

Chapter 7

Biomass Power Plants

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Chapter 7: BIOMASS POWER PLANTS

7.1 CURRENT BIOMASS POWER PLANTS

Currently there are nine biomass power plants operating in the San Joaquin Valley Air Basin (SJVAB), with three biomass power plants that are located outside of the SJVAB. While there are a total of 12 biomass power plants that could accept agricultural materials in the SJVAB, District's data is available only for those facilities located in the SJVAB. Five of the nine biomass power plants are required to burn agricultural material in order to offset emissions as required by conditions on their operating permits with the District. District staff found that biomass facilities generally accept agricultural materials, forestry materials, and urban wood residues to be used as fuel for their boilers. Information from some biomass fuel buyers and operators indicate that biomass power plants will accept any clean and untreated organic material that is free of dirt and other unburnable contaminants like pressure treated and painted wood material. According to CBEA, several plants are now operating above 90% availability and many are in the mid to high 80 percent range, which is recognized in the industry as excellent performance.

Although biomass power plant operations and facilities are unique, they do follow the same general process to produce electricity from biomass fuel. The following biomass process description is a generalized representation of the process the biomass facilities utilize. This description is an aggregate derived from several biomass power plant operational procedures and equipment. Again, it is important to note that this description is not of one particular facility, but a combination of several facilities to provide a general understanding of the processes biomass power plants use to produce electricity from biomass fuel.

Trucks deliver the biomass fuel to the biomass power plant site. Biomass fuel can be agricultural materials, urban wood waste, or forestry materials. Biomass fuel types are discussed further in Section 7.1.2. The material is unloaded using either self-unloading trucks or a trailer tipper. A trailer tipper operates as follows: the truck trailer is driven onto the tipper, then the entire trailer is elevated to an angle such that the material free falls out the back of the trailer. The unloaded fuel is transported to conveyors for direct feed to the boiler or to a fuel storage area.

The first conveyor discharges the biomass material onto another conveyor, which then feeds through a fuel sizing system. The sizing system screens the fuel before delivery to metering bins. The enclosed conveyors are ventilated to fabric collectors. A large magnet removes magnetic materials and the non-metallic material passes to a hog screen and then to the fixed stacker. The material in

the storage piles is mixed and fed to the boiler feed conveyor. The blended biomass fuel is then fed to the boiler.

Hot combustion gases flow upward through the boiler, where heat is transferred through water tubes to produce high-pressure steam. The steam is then directed to a steam turbine generator to create electricity. Low-pressure steam discharged from the turbine is condensed and returned to the boiler as boiler feed water. Flyash from the combustor operation is collected from various points in the flue gas system in an enclosed dry mechanical system in order to minimize fugitive dust emissions. After collection, the Flyash is delivered to an ash storage bin, or a silo, for transfer offsite. According to the permit information for biomass facilities, the ash can be disposed of, or used to make soil additives, agricultural fertilizer, for use in the corrals at dairies or for road construction.

Flue gasses pass through the super heater, boiler, multi-cyclones, and economizer before entering the pulsejet baghouse. Alternatively, the boiler flue gas is injected with ammonia for NO_x control, injected with limestone for SO_x control, and injected with sodium bicarbonate injection for corrosion control, before it is vented to a fabric filter dust collector. Alternatively, exhaust gases are controlled with Non-Selective Catalytic Reduction (NSCR) and an Electrostatic Precipitator (ESP) before discharging through a stack.

All nine power plants in the SJVAB utilize both agricultural wood materials and non-agricultural materials as biomass fuel for their operations. Five of the nine facilities are required to have agricultural fuel offsets per permit conditions with the District. The table below illustrates the permitted mega watt (MW) output capacity at each facility and if the facility is required to have agricultural fuel offsets per permit conditions.

Table 7-1 Facility Megawatt Capacity and Agricultural Offsets Required

Facility ID	Permitted Output Capacity (MW)	Ag Offsets Required
A	12.5	No
B	30	Yes
C	56.5	Yes
D	11.5	No
E	25.8	Yes
F	12.5	No*
G	28.5	Yes
H	9.4	No
I	20.5	Yes

* Language in the permit states that if quarterly actual NO_x emissions from this boiler exceed 5,000 lbs, then agricultural offsets are required. If the quarterly NO_x emissions from this boiler do not exceed 5,000 lbs, then agricultural offsets are not required.

7.1.1 Locations

District staff expects that prohibition of open burning of additional agricultural material would generate a substantial amount of agricultural material to be dealt with alternatively. A key question to ask is whether biomass power plants have the capacity to handle agricultural material that would otherwise be open burned. Other aspects of that question are: 1) are the power plants located near the crops and 2) are they distributed enough throughout the SJVAB so that they could effectively accept additional agricultural material as biomass fuel. The currently operating biomass plants are located in six of the eight counties within the SJVAB. Table 7-2 below lists each biomass facility and its location.

Table 7-2 Facility Name and Location in the San Joaquin Valley Air Basin

Facility Name	City	County	Region
Rio Bravo Fresno	Fresno	Fresno	Central SJVAB
Covanta Mendota LP	Mendota	Fresno	Central SJVAB
Madera Power, LLC	Firebaugh	Madera	Central SJVAB
Ampersand Chowchilla Biomass LLC	Chowchilla	Madera	Central SJVAB
Covanta Delano	Delano	Kern	South SJVAB
Sierra Power Corporation	Terra Bella	Tulare	South SJVAB
Dinuba Energy	Reedley	Tulare	South SJVAB
Merced Power LLC	EL Nido	Merced	North SJVAB
Thermal Energy Dev Partnership LP	Tracy	San Joaquin	North SJVAB

