D. CLAYPOOL**
  Board Chair, Honey Lake Valley Resource Conservation District
- ☐ **PATRICK K. O'ROURKE, MPA/CFRM**
  Board Member, Redwood Region Economic Development Commission
- ☐ **SANDY SEIFERT- RAFFELSON** (INCUMBENT)
  Finance Manager/Treasurer, Herlong Public Utility District
- ☐ **JAMES (Jim) M. HAMLIN**
  Board President, Burney Water District

ADOPTED this ____ day of _____________, 2019 by the Redwood Coast Energy Authority at a public meeting by the following votes:

AYES: ______________________________
NOES: ______________________________
ABSTAIN: ______________________________
ABSENT: ______________________________

ATTEST: ______________________________

APPROVED: ______________________________

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

This information will be distributed to the membership with the ballot, "exactly as submitted" by the candidates – no attachments will be accepted. No statements are endorsed by SDRMA.

Candidate* Bob Swan
District/Agency Groveland Community Services District (GCSD)
Work Address P.O. Box 350, Groveland, CA 95321
Work Phone (209) 962-7161 Home Phone [redacted]

*The name or nickname and any designations (i.e. CPA, SDA, etc.) you enter here will be printed [redacted] exactly as submitted.

Why do you want to serve on the SDRMA Board of Directors? (Response Required)

I am a current Board member. I would like to be elected to a second term because:
1. As a board member of Groveland CSD, I am particularly aware of the great value that smaller districts get from SDRMA, and I'd like to continue to do my part to make sure that this important agency continues to operate smoothly and stably into the indefinite future.
2. The insurance market in California (and nationwide) is going through a period of rapid change. The Board and staff are engaged in a major re-evaluation of SDRMA's approach to fulfilling its mission of providing cost-effective risk management services to it members. I believe that it is important to maintain Board continuity in this effort.
3. SDRMA Board members are either board members ("electeds") or employees of a member agency. I think there is value in having a balance between elected and employee Board members. The Board seats that are NOT up for election are currently 3 employees / 1 elected. I'd like to make sure the new Board has at least 2 elected members.

What Board or committee experience do you have that would help you to be an effective Board Member? (SDRMA or any other organization) (Response Required)

1. SDRMA Board Member since 2016. This year (2019), I serve as Secretary. During our "no CEO" period in late 2017 - early 2018, I was a member of the ad hoc Personnel Committee. I am also a member of the Alliance Executive Council, and a backup member of the Legislative Committee.

2. Groveland CSD Board Member since I was appointed in June 2013. For the years 2014-2018, I served as Board President. (We finally implemented mandatory rotation of the office in 2019).

3. Member of the Board of Southside Community Connections, a local nonprofit in Groveland that provides educational, social, and recreational services to seniors, as well as free transportation to those who cannot drive.

4. Board Member (currently Treasurer) of Pine Cone Performers, a local choral and acting group, since 2010.

5. Back during my work life, I was a corporate representative on an IEEE standards committee concerned with wireless networking. It was very educational being on a committee where the members had widely differing (competing) goals.

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

What special skills, talents, or experience (including volunteer experience) do you have? (Response Required)

History: BS Physics, MS Computer Science. 3 years in USAF. 30 years in the semiconductor industry, first as an engineering manager, later as a business unit manager. Now retired (so I have plenty of time).

Skills, etc.: Very familiar with financial reports, cost accounting, quantitative analysis. Working knowledge of modern computer and communications technology. Managed distributed organizations with up to 150 technical people and up to $120M in annual sales. Pretty good at listening to different views, and helping to achieve consensus (or, at least, compromise).

What is your overall vision for SDRMA? (Response Required)

Well, obviously I support our (newly revised) vision statement: "To be the exemplary public agency risk pool of choice for California special districts and other public agencies". In order to achieve this vision, I believe the key issues are:

1. Maintain long term financial stability. This includes ensuring that there is a fair allocation of cost versus risk across the pool membership.

2. Continue to retain / acquire highly qualified staff, and ensure that this is a desireable place to work.

3. Remember who are our target clientele, which in my opinion are small to mid-sized districts with limited options for insurance.

4. In light of ever-evolving California workers-compensation law, expand risk-management training even further than we now provide.

