SCE BIOMASS POWER PLANT ENVIRONMENTAL ANALYSIS

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Prepared For:
Southern California Edison, Project Development Division
2244 Walnut Grove Avenue
Rosemead, CA 91770

Prepared By:
TSS Consultants
2724 Kilgore Road
Rancho Cordova, CA 95670

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1.0 SUMMARY OF FINDINGS

Southern California Edison Company (SCE) is assessing the technical, economic, and permitting feasibility of a woody biomass fired electrical generation facility scaled to 10-12 megawatts (MW). This report is the summation of a regulatory analysis regarding such a proposed concept.

Principal objectives for this regulatory analysis include:

- How applicable definitions, legislative actions, and agency regulations apply
- Whether it is permittable within the extant environmental framework
- What is the magnitude of barriers, identifying work needed to overcome them
- What parameters are defined, under which such a facility is deemed prudent

The regulatory analysis was broken into several tasks. These tasks specifically evaluated several facets of the regulatory permitting of a biomass power plant to be constructed and operated in Central California (specifically the Shaver Lake area of Fresno County). The tasks included:

- Effects of Existing Laws and Initiatives
- Effect of Boiler Technologies on the Permitting Process
- San Joaquin Valley Air Pollution Control District
- Impact of Best Available Control Technology Requirements
- Emission Offset Credits
- Water and Land Use Permitting Requirements
- Additional Principal Permitting Requirements
- Major Obstacles and Critical Path Permitting Items

The following Sections 2.0 through 9.0 detail the results of these tasks. Below is a brief summary of the finding of each task.

Effects of Existing Laws and Initiatives

A biomass-fueled power generation facility fits directly within the scope of the legislative and regulatory measures that have been passed within the past 6 years. Current regulation, legislation, and executive directives make explicit or implicit mention of biomass power. In summary, SB1368 provides clear interpretation of compliance for biomass power generation, while AB32 represents a work-in-progress, with California Renewable Portfolio Standards (RPS) and California Governor's Executive Orders providing general support. The recently passed American Recovery and Reinvestment Act of 2009 (ARRA) also significantly supports biomass energy development.

SB1368 established an emission performance standard (EPS) with which all long-term investments for baseload generation by California utilities must comply. Resulting state regulation has established using biomass in an electric generation facility would be compliant with the EPS.

Biomass is widely accepted as a renewable energy source. An argument can be made that the use of biomass to generate energy is a carbon neutral process. This is particularly the case since, by definition, a carbon-neutral fuel does not contribute a positive net increase in anthropogenic greenhouse gas (GHG) emissions.

Per California RPS Guidelines, RPS-eligible biomass facilities are eligible for financial incentives to reduce generation-to-market costs, although not explicitly stated in AB32. The federal ARRA specifically provides for increasing funds and tax credits to activities that relate to a prospective biomass-fired power generation facility.

Effect of Boiler Technologies on the Permitting Process

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rules and Regulations apply to the biomass-fueled power plant permitting process. The SJVAPCD rules specify emissions compliance limits, but do not specify what technology or boiler system must be supplied to meet these limits, nor prescribe what emission controls to use. Technology chosen does not appreciably affect the permitting process. As a result, all boiler options are available for use at a prospective biomass generation facility. Certain categories of emissions control technologies may be required to meet SJVAPCD permitting requirements on the basis of the boiler technology chosen.

San Joaquin Valley Air Pollution Control District

The SJVAPCD does not specify emission limits by boiler type or by fuel type. But emissions limitations are based on throughput or rate (volume or time), which could be impacted by choice of biomass fuel. Thus, compliance to regulations could be impacted by fuel. SJVAPCD regulations make no allowance for elevation in calculating their emission limits, thus there is no additional benefit to include in the comparisons.

Impact of Best Available Control Technology Requirements

Best Available Control Technology (BACT) is required on a pollutant-specific basis. Emission control equipment required could include selective non-catalytic reduction (SNCR) with urea injection for oxides of Nitrogen (NOx), limestone injection for oxides of Sulfur (SOx), dry electro-static precipitator with baghouse for particulate matter (PM), and good combustion practice for Carbon Monoxide (CO) and Volatile Organic Compounds (VOC). In the SJVAPCD jurisdiction, there is no imposed emission control for CO_2.

Emission Offset Credits

The SJVAPCD has jurisdiction over applying federal, state, and local air pollution control laws and regulations, of which offsetting emissions is a requirement if certain criteria pollutant emission thresholds are exceeded (in a specified period of time).

It is expected that Emission Offsets will need to be provided for NOx and CO. These offsets will likely have to be purchased. There is no current allowance within San Joaquin Valley Air Pollution Control District (SJVAPCD) regulations to issue emission reduction credits (ERCs) due to reduction of open pile burning of forestry waste.

There are also no current GHG emission credits as relate to forestry or wood-waste biomass, though such is under scrutiny worldwide and could come into play by the time a decision is made to submit documentation for a prospective facility. However, GHG do not currently have to be offset for biomass energy production in the SJVPACD..

Water and Land Use Permitting Requirements

Water discharge (from power plant operations) to land or surface water does require a permit from the Regional Water Quality Control Board, unless a zero-discharge facility design is employed. A storm water discharge permit is required from the Board for both construction and operation, requiring submittal and implementation of a plan with monitoring and reporting requirements.

Regarding land use, prospective sites may require a conditional use permit (CUP), particularly where it could be posed that a biomass plant would allow for forest management of fuels treatment and timber harvest residuals.

Water supply will not trigger any permitting requirements.

Additional Principal Permitting Requirements

In regards to air quality permitting, the most stringent rules are at a local level, the SJVAPCD, not the federal. Some local regulations do implement the federal regulations and standards by reference.

Since the prospective siting is on non-federal lands, it is deemed the California Environmental Quality Act (CEQA) applies. It is possible that a federal agency will file as an interested party or potentially as a responsible party in the CEQA review process, most likely the USDA Forest Service, since a portion of the biomass fuel resources noted for this feasibility study concept will be derived from is federal forested lands.

Due to prior jurisdictional determinations, it is deemed the lead agency for CEQA review will be the local land use control agency, the Fresno County Department of Public Works and Planning.

Major Obstacles and Critical Path Permitting Items

For the construction and operation of a biomass power plant in the Shaver Lake areas, three principal permitting areas have been identified: Air quality; land use; and water use, including waste water/storm water discharge. The land use permit, a.k.a. the CUP, along with its accompany CEQA process will be the critical path item in the power plant permitting process. The CUP must be in place prior to any on-site construction activities. This is also true for the air quality permit. Facility design and engineering, at least preliminary, is typically also required before the permitting process begins

In permitting of the biomass power plant the following steps are recommended:

- Prepare communications plan
- Prepare project description and preliminary design drawings
- Pre-application meetings with regulatory agencies
- Preparation and submittal of appropriate applications
- Agency interface during permit processing by regulatory agencies

2.0 EFFECTS OF EXISTING LAWS AND INITIATIVES

A biomass-fueled power generation facility fits directly within the scope of the legislative and regulatory measures that have been passed within the past 6 years. Current regulation or legislation makes explicit or implicit mention of biomass power. They are reviewed with supporting definitions from industry to show how they could apply to a prospective facility. In summary, SB1368 provides clear interpretation of compliance for biomass power generation, while AB32 represents a work-in-progress, with California Renewable Portfolio Standards (RPS) and California Governor's Executive Orders providing general support. This write-up details the scientific and technical background behind biomass' carbon-neutrality and provides discussion of the legislative mandate for greenhouse gas (GHG) emission reduction in California.

2.1 Laws and Initiatives – Compliance

SB1368 established an emission performance standard (EPS) with which all long-term investments for baseload generation by California utilities must comply, as signed into law September 29, 2006. SB1368 amends the Public Utilities Code (PUC), Division 4.1, to include a chapter titled, "Chapter 3: Greenhouse Gases Emission Performance Standard for Baseload Electrical Generating Resources." SB1368 further directed the CEC to establish regulations for implementing the GHG Emission Performance Standards (EPS) defined by SB1368, as reflected in California Code of Regulations (CCR), Title 21, Section 2903 and Section 2904. This first quote specifies compliance, which is a consistent high-level goal for the utility:

> "Power plants that are using only biomass fuels that would otherwise be disposed of utilizing open burning, forest accumulation, spreading, composting, uncontrolled landfill, or landfill utilizing gas collection with flare or engine" are determined to be in compliance with EPS. [CCR, Title 21, §Section 2903 (b)(2)]

This regulation is a demonstrated statement of concurrence to the underlying science, which can be confusing, where it speaks to implication of the different types of carbon, appears to imply the code allows more for biomass than for other power generations, though lands on a determination that biomass carbon does offset GHG emissions.

2.2 Carbon and Biomass Power Generation

Biomass is widely accepted as a renewable energy source. An argument can be made that the use of biomass to generate energy (biomass to energy, or BTE) is a carbon neutral process.

Power generation from biomass combustion is unique in its characterization as renewable energy as it is also a process that produces greenhouse gases. This apparent inconsistency can be rectified by considering the source of carbon in biomass. *Biogenic* carbon is stored in biomass, released as carbon dioxide to the atmosphere through combustion, and removed from the atmosphere through photosynthesis and other biological processes. As a result of the time scale on which biological processes operate, carbon released through burning of biomass material is actively exchanged and returned quickly to the environment, mainly through photosynthesis and uptake by oceans. Conversely, combustion of fossil fuels contributes to anthropogenic GHG emissions, whereby *ancient* carbon that was previously geologically sequestered is released.

By definition, a carbon-neutral fuel does not contribute a positive net increase in anthropogenic GHG emissions. Biomass and direct-combustion biomass power falls within this definition.

Power generation from biomass combustion can contribute to a reduction of greenhouse gas emission global warming potential (GWP) when compared to the current practice of biomass waste disposal. Current disposal practices include transport to landfill sites, decomposition on-site, and pile burning on-site [Mann and Spath 2002]. These disposal practices lead to the production of methane, which on a 100-year time horizon has 25 times more global warming potential than carbon dioxide, on a mass comparison [IPCC (Intergovernmental Panel on Climate Change) 2007]. In effect, 1 kg of methane contributes the global warming potential of 25 kg of CO_2-equivalent. Burning 1 kg methane will produce approximately 3 kg of CO_2, avoiding 22 kg CO_2-equivalent emissions. As a result, the BTE process can record a net decrease in GWP.

To substantiate this position, there is an underlying assumption that methane is produced from decomposition of biomass in conventional disposal methods. A biomass industry study finds that through decomposition, 5 to 50% of total carbon stored in biomass is released as methane [USA Biomass Power Producers Alliance 2007]. Other similar work states approximately 9% of the carbon in biomass residues end up as methane if not burned in a power plant and 61% of the carbon ends up as CO_2 [Mann and Spath 2002]. Remaining 30% is resistant to decomposition due to presence of lignin compounds or inadequate conditions for the microbes carrying out the decomposition process [Mann and Spath 2002]. Also, if biomass residue is used as fuel in a direct-combustion power plant, a net reduction is realized of 0.63 lbs CO_2-equivalent for every 1 lb of biomass combusted [Mann and Spath 2002]. Thus, significant reduction is experienced in GHG emissions from power plant biomass combustion compared to the current state of disposal.