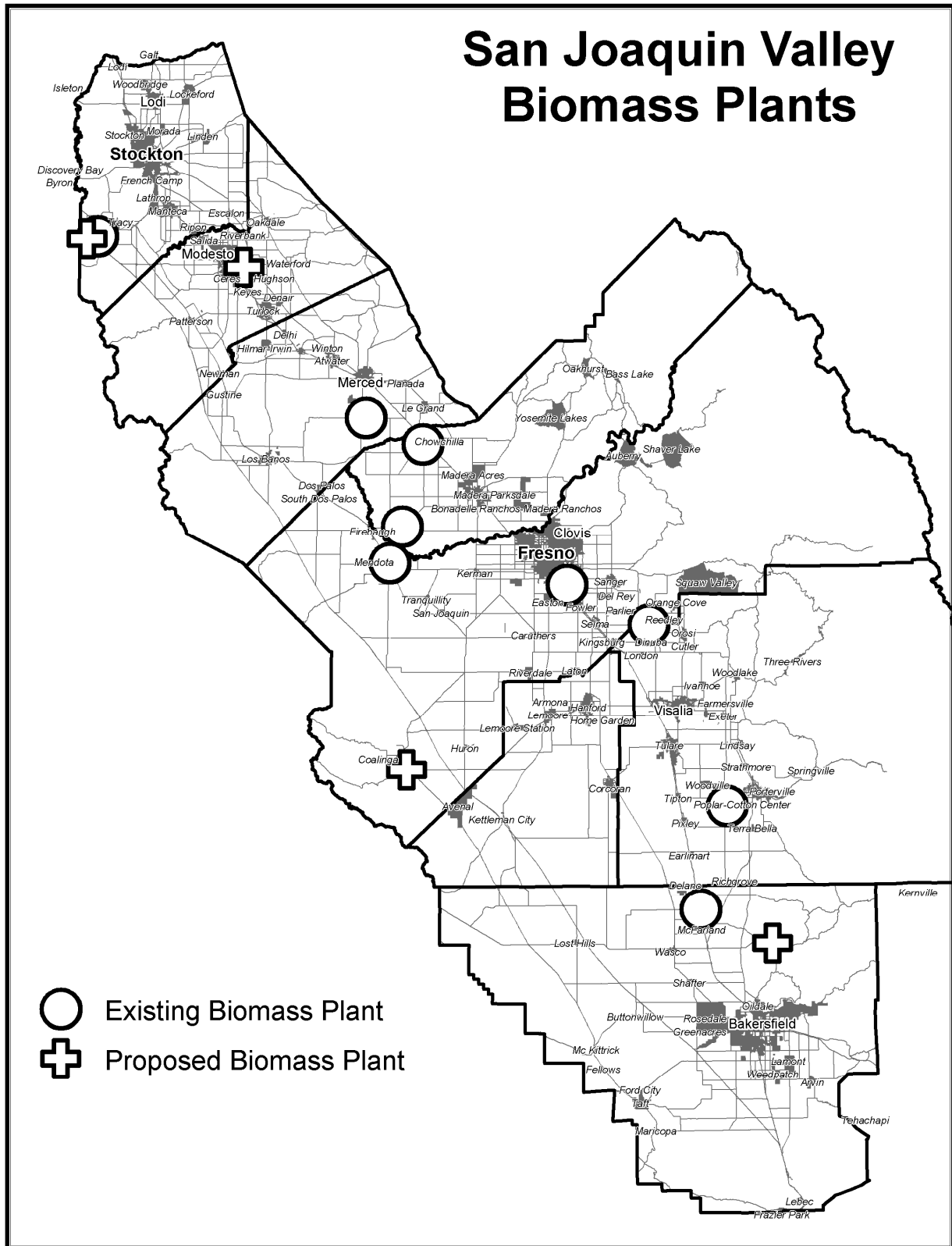
The California Biomass Energy Alliance (CBEA) is a trade association representing 33 biomass energy facilities located in 19 counties throughout California generating more than 650 MW of renewable electric power. CBEA has brought to the attention of District staff that there are three, biomass power plants located outside of the District boundaries that also accept agricultural materials from the SJVAB as fuel. The three plants identified by the CBEA are the Chinese Station power plant and Sierra Pacific Sonora power plant in Tuolumne County, and the Sierra Pacific Lincoln power plant in Placer County. However, staff does not have the five-year history through quarterly reports for these plants as to operating hours, or how much bone dry tons (BDT) per year they accept and burn or how much of the BDT used is agricultural material from the SJVAB. Therefore, these plants were not included in the analysis later in this chapter, or in other chapters of this report.

To better illustrate the locations of the biomass power plants, staff have included a map, as Figure 7-1, on the next page. As illustrated in the map, the nine existing biomass power plants are located at various locations throughout the

SJVAB. The locations of the three biomass power plants that are not in the SJVAB that accept agricultural materials as biomass fuel. All three plants are located north of the SJVAB.

Also illustrated in Figure 7-1 are the locations of four of the potential future biomass power plants. These future power plants are currently undergoing the permitting process with the District and further discussed in Section 7.2.6. Not illustrated on the map on the following page are the two biomass power plants in Stockton that may potentially accept agricultural material as biomass fuel in the future. These six plants are discussed further in Section 7.2.6.

Figure 7-1 Map of the San Joaquin Valley Air Basin with Locations of Existing and Potential Biomass Plants



7.1.2 Fuel Use and Storage Capacities

The percentage of agricultural material fuel versus non-agricultural material fuel that a biomass power plant accepts is constantly changing. Upon reviewing District database information and snapshot data of biomass power plant activities provided by the Compliance Department, it appears the percentage of agricultural material accepted generally varies greatly; from as little as 0% of accepted fuel to as high as 70%.

Biomass power plants accept urban waste materials and some forestry materials in addition to agricultural materials as fuel. Non-agricultural fuels include such materials as mill chips, cedar bark, forest slash/cull, hog fuel (mill residue), sawdust, construction wood waste, landfill derived wood, landscape tree trimmings, pallet/bin wood, and urban development clearing trees. Urban wood waste must contain less than 1% by weight of plastic, rubber, metals, roofing felt paper, and other non-wood contaminants other than dirt or ash. No asbestos-containing materials are approved as fuel.

SJVAB biomass power plants have very broad acceptance policies for agricultural wood fuel. This includes citrus and grape wood along with the other commonly accepted wood types. The limitation the biomass power plants have are that all treated wood posts, wire and drip line must be removed from the grape wood prior to grinding. CBEA states that the biomass power plants do have the ability to accept vines and that the removal of the wiring from the vineyard wood is a relatively minor issue in terms of the plants' ability to accept those materials.

Biomass power plant operators have indicated that previous concerns regarding certain materials have been alleviated over the past few years as the operators have improved the methods in processing the materials to better suit the needs of the plant. For example, in the past citrus materials caused concern for plant operators because the stringy citrus materials have the tendency to bind on the fuel handling conveyors and plug the fuel metering bins and this upsets the combustion process resulting in higher emissions and equipment deterioration due to temperature cycling. The operator also indicated that citrus wood ground to about 3-inch size screen poses minimal plugging problem. Now, due to considerable changes in the processing of the citrus materials, it has been reported that the operators no longer believe this is the case. Biomass power plant operators have indicated that they now mix citrus chips with chips from other crops to promote better flow of the materials through the equipment. Conversations with biomass plant operators and comments from the California Citrus Mutual indicate that the biomass power plants that do accept citrus materials can blend up to 25% citrus chips with other biomass fuel for combustion. It is important to note however, that it is relatively more affordable

for the biomass power plants to accept urban waste than agricultural materials because the residents of the community typically subsidize urban waste.

The combined storage capacity for the biomass facilities in the SJVAB at the time this report is about 266 acres. It is important to note that the available storage capacity at any given facility at any given time can vary. The primary factors affecting the amount of available storage are the amount of fuel previously received, and the tons of fuel stored per acre combined with the tons of fuel burned each day. Another source for uncertainty regarding the storage capacity of a facility is that the tons of material stored per acre could vary from one acre to the next. Conversations with biomass power plant operators indicated the amount of tons of material stored per acre varies by factors including: (1) if the material is received green or bone dry, (2) if the material is urban or agriculture, and (3) how high and wide the material is piled when it is received. Due to the variability of tons/acre storage capacity, it would be difficult to calculate that amount of material that the biomass plants can actually store the remaining crop type.

District staff received additional information from CBEA regarding the storage capacity at the 12 biomass power plants. According to CBEA, the wood fuel storage capacity, using current storage practices, from the 12 biomass plants is summarized below. The current storage capacity of Covanta Delano alone is 125,000 green tons. The total maximum storage capacity at all 12 facilities that use SJ Valley Ag Waste is 782,500 tons. Further, the majority of these facilities can store 60-175 operating days of fuel. This large storage capacity allows the use of wood fuel such as citrus and other types of fuel that may be stockpiled at significantly higher amounts and percentages than the actual fuel mix to the boiler (i.e. Covanta Delano may receive 50% citrus in the total agriculture deliveries for several months and then blend the fuel later to achieve an ideal mix to the boilers of 30% citrus). CBEA also indicated that many of the larger orchard removal contractors have storage capabilities. For example, one northern District contractor regularly stores as much as 20,000 tons of agriculture waste at its truck re-load facility.