5. Maintain good relations with our re-insurers (who insulate us from catastrophe). In the long run, explore the possibility of joining a "captive" re-insurer to improve stability.

I certify that I meet the candidate qualifications as outlined in the SDRMA election policy. I further certify that I am willing to serve as a director on SDRMA's Board of Directors. I will commit the time and effort necessary to serve. Please consider my application for nomination/candidacy to the Board of Directors.

Candidate Signature [redacted] Date 4-24-2019

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

This information will be distributed to the membership with the ballot, "exactly as submitted" by the candidates – no attachments will be accepted. No statements are endorsed by SDRMA.

Candidate* Jesse D. Claypool
District/Agency Honey Lake Valley Resource Conservation District
Work Address USDA Service Center 170 Russell Avenue, Suite C Susanville, CA 96130
Work Phone 530-257-7271 ext 100 Home Phone [redacted]

*The name or nickname and any designations (i.e. CPA, SDA, etc.) you enter here will be printed on the official ballot, exactly as submitted.

Why do you want to serve on the SDRMA Board of Directors? (Response Required)

My interest for being on the SDRMA Board of Directors is because I believe it is imperative for there to be a knowledgeable and experienced voice on the Board with the perspective of the small to mid-size special district, working together with the other SDRMA Board Members, to ensure relevant—affordable solutions are available to all size special districts.

What Board or committee experience do you have that would help you to be an effective Board Member? (SDRMA or any other organization) (Response Required)

I am currently serving my fifth (5th) consecutive term as Chairman of the Board of a special district. I served two (2) yrs. on a Technical Advisory Committee for the prevention of violence against schools K-12. I served one (1) term on an elementary school board. I am currently serving my second (2nd) consecutive term on CSDA's committee for Professional Development. I am currently serving my sixth (6th) consecutive term on the board of a Regional Water Management Group. I am currently serving my second (2nd) consecutive term on CSDA's committee for Member Services. I am currently serving as a member of the County's Civil Grand Jury.

I have attended and completed the California School Board Association's New Board Member Training. I have Certificates of Completion from CSDA for General Manager Evaluation, Exercising Legislative Authority and Achieving Transparency. I attended and completed CSDA's Extraordinary Leader training. I attended and completed CSDA's Special District Leadership Academy and I have received CSDA's Recognition in Special District Governance certificate.

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

What special skills, talents, or experience (including volunteer experience) do you have? (Response Required)

My experience with special districts and governance, belief in the importance of quality governing policies, the ability to work effectively with the other board members and staff and a desire to give back to SDRMA and its membership will be what I bring to the SDRMA Board of Directors.

What is your overall vision for SDRMA? (Response Required)

For SDRMA to continually advance as an industry leader providing affordable solutions for special districts of any size enabling them to be effective within the communities they serve.

I certify that I meet the candidate qualifications as outlined in the SDRMA election policy. I further certify that I am willing to serve as a director on SDRMA's Board of Directors. I will commit the time and effort necessary to serve. Please consider my application for nomination/candidacy to the Board of Directors.

Candidate Signature [redacted] Date 4-26-19

Special District Risk Management Authority Board of Directors Candidate's Statement of Qualifications

This information will be distributed to the membership with the ballot, "exactly as submitted" by the candidates – no attachments will be accepted. No statements are endorsed by SDRMA.

Candidate* Patrick K. O'Rourke, MPA/CFRM

District/Agency Redwood Region Economic Development Commission (RREDC)

Work Address 520 E Street Eureka, CA 95501

Work Phone 707-445-9651 Home Phone [redacted]

*The name or nickname and any designations (i.e. CPA, SDA, etc.) you enter here will be printed [redacted], exactly as submitted.

Why do you want to serve on the SDRMA Board of Directors? (Response Required)

I have considerable interest, knowledge, and experience in board leadership; board service; and board governance/policy development & oversight in for-profits, nonprofits, a joint powers authority/SDRMA member organization, and as an elected city councilman. I also have considerable experience (as a top-level executive board leader and manager) in organizational risk management and risk mitigation/prevention. I would like to share my knowledge, skills, abilities, and experience in service to SDRMA members, via my service on SDRMA's board of directors. I believe that my knowledge, experience, and dedication to excellence and implementation of best practices in governance and policy development/oversight will serve SDRMA well, and will assist SDRMA in maintaining its "Excellence" accreditation via the California Association of Joint Powers Authorities (CAJPA).