In addition, if energy produced from a biomass power plant offsets demand from a fossil fuel fired power plant, even more GHG emission reduction is experienced. A majority of the fossil fuel based generation that occurs in California uses natural gas. Natural gas fired combined cycle power plants produce approximately 0.65 tons CO_2-equivalent/MWh_e (which accounts for methane losses during extraction and delivery) [Spath and Mann 2000]. Biomass direct combustion, particularly wood and wood waste, produce approximately 1.45 tons CO_2/MWh_e. However, this contribution can be removed from the carbon accounting process because carbon stored within biomass is considered biogenic carbon, and does not contribute to anthropogenic carbon emissions. As a result of offsetting the demand from fossil fuel fired power plants, the redirected disposal of biomass residues, and the recognition of biomass as a biogenic fuel source, biomass direct-combustion power plants can be credited 1.0-1.2 tons CO_2-equivalent per MWh generated (54% due to offset demand, 46% due to alternative disposal).

Current practices for biomass disposal are inefficient, contribute to the disposer's greenhouse gas emission profile, and do not realize the potential for diverting this waste stream into currently available BTE technology. Diverting a current biomass waste stream into a power plant reduces approximately 0.5 tons CO2 emissions per MWh generated. If the power generated in this power plant offsets demand from a natural gas-fired power plant, then at least an additional 0.5 tons CO_2 emissions per MWh can be realized. (This emission reduction will increase in locations with a more carbon intense generation mix). Diversion of biomass from the current waste stream into controlled, modern direct-combustion biomass power plants create an economical and currently available method to reduce GHG emissions.

2.3 Laws and Initiatives – CO2 Limit

In addition to specific mention of compliance to EPS for biomass facilities, SB1368 identified how CO2 emissions are determined should the facility use a fuel blend, and how the emissions compare to natural-gas fired power generation, which constitutes a low-carbon source.

- If a plant is not eligible for RPS certification and it uses biomass fuel in combination with other fuel(s), the power plant's average CO2 emissions from fuels other than biomass are used for determination of compliance with EPS. [CCR, Title 21, §Section 2904 (b)]

- Electricity generated by a zero or low-carbon source that contracts on a cost-of-service basis may recover their long-term investment in rates. A zero or low-carbon source is defined in Section 8340, subpart (n) as a resource that falls under the EPS (less than 1,100 lbs CO2/MWh). [PUC, Division 4.1, Section 8341 (b)(6)]

- EPS for all baseload generation of load-serving entities is to be established as "the rate of emissions of GHG that is no higher than the rate of emissions of GHG for combined-cycle natural gas baseload generation." This caps the emission rate at 1,100 lbs CO2 per MWh generated (0.55 tons CO2/MWh). [PUC, Division 4.1, Section 8341 (d)(1)]

This specified lower-end limit for natural gas, along with biomass compliance determination, implies it is recognized there are other incidental benefits for use of biomass as a fuel source (as addressed herein under *Carbon and Biomass Power Generation*.).

2.4 Laws and Initiatives – Net Emissions

Biomass fuel is specifically identified as a renewable energy source, and BTE technology has the ability to take advantage of legislative mandates to achieve the state's renewable energy goals. There has also been pre-work in the forestry sector to attempt to craft a standardized process to propound and support how forest treatment is a carbon sink, not a carbon source. Part of a problem statement toward this end recognizes silos exist for various yet related areas of impact.

- Biomass is defined as any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, sludge derived from organic matter, and wood and wood waste from timbering operations." [California Energy Commission (CEC) Renewable Energy, Overall Program Guidebook]

- Emissions from facilities generating electricity from biomass will consider net emissions from growing, processing, and utilizing the fuel, but is silent on what are the acceptable variables to factor into that equation. However, biomass facilities that utilize fuels that would have been otherwise open burned or left to decay are deemed EPS compliant regardless of emissions, so calculated emissions become immaterial. [PUC, Division 4.1, Section 8341 (d)(4) and PUC Decision 07-01-039, Rulemaking 06-04-009, Section 1.4]

- Defines ability of State of California to reduce its GHG emissions to 1990 levels by 2020. [AB32, California Global Warming Solutions Act of 2006, into law September 2006]

- By January 2011, the California Air Resources Board (CARB) will adopt state GHG emission limits and reduction measures. [Health and Safety Code as Division 25.5, Section 38562 (a)]

- California's RPS set the current 20% renewable energy deadline for 2010, and defines a tracking and verification system to prevent double counting of renewable energy output [established with 2002 passing of SB1078, and 2003 Energy Action Plan I], with a proposed increase to 33% RPS by 2030 [2005 Energy Action Plan II].

- The state is to meet a 20% target use of biomass for electricity within the state goals for renewable generation capacity for 2010 and 2020 [Governor's Executive Order S-06-06]

- Increase use of biomass contribute solutions to risk of catastrophic wildfires, air pollution from open burning of biomass, and GHG emissions from landfills, and use of waste and residue from forests for energy production can decrease GHG emissions from biomass decomposition that would otherwise occur [Governor's Executive Order S-06-06]

- AB32 considers the California forestry sector a net carbon sink. As result, net emissions reductions from forests are predicted to contribute a reduction of 5 million metric tons per year of CO_2-equivalent to the 2020 GHG emissions reduction goal. [Climate Change Draft Scoping Plan, released by California Air Resources Board (CARB) June 2008, with a proposed scoping plan released in October 2008 and approved in December 11, 2008 [CARB Resolution 08-47]

- Method and means to achieve compliance to the scoping plan, as relates to a prospective biomass-fired power generation facility, are not specifically identified in AB32, which does not impact operating procedures. Potential future impact may result in an increased focus on certification activities that may come as result of AB32.

2.5 Laws and Initiatives – Financial Benefits

In alignment to a perspective on an overall impact, financial models seem support market-based methodology to potentially generate financial benefits, such as is outlined in AB32. Although not explicitly stated in AB32, per California RPS Guidelines, RPS-eligible biomass facilities are eligible for financial incentives to reduce generation-to-market costs. Pertinent details include:

- Entities that voluntarily reduce their emissions prior to implementation of section 38562 will receive credit. [Health and Safety Code as Division 25.5, Section 38562 (b)(3)]

- CARB may adopt a "market-based declining annual aggregated emission limits" for GHG emitters by January 2011. This is the mandate for a "cap-and-trade" system. [Health and Safety Code as Division 25.5, Section 38562 (c)]

- Biomass power generation facilities that utilize solid fuels are eligible for the Existing Renewable Facilities Program (ERFP), which has $75M of incentive funding, set aside for calendar years 2007-2011. Facilities must be RPS-certified to be eligible for ERFP, which complies with the AB32 Scoping Plan. [CEC Existing Renewable Facilities Program 6th Edition Guidebook, and Climate Change Scoping Plan, October 2008]

- The American Recovery and Reinvestment Act of 2009 (ARRA) specifically provides for increasing funds to activities that relate to a prospective biomass-fired power generation facility, specifically with regard to capital and road improvements on US Forest Service lands ($650 Million), wildland fire management measures ($500 Million, of which $250M is dedicated for public lands and $250M is dedicated to State and private land management), and wood-to-energy grants (up to $50M). [H.R. 1 Division A, Title VII-Interior, Environment, and Related Agencies appropriations, USDA Forest Service, Capital Improvement and Maintenance and Wildland Fire Management]

- The ARRA specifically notes benefits to utilizing biomass power. It defines "open loop biomass" as any solid nonhazardous, cellulosic waste material or any lignin material which is derived from any of the following forest related resources: mill and harvesting residues, pre-commercial thinning, slash, solid wood waste materials, including pallets, crates, dunnage manufacturing, and construction wood waste. Such facility is eligible for 30% grant, 30% energy credit, or renewable energy production credit. [Investment Tax Credit: H.R.1 Division B, Section 1103; Production Tax Credit: H.R. 1 Division B, Section 1101, 1103; Renewable Energy Grants: H.R. 1 Division B, Section 1104, 1603; IRS code section 45(c)(3)(a)(ii)]

- The mineral content in forestry ash is a valuable and viable nutrient for the forest. Land managers have a long-held practice of prescribed burns, since it provides beneficial return of nutrients to the soil and to the forest (Zafar, 2009). Where the identified fuel source for a prospective project is deemed to be exclusively forest-based and ag-based, nutrient-rich ash can be returned to the soil of the region, for improved health of the forest. This ash is thus a marketable commodity.

- Waste diversion credits typically apply to material diverted from landfills. However, biomass conversion via direct combustion or gasification does not now qualify for waste diversion credits. Several legislative bills have attempted to fix this (the latest being AB 177, Bogh 2005). An argument could be posed that, if restricted from open burning, this wood waste residue otherwise could be destined for landfill, and would thus qualify for diversion credits. Regulations of the agency where a prospective biomass-fired facility might be sited do not include forest wood waste in the category that is eligible for diversion credits. If this apparent inequity is resolved, it provides another revenue stream for a prospective project.

It would thus seem the applicable regulations are lining up to support a positive cash flow for a biomass power generation. Should the utility pursue installation of a prospective biomass-fired power generation project, the Operations & Maintenance costs should reflect this factor.

3.0 EFFECT OF BOILER TECHNOLOGIES ON THE PERMITTING PROCESS

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rules and Regulations apply to the permitting process. They specify emissions compliance limits (see section 4.0), but do not specify what technology or boiler system must be supplied to meet these limits (as determined in BACT analysis, see section 5.0), nor prescribe what emission controls to use. Technology chosen does not appreciably affect the permitting process. As a result, all boiler options are available for use at a prospective biomass generation facility. Certain categories of emissions control technologies may be required to meet SJVAPCD permitting requirements on the basis of the boiler technology chosen.

While the type of boiler plays a large role in the emissions generated from a biomass-combustion electricity generation facility, the fuel and its constituents are the underlying cause for emissions related issues that may arise in the combustion process. Emissions controls are incidental to the boiler technology, and in addition, there are other emissions control mechanisms to consider, that are separate from the boiler technology.

Control mechanisms that are related to SJVAPCD's criteria emissions include:

- NOx Control – Staged fuel combustion and flue gas recirculation, selective non-catalytic reduction (injection of ammonia or urea)
- CO Control – Catalytic converters
- PM10 Control – Settling chambers, filters (electrostatic, bag), scrubbers
- SOx Control – Wet or dry scrubbers (wood-based fuels generally have low sulfur content, thus SOx control would be required if proposed fuel mix is utilized)
- VOCs – Scrubber (if drying biomass, VOC emissions may be experienced. Scrubber on dryer flue gas outlet will be necessary to remove VOC emissions. Does not apply to boilers)

Incidental to biomass boiler systems is the potential for a variety of emissions scenarios. Thus, the choice of boiler type has a consequential effect on the type of technologies that will be necessary to meet SJVAPCD emissions standards. Thus, TSS supplies an overview of common boiler systems and a description of potential emission scenarios that have been historically experienced.