Table 7-3 Fuel Storage Capacity for 12 Existing Biomass Plants That Use Ag Waste From SJVAD

Facility Name	Region Served	Daily Fuel	Maximum Fuel Storage Capacity		
		Use (GT)	Acres	Tons	Days
Rio Bravo Fresno	Central	850	8	35,000	41
Covanta Mendota	Central	800	35	54,000	68
Madera Power	Central	830	80	145,000	175
Ampersand Chowchilla	Central	360	2	6,000	17
Subtotal/Average		2,840	125	240,000	85
Covanta Delano	South	1,625	77	125,000	77
Dinuba Energy	South	415	20	45,000	108
Sierra Power	South	295	4	20,000	68
Subtotal/Average		2,335	101	190,000	81
Merced Power	North	360	10	19,000	53
Thermal Energy	North	631	28	24,000	38
SPI Sonora	North	250	5	7,500	30
Chinese Station	North	710	15	45,000	63
SPI Lincoln	North	600	20	36,000	60
Subtotal/Average		2,551	78	112,500	44
TOTAL ALL		7,726	304	542,500	70

7.1.3 Historical Fuel Usage

All nine power plants in the SJVAB utilize both agricultural wood materials and non-agricultural materials in their operations. The power plants generate electricity by burning the biomass fuel in combustors or boilers to produce steam. The steam is used to spin turbines, which in turn generate electricity.

District staff analyzed the historical fuel usage of the annual bone dry tons (BDT) burned at the nine biomass facilities in the SJVAB. In order to do so, staff reviewed quarterly reports submitted to the District for the past five years (2005-2009) from the biomass plants. It is important to note that at the time of this analysis, two of the facilities had not been in operation for five full years.

For the analysis, staff made the following assumptions:

1. For facilities with data from one or two quarters of a year unavailable at the time of this report, staff assumed the unavailable data to be equivalent to the average of the other quarters for the same facility for the same year.
2. Facilities reporting agricultural fuel received instead of burned, staff assumed the facility burned the total quantity of agricultural fuel received.
3. For facilities that only reported agricultural offset records, staff assumed the agricultural offsets burned is the total agricultural fuel burned.

4. For the two facilities in operation for less than five full years, staff assumed the average information for total time of operations to be equivalent to a five-year average.

Facility A: Staff assumed the fuel usage by using data provided by the facility as a snapshot of activity (273 BDT/day) provided by the District Compliance Department. Staff applied this snapshot number to the total operating days for each quarter to estimate the total annual BDT burned. Staff assumed agricultural fuel by using data provided by the facility as a snapshot of activity (219 BDT/day). Staff applied this snapshot number to the total operating days for each quarter to estimate the total agricultural fuel used.

5. Facility B: Staff estimated the total annual BDT burned by assuming the facility operated at the high-end BDT capacity of 213,609 BDT/yr. However, historical data indicates this facility operates an average 82% of the time. Therefore, staff adjusted the estimated BDT to 82% totaling in an annual BDT of 175,159 BDT/year (213,609 BDT/year x 0.82). Agricultural fuel records were available.
6. Facility C: This facility advertises on its website that it has a capacity of 1293 tpd of BDT biomass fuel. For purposes of this analysis, staff assumed the plant is operational 365 days per year, giving it an annual fuel capacity of 471,945 BDT (1,273 BDT/day x 365 days). Staff assumed 70% of the total BDT/year was agricultural fuel based on a snapshot of fuel use provided by the District compliance department.
7. Facility D: Staff assumed that of the total BDT (84,589 BDT/year) burned, 25% is agricultural fuel based on a snapshot of usage for this facility provided by the District Compliance department. The total BDT of agricultural material fuel burned is 21,147 BDT/year (84,589 BDT/year x 0.25).
8. Facility F: Staff assumed total annual BDT burned to be equivalent to the low-end BDT capacity, as presented later in this report. Agricultural fuel records were available.
9. Facility I: District staff estimated the total annual BDT fuel burned by assuming the snapshot data of BDT fuel burned and Fuel percentages provided by the Compliance department is indicative of activities for an entire year. Staff multiplied the snapshot data (468 BDT/day) by the 5-year average operating days/year (347). Staff estimated the total annual agricultural material fuel burned by assuming the snapshot data of BDT fuel burned (234 BDT/day) and Fuel percentages provided by the Compliance department is indicative of the entire year. Staff multiplied the Snapshot data (234 BDT/day) by the 5-year average operating days/year (347). The total annual

BDT agricultural material fuel burned is 81,198 BDT/year (234 BDT/day x 347 days).

Table 7-3 Average Annual Historical BDT Fuel Use (2005-2009)

Biomass Facility	Annual BDT Agricultural Material Burned (tpy)	Annual BDT Urban Waste Burned (tpy)	Total Annual BDT Burned (tpy)
A	49,584	12,227	61,811
B	125,838	49,321	175,159
C	330,362	141,583	471,945
D	21,147	63,442	84,589
E	41,028	88,655	129,683
F	8,660	83,367	92,027
G	117,202	106,590	223,793
H	21,992	50,674	72,666
I	81,198	81,189	162,378

District staff reviewed the five-year historical fuel usage of the biomass power plants to determine if the ratio of agricultural material to urban waste has varied due to the housing market boom and subsequent economic downturn.

Presented in Table 7-4 is the average annual percentage of agricultural material burned at the biomass plants from the plants that reported the total BDT and agricultural material BDT in their quarterly reports. In 2008, the use of agricultural material at the biomass power plants was twenty-five percent of the total fuel used, in 2009 the use of agricultural materials increased to forty-three percent. Staff attributes this fluctuation in percentage of agricultural fuel used to the construction industry boom and the following economic downturn. However, CBEA has submitted comments stating that there was a shortage of agricultural fuel in 2006.

Table 7-4 Average Annual Percentage of Agricultural Material Burned

Year	2005	2006	2007	2008	2009
Ave % Ag Material	58%	24%	41%	25%	43%

Historically, there have been occasions when biomass plants had to turn away agricultural materials. During the fall of 2007, several biomass power plants in the District had to temporarily shut down plant operations due to equipment failures or maintenance purposes. In addition, some biomass power plants had to refuse chipping material because storage space was not available. Issues such as lack of storage space and equipment failure can create situations when the biomass power plant operators must turn away agricultural materials. This inability to guarantee that a facility can accept agricultural biomass at all times creates uncertainty in the ability of the biomass plants to accept increased

amounts of agricultural fuel that would be generated by a complete prohibition of open burning.

It is important to note that the reason the plants were off-line for several months during the period of 2007 was due to plant improvements and refurbishments. One of the South Valley plants did an \$18 million refurbishment of the plant in the third quarter of 2007, which lasted for several months. A Central SJVAB power plant invested over \$14 million in refurbishing their facility and came back on-line in December 2008. In October 2008 another Central SJVAB plant invested over \$10 million to refurbish the combustor, which improved its operational availability by 20%. One North SJVAB plant has invested \$4 million on refurbishments over the past 2.5 years, and plans to invest another \$2 million in 2009-2010.

Although there have been periods of inoperation at the facilities, the nine facilities averaged 6,029 operating hours per year, out of a possible 8,760 hours per year. Converting operating hours into days translates to mean that the biomass power plants were in operation for an average of 251 of 365 days per year, or 69% of the time. Staff evaluated the operating hours as reported to the District by the biomass power plants in the quarterly reports. Again, for the two facilities that have not been in operation for the full five years, staff assumed the average of total operating time to be equivalent to a five-year average.

7.1.4 Emissions and Emission Controls

7.1.4.1 Emissions

Criteria Pollutant Emissions

The 2009 emission data reports are not due the District from the biomass power plants until June of 2010; therefore, an emission inventory for 2009 is unavailable at the time of this report. Of the nine facilities, two facilities were not in operation for the full year of 2008; therefore, staff did not include emissions data from these facilities in this emission inventory. Additionally, data is unavailable at the time of this report for one of the facilities for the year 2008. However, the 2009 emissions data is available for this facility. Staff substituted the 2009 emission inventory from this facility for the 2008 emission inventory.