What Board or committee experience do you have that would help you to be an effective Board Member? (SDRMA or any other organization) (Response Required)

Having served in board leadership roles (25+ years in for-profit entities; 25+ years in nonprofit & private/public foundations; and 2+ years in a Joint Powers Authority [SDRMA member organization]), I am well-versed and experienced in board governance; policy development; financial statement analysis and budget review; executive management search/selection, oversight and evaluation; organizational risk management/mitigation; litigation oversight; and best practices in organizational governance. At SDRMA member organization, Redwood Region Economic Development Commission (RREDC), I have served as 2019 Immediate Past Chair; 2018 Board Chair; 2017 Vice Chair; Chair of Executive Committee; and Member of the Loan Committee. I have in-depth knowledge of policy governance (Culver, et al.); I am an advocate for transparency & best practices; and I am knowledgeable & experienced in California's Ralph M. Brown Act and Roberts Rules of Order. I have also served in board governance and board leadership roles in several nonprofit organizations and in both public and private foundations, including as Board Chair (12+ years) and in President & Vice President roles. I have also Chaired Search/Selection committees; Public Relations committees; Fund Development committees; and Finance/Audit committees.

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

What special skills, talents, or experience (including volunteer experience) do you have? (Response Required)

Besides holding a Master of Public Affairs degree, with a specialty in nonprofit management; having completed all coursework and written/oral exams (all except dissertation) for a PhD in Mass Communication, with a specialty in public relations and a cognate in organizational communication management, I have several other directly-relevant skills/talents/experience including: I am expertly adept at executive-level relationship development and stewardship, and have served as an organizational & industry advocate and liaison working closely with community organizations, local/county/state elected officials, and public/private entities/organizations and foundations. I am expertly adept at financial and operational analysis, and at asset/portfolio management and risk mitigation. I have taught for-credit university courses in corporate leadership; in entrepreneurial leadership research and practice; as well as having published peer-reviewed academic research on leadership in public relations.

What is your overall vision for SDRMA? (Response Required)

My vision for SDRMA would be for SDRMA to continue to add value to its members; operate with the highest ethical practices and transparency; continue in providing excellence in service, education, safety and compliance training; help members to mitigate and reduce risk; provide expedient claims review and response; provide members with state-of-the-art education and information; educate members to minimize losses/risk in member workplaces; and to continue to provide members with comprehensive coverage for property/liability, workers comp, and health benefits.

I would envision SDRMA management and staff enjoying a quality of life that will ensure their happiness and continue an atmosphere of dedicated service to SDRMA members. I would also envision that SDRMA will continue to operate with efficiencies that minimize costs/expenses, continue to enable SDRMA to maintain competitive premium rates, and (when possible) lower organizational and member costs. I would also envision a governing board that embraces and employs best governing practices in all areas of policy development; executive management oversight; financial review/audit; and in investing and spreading portfolio assets to minimize portfolio investment risks and maximize return on investments. Finally, I would envision SDRMA, and its management team/staff, operating in ways that will continue to earn accreditation "Excellence" from the California Association of Joint Powers Authorities (CAJPA).

I certify that I meet the candidate qualifications as outlined in the SDRMA election policy. I further certify that I am willing to serve as a director on SDRMA's Board of Directors. I will commit the time and effort necessary to serve. Please consider my application for nomination/candidacy to the Board of Directors.

Candidate Signature [redacted] Date 3/25/[redacted] 2019

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

This information will be distributed to the membership with the ballot, "exactly as submitted" by the candidates No statements are endorsed by SDRMA.

Candidate* Sandy Seifert-Raffelson

District/Agency Herlong Public Utility District

Work Address 447-855 Plumas St., P o Box 115, Herlong, CA 96113

Work Phone (530) 827-3150 Cell Phone [redacted]

*The name or nickname and any designations (i.e. CPA, SDA, etc.) you enter here will be printed on the official ballot, exactly as submitted.

Why do you want to serve on the SDRMA Board of Directors?