Boilers for biomass combustion are of three separate types of technology:

- Fixed Bed Combustion
- Fluidized Bed Combustion (FBC)
- Pulverized Fuel Combustion (PFC)

3.1 Fixed Bed Combustion

Fixed bed combustion of biomass relies on various types of grates in order to achieve the correct combustion for the mixtures of fuels being input into the boiler. Flexibility of grate furnaces accept generally high moisture content fuel, of various particle size, and with high ash content. As a result, grate furnaces require little pre-treatment of fuels before introduction into the boiler. Fixed bed combustion and grate furnaces bring up the following emissions control permitting issues:

- Higher NOx formation potential (due to higher temperatures experienced in combustion chamber and flue gas)
- Low PM created (from ash not being suspended in air)
- Less CO control than FBC technology (excess air content required for complete combustion is higher, difficult to achieve thorough air fuel mixture)

3.2 Fluidized Bed Combustion

Boilers that utilize FBC technology realize advantages over the other two types of boilers available. FBC requires input air to “fluidize” or suspend the fuel, air, and inert particle mixture, allowing for more complete combustion of fuel with a low amount of excess air, both of which contribute to lower pollutant formation. By suspending the fuel in air, good mixing of fuel is achieved, and a variety of fuel types and burn conditions can be accommodated. For instance, type of biomass combusted does not need to be uniform and can contain a variety of sources. Caveat to this flexibility is requirement for fuel pre-treatment, specifically ensuring that the particle size is in the correct range (smaller than 40-80 mm diameter dependent on specific FBC), and impurities such as metals need to be removed from the fuel prior to introduction to the boiler. Per SJVAPCD’s required emissions controls in their permitting requirements, FBC’s impact the following:

- Lower thermal NOx formation (due to relatively low flue gas temperatures)
- Elevated particulate matter (PM) will be present, thus requiring PM emissions controls such as an electrostatic precipitator
- CO formation control (from complete combustion)

3.3 Pulverized Fuel Combustion

PFC requires very specific fuel inputs, solely sawdust and fine shavings. Fuel input should have a low moisture content and have no particles greater than 10-20 mm diameter. Due to the fuel conditions, an increased risk of explosions is present. High combustion temperatures are experienced with PFC due to the complete combustion that occurs with little excess air. PFC’s present the following permitting advantages/disadvantages:

- Low NOx emissions (with appropriate air staging)
- High PM (from ash in suspension in fuel and combustion products)
- Advanced design leads to low CO formation

4.0 SAN JOAQUIN VALLEY APCD REGULATIONS

The SJVAPCD does not specify emission limits by boiler type or by fuel type. But emissions limitations are based on throughput or rate (volume or time), which could be impacted by choice of fuel. Thus, compliance to regulations could be impacted by fuel. SJVAPCD regulations make no allowance for elevation in calculating their emission limits, thus there is no benefit. (Section 5.0 addresses emission thresholds due to BACT, and section 6.0 addresses emission offset requirements.)

4.1 Criteria Pollutant Emission Limitations

The SJVAPCD has several rules regarding the emissions limitrs of a boiler system. Those related to a biomass boiler are listed in Table 1 below.

Table 1 – Emission Limits

Criteria Pollutant	Compliance Limit	Source
VOC	No separate emission limits, aside from major source and emission offset requirements.	1. SJVAPCD Rule 2201 §3.24.1 2. SJVAPCD Rule 2201 §4.5.3
NO_x	1. 115 ppmv corrected to 3% O_2 (24-hr block average) 2. 140 lbs/hour NO_2	1. SJVAPCD Rule 4352 §5.1 2. SJVAPCD Rule 4301 §5.2.2
CO	400 ppmv corrected to 3% O_2 (24-hr block average)	SJVAPCD Rule 4352 §5.1
SO_x	200 lb/hour SO_2	SJVAPCD Rule 4301 §5.2.1
PM	1. 0.1 gr/dscf 2. 0.030 lb/MMBtu (4.05 lb/hr @ 135 MMBtu/hr)	1. SJVAPCD Rule 4201 §3.0 2. 40 CFR 60 §60.43b(h)(1) if heat input >100 MMBtu/hr 3. 40 CFR 60 §60.43c(e)(1) if heat input is 30-99 MMBtu/hr
Opacity	20% opacity (6 minute rolling average) except one 6-min period/hour not more than 27%	1. 40 CFR 60 §60.43b(f) if heat input is > 100 MMBtu/hr 2. 40 CFR60 §60.43c(c) if heat input is 30-99 MMBtu/hr
Combustion Contaminants[1]	1. 0.1 gr/dscf 2. 10 lbs/hour	1. SJVAPCD Rule 4301 §5.1 2. SJVAPCD Rule 4301 §5.2.3

The above table indicates compliance limitations, by criteria pollutant, as specified in Rule 4201, Particulate Matter Concentration, in Rule 4301, Fuel Burning Equipment, and in Rule 4352, Solid Fuel Fired Boilers, Steam Generator, and Process Heaters. The table also notes Rule 4001, New Source Performance Standards, which indicates provisions of 40 CFR 60 are adopted by reference without change, which includes federal standards for Industrial-Commercial-Institutional Steam Generator Units (40 CFR 60 Subpart DB). (Section 5.0 addresses additional applicable emission thresholds due to application of BACT. Section 6.0 addresses stated thresholds for providing emission reduction credits.)

[1] Definition: Particulate matter discharged into the atmosphere from the burning of any kind of material containing carbon in a free or combined state. (SJVAPCD Rule 1020 §3.12)

The following SJVAPCD rules apply to the proposed facility, however PM limits imposed by these District rules are either less stringent or the same as rules indicated in Table 1. The rules below apply to facilities not explicitly regulated by the federal EPA, however they may apply to the proposed power plant.

- Rule 4202 – Imposes a limit of 9.73 to 14.97 lbs/hr of PM based on a fuel use rate of 80,000 BDT/year (9 BDT/hr). This limit exceeds the lower limit provided under 40 CFR 60 §60.43b(h)(1).
- Rule 4203 – Rule 4203 limits PM emissions from facilities combusting rubbish in excess of 100 lb/hr to 0.1 gr/dscf. Urban wood waste may fall under the SJVAPCD rubbish definition per SJVAPCD Rule 1020. This limit is identical to the limit defined in SJVAPCD Rule 4201 §3.0.
- Rule 4301 – Rule 1020 defines PM as combustion contaminants. Rule 4301 section 5.2.3 limits emissions of combustion contaminants to 10 lbs.hr. This limit exceeds the lower limit provided under 40 CFR 60 §60.43b(h)(1).

4.1.1 Boiler Throughput Considerations

Based on the TSS Consultants (TSS) Fuel Availability Study[2], the fuel available limits the generating facility to approximately 10 MW net capacity (135 MMBtu/hr heat input). Additionally, the study indicates that without changes to operations, there is enough fuel for a 7 MW facility (94 MMBtu/hr heat input). A facility with a heat input capacity within the range of 10 MMBtu/hr to 250 MMBtu/hr (750KW to 18MW) would be held to the same compliance limits for criteria pollutants (VOC, NOx, CO, SOx, PM).

4.1.2 Fuel Type Considerations

Based on the Fuel Availability Study, fuels that are being considered for this prospective power plant are limited to: forest restoration residuals, timber harvest residuals, sawmill residuals, and wildland urban interface residuals (with possible augmentation from agricultural residuals, as provided by the trucks in their return trip from San Joaquin Valley floor locations). This proposed fuel feedstock is composed of forest-based and ag-based residuals, which would yield a particular profile of air emissions.

It was not discussed in the Fuel Availability study, but should plans change for other fuel feedstocks to be introduced into the boiler, such as municipal solid waste (MSW) or fossil fuels (natural gas), this mixed fuel feedstock will modify the air emissions profile, and thus the permitted air emission rates could change as compared to that imposed on a power plant solely utilizing a forest-based feedstock.

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[2] "*Fuel Availability Study for a Wood Waste Fired Generation Facility Sited within Southern California Edison Forest Land*", prepared by TSS Consultants, August 2008

4.2 Major Source Definition

It is not expected a prospective biomass facility would exceed Major Source category emission thresholds, with installation of appropriate emission controls.

Emissions produced by a power plant determine if the facility is a major source (per SJVAPCD Rule 2201 §4.5.3, provided below in Table 2). Exceeding any one pollutant puts the facility into the major source category. Such determination will not exempt the facility from compliance with emission limits or emission offset requirements, but instead adds considerably more reporting requirements including preparation and approval of a federally mandated Title V operating permit.

A potential major source can incorporate emissions controls in its design to lower emissions below the major threshold if the physical limitation imposed by the emissions controls are covered by the air district's permit. Potential emissions of a prospective biopower electricity generation facility would vary based on fuel mix, boiler technology, and installed emission controls (see section 3.0, Effect of Boiler Technology).

Table 2 – SJVAPCD Major Source Emission Thresholds

Criteria Pollutant	Emission Thresholds for Major Source (lbs/year)
VOCs	50,000
NO_x	50,000
CO	200,000
SO_x	140,000
PM_{10}	140,000

Note that a new version of Rule 2201 may come into effect, by the time a permit application is submitted and deemed complete for a prospective biopower project, whereby the major source thresholds for NOx and VOCs are considerably lower. (The SJVAPCD website notes Rule 2201, Federally Enforceable Potential to Emit, as approved as of December 2008, and that the becomes effective when EPA issues final approval into the State Implementation Plan that will be published in the Federal Register. Until such time, Rule 2201 as amended on September 21, 2006 applies. In order to avoid classification as a major source under the proposed Rule 2201, NO_x emissions must be under 20,000 lbs/year. This limit is technically feasible however it may be cost-prohibitive to deploy. Technology such as regenerative selective catalytic reduction (RSCR) has been shown to reduce NO_x emissions sufficiently to avoid major source classification under the proposed SJVAPCD Rule 2201.

For the sake of preliminary planning, a rough estimate of permit emission limits is approximated at the threshold limits for providing offsets (per Table 3 below, taken from SJVAPCD Rule 2201 §4.5.3). However, it is expected these thresholds will be exceeded for NOx, CO, and VOC (See discussion in section 6.0 on Emission Offsets). Thus, for a facility similarly sized (see Boiler Throughput Considerations, above), the facility should not be deemed a Major Source if NO_x is controlled efficiently.