Table 7-5 2008 Emissions Inventory for SJVAB Biomass Facilities

Pollutant	VOC	NOX	PM10	SOX
Emissions (tons per year)	48.34	567.16	191.26	101.18

For purposes of the emission inventory for biomass facilities for the SJVAB for 2008, District staff made the following assumptions:

1. The 2009 emission inventory for the one facility with an unavailable inventory for 2008 is equivalent to the 2008 inventory.
2. The best available inventory for one facility only includes NOX emissions. To determine VOC, PM, and SOX emissions, staff assumed the ratio of VOC, PM, and SOX to NOX emissions is equivalent for this facility to the ratio reported by another facility with similar NOX emissions.

Green House Gas Emissions

As discussed in the CEQA analysis and report, Global Climate Change (GCC) is now generally accepted by the scientific community to be caused by Greenhouse Gases (GHGs). GHGs are gases that trap heat in the atmosphere. Some greenhouse gases such as water vapor occur naturally and are emitted to the atmosphere through natural processes while others are emitted through human activities. The most common GHG that results from human activity is carbon dioxide, followed by methane and nitrous oxide.

The analysis in this report identifies biomass facilities as one of the feasible alternatives to open burning. The identified alternatives have the potential to result in changes in GHG emissions because of possible increased fuel consumption associated with equipment used to grind/chip and transport agricultural biomass. District staff examined the recommendations to determine their potential to have a cumulatively significant impact on global climate change, results of which are presented below. The analysis demonstrates that implementation of the recommended alternatives to open burning will not have a cumulative significant impact on global climate change.

Potential Greenhouse Gas Impacts

Staff is exploring alternatives to the existing practice for disposing of orchard removal material by burning it in place (open burning). The alternative to open burning of orchard removal materials is chipping the organic matter and using the chipped material as fuel in a biomass plant to produce electricity. Sources of GHG emissions from this alternative include fuel consumed in chipping the plant material; fuel consumed in transporting the chipped material to a biomass plant; fuel consumed in processing the chipped material at the biomass plant; and combustion of the chipped material to produce electricity at the biomass facility.

The alternative practice of burning chipped material in a biomass power plant would not result in an increase in GHG emissions compared to open burning the material. In fact, burning the material in a biomass plant would produce a net GHG benefit by producing electric power from a renewable source of energy rather than a fossil fuel. This concept is one of the strategies adopted by the

State of California to reduce GHG emissions to 1990 levels by the year 2020 by requiring the state's load serving entities to meet a 33 percent renewable energy target by 2020 (Executive Order S-21-09). Biomass fuels burned in existing facilities are currently transported from various locations outside and within the San Joaquin Valley Air Basin. Use of locally produced fuel could reduce VMT associated with transporting materials, and thus result in a net GHG benefit. GHG emissions associated with chipping orchard removal material are expected to be offset by the benefits associated with displacing fossil fuels and reducing VMT.

The District concludes, GHG emissions resulting from alternatives to open burning of orchard removal materials and prunings are expected to have a net positive benefit on global climatic change compared to the status quo of open burning. Therefore, the District concludes that implementation of the recommendations would have a less than cumulatively significant impact on global climatic change. For further discussion regarding GHGs please see the published CEQA analysis report.

7.1.4.2 Emission Controls

Although biomass power plant operations and facilities are unique, they do follow the same general process to reduce emissions from the processing of biomass fuel. The following is a description of methodologies and technologies the biomass facilities use, or could use, to reduce emissions. District staff researched information on solid fuel-fired boilers by examining the District's Permit database, California Air Resources Board (ARB) Best Available Control Technology (BACT) Clearinghouse, other air districts' BACT Clearinghouses. District staff also researched the United States Environmental Protection Agency (EPA) BACT Clearinghouse, European Commission Integrated Pollution Prevention and Control (IPPC) Best Available Techniques, other local air districts and other states' regulations, and technical documents published in the internet. District staff also reviewed the Permit-to Operate (PTO) for each biomass facility.

NOx Emission Control Technologies

Common fuel types for solid fuel-fired boilers are agricultural material (biomass), coke, coal, wood wastes, paper, walnut shells, pistachio shells, tire-derived fuel, municipal solid waste, and other solid waste. For the purpose of this analysis, NOx emission limits are based on the fuel type, and are divided into three categories based on their composition. The categories include municipal solid waste, biomass, and others. Each solid fuel is either homogeneous or heterogeneous. Under a homogeneous condition, the fuel meets specific criteria and is sorted by content. Examples of homogeneous fuels are walnut shells, coke, and woodchips. Heterogeneous fuel is unsorted, and untreated. An example is municipal solid waste, which contains a wide variety of combustible materials having widely varying heat content values. The fuel type is important

when considering the emission reduction effectiveness of an emission control technology. Unlike gaseous fuel-fired units, solid fuel-fired units present more difficult technological challenges in controlling NO_x, PM, and SO_x emissions to a much lower because of varying fuel composition.

NO_x emission control techniques generally fall into two categories: (a) combustion modifications; and (b) post combustion modifications (add-on controls). Typically, these control systems are successful in simultaneously attaining low NO_x and CO emission levels. Most of the NO_x formed during combustion of natural gas is from high temperature reaction of nitrogen (N₂) with oxygen (O₂). NO_x formed this way is referred to as “thermal NO_x” and is considered a function of flame temperature and oxygen concentration. Studies of combustion processes indicate that significant amounts thermal NO_x are formed when the flame temperature is above 2,300 °F.

Combustion Modification

Combustion modification systems are designed to reduce thermal NO_x formation by changing the flame characteristics to reduce peak flame temperature. Combustion controls include low excess air operation, staged combustion, over fire air ports, biased firing, and burners out of service.

Combustion modification is also achieved by different burner designs such as Low NO_x and Ultra Low NO_x burners. Some of the design principles used in Ultra low NO_x and Low NO_x burner include staged air burners, staged fuel burners, pre-mix burners, internal recirculation, and radiant burners.

Combustion control systems may be used by itself or in combination with Flue Gas Recirculation (FGR). FGR recycles a portion of the exhaust stream back into the burner wind box, mixing low oxygen air with combustion air prior to entering the combustion chamber. This technique reduces thermal NO_x formation by reducing the peak temperature and by reducing oxygen in the combustion zone.

Low Excess Air

Low excess air is a comparatively simple and easy to implement operational measure for reducing NO_x emissions. By reducing the amount of oxygen available in the combustion zone to the minimum amount needed for complete combustion, fuel-bound nitrogen conversion and to the less extent thermal NO_x formation are reduced. There is no additional energy required for low excess air firing, and if properly operated, no reduction in availability of the power plant should result from this type of emission control technique. As the oxygen level is reduced, however, combustion may become incomplete and the amount of unburned carbon in the ash may increase. Reducing the amount of oxygen in the combustion zone in the primary zones to very low amounts can also lead to high levels of carbon monoxide. The results of such changes can be a reduction

in the boiler efficiency, slagging, corrosion, and counteractive overall impact on the boiler performance.

Air Staging

NO_x reduction by air staging is based on the creation of two divided combustion zones: a primary combustion zone with a lack of oxygen, and a secondary combustion zone with excess oxygen in order to ensure complete burn-out. Air staging reduces the amount of available oxygen (in 70 – 90% of the primary air) in the primary combustion zone. The sub-stoichiometric condition in the primary combustion zone suppresses the conversion of fuel-bound nitrogen to NO_x. In addition, the formation of thermal NO_x is reduced to some extent by resulting lower peak flame temperature. In the secondary zone, 10-30% of the combustion air is injected above the combustion zone. Combustion is completed at this increased flame volume. Therefore, the relatively low-temperature secondary stage limits the production of thermal NO_x.