I am a current Board member of SDRMA and feel that I have added my financial background to make better informed decisions for our members. As a Board member, I continue to improve my education of insurance issues and look forward to representing small District's and Northern California as a voice on the SDRMA Board. I feel I am an asset to the Board with my degree in Business and my 30 plus years' experience in accounting and auditing.

I understand the challenges that small District face every day when it comes to managing liability insurance, worker's compensation and health insurance for a few employees with limit revenue and staff. My education and experience give me an appreciation of the importance of risk management services and programs, especially for smaller District that lack expertise with insurance issues on a daily basis.

I feel I am an asset to this Board, and would love a chance to stay on 4 more years!

What Board or committee experience do you have that would help you to be an effective Board Member? (SDRMA or any other organization)

While serving on the SDRMA Board, I have been privilege to be Secretary of the Board for two years, and currently the Vice-President. I have served on CSDA's Audit and Financial Committee's for 6 years; I have served on the SDLF Board; Northeastern Rural Health Clinic Board; Fair Board; School and Church boards; 4-H Council and leader for 15 years; and UC Davis Equine Board. In the past 25 years, I have learn that there is no "I" in Board and it can be very rewarding to be part of a team that makes a difference for others.

As part of my many duties working with Herlong PUD, I worked to form the District and was directly involved with LAFCo, Lassen County Board of Supervisors and County Clerk to establish the initial Board of Directors and first Policies for HPUD. I have administered the financial portion of 2 large capital improvement project with USDA as well as worked on the first ever successful water utility privatization project with the US Army and Department of Defense. I am currently working on a 4.2 million grant from California for new infrastructure for the small District HPUD absorb through LAFCo in 2017. I am also the primary administrator of a federal contract for utility services with the Federal Bureau of Prison and the US Army.

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

What special skills, talents, or experience (including volunteer experience) do you have?

I have my Bachelor's Degree in Business with a minor in Sociology. I have audited Small Districts for 5 years, worked for a Small District for almost 15 years and have over 30 years of accounting experience. I am a good communicator and organizer. I have served on several Boards and feel I work well within groups or special committee. I am willing to go that extra mile to see things get completed.

I believe in recognition for jobs well done. I encourage incentive programs that get members motivated to participate and strive to do their very best to keep all losses at a minimum and reward those with no losses.

I have completed my Certificate for Special District Board Secretary/Clerk Program in both regular and advance course work through CSDA and co-sponsored by SDRMA. I have completed the CSDA Special District Leadership Academy and Special District Governance Academy. I am in the processes of getting my small District re-certified for their District of Transparency and hope one day to attain our District of Distinction.

I work for a District in Northeastern California that has under gone major changes from a Cooperative Company to a 501c12 Corporation, to finally a Public Utility District. I have worked with LAFCo to become a District. Also our small District consolidated another small District into our District. Through past experience I feel I make a great Board member representing the small districts of Northern California and their unique issues and will make decisions that would help all rural/small districts.

What is your overall vision for SDRMA?

For SDRMA to be at the top of the risk management field and to continue communicating and listening to the needs of all California Special Districts and meeting those needs at a reasonable price that Special Districts can afford. I would like to continue education and rewards for no claims and explore avenues of financial endeavors that will benefit our customers.

I certify that I meet the candidate qualifications as outlined in the SDRMA election policy. I further certify that I am willing to serve as a director on SDRMA's Board of Directors. I will commit the time and effort necessary to serve. Please consider my application for nomination/candidac[redacted]

Candidate Signature [redacted] Date 4/16/19

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

This information will be distributed to the membership with the ballot, "exactly as submitted" by the candidates – no attachments will be accepted. No statements are endorsed by SDRMA.

Candidate* James (Jim) M. Hamlin

District/Agency Burney Water District

Work Address 20222 Hudson St. Burney, Ca. 96013

Work Phone (530) 335-3582 Cell Phone

*The name or nickname and any designations (i.e. CPA, SDA, etc.) you enter here will be printed on the official ballot, exactly as submitted.

Why do you want to serve on the SDRMA Board of Directors? (Response Required)

Hope to serve and help with decisions being made to both strengthen SDRMA and move into new areas. Our districts are facing new challenges constantly.