Table 3 – SJVAPCD Emission Offset Threshold

Criteria Pollutant	Emission Offset Threshold Level (lbs/year)
VOCs	20,000
NO_x	20,000
CO (non-attainment)	30,000
SO_{x+}	54,750
PM_{10}	29,200

(It is expected NOx, CO, and VOC may exceed these noted thresholds)

4.3 Federal Title V Permitting

SJVAPCD Rule 2520 requires that a facility must obtain preconstruction review permit under the the requirements of the Prevention of Significant Deterioration (PSD) program per the federal Clean Air Act. To determine if a 10 MW biomass-fired plant meets the threshold to trigger PSD review, the federal rules must be reviewed. In summary, current regulations give no requirement to submit for a Title V permit for biopower generation.

The definition for a PSD major stationary source is set forth in 40 CFR 52.21(b)(1)(i):

> (a) Any of the following stationary sources of air pollutants which emits, or has the potential to emit, 100 tons per year or more of any regulated NSR pollutant: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants (with thermal dryers), primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants (which does not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140), fossil-fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;
>
> (b) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of a regulated NSR pollutant; or

> (c) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) of this section, as a major stationary source, if the changes would constitute a major stationary source by itself.

The primary fuel for a prospective facility will be woody biomass, as augmented by agricultural residue and urban wood waste. It is not fossil-fuel fired steam electric plant, and is not a specifically identified process in paragraph (a). As an academic exercise, even if it is assumed the noted limits for municipal incinerators apply (250 tons per day) or that such a biopower facility might be considered a fuel conversion plant, the emission threshold is not triggered. For a prospective biopower facility, criteria pollutant emissions are not expected to exceed roughly 50 tons/year (per discussion in section 4.2). Thus, the noted threshold of 100 tons or more per year of any criteria pollutant for any stationary source does not apply, per paragraph a. The expected heat input rating for a prospective facility is on the order of 135 MMBtu/hr, so will not exceed 250 MMBtu/hr, as noted in paragraph (b). No other criteria are identified to trigger the major stationary source definition, per paragraph (c). Thus, the authors contend Title V does not apply.

4.4 Hazardous Air Pollutants

Biomass fired power plants that emit threshold levels of hazardous air pollutants (HAPS), a.k.a. air toxics can be classified as major sources and subject to the federal NESHAPS and Maximum Achievable Control Technology (MACT) requirements. SJVAPCD Rule 2520 establishes these thresholds for air toxics as the following: A stationary source that emits or has the potential to emit, including fugitive emissions, 10 TPY or ore of a hazardous air pollutant, or 25 TPY or more of combination of hazardous air pollutants shall be considered a major source and subject to NESHAPS and MACT federal requirements. Based on TSS experience and data from biomass power plant source test for HAPs, a 10 to 12 MW facility combusting woody biomass will not exceed these hazardous air pollutant thresholds, with such emissions anticipated in the range of 12 to 14.5 TPY, with no single HAPS exceeding 10 TPY.

5.0 IMPACT OF BACT REQUIREMENTS

Best Available Control Technology (BACT) is required on a pollutant specific basis. Emission control equipment required could include selective non-catalytic reduction (SNCR) with urea injection for NOx, limestone injection for SOx, dry electro-static precipitator with baghouse for PM, and good combustion practice for CO and VOC.

5.1 Best Available Control Technology Requirements

The SJVAPCD New Stationary Source Review (Rule 2201 §4.1) requires that BACT requirements apply for all new emission sources on pollutant-by-pollutant basis, with exceptions, under the following conditions:

- Emissions are less than 2.0 lb/day (SJVAPCD Rule 2201 §4.1.1); or,
- If potential to emit CO is less than 200,000 lb/year. (SJVAPCD Rule 2201 §4.2.1)

It is assumed BACT applies for each criteria pollutant. SJVACPD requires Emission Offsets be supplied if certain thresholds are exceeded, on pollutant specific basis (SJVAPCD Rule 2201 §4.5). For this project concept, it is assumed those thresholds are not exceeded, thus forming the upper bound, which equate to no less than 55 lbs/day. (See section 6.0 for discussion of emission offset thresholds by-pollutant.)

SJVAPCD requires a "top-down" BACT process that starts by considering the most stringent form of emissions reduction technology possible, and then analyzes all the reasonably available information to determine whether the related air emissions control method is technically feasible and economically justifiable. The SJVAPCD employs economic test procedures for determining economic feasibility of a BACT option. Economic feasibility is not typically given much, if any, weight if the source is "major" for a particular non-attainment pollutant where BACT is required.

Additionally, regulations do not specify whether non-attainment status of the Fresno County region will impact BACT requirements, however this is likely to be considered during the BACT review process. Specifically, the air district is in non-attainment for ozone, and where NOx is precursor to ozone, emission control equipment for NO_x will likely be required as part of meeting the BACT requirements, along with installation of emission control equipment for other criteria pollutants (as addressed below).

5.2 Likely Applicable NOx Emission Controls

Taking a top-down approach, Selective Catalytic Reduction (SCR) is a technology that is considered for NO_x control, as it has the potential to reduce emission by more than 90%. However, due to the varied nature of biomass fuels, contaminants in the flue gas often poison the catalyst, rendering the SCR method economically ineffective in predictably removing NOx emissions. Thus, Selective Non-Catalytic Reduction (SNCR) methods are often applied for biomass boiler operations as ammonia or urea injection into the combustion chamber. Decision to use aqueous ammonia or urea rests with the applicant.

SNCR removes approximately 60-80% of the NO_x emissions in flue gas. SJVAPCD does not have permitting authority over the storage tank itself, but as ammonia provides the means to meet BACT, it is included for completeness in this section. In other air districts, if a storage tank could emit any air pollutant, the air district can require a permit, even if there are no prohibitory regulations that would otherwise cover the tank. In the Central Valley of California, however, ammonia tanks are fairly well regulated by other agencies due to their potential hazard to human health and safety (as covered in below paragraphs), so the SJVACPD does not additionally regulate them for potential air pollution.

Transport and storage of ammonia or urea is necessary for the catalytic reduction of NO_x. Anhydrous ammonia is used for SCR, and aqueous ammonia or urea for SNCR. The transport of ammonia requires regulatory compliance to Federal Hazardous Material Transportation Regulations in Code of Federal Regulations Title 49. County of Fresno Department of Public Health regulates storage of these compounds, as it is the designated Certified Unified Program Agency (CUPA) for Fresno County.

Regulation of a storage tank is under purview of the building department and the CUPA. If it holds more than 10,000 pounds of ammonia (100% equivalent)[3], the ammonia tank is required to have Risk Management Plan (RMP), under California Health & Safety Code and Clean Air Act and 40 CFR 68. The RMP is a detailed analysis of the potential for an accidental release and identification of mitigation measures to reduce a potential impact. In the central valley, ammonia storage is common, as it is used as fertilizer feedstock, refrigerant (food processing), and NOx emission control. Bringing it uphill is new, so local residents may voice their opinion during the land use permitting and the California Environmental Quality Act (CEQA) process (see section 7.3, Land Use and section 8.0, on CEQA issues).

In comparison, urea storage would not require submittal of a RMP, but it is considered a hazardous material and would be included in a facility Hazardous Materials Management Plan (HMMP, a.k.a facility "Business Plan"). Such plan is required by CUPA to assist in emergency planning and response to hazardous materials accidents. The HMMP must contain procedures to protect health and safety of persons, property, and the environment in the event of a release or threatened release of a hazardous material. The HMMP is submitted to the CUPA and the local fire department. Once submitted to these public agencies, it is deemed public information, thus is open to public review. Given its lesser regulatory requirement and lessened impact to the environment, urea would be the recommended approach, should there be an option.

There are no regulations, statutes, or requirements in state or federal law and regulations, nor in the Fresno County CUPA requirements that exclude address of the transportation, storage, or use of ammonia and/or urea into or through forested lands.

[3] "Anhydrous" means without water, where the ammonia is stored as a gas at high pressure, while "aqueous" means the ammonia is diluted to some degree with water, Typically, aqueous ammonia is specified at concentrations of 19.5%, 25%, or 29% pure ammonia in water

5.3 Previously Imposed BACT Requirements

Biomass power facilities in the state were studied for their BACT determinations[4], and the requirements and technologies utilized. (Also see section 3.0 for discussion of boiler type impact on emissions.) Utilizing that data along with information from BACT determination in the SJVAPCD, Table 4 below summarizes potential technologies that may be required to meet the permit requirements:

Table 4 – Typical SJVAPCT BACT Requirements

Pollutant	Control method(s)
VOC (precursor to Ozone)	• Good combustion practice
NOx (precursor to Ozone)	• Use of natural gas as auxiliary fuel • Selective non-catalytic reduction (SNCR) using ammonia/urea injection
CO	• Good combustion practice
SO_2	• Maintaining good combustion with excessively wet fuel • Limestone injection • Use of natural gas as auxiliary fuel
PM/PM_{10}	• Dry electrostatic precipitator (ESP) • Baghouse

While SJVAPCD BACT requirements do not indicate a specific technology and limits on criteria pollutant emissions, previous California and SJVAPCD biomass facilities provide precedence regarding what a SCE biomass facility may encounter. Review of SJVAPCD BACT records on the review process shows two instances of permit issuance (within the range of a conceptual project) that provide insight into BACT emission requirements.

Facility #1 – 259 MMBtu/hr Grate Biomass-Fired Boiler, Tracy, CA (Review: 9/28/04)

- VOC Requirement: BACT was not triggered for this pollutant
- NOx Requirement: BACT was not triggered for this pollutant
- CO Requirement: 400 ppmvd measured at 3% excess O_2
- SOx Requirement: BACT was not triggered for this pollutant
- PM_{10} Requirement: BACT was not triggered for this pollutant

The Tracy, CA facility is a unique case due to the lack of BACT requirements being triggered for a majority of pollutant types. Interviews with SJVAPCD permitting staff have indicated that the likely explanation for the lack of BACT requirements for the

[4] California Air Resource Board BACT Clearinghouse Database

Tracy facility is the result of the facility being grandfathered when BACT was imposed in the district. The CO requirements are due to BACT conditions being triggered due to an increase in potential to emit during a Title V permit review in 2004. The Tracy facility is unique with regard to BACT requirements, however it is not exempt from emission limitations mandated by SJVAPCD New Source Review (NSR) rules and federal Standards of Performance for Industrial-Commercial-Institutional Steam Generator Units (40 CFR 60 Subpart DB). Further details of emission limitations imposed by SJVAPCD NSR rules and 40 CFR 60 Subpart DB are discussed in section 4.0.

Although it occurred 12 years earlier, the permit issued in 1992 for a nearby biomass fired generating station could be deemed more representative of what to expect. Summary of the BACT requirements imposed are provided (below). It shows the flow rate limit for the noted criteria pollutant, per the extant BACT regulations, and the technology employed to meet that requirement. After application of BACT, NSR and federal standards (40 CFR 60), both facilities are subject to similar emission limits.