In boilers, the following options exist for achieving air-staging:

- Biased Burner Firing

Biased burner firing is frequently used as a retrofit measure at existing installations (only for vertical boilers) as it does not require major alteration of the combustion installation. The lower burners operate fuel-rich whereas upper burners are supplied with excess air.

- Burners Out of Service (BOOS)

Since putting some burners out of service does not require a major alteration of the combustion installation, it is frequently used as a retrofit measure at existing vertical boilers. The lower burners are operated under fuel-rich conditions, whereas the upper burners are not in use, injecting only air. The effect is similar to over fire air, but NO_x reduction by BOOS is not as efficient. Problems may arise with maintaining the fuel input, because the same amount of thermal energy has to be supplied to the unit with fewer operating burners. Therefore, this control technique is generally restricted to gas- or oil-fired combustion processes.

- Over Fire Air (OFA)

For over fire air operation, air ports (wind boxes) are installed in addition to existing burners. A part of the combustion air is injected through these separate ports, which are located above the top row of burners. Burners can then be operated with low excess air, which inhibits NO_x formation, the over fire air ensuring complete burn-out. Typically 15-30% of the total

combustion air that would normally pass through the burners is diverted to the over fire ports. Retrofitting over fire air to an existing boiler involves applying water-wall tube modifications to create the ports for the secondary air nozzles and the addition of ducts and wind box.

Flue Gas Recirculation

The recirculation of flue gas results in a reduction of available oxygen in the combustion zone, and since it directly cools the flame, in a decrease of the flame temperature; therefore, both fuel-bound nitrogen conversion and thermal NO_x formation are reduced. The recirculation of the flue gas into the combustion air has proven to be a successful method for NO_x abatement in high temperature combustion systems such as wet bottom boilers and oil-or-gas-fired units.

Reduced Air Preheat

The combustion air preheat temperature has a significant impact on NO_x formation mainly for gas and oil firing systems. For these fuels, the main part of NO_x is determined by thermal NO mechanism, which depends on the combustion temperature. Reducing air preheat temperature results in lower flame temperatures (peak temperatures) in the combustion zone. There are two major drawbacks of this technology. First, in several boilers, e.g., in coal burning, high combustion temperatures are required and accordingly high air preheater temperatures are essential for the proper functioning of the combustion installation. Secondly, lowering the air preheat temperature results in a higher fuel consumption, since the higher portion of the thermal energy contained in the flue gas cannot be utilized and ends up leaving the plant via the stack. This can, however, be counterbalanced by utilizing certain energy conservation methods, such as increasing the size of the economizer.

Fuel Staging

Fuel staging (also called reburning) is based on the creation of different zones in the boiler by staged injection of fuel and air. The aim is to reduce back to nitrogen the nitrogen oxides that have already been formed. Reburning involves combustion in three zones. In the primary combustion zone, 80-85% of the fuel is burned in an oxidizing or slight reducing atmosphere. This primary burn-out zone is necessary in order to avoid the transfer of excess oxygen in the reburning zone, which would otherwise support possible NO_x formation. In the second combustion zone (often called reburning zone), secondary or reburning fuel is injected in a reducing atmosphere. Hydrocarbon radicals are produced, reacting with the nitrogen oxides already formed in the primary zone; other unwanted volatile nitrogen compounds like ammonia are generated as well. In the third zone, the combustion completes through the addition of final air into the burn-out zone. Different fuels can serve as reburning fuel (pulverized coal, fuel oil, natural gas, etc.), but natural gas is generally used due to its inherent properties.

Low NO_x Burner (LNB)

Low NO_x burners modify the means of introducing air and fuel to delay the mixing, reduce the availability of oxygen, and reduce the peak flame temperature. LNBs retard the conversion of fuel-bound nitrogen to NO_x and the formation of thermal NO_x, while maintaining high combustion efficiency. The pressure drop in the ducts increases, causing more operational expenses. There could also be some corrosion problems especially if the process is not properly controlled. The low NO_x burning techniques requires, at least, the burners to be changed and installation of OFA. If existing burners are classical burners, then changing the burners can usually be done very cost-effectively. However, if the burners are delayed combustion low NO_x burners (old type), the benefits of retrofitting such burners into rapid injection low NO_x burners can only be effectively assessed on a case-by-case basis.

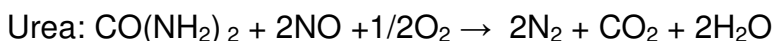
Dilution-based Combustion Control

Dilution-based combustion control strategies reduce thermal NO_x formation by introducing inert material into the flame. The injected inert absorbs heat without reacting, thereby reducing peak flame temperature and reducing the potential for NO_x formation. Water or steam injection reduces flame temperatures by using a portion of the flame's heat to convert water from liquid to vapor. The disadvantage of this control technique is that the heat efficiency of the device is reduced by one to four percent. In flue gas recirculation (FGR), about 10% to 25% of the flue gas is siphoned off from the combustion exhaust stream to be used as combustion air for the burner. Since the flue gas has less oxygen than atmospheric air, the additional nitrogen in the flue gas acts as an inert component in the combustion process, reducing peak flame temperature. Flue gas recirculation may not be a feasible retrofit technology for many devices due to size or layout constraints.

Post Combustion Controls (Flue Gas Treatment)

Selective Non-Catalytic Reduction (SNCR)

SNCR involves direct injection of ammonia or urea at the flue gas temperatures of about 1600^oF to 1900^oF. Ammonia or urea reacts with NO_x in the flue gas to produce N₂ and water. The reactions in the SNCR are due to the thermal decomposition of ammonia or urea and the subsequent NO_x reduction. A simplified NO_x reduction reaction in SNCR is shown below.



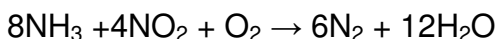
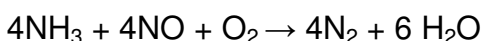
The temperature of the flue gas at the point of ammonia or urea injection and the amount of unreacted NH₃ (ammonia slip) that will pass through the SNCR can significantly affect the efficiency of NO_x reduction. At temperatures below the desired operating range, the reduction reactions diminish and ammonia slip

increases. Above the desired temperature range, NH_3 is oxidized to NO_x , which results in decreased NO_x reduction efficiencies.

An important factor to the performance of SNCR is the mixing of the reactant and the flue gas within the reaction zone. Design considerations include delivering the reagent in the proper temperature window, and allowing sufficient residence time of the reagent and flue gas in the proper temperature window. Additionally, other factors such as reagent to NO_x ratio and fuel sulfur content also influence the performance and reduction efficiency of SNCR.

Selective Catalytic Reduction (SCR)

SCR involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_x to elemental nitrogen (N_2) and water. The overall SCR reactions are shown below.



Flue gas temperature, SCR inlet NO_x concentration, catalyst surface area, volume, and age of the catalyst, and acceptable amount of ammonia slip influence the performance of the SCR. The catalyst lowers the activation energy of the NO_x decomposition reaction and allows NO_x reduction to proceed at a lower temperature that is required by SNCR. Depending on the type of catalyst used, the optimal temperature range is typically between 650°F to 800°F. Below this temperature range ammonium sulfate can form which causes catalyst deactivation. Above the optimum temperature, the catalyst will sinter and rapidly deactivate. SCR is considered technological feasible for control of NO_x from solid fuel-fired units.

Regenerative Selective Catalytic Reduction (RSCR)

The following information is an extract from a technical document published by Babcock Power Environmental: "RSCR is a regenerative selective catalytic device achieving NO_x reductions of >80%, applied to the cold gas (after the boiler and particulate removal equipment) prior to discharge to the stack achieving NO_x reductions of >80%. RSCR is a combination of two established and proven technologies: Regenerative Thermal Oxidizer (RTO) and SCR. By utilizing the direct contact regenerative heater technology (usually associated with an RTO, in which cycling beds of ceramic media used to transfer heat, the low temperature issue is resolved. NO_x reduction takes place in SCR catalyst modules positioned above the heat transfer bed, where the flue gas has been heated to around 600°F and the proper amount of ammonia has been added upstream of the canisters. Either anhydrous or aqueous ammonia can be used.