What Board or committee experience do you have that would help you to be an effective Board Member? (SDRMA or any other organization) (Response Required)

See Next

Special District Risk Management Authority
Board of Directors
Candidate's Statement of Qualifications

What special skills, talents, or experience (including volunteer experience) do you have? (Response Required)

September 1972 until January 2014, owned and operated a Insurance brokerage
Sold business and retired.
Board Member of Mayers Memorial Hospital District From 1990 until 2014
Served on the Associal of Hospital Districts for six years.
Served on the board of Burney Water District the previous six years. Current
Serving on Mayers Memorial Hospital Financial Board.

What is your overall vision for SDRMA? (Response Required)

SDRMA Board must be strong and protect the concerns of their members. Need to have a listening ear for the districts that are represented. Need to use caution when jumping into new areas, not jepordise their strong programs and beliefs for new programs.

I certify that I meet the candidate qualifications as outlined in the SDRMA election policy. I further certify that I am willing to serve as a director on SDRMA's Board of Directors. I will commit the time and effort necessary to serve. Please consider my application for nomination/candidacy to the Board of Directors.

Candidate Signature [redacted] Date 3-27-2019

Materials Received After Packet Publication

SDRMA

SPECIAL DISTRICT RISK MANAGEMENT AUTHORITY

OFFICIAL 2019 ELECTION BALLOT
SPECIAL DISTRICT RISK MANAGEMENT AUTHORITY
BOARD OF DIRECTORS

VOTE FOR ONLY THREE (3) CANDIDATES

Mark each selection directly onto the ballot, voting for no more than three (3) candidates. Each candidate may receive only one (1) vote per ballot. A ballot received with more than three (3) candidates selected will be considered invalid and not counted. All ballots must be sealed and received by mail or hand delivery in the enclosed self-addressed, stamped envelope at SDRMA on or before 4:30 p.m., Wednesday, August 21, 2019. Faxes or electronic transmissions are NOT acceptable.

☑ **BOB SWAN** (INCUMBENT)
Board Member, Groveland Community Services District

☑ **JESSE D. CLAYPOOL**
Board Chair, Honey Lake Valley Resource Conservation District

☐ **PATRICK K. O'ROURKE, MPA/CFRM**
Board Member, Redwood Region Economic Development Commission

☑ **SANDY SEIFERT- RAFFELSON** (INCUMBENT)
Finance Manager/Treasurer, Herlong Public Utility District

☐ **JAMES (Jim) M. HAMLIN**
Board President, Burney Water District

ADOPTED this 25th day of July, 2019 by the Redwood Coast Energy Authority at a public meeting by the following votes:

AYES: Garnes, Woo, Smith, Miller, Fennell
NOES: ~~Woo~~ Daugherty, Winkler
ABSTAIN: ~~Garnes~~
ABSENT: Allison, Glaser

ATTEST:

APPROVED:

REDWOOD COAST
EnergyAuthority

STAFF REPORT

Agenda Item # 11.1

AGENDA DATE:	July 25, 2019
TO:	Board of Directors
PREPARED BY:	Matthew Marshall, Executive Director Richard Engel, Director of Power Resources
SUBJECT:	Community Choice Energy Program Updates

SUMMARY

Continuation of DG Fairhaven Biomass Contract.

RCEA obtains a portion of its renewable energy from DG Fairhaven Power, LLC under a one-year contract with an annual option to renew. After its first year, the Board authorized renewal of the contract earlier this year. The contract is now set to expire at the end of February 2020.

Both parties would benefit from an early decision whether to renew the contract. The resource adequacy (RA) market that RCEA is required to participate in has become tight in the past year, and we will need to begin shopping soon for an alternative source of the RA that DG Fairhaven provides if the Board chooses not to renew the contract. Similarly, DG Fairhaven's owners would benefit from getting early notice of RCEA's plans in case they need to look for an alternative buyer of their power. Staff will return to the Board in August with analysis to assist in deciding whether to renew the contract.

RCEA Membership in California Community Choice Association.

Since beginning the process of launching a community choice program, RCEA has been a member of the California Community Choice Association (CalCCA). As the trade association for community choice aggregators, CalCCA's mission is to create a legislative and regulatory environment that supports the development and long-term sustainability of locally-run CCA electricity providers in California through education, technical guidance, and regulatory and legislative advocacy.