Facility #2 – 315 MMBtu/hr Fluidized-Bed Biomass Boiler, Delano, CA (9/21/92)

- VOC Requirement: 0.024 lb/MMBtu (technology employed: using NG as auxiliary fuel)
- NO_x Requirement: 63 ppmvd measured at 3% excess O_2 (technology employed: using NH_3 injection and NG as auxiliary fuel)
- CO Requirement: 183 ppmvd measured at 3% excess O_2 (technology employed: using NG as auxiliary fuel)
- SO_x Requirement: 23 ppmvd measured at 3% excess O_2 (technology employed: limestone injection and NG as auxiliary fuel)
- PM_{10} Requirement: 0.045 lb/MMBtu (technology employed: using a baghouse)

The BACT requirements for the Delano facility boiler are identical to the permit emission limits imposed on the facility. (An exception is the VOC requirement, where the permit limits VOC emissions to 0.020 lb/MMBtu. This discrepancy is likely due to different review dates reported in BACT review and permit renewal).

5.4 Integration of Carbon Reduction

There is no allowance within the current BACT regulations for the positive reduction possible due to carbon sequestration achieved by a forest. There also seems to be no imposed emission control equipment for CO_2. Thus, any positive impacts would be left to identify and recoup at a later time (not during the pre-permitting process). Any reduction in carbon emissions would be considered in the CEQA process and/or in the context of a future cap and trade system for GHG. (Also see Section 6.0, addressing emission offset requirements and further discussion of GHG, and Section 8.0 for an address of CEQA as related to this prospective biopower project.)

6.0 EMISSION OFFSET CREDITS

It is expected that Emission Offsets will need to be provided. There is no current allowance within the SJVAPCD regulations to issue emission reduction credits (ERCs) due to reduction of open pile burning of forestry waste. However, such was recognized in earlier version of local regulations, and another nearby agency has a stipulation and formula for how to compute the reductions and resultant ERCs. This may speak to an opportunity to visit the latitude within extant regulations, should the matter be deemed worthy of re-address with the local agency. There are also no current GHG emission credits as relate to forestry or wood-waste biomass, though such is under scrutiny worldwide and could come into play by the time a decision is made to submit documentation for a prospective facility.

6.1 Current Regulatory Framework

SJVAPCD has jurisdiction over applying federal, state, and local air pollution control laws and regulations, of which offsetting emissions is a requirement if certain criteria pollutant emission thresholds are exceeded (in a specified period of time). ERCs and offsets are considered on a pollutant-by-pollutant basis. Criteria pollutant ERCs needed for this prospective project would include NOx, CO, and VOC (see section 5.0, Impact of BACT Requirements). Emission offsets are required for New and Modified Stationary Sources, per SJVAPCD Rule 2201, which is addressed in this section as relates to emission offsets. Other aspects of that rule are addressed in section 5.0, as relate to BACT, or section 4.0, catchall for any other applicable SJVAPCD regulation.

The current regulatory structure does not provide for issuing ERCs as result of diversion of forest-sourced biomass to biomass-fueled power generation facilities. If emissions are reduced beyond an established baseline (SJVAPCD Rule 2201 §3.8), then Actual Emission Reductions (AER)[5] are eligible for banking and are considered transferrable by the SJVAPCD (SJVAPCD Rule 2201 §3.2). Based on this definition, current regulation does not account for the historic emissions that would be avoided due to diversion of biomass residue or agriculture residues from an alternate fate (i.e. open pile burning) because there is no recorded baseline of those emissions. Biomass facilities are unique in that they may use AERs that occurred in any calendar quarter as offsets, compared to other facilities (such as fossil fuel fired facilities) that only may use AERs as offsets in the calendar quarter the AER occurred. (SJVAPCD Rule 2201 §4.13.4, 4.13.5, 4.13.6).

Emission offsets must be supplied if the "post-project potential to emit" exceeds noted thresholds (SJVAPCD Rule 2201 §4.5.3, provided below in Table 5). Potential to emit determination is made on a basis of maximum capacity to emit based on the facility's operational and physical design. Thus, supplying sufficient emission controls could reduce the number of required offsets. None of the noted emission offset exemptions apply to a prospective biomass project (SJVAPCD Rule 2201 §4.6).

[5]AER = Historic Actual Emissions – Post-Project Potential to Emit (SJVPACD Rule 2201 §4.12)

It is likely that NOx will be over this threshold, even with SNCR controls (assuming SNCR can eliminate up to 70% of NOx pre-control emissions). CO will likely be exceeded, and VOCs could be included depending on which EPA Method the district wants to employ for VOC emissions testing. PM should be very low if an appropriate ESP unit is used. (See section 4.0 for discussion of Emission Limits)

Table 5 – Emission Offset Thresholds

Criteria Pollutant	Emission Offset Threshold Level (lbs/year)	(tons/year)
VOCs	20,000	10
NO_x	20,000	10
CO (non-attainment)	30,000	15
SO_{x+}	54,750	27.4
PM_{10}	29,200	14.6

District Rule 2201 §4.8 establishes a distance ratio from the stationary source needing offsets from location of the source of the offset. This distance ratio increases the amount of offsets that must be supplied to comply with SJVAPCD rules, as shown in Table 6. Given the possible remote location of a prospective biomass-fired electricity generation facility, highest offset applies (meaning largest devaluation of the ERCs from the bank).

Table 6 – Emission Offset Ratios & Distance

Offset Ratio	Original Location of Emission Offsets
1.0	At the same stationary source as the new or modified emissions unit
1.2 for minor source **1.3 for major source**	Within 15 miles of the new or modified emission unit's stationary source
1.5	15 or more miles from the new or modified emissions unit' stationary source

Emission offsets supplied as ERCs can be obtained from the SJVAPCD's ERC bank and other operating facilities in or near the SJVAPCD's jurisdiction. (SJVAPCD Rule 2301). ERCs from the bank are not restricted in the number that can be acquired, though SJVAPCD prefers ERCs be acquired from an outside source, before depleting the bank. There is not a robust market established, but it is expected that a one-time emission offset purchase will amount to $30,000-$80,000 per ton of criteria pollutant. Estimated impact to a prospective biomass power generation facility project with the emissions profile as approximated would be roughly $570,000-$1,520,000[6] (as would be included in facility capital start-up costs, see TSS Cost Estimate report[7]).

[6] Conservative estimate of 19 tons of emission reduction credits required, based on an assumption of 100,000 lbs steam/hr boiler, 164 MMBtu/lb steam (EPA AP-42), similar (and new) boiler source test data emission factors of CO 0.135 lb/MMBtu, NOx 0.166 lb/MMBtu and 50% SNCR removal efficiency, and 1.5 offset ratio. Low range estimate based on $30,000/ton and high range estimate based on $80,000/ton per recent SJVAPCD emission reduction transaction data.

[7] "*Cost Estimates for Capital Expenditure and Operations & Maintenance Based on Technology Review*", prepared by TSS Consultants, April 2009

6.2 Offset Potential for Criteria Pollutants

Through other work TSS has conducted in SJVAPCD, criteria pollutant ERC generation for biomass facilities is slightly different from ERC generation for other facilities. By TSS experience, SJVAPCD recognizes forest residues as offset-creditable fuels, but excludes urban wood waste[8]. Forest-based residuals were identified as the sole potential fuel source for this prospective project concept (see Fuel Availability Report, August 2008). Adding ag-residuals for the back-haul process would not appreciably change the emissions profile. A mixed fuel feedstock (i.e., mixed with other than forest or ag) would modify not only the offset requirements that are imposed but also the emission limits (see section 4.0, SJVAPCD Regulations).

Also, previous TSS projects in the SJVAPCD recognized ERCs from diversion of material that would otherwise be open-burned (4/25/02 version of Rule 2201 §3.10), however, the current version of Rule 2201 does not allow for issuing this type of ERC. TSS experience working with Placer County Air Pollution Control District (PCAPCD) indicates that PCAPCD provides additional incentives and guidance for ERC generation. PCAPCD's Rule 506 Section 405.7 outlines the Open Burn Biomass ERC Calculation:

ERC = (Acres Burned – Discount Acreage) * Historic Burn Fraction * Fuel Loading * Emission Factor * Quarterly Burn Fraction

TSS is collaborating with PCAPCD in conducting research to determine the scientific background behind diversion of open burned material to biomass power plants. PCAPCD is attempting to quantify if power can be displaced from fossil-fired facilities, whether reduction occurs in intensity or frequency of wildfire events, and what are the associated benefits for development of more robust criteria pollutant ERC accounting schemes[9]. Such information may be of use for this project concept.

6.3 Offset Potential for Greenhouse Gases

Under SJVAPCD's current rules and regulation, there are no accounting protocols or ERCs offered for GHG's, however this is likely to change in the future. In November 2008, SJVAPCD released a conceptual report that outlined how the air district intends to address GHG impacts in the CEQA review process and outlines the creation of a district wide GHG offset banking system and carbon exchange. The proposed GHG banking system and carbon exchange are currently proposed as voluntary and will serve the purpose of banking GHG emission reductions in excess of state mandated reductions. It does not specifically address forestry waste.

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[8] SJVAPCD Rule 2201, Section 3.10 recognizes alfalfa, barley, beanstraw, corn, orchard prunings, vineyard prunings, oats, wheat, and forest residues as offset-creditable fuels. Other types of fuels are considered non-creditable fuels or not recognized as biomass fuels, including grape stems, grape pumice, almond shells, walnut shells, construction wood waste, and urban wood waste.

[9] The scientific modeling necessary for the validation of these concepts is being conducted by the USFS, Pacific Southwest Research Station.

At the State level, CARB accepted the AB32 scoping plan presented in December 2008. This plan outlined the regulation, and mandated GHG emission reductions for various industries through 2020. CARB indicated their strategy for forestry GHG accounting in the AB32 scoping plan (section II-7, and appendix C), and through the California Climate Action Registry's (CCAR) forestry protocols. TSS is aware that local offices of the US Forest Service are gathering data as part of their preparing to meet AB32 requirements.

TSS has not observed a clear trajectory of how CCAR's recommended protocols will be received, modified, or integrated into the AB32 recommendations. Additionally, AB32 and CCAR's forestry protocols do not outline a clear connection between diversion of open-burned biomass and biomass power generation, though the AB32 scoping plan indicates that biomass fuels will be accounted for in the energy sector. TSS is also aware that the Western Climate Initiative (WCI) is planning to recognize forest-sourced biomass fuel as carbon-neutral fuels, with a caveat that the fuel must be sourced from forested lands with sustainable forestry management plans in place, which this forest has. CARB has indicated that it will be closely aligning with the WCI GHG policies and procedures.

Similar to the criteria pollutant research for ERCs that PCAPCD is conducting, TSS is aware that PCAPCD is investigating the GHG benefits of diversion of biomass material to power plants, and is attempting to determine the impact on the rate of carbon sequestration from forest thinning activities that would fuel a biomass power plant. Potential acceptance of such a protocol by the SJVAPCD is unknown at this time.