The primary application of RSCR is the reduction of NO_x emissions in the flue gas found at the tail end of the biomass boiler where the gas temperatures are cool, typically 300°F to 400°F. In an RSCR, the temperature of the flue gas is temporarily elevated for optimal catalyst performance and the heat is recovered before sending the cleaned flue gas to the stack. The main advantage of RSCR is its high thermal temperature versus standard tail-end solutions in which the heat exchanger and duct is used. The RSCR thermal efficiency can be guaranteed as high as 95% in contrast to the standard tail end solutions that typically achieve 70 to 75% efficiency.

Hybrid Selective Reduction (HSR)

HSR is a combination of SNCR and SCR that is designed to provide the performance of full SCR with significantly lower costs. In HSR, an SNCR is used to achieve some NO_x reduction and to produce a controlled amount of ammonia slip that is used in a downstream in-duct SCR reactor for additional reduction. HSR has been demonstrated to reduce NO_x emissions by 50% to 98% on a 320 MMBtu/hr coal fired boiler; therefore, it is considered technologically feasible for control of NO_x from solid-fuel fired boilers. Currently, the District has received an application for an operating permit for biomass fuel fired boilers where the applicant is proposing to install and operate both SNCR and SCR on four boilers to achieve 0.012 lb NO_x/MMBtu (about 9.8 ppmv at 3% oxygen) . It is important to mention that the District has recently received a permit application from a company that intends to operate four biomass fired boilers that will utilize SCR and SNCR to achieve a NO_x emission level of 0.012 lb/MMBtu.

Particulate Matter Control Technologies

Particulate matter (PM) in solid fuel-fired unit is formed due to the inert solids contained in the fuel, the unburned hydrocarbon fuels, as well as byproducts of limestone injection, which accumulate to form particles. District staff reviewed the EPA BACT Clearinghouse to determine technologies to control PM emissions from solid fuel-fired units. PM control technologies that were listed in the database include electrostatic precipitators, fabric filter/baghouses, wet scrubbers, and mechanical separators. The PM and SO_x control technologies and emission limits of the permitted units operating in the SJVAB are shown in the Table on the next page. It is important to note that one of the biomass power plants has two boilers and both are included in this list. As such, there are ten boilers listed here for the nine facilities.

Table 7-6 Permit PM10 and SOx Limits of Solid Fuel-Fired Biomass Units in the District

Unit Size MMBtu/hr	Existing PM and SOx Control Technology	Permit PM10 Limit	Permit SOx Limit lb/MMBtu	Fuel Type
171.2	Multicyclone and ESP	0.016 gr/dscf @ 12% CO ₂	0.061	Biomass and construction wood waste
185	Multicyclone and baghouse; limestone injection	0.04 lb/MMbtu	0.04 lb/MMbtu	Biomass
185	Baghouse and limestone injection	0.04 lb/MMbtu	0.04 lb/MMbtu	Biomass, construction wood waste, and urban wood waste
11.5 MW (189 MMBtu/hr)	Multicyclone and ESP; Lime and soda ash injection	0.0144 gr/dscf @ 12% CO ₂	9.9 lb/hr	Biomass, construction wood waste, and urban wood waste
259	ESP and Lime injection	8.75 lb/hr	6.25 lb/hr	Biomass
400	Multicyclone and Fabric Filter	0.010 gr/dscf @ 12% CO ₂	23 ppmv @ 3% O ₂	Biomass, construction wood waste, and urban wood waste
315	Fabric Filter and lime and NAHCO ₃	0.045 lb/MMbtu	23 ppmv @ 3% O ₂	Biomass, construction wood waste, and urban wood waste
317	Baghouse	0.010 gr/dscf @ 12% CO ₂	247 lb/day	Biomass
352	ESP	17.4 lb/hr for condensable and 5.8 lb/hr for filterable	10 lb/hr	Biomass, construction wood waste, and urban wood waste
460	Multicyclone and Baghouse	0.03 lb/MMBtu	1.2 lb/MMBtu	Biomass, construction wood waste, and urban wood waste

Electrostatic Precipitator (ESP)

An ESP is a particle control device that uses electrical forces to move the particles out by flowing gas stream onto collector plate. The particles are given electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane. One the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is done by knocking them loose from the plates and allowing the collected layer to slide down into a hopper. Some ESPs remove the particles by intermittent or continuous washing with water. ESPs are configured in several ways. Some of these configurations have been developed for special control action, and others have evolved for economic reasons. The types of

ESPs are plate-wire precipitator, flat plate precipitator, tubular precipitator, and two-stage precipitator.

Units using limestone injection in a dry scrubber for control of SO_x rarely use ESPs because the use of flue gas desulfurization/baghouse combination significantly increases control of SO_x emissions while achieving comparable PM control. When flue gas passes through the filter cake, additional SO_x is removed by unreacted limestone and CaO in the filter cake. Also, due to the high resistivity of the PM₁₀ (mostly CaO and CaSO₃), a large ESP plate area would be required to match the control efficiency of baghouses, which makes ESP more expensive than baghouses.

Fabric Filter/Baghouse

A fabric filter consists of one or more isolated compartments containing rows of filter bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle-laden gas passes up along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filters are cyclically operated, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter, with efficiencies in excess of 99 percent. The layer of dust or dust cake collected on the fabric is primarily responsible for such high efficiency. As the flue gas passes the filter cake additional SO_x is removed. Gas temperatures up to about 500°F with surges to about 550°F can be routinely accommodated in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting. The primary disadvantage of baghouses compared to ESPs is the higher-pressure drop across the baghouse resulting in increased fan power requirements for the system.

Wet Scrubber

A wet scrubber is a control device that removes PM and acid gases from waste gas streams of stationary point sources. The pollutants are removed primarily through impaction, diffusion, interception, and/or absorption of the pollutants onto droplets of liquid. Collection efficiencies for wet scrubbers vary with particle size and distribution of the waste stream. Generally, collection efficiency decreases as the particle size decreases. Collection efficiencies also vary with scrubber type. The efficiency ranges from greater than 99% for venture scrubbers to 40-60% (or lower) for simple spray towers. It is important to note that none of the permitted solid fuel-fired units in the SJVAB currently operates wet scrubbers.

SO_x Control Technologies

SO₂ is formed during the combustion process because of thermal oxidation of the sulfur contained in the fuel. A portion of the sulfur is further oxidized to SO₃. At temperatures below approximately 600°F, sulfur trioxide readily combines with moisture in the flue gas or in the atmosphere to form sulfuric acid (H₂SO₄). These sulfur compounds are acidic and can be controlled using the same technology. SO₂ and H₂SO₄ control technologies are discussed below.

Dry Flue Gas Desulfurization

The use of a dry flue gas desulfurization system such as lime spray drying followed by a baghouse has the potential to reduce Sox emissions by 75% to 90%. The lowest permitted SO₂ emission rate for a biomass-fired boiler using lime spray scrubbing technology is 0.10 lb/MMBtu.

Circulating Dry Scrubber (CDS)

The CDS is a once-through dry technology where flue gas, ash, and lime sorbent form in a fluidized bed in an adsorbent vessel. The flue gas is humidified in the vessel to assist the adsorption reactions between lime and SO_x. The by-products leave the absorber in a dry form with the flue gas and are subsequently captured in a downstream particulate collection device. It is important to note that CDS have only been domestically applied to two coal fired boilers.