CalCCA has a current annual budget of approximately $4 million, with the largest budget areas being: regulatory and legislative engagement (48%), staff (37%), and marking and communications (6%). To support this budget and the associated degree of regulatory and legislative engagement, CalCCA's membership costs are increasing in FY19-20; for RCEA the increase is from $98,250 last year up to $108,960.

CalCCA membership fees are scaled based on the size of the CCA, and so as one of the smallest CCA's RCEA contributes less than 3% of CalCCA's annual budget. However, as an operational member of CalCCA RCEA has an equal voting position in the 13-member CalCCA Board of Directors, which is made up of the chief executive officers of each CCA (Executive Director Marshall is currently the CalCCA Board Treasurer).

Of critical importance to RCEA is CalCCA's central role in 1) representing the interests of CCAs in the many CPUC regulatory proceedings that could have significant impacts to RCEA and/or our customers, and 2) advocating in Sacramento on the numerous pieces of legislation each year that

would affect CCAs. Staff will provide a brief update at the meeting on current regulatory and legislative activities of particular significance to CCAs.

FINANCIAL IMPACTS

Without CalCCA's representation RCEA would have to incur significantly higher costs to provide its own regulatory and legislative representation at the CPUC and in Sacramento; by sharing and coordinating staffing and consultant costs with the other (mostly much larger) CCAs across the state RCEA receives a much higher level of support and resulting impact than would be possible outside of CalCCA.

The potential negative impact of not having strong representation could be quite significant to RCEA and our customers. Two examples would be the ongoing Resource Adequacy (RA) and Power Charge Indifference Adjustment (PCIA) proceedings at the CPUC: RCEA's annual RA cost is close to $4 million and RCEA's customers collectively pay close to $20 million in PCIA charges every year—so even small changes to the CPUC rules governing the RA and PCIA processes could result in large financial impacts.

RECOMMENDED ACTIONS

Approve increase to RCEA's annual CalCCA membership dues up to $108,960.

ATTACHMENTS

CalCCA FY19-20 Operational Member Dues Letter.

California Community Choice Association
Operational Member Dues
FY 19_20
(July 1, 2019-June 30, 2020)

Redwood Coast Energy Authority

Dear Director Marshall,

On June 13, 2019, the CalCCA Board unanimously approved the following:

1. Updated FY19_20 Dues Methodology.

This year, the operational membership dues will no longer be split into two separate categories for supporting operations and regulatory matters and instead will be one single sum. Additionally, the variable rate portion was increased to .18% and the overall cap was increased to $330,000.

For FY 19_20 Redwood Coast Energy Authority has elected to be an Operational Member with a seat on the Board of Directors. Based on the new methodology in Scenario 1 of the attached report, the annual contribution will be $108,960 for the year (as compared to $98,520 for the previous year).

Quarterly payment invoices will be sent at the beginning of each fiscal year quarter (July, October, January, April) from the CalCCA Quickbooks system to your contact(s) on file. Payments are due 30 days after receipt of the invoice.

Please do not hesitate to contact me if you have any questions or would like to discuss your membership. We sincerely appreciate your continued partnership and involvement in CalCCA as we enter our fourth year of operations.

Thank you,

Martha Serianz
Director of Operations and Membership
California Community Choice Association
510-290-4187
martha@cal-cca.org