On the global stage, GHG has captured a central position. Future developments on market and regulatory determination on the role forests, biomass, and GHG trading markets should be monitored for future impact on a prospective project. However, given the status of current GHG regulatory promulgation at the state and local level, consideration of GHG impacts should be limited in the decision making process, if a decision is reached on a prospective project within the year. Legislative and regulatory developments since this analysis was completed may make it advisable to re-evaluate potential GHG impact of such a biopower project.

7.0 WATER AND LAND USE PERMITTING REQUIREMENTS

Water supply will not trigger any permitting requirements. Water discharge to land or surface water does require a permit, unless a zero-discharge facility design is employed. A storm water discharge permit is required for both construction and operation, requiring submittal and implementation of a plan with monitoring and reporting requirements. Regarding land use, prospective sites may require a conditional use permit, particularly where it could be posed that a biomass plant would allow for forest management of fuels treatment and timber harvest residuals. Ash could be used as a soil amendment.

7.1 Water Rights Requirements

The matter of whether each of the prospective sites have adequate surface water rights to be able to obtain adequate cooling water was not raised as an issue for address in this environmental analysis. Notwithstanding that, there is a process in California for appropriating water rights on rivers and streams. However, such appropriation by permit application to the State cannot be done for rivers and streams where water rights are already fully appropriated. Based on a map of fully appropriated stream systems in Fresno, it appears not all water rights have been fully appropriated in the Shaver Lake area. It will be necessary for SCE to determine what water rights are available at the prospective sites. More than likely, SCE has water rights on or near properties it owns. State of California administers a water rights program through the State Water Resources Control Board, Water Rights Division (www.waterboards.ca.gov/waterrights/).

7.2 Water Supply and Discharge

The Central Valley Regional Water Quality Control Board and the State Water Resources Control Board are the permitting agencies for all water-related permitting issues pertinent to a proposed biomass power generation facility. Water supply will not trigger any permitting requirements, however there may be constraints on water use at the facility due to locally available supply. There are two potential permitting issues related to water use and discharge from the facility: cooling water discharge and storm water discharge.

From experience, a 7MW biomass power plant using air cooling requires approximately 4-8 gallons per minute (gpm) cooling water (8640 gallons per day). Likewise, a 15MW facility requires roughly 8-16 gpm (17,280 gallons per day). Given potential constraints of a limited water supply available for cooling purposes, it is recommended that the prospective biomass generation facility employ water-use reduction design measures to reduce cooling water demand to ease the burden on a limited local water supply, such as use of air-cooling and/or gray water recycling

Such options could also streamline the water discharge permitting process. Cooling water discharge to land or surface waters requires a water discharge permit. This type of discharge falls under the National Pollutant Discharge Elimination System (NPDES) and requires NPDES permit (known in California as Waste Discharge Requirements permit).

To avoid the need for a NPDES permit, a prospective generating facility can be designed as a zero-discharge facility by incorporating the sawmill water needs in tandem with the power facility's water discharge. It is expected the proposed facility will generate 20 gallons per minute of wastewater discharge from blowdown. Half of this discharge could be utilized by the SNCR system, and the other half can be diverted to the sawmill for cooling purposes. This zero-discharge system would streamline permitting requirements, reduce sawmill water requirement issues, and side step the potential issues presented by constructing an evaporation pond on the site's impermeable soils. Residual brine can be offered for sale in a secondary market (as is done in similar facilities across the country).

A storm water discharge permit is also required for both construction and operation. Per the Clean Water Act and the NPDES mandated by US EPA, industrial activities and the electrical generation facilities (as defined under SIC code 4911, Electrical Services, Steam Electric Generation Facilities) with the potential to generate storm water discharge are required to acquire a storm water discharge permit. Under the General Industrial Permit currently issued by the California State Water Resource Control Board (Industrial Storm Water General Permit Order 97-03-DWQ), this permitting process requires implementation of a Storm Water Pollution Prevention Plan (SWPPP), and Monitoring and Reporting program for operation at a power plant. For construction, there will need to be a separate SWPPP, per General Permit for Discharges of Storm Water Associated with Construction Activity (Construction General Permit, 99-08-DWQ).

7.3 Land Use

Fresno County is the authority for approving land use options in this area. Three prospective sites for a biomass power plant were identified. Using the latitude/longitude coordinates, the Fresno County parcel number was determined for each site. In turn, this allowed for determination of the county-designated zoning of the three sites. The zoning category determines what can be built and operated on the particular property. Each site is on non-federal property. All three sites appear to be privately owned. The zoning and current/past uses of these sites are detailed in the following Table 7.

Table 7 – Potential Sites with Zoning Designation and Use

Site	Assessor Parcel Number	Zoning Designation	Current/Former Use
1	120-08-012	Timber Preserve	Current hydroelectric-related facilities, electric sub-station
2	120-12-027	Timber Preserve	Former landfill
3	133-03-049	Resource Conservation	Former sawmill site

The Fresno County Zoning Ordinances were reviewed with respect to biomass power plant development on the aforementioned sites. Two of the sites (Sites 1 and 2) were categorized per the Fresno County Zoning Ordinance as Timber Preserve Zone (TPZ). That TPZ designation is found in Section 814 of the ordinance and potentially allows for a biomass power plant. The preamble states:

> “The “TPZ” Timberland Preserve Zone District is intended to be an exclusive district for the growing and harvesting of timber and for those uses which are an integral part of a timber management operation”

Section 814 further defines processing facilities that can exist in a TPZ and that any timber related processing facility is subject to a Conditional Use Permit (CUP). Under that section it states an allowable use (with CUP) as:

> "Timber products processing plants, including but not limited to sawmills, lumber and plywood mills and planning mills, provided that such plants are secondary or incidental to a timber growing and harvesting operation on the same parcel"

It can be argued that a biomass power plant is a part of such a definition - i.e. the active and necessary management of the regional timberlands necessitates a "processing" plant for the fuels treatment and timber harvest residuals.

The third site proposed for the biomass power plant is located on land designated by Fresno County as Resource Conservation District zoning (Section 813 of the Fresno County Zoning Ordinance). The “R-C” (Resource Conservation) District is intended:

> “To provide for the conservation and protection of natural resources and natural habitat areas.”

For construction and operation of a power plant in the R-C District, Section 813.3 has the same language regarding timber products processing facilities as the TPZ District above.

Both the R-C and TPZ District appear to require that a CUP be obtained from Fresno County for siting a biomass power plant on any of the three proposed sites. The Fresno County Zoning Ordinance requires a CUP for certain use of land or types of businesses which are not allowed as a matter of right in a particular zone district (as above). These certain uses are described for each zoning district identified in the zoning ordinance.

A CUP is obtained through a formal application process with Fresno County Department of Public Works and Planning. The planning staff use the information supplied to make a determination of findings regarding the potential environmental impact of a project, as well as the projects consistency with the County General Plan. The CEQA process is also included in the CUP process. (See section 8.0 for more on CEQA). Findings by the planning staff in the CEQA Initial Study portion of the process could determine an Environmental Impact Report may have to be prepared or that a Negative Declaration applies. The zoning ordinances also give considerable leeway to the Planning Director, Planning Commission, and ultimately the Board of Supervisors in allowing various land uses under conditional use permitting. A big plus for a prospective biomass project is that it is a "Healthy Forest" project, i.e. reducing hazardous forest fuels, thus improving forest health and reducing destructive wildfire (and all the positive societal and environmental benefits that go along with that perspective).

7.4 Ash Handling and Use

Ash application as soil amendment may fall under jurisdiction of Central Valley Regional Water Quality Control Board depending on its application methodology. As woody biomass from a prospective power plant will all be forest-sourced and ag-sourced, it can be expected that the ash will be non-hazardous per California and federal regulations, i.e., it should not contain constituents that would make it hazardous such as heavy metals. To ensure this, analytical sampling should be conducted on the ash during initial operations.

As a soil amendment, the ash could be considered a product and not a waste. It would have to be applied to land as a product in a manner that does constitute a disposal. Ash application as soil amendment in the forest might be an acceptable practice if application rates are consistent with the amount of material removed by vegetation treatments and if the ash is derived from forest materials. In other words, apply ash to mimic the residual from a surface burn and replace nutrients removed through silvicultural treatments.
Ash application is sometimes used to replace nutrients removed through whole tree harvesting. There are many potential benefits documented for the use of ash as a soil amendment. For example, ash has been shown to increase porosity, water-holding capacity, pH, conductivity, and dissolved SO4, CO3,, HCO3,, Cl- and basic cations. The potential is that these effects will promote increased growth of plants and result in greater carbon accumulation in the soil than in untreated soils. Thus, use of ash as a soil amendment can even have a carbon sequestration benefit.

Ash application is a fairly widespread, especially in Scandinavian countries. The United Kingdom is investigating it as part of a renewable energy program. Application in the United States is most common in the northeast and south, and accounts for between 5% and 20% of the ash disposal from wood-fired boilers. Some states have specific regulations governing this practice. The jurisdiction within which a prospective facility is being considered does not address use of ash as a soil amendment. Thus, it could be part of the permitting process to show the benefits of removing it from the waste stream and of placing on the soil as nourishment.

Ash from the combustion of woody biomass in a controlled system, such as a boiler, yields approximately 3 to 5% ash per volume of woody biomass input. Therefore, a gross 10 MW biomass power plant using 8,000 BDT of woody biomass per year per MW (80,000 BDT) would yield approximately 2,400 to 4,000 tons of ash per year.

This ash will either be disposed of in an appropriately permitted facility, or a product use for the ash will have to be found i.e., use in building materials, road sub-base materials, or potentially returned to the forest as a soil amendment. Preferred method of handling, as stated to TSS, is to return to the forest floor as a soil amendment product. Thus, a proposed method of address for so utilizing the ash could be to transfer the ash to a soil amendment vendor so it can be considered a product and not waste. Some portion could be retained for soil amendment within the forest, if desired, but the volume is too high for all of it to be used onsite. Besides, providing to an outside vendor validates it is a viable product, while also providing an income stream to the prospective project.

Wood ash applied to forested landscapes as a soil amendment agent has had beneficial impacts to forested landscaped. Ash application trials in the Lake Almanor region of California have seen positive growth response in ponderosa pine plantations.[10] It is anticipated that forest managers (public and private) will be interested in implementation of similar ash application trials to forested landscapes close in to Shaver Lake.

If use of ash as a soil amendment were to be pursued as a business practice, the concept of "waste/product" dichotomy may require more analysis. To get a WDR permit from the RWQCB for land application of ash, it would be required to file a WDR application for the disposal of ash to land, however this approach considers the ash as a waste only. If the ash is considered to be applied to land as a soil amendment product, as is the case with other biomass power plants in California, it would then fall under the definition of "land application on non-hazardous ash" found §17376, Title 13, CA Code of Regulations, which further elaborates that land application does not constitute disposal. This potential beneficial use of ash in land application is then under the purview of the California Department of Food and Agriculture. Many California biomass plants have their ash used in land application and work with their respective County Ag Commissioner in assuring proper application use.