Wet Scrubber

Wet scrubber is a one-through control technology where a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO₂ is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport and disposal. Wet scrubbers can be classified on the basis of the reagents used and the by-products generated. The typical reagents used in this process are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. The reaction by-products are calcium sulfite and calcium sulfate. Calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application uses limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate. Wet scrubbers are commercially available and are generally only applied on coal-fired boilers.

Regenerable Wet Scrubber (RWS)

RWS technology uses sodium sulfite, magnesium oxide, calcium carbonate, amine, or ammonia as the sorbent for removal of SO₂ from the flue gas. The spent sorbet is regenerated to produce concentrated streams of SO₂ or other sulfur compounds, which may be further processed to produce other products. This technology may require additional flue gas treatment prior to SO₂ absorption process to remove other flue gas constituents such as hydrogen chloride and hydrogen fluoride that

may affect the sorbent and/or final by-product. Sodium sulfite and ammonia-based technologies are commercially available and have control efficiencies ranging from 90% to 95%.

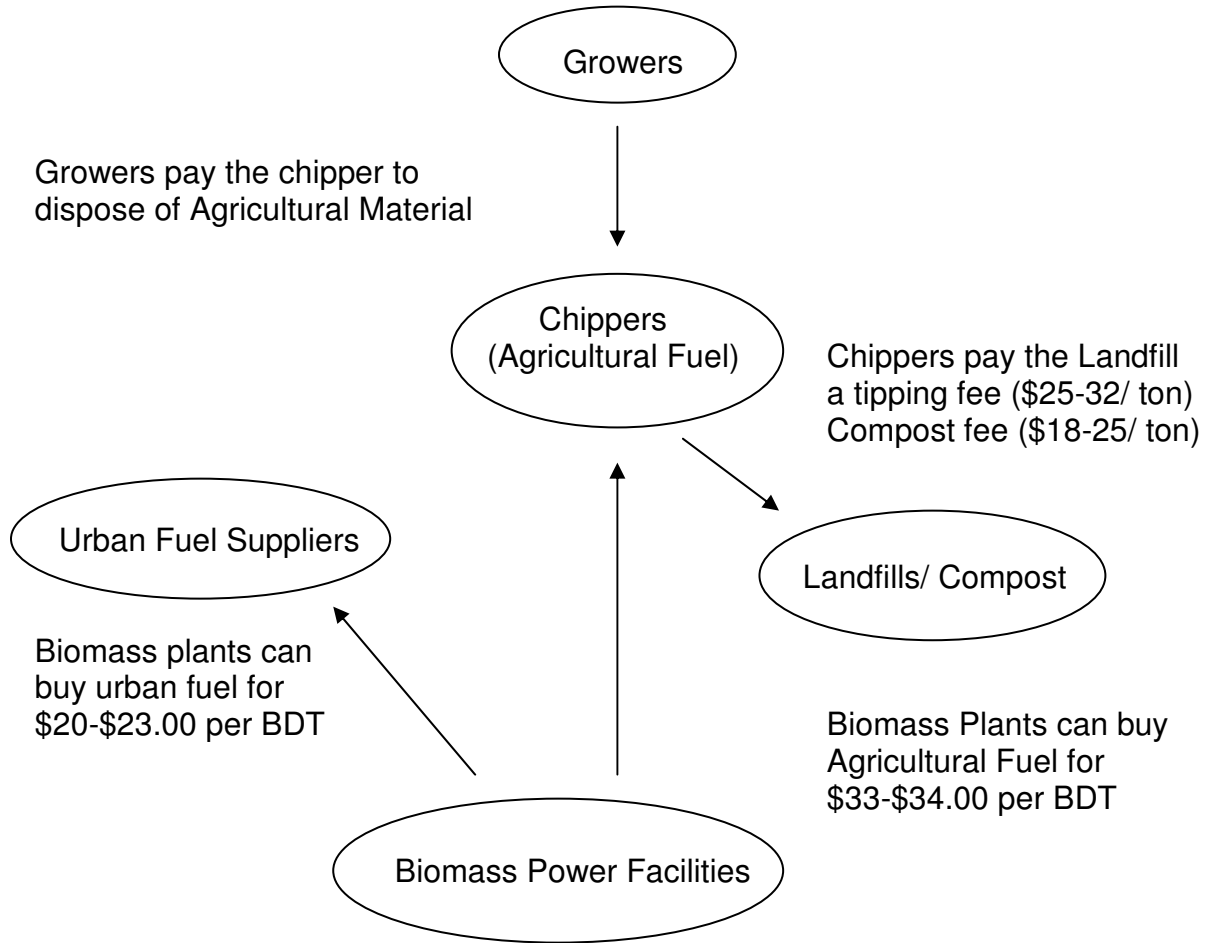
7.1.5 Economics – Agricultural Fuel vs. Urban Fuel

In the SJVAB, several biomass power plants are required to burn agricultural material in order to offset emissions under permit with the District. Before this permit requirement, biomass power plants received agricultural material to burn for free. Today, however, selling agricultural material to biomass plants is a source of revenue for chipping operators.

A grower that needs to remove agricultural material off-site will hire a chipping operator. In the SJVAB, the chipping companies typically propose an initial contract with growers to chip their orchard removal material. The contract is written prior to the job and establishes a tentative agreement, which includes an estimated cost for the removal, chipping and transportation of the material to a biomass power plant. The contract usually includes a line item that states the terms of the contract based on when a local biomass power plant accepts the chipped material. A grower's final cost of chipping orchard removals can vary due to the presiding condition of each contract that all material is accepted and paid for by a biomass power plant. If the biomass power plant rejects the chipped materials, then the chipping company would likely return the materials back to the grower.

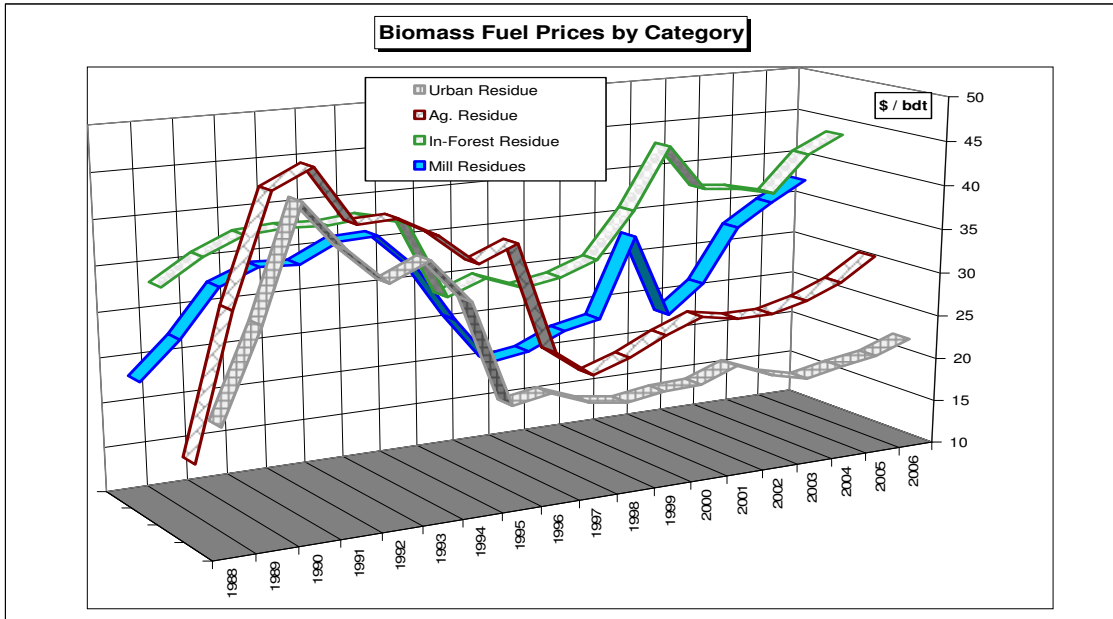
If the agricultural material is sent to a landfill, the chipper must pay a tipping fee of about \$25.00 to \$32.00 per ton to the operator. If sent to a compost facility, the cost is less for the chipper, ranging from \$18.00 to \$25.00 per ton for the tipping fee. However, if sent to a biomass power plant, the biomass operators pay the chipper around \$34.00 per BDT. Considering the availability of agricultural, forestry, and urban residues, it is relatively more affordable to accept urban residues at the biomass power plants. The Figure 7-2, diagrams the movement of money through a SJVAB biomass market.