CALCCA

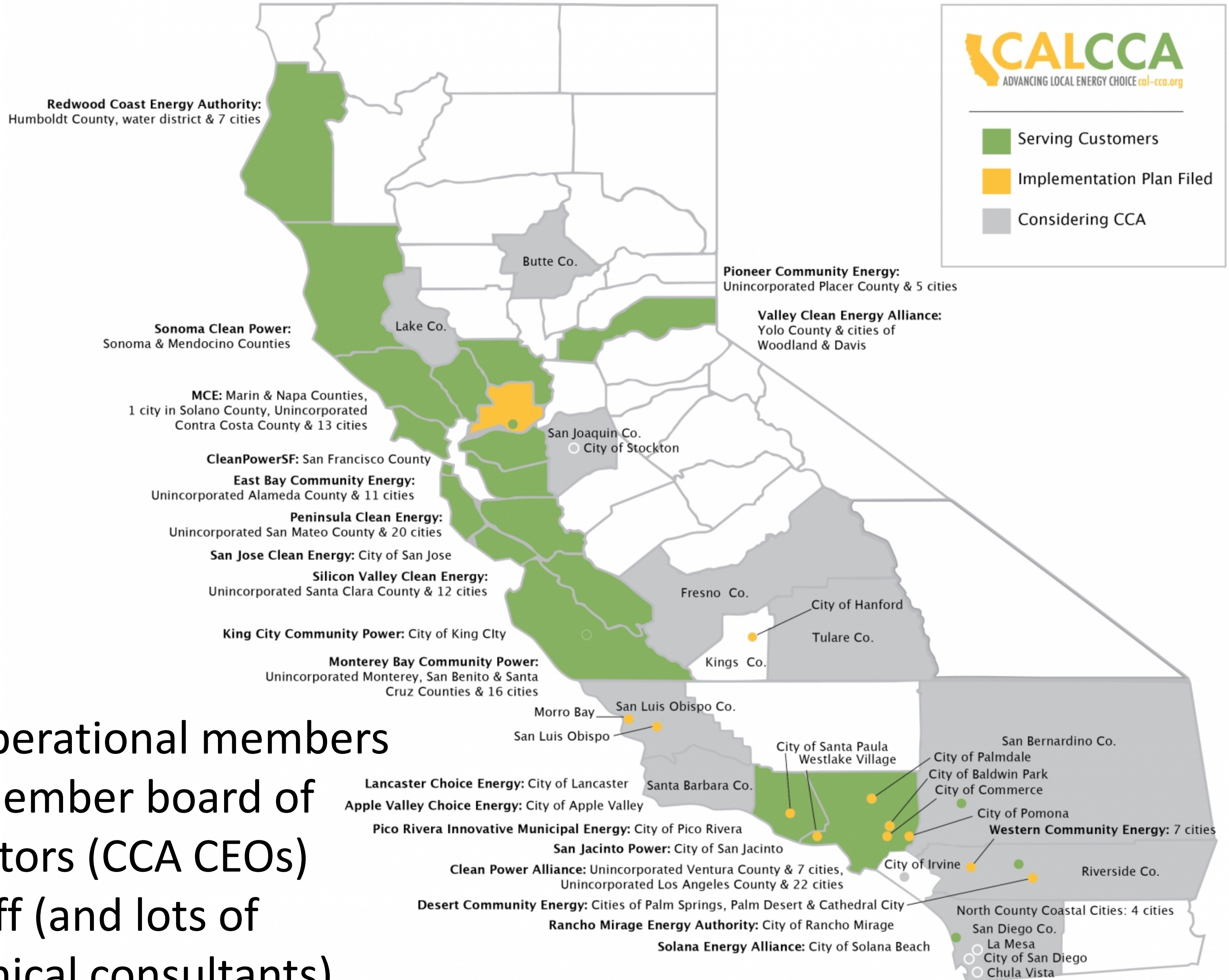
ADVANCING LOCAL ENERGY CHOICE

Materials received after agenda publication:
Presented at the meeting
by Executive Director Matthew Marshall

CALCCA
ADVANCING LOCAL ENERGY CHOICE

The California Community Choice Association's mission is to create a legislative and regulatory environment that supports the development and long-term sustainability of locally-run Community Choice Aggregation electricity providers in California.

We serve our members and strengthen our collective voice through education, technical guidance and regulatory and legislative advocacy.



- 18 operational members
- 13-member board of directors (CCA CEOs)
- 6 staff (and lots of technical consultants)

Regulatory Engagement

- ~50 CPUC filings in FY18-19 (about one per week)
- Key proceedings currently in progress include:
  1. PCIA Working Group 1, Benchmarking and True-up
  2. PCIA Working Group 2, Prepayment
  3. PCIA Working Group 3, Portfolio Optimization
  4. Resource Adequacy, Phase 2, Track 2, Central Buyer
  5. Resource Adequacy, Phase 2, Track 3, sales framework for IOU excess RA
  6. Integrated Resource Planning, Phase 2, Procurement Track
  7. Public Safety Power Shutoff Rulemaking, Phase 2

Legislative Engagement

- 25 bills in 2019 identified by CalCCA as priority bills
- Nine of those eventually amended with provisions that would be highly problematic for CCA operations.
- All but one of those 9 bills either amended, failed passage, or tabled until next year.