If as worst-case scenario, RWQCB decides that such a soil application cannot occur, or the ash exceeds hazardous or toxic threshold and the wood ash is deemed waste, the landfill tipping fee estimates are under $40/ton, where 2,400 to 4,000 tons ash/year would result in $96,000 to $160,000, respectively. There is no separate permit required for the power plant to dispose of ash in an appropriately permitted landfill.

[10]Roseburg Forest Products land applications in 1985 to 1990.

8.0 ADDITIONAL PRINCIPAL PERMITTING REQUIREMENTS

The primary over-arching environmental issue, in terms of both impact to a prospective project timeline and the potential for public relations issues, is the required review to be conducted under CEQA.

8.1 Federal/State Air Rules v. Local District Air Rules

The more stringent rules occur at the local level, not at the federal level. The federal rules allow local rules to be more stringent. Where more stringent local regulations were not issued, the applicable federal regulations for a prospective biopower project are noted (see section 4.1, Criteria Pollutant Emission Limitations and Table 1, Emission Limits).

The federal Clean Air Act (and amendments), and the air quality regulations of 40 CFR are the overarching statues and regulations for air quality permitting and compliance. Under these federal laws and regulations, U.S. EPA set the rules by which the California Air Resources Board (CARB) and its 35 local and regional air districts must minimally comply whereby the state, or any of the districts, cannot have air quality rules weaker than federal rules. The state through legislation and regulation may promulgate air rules more stringent than the federal government. Likewise, the local air districts may impose more stringent regulations and rules than the state, provided those regulations and rules do not usurp state or federal air laws and rules. For the prospective project concept, the most stringent rules are at a local level, San Joaquin Valley Air Pollution Control District. Some local regulations do implement the federal regulations and standards by reference. (See previous sections). CEQA requirements are not superseded by local regulations.

8.2 Permitting and Environmental Impact Review

Prior to the issuance of any environmental permit for projects on non-federal managed lands, involved agencies must consider CEQA. There is a similar environmental impact process known as the National Environmental Policy Act (NEPA) for projects on federally managed lands. Since the prospective siting is on non-federal lands, it is deemed CEQA applies. It is possible that a federal agency will file as an interested party or potentially as a responsible party in the CEQA review process, most likely the USDA Forest Service, since a portion of the biomass fuel resources noted for this feasibility study concept will be derived from is federal forested lands.

CEQA is regarded as the foundation of environmental law and policy in California. The main objectives of CEQA are to disclose to decision makers and the public, prior to discretionary decision making, any potentially significant environmental effects of proposed projects and to require public agencies to avoid or reduce significant adverse environmental effects by implementing feasible alternatives or mitigation measures. This prospective project is deemed discretionary since it includes a conditional use permit application and review (covered under Other Appropriate Agency CEQA Review).

CEQA review can fall under a few different processes as outlined below, typically dependent upon circumstances or location of a prospective power generation facility. Due to prior jurisdictional determinations, it is deemed the lead agency for CEQA review will be the local land agency, Fresno County Department of Public Works and Planning.

8.3 CPUC-directed Utility Environmental Review

Rules relating to the planning and construction of electric generation facilities by investor owned utilities are established by the California Public Utilities Commission (CPUC) in their General Order No. 131-D. That order establishes Certificate of Public Convenience and Necessity (CPCN) is required for an electric public utility to begin construction of a new electric generating plant having a net capacity at the busbar in excess of 50 MW [Section III-A of General Order No. 131-D]. The prospective biomass power plant is in the 10 MW range, so a CPCN would not be needed. Without the need to issue a CPCN, which constitutes a discretionary decision by the CPUC, the CEQA review appears not to be under the purview of the CPUC. CPUC also has fiduciary responsibility of approving spending of regulated utilities, so CPUC may file as an interested party for CEQA.

8.4 CEC Environmental and Siting Review Authority

The California Resources Agency has certified certain state regulatory programs to be "CEQA-equivalent" thus exempting those agencies from CEQA's requirements to prepare EIRs and Negative Declarations, such as the California Energy Commission (CEC). Those agencies, in the environmental review of electrical generation power plants, are subject to other provisions of CEQA and requires them to prepare "substitute documents" that must include environmental impact review and mitigation. The CEC environmental and siting authority is set forth in Section 25500 et. seq. of the California Public Resources Code. The CEC jurisdiction includes review of proposed power plants that are 50 MW or larger. Thus, the proposed 10MW biomass power plant would not be subject to the CEC environmental and siting review as the lead agency, and instead would be reviewed by other applicable and appropriate agencies.

8.5 Other Appropriate Agency CEQA Review

Determination of which is appropriate as lead agency for CEQA review is determined by certain prioritized criteria. As relates to a prospective biomass facility as described, the determining factor is the land use permit, as would be issued by Fresno County.

One of principal permits that will be needed for a biomass power plant located on privately held lands within the Sierra National Forest will be a Conditional Use Permit (CUP) from Fresno County (see section 7.0, Water and Land Use Permitting Requirements). Application for a CUP will trigger the need for CEQA process on the part of the County. As it is a potential discretionary land use decision, generally the land use agency become the "lead" agency for the CEQA review. This is noteworthy as there are other agencies, such as the SJVAPCD (air permit) and the Central Valley Regional Water Quality Control Board (possible wastewater discharge permit) which have discretionary approvals potentially necessary for the proposed biomass power plant and must follow the CEQA process as well. However, these other agencies should be able to piggy-back on the CEQA process the County of Fresno will have to perform in its CUP application review and approval. The other agencies can be designated as "responsible" agencies and be involved in the process so as to meet their own CEQA review needs and requirements.

8.6 Fresno County CEQA Process

CEQA requires environmental evaluations to be conducted prior to initiating a public project or activity, or prior to granting discretionary approval of a private project such as a biomass power plant facility. Under Fresno County policy, the Department of Public Works and Planning (Department), is responsible for the preparation of environmental documents required for compliance with CEQA. The Department has responsibility to first determine if a proposed activity is a project, as defined in the Guidelines. If not determined be a project, it is not subject to CEQA. Issuance of a CUP appears necessary for a proposed biomass power plant for the zoning codes of the three potential sites, and would constitute a discretionary approval decision on the part of Fresno County.

Once it is deemed a project, the Department determines if the proposed project has exempt status under the regulatory CEQA Guidelines, including:

- Statutory Exemptions are granted by the State Legislature where activities are ministerial in nature, such that they require little or no judgment but are based on established and/or objective standards, such as a building permit.

- Categorical Exemptions are classes of projects determined by the California Resources Agency to not have a significant effect on the environment.

- CEQA also contains a general rule that, where it can be seen with certainty that a project will not have a significant effect on the environment, the project is not subject to CEQA.

The Department is to conduct an environmental review to determine if a possible exemption applies for all discretionary projects. Based on exemptions available, it is deemed that a prospective 10 MW biomass power generation facility would not be exempt. (See previous sections, for address of anticipated environmental impacts.) As it would not be exempt, the Department would then prepare an Initial Study (IS) in order to determine whether a project may have a significant effect on the environment.

This IS is prepared based in part on environmental and facility information on the proposed project supplied by the CUP applicant. If the IS shows that there is no substantial evidence that a project may have a significant effect, a Negative Declaration shall be prepared by the Department. Additionally, the Department could prepare a Mitigated Negative Declaration if potentially significant effects are identified but revisions made by or agreed to by the applicant that would eliminate/avoid the effects or mitigate the effects to a point where clearly no significant effects would occur. Some such mitigation could be provided for a prospective project as described.

If the IS shows that a project may have a significant effect on the environment, the Department is responsible for preparation of an Environmental Impact Report (EIR). The EIR process, involving usually extensive environmental information gathering, data reduction, impact analysis, and mitigation measures development, along with the required public review process, can easily take 9-12 months (and possibly longer depending on the controversial nature of a proposed project). Although a prospective biomass power generation facility would not necessarily be deemed controversial, and in some circles it is deemed more of a benefit, there are individual areas of concern that need specific address. And although the Department has previously permitted biomass power facilities, so it has the expertise and sophistication for the process, there is no implicit anticipation that it will occur at the short-end of the timeline.

Fresno County does not appear to accept applicant prepared environmental impact analysis, which is becoming more typical with the larger agencies. The Department has an elaborate EIR consultant review process as indicated in Figure 1 below.

8.7 Federal Environmental Impact Review

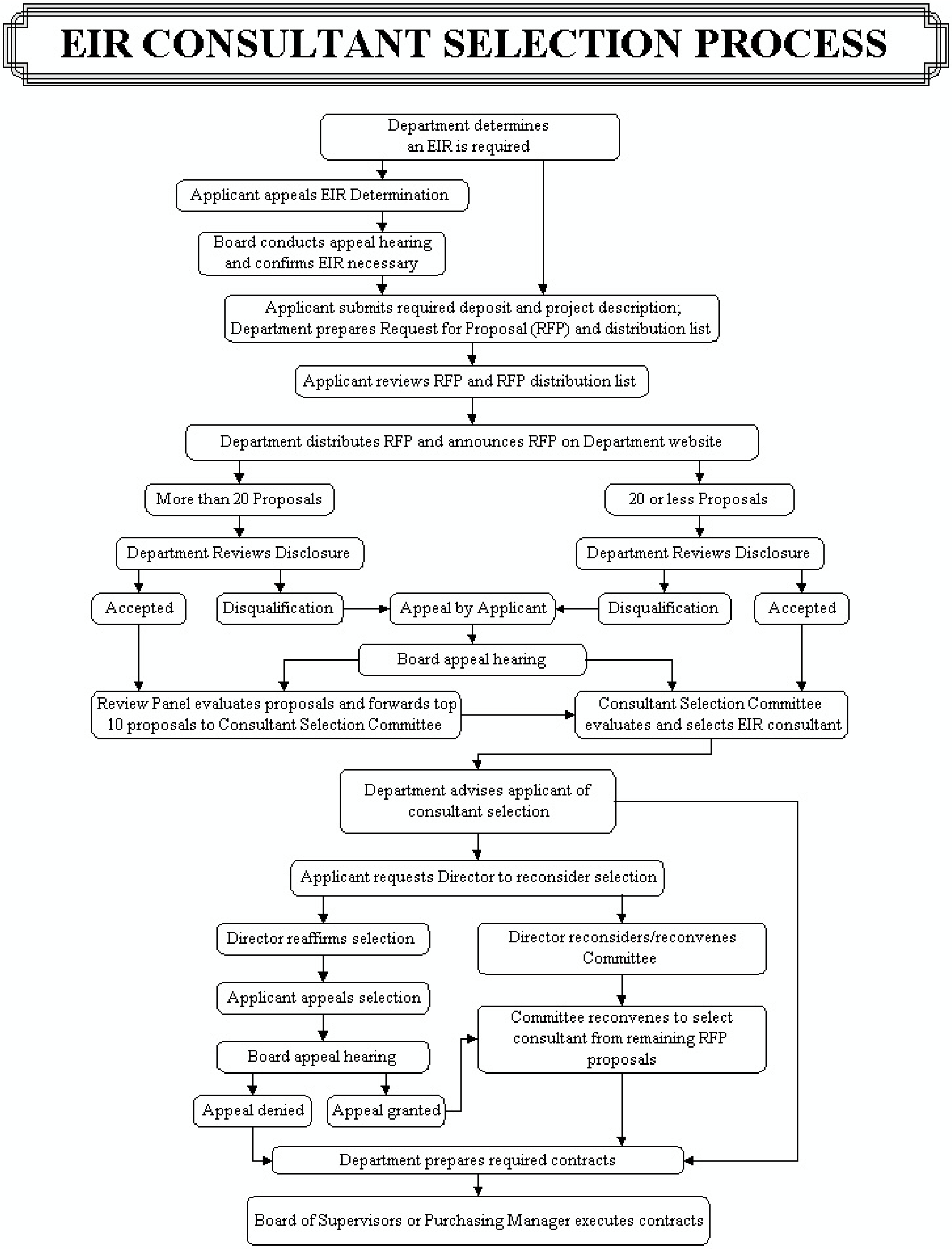
As none of the proposed biomass power plant sites are on federally managed lands, the NEPA environmental assessment process would be applicable. Federal agencies, however, can join the CEQA process by submitting comments in any phase of the County CEQA review (as noted in the various sections above).

The NEPA process may be invoked if there is any substantive transmission line work that might occur across federal lands. Such is unlikely, due to the MW-level of a prospective facility, specifically it would connect at the distribution-level, which is lower than the transmission-level, and does not require transmission line work.

8.8 Endangered Species Issues

The utility has longterm work experience in managing its endangered species issues, and thus it was not part of the work product required of TSS to look into how to incorporate such into permitting requirements for a prospective biopower facility. Nonetheless, it is a known element of required address, including identification of necessary mitigation that would be part of the air agency permits, and is noted with a placeholder in the following section of this report (see Section 9.0, Major Obstacles and Critical Path Items).

Figure 1 – Fresno County EIR Consultant Selection Process



9.0 MAJOR OBSTACLES AND CRITICAL PATH ITEMS

For the construction and operation of a biomass power plant in the Shaver Lake area, three principal permitting areas have been identified: Air quality; land use; and water use, including waste water/storm water discharge. The land use permit, a.k.a. the CUP, along with its accompanying CEQA process will be the critical path item in the power plant permitting process (as described in sections 7.0 and 8.0). The CUP must be in place prior to any on-site construction activities. This is also true for the air quality permit. Facility design and engineering, at least preliminary, is typically also required before the permitting process begins. As noted in earlier sections of this report, consideration for water rights, permitting for land application of ash, and endangered species issues would also need to be addressed as part of the full planning process. Where TSS was not called upon to access applicability of those facets, such noted with placeholders and an approximate timeframe for completion.

Permitting Plan Steps

In permitting of the biomass power plant the following steps are recommended:

- Prepare communications plan
- Prepare project description and preliminary design drawings
- Pre-application meetings with regulatory agencies
- Preparation and submittal of appropriate applications
- Agency interface during permit processing by regulatory agencies

<u>Communications Plan</u>

A communications plan for this project is recommended to allow for the following:

- Provide a comprehensive framework of actions that will allow agency representatives, elected officials and others to become informed about and ultimately support a biomass power plant in the prospective area.
- Provide adequate information to federal, state and county administrators, land managers and regulators of the project's design and engineering process and progress, so that their participation and support can be obtained.
- Allow nearby community members to provide input in the process, to consider that their views were consulted, and to afford the opportunity to understand the benefits of a prospective project.
- Facilitate beneficial media coverage regarding the proposed facility.

Project Description/Preliminary Design Drawings

The critical path agency, i.e., the Fresno County Department of Public Works and Planning will require preliminary documents such as a detailed project description to initiate the CEQA process. Maps and preliminary design drawings should to be prepared prior to conducting pre-application meetings with the principal permitting agencies. Process Flow Diagram provided as part of the Request for Quotes on the finances does not fully meet the requirement for project description and preliminary drawings.

Pre-Application Meetings

The regulatory agencies themselves recommend a pre-application meeting to discuss the basics of the proposed project, what their information needs are, and to establish a permitting schedule. In this order, it is suggested the agencies to meet with are:

Conditional Use Permit
Fresno County Department of Public Works and Planning
2220 Tulare Street, 6th floor, Fresno, CA 93721
Alan Weaver, Director

Air Quality Permit
San Joaquin Valley Air Pollution Control District
Central Region
1990 E. Gettysburg Ave., Fresno, CA 93726
Dave Warner, Director of Permit Services

Wastewater/Storm water Discharge
Central Valley Regional Water Quality Control Board
1685 "E" Street, Fresno, CA 93706-2007
W. Dale Harvey, NPDES/Storm water Program Manager

Prepare/Submit Applications

The applications will require that a prospective biomass project have sufficient design and engineering accomplished, where the necessary technical information can accompany the applications. For the three principal permits, such technical information must include:

- Conditional Use Permit – Information sufficient for Department of Public Works and Planning to prepare Environmental Checklist/Initial Study per CEQA requirements. This includes project description and siting location environmental setting preliminary information about geology, air quality, hydrology, biological resources, land use, traffic/transportation, utilities and public services, hazardous materials/waste, solid waste, noise, public health and safety, aesthetics, cultural and historic resources, housing, and recreation.

- Air permit – facility design drawings, emissions units equipment list and descriptions, emissions control equipment list (equipment models and serial numbers), emissions calculations, identification of available ERCs.
- Wastewater/Storm water discharge – facility design drawings, facility process water balance, wastewater treatment/recycle system design specifications and drawings, projected storm water runoff volumes and capture system design.

Agency Interface

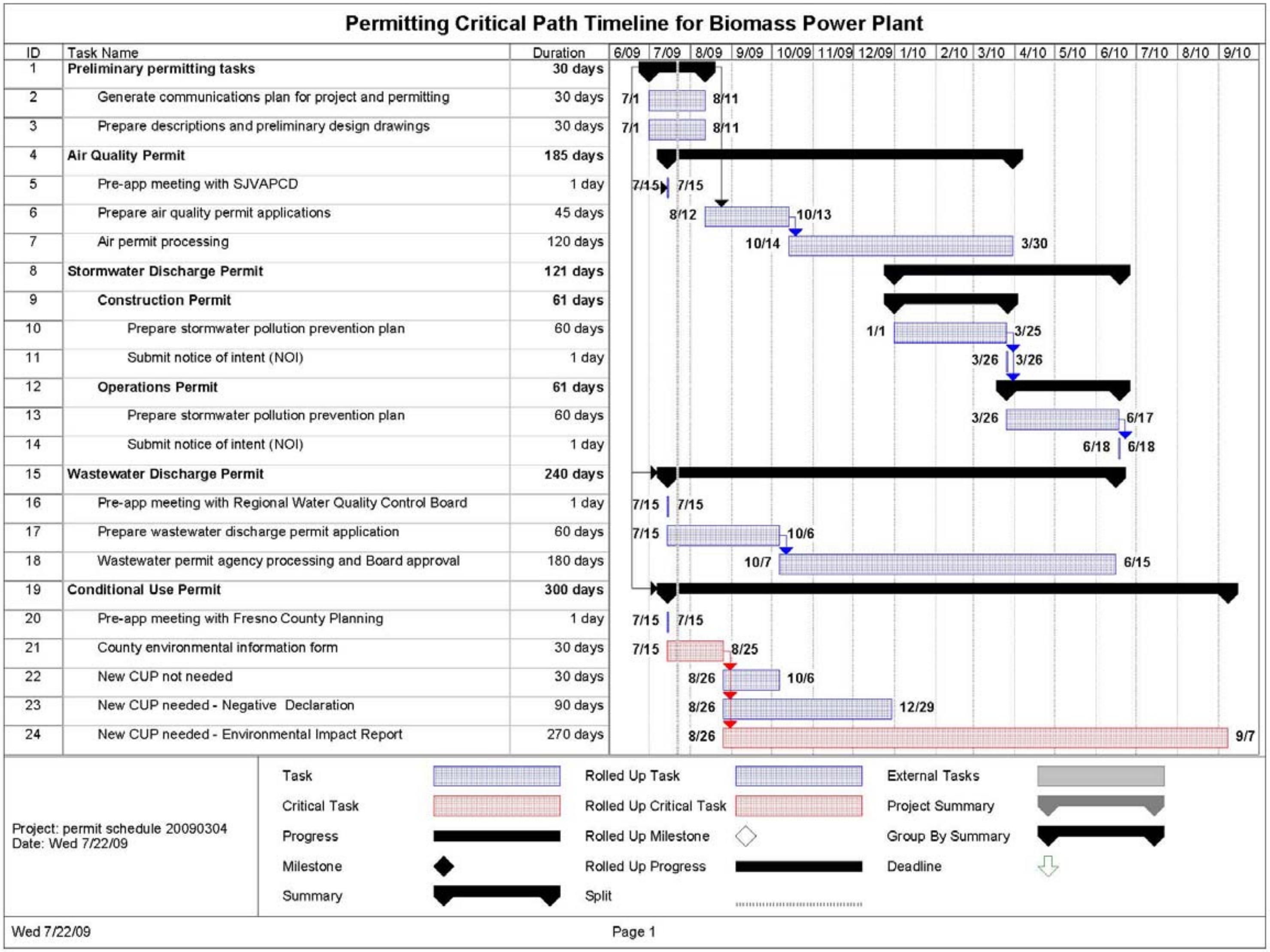
Adequate resources must be made available to the agencies during the agency processing of the permit applications. Upon initial submittal of the applications, there will be a period of at least 30 days in where the agency determines if the permit application contains sufficient information to be processed. Conceptually, the 30-day application process could be coincidental, and requests for data could be similar. Unfortunately, such might be the unusual case. The agency determination can be greatly enhanced by having the pre-application meeting and by interfacing closely with the agency during permit application preparation and sufficiency determination periods. Once the permit is deemed adequate for processing, continued interfacing with the agency is still critical, particularly in terms of keeping them on schedule. As with any regulatory interface, they would seem to appreciate having the bulk of the work done external to their office, where the agency is tasked more with review-level work.

Critical Path Timeline

Following in Figure 2 is the Critical Path Timeline.

This shows the Conditional Use Permit process, coupled with required CEQA process, forms the critical path, particularly if an Environmental Impact Report (EIR) is needed. If Fresno County is the lead agency, and determines that an EIR is not necessary, and instead a Negative Declaration (or Mitigated Negative Declaration) will suffice, the Regional Water Board permit process becomes the permitting critical path element. The difference between these two paths is roughly 2 ½ months. Overall, the range of the permitting phase of this prospective project moving forward would be 11 to 14 months.

Figure 2 – Critical Path



Timeline

10.0 REFERENCES

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