Figure 7-2 Current Biomass Fuel Market: Movement of Money



Within the biomass fuel market, there is a considerable price difference between the cost of urban fuels and agricultural fuels. Data throughout the state shows an average price difference of about \$12 per BDT of fuel between urban fuel and agricultural fuel. Figure 7-3 diagrams the price difference between biomass fuel markets, showing a consistent gap between agricultural fuel and urban fuel.

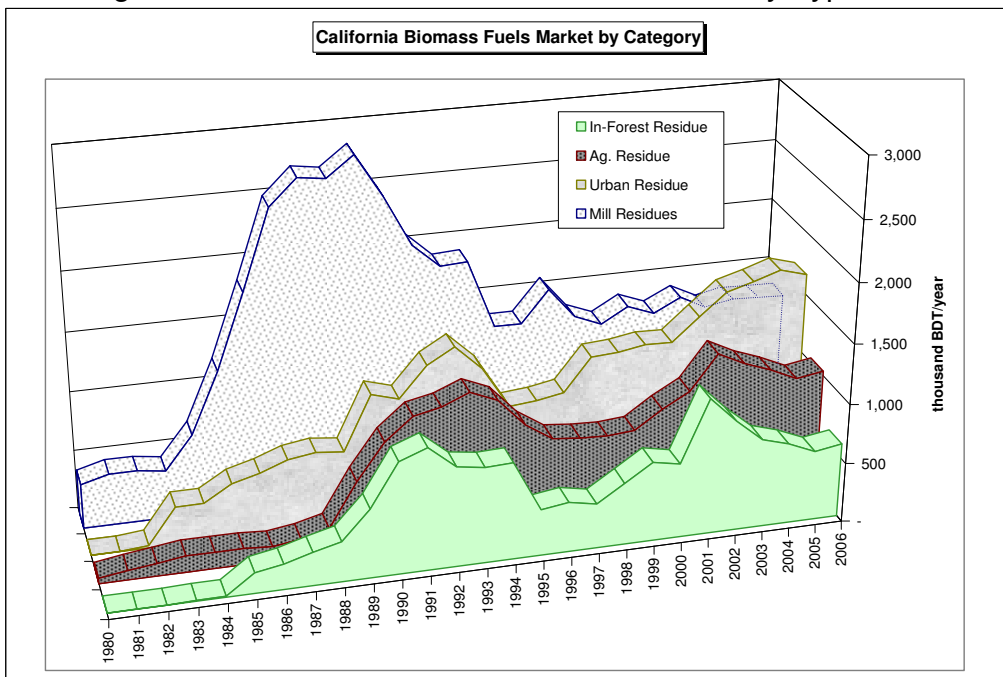
Figure 7-3 Biomass Fuel Prices by Category



Morris, G., *Biomass Energy Production in California 2006: Update of the California Biomass Database*, report of the Green Power Institute, December 2006.

While prices may vary, the price difference between agricultural fuel and urban fuel of the SJVAB has maintained consistent as illustrated by the Figure 7-4.

Figure 7-4 California Biomass Fuels Market by Type of Fuel

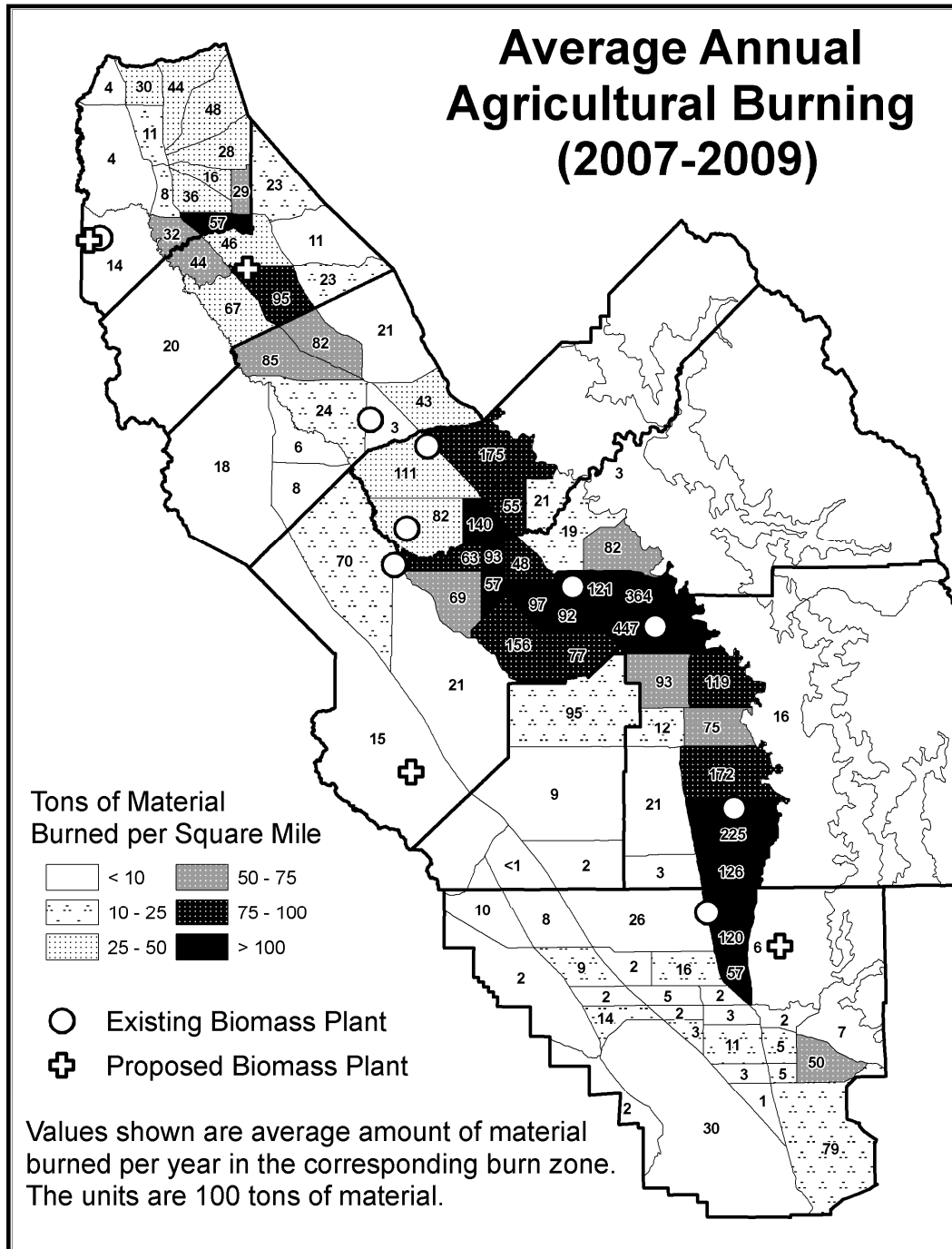


Morris, G., *Biomass Energy Production in California 2006: Update of the California Biomass Database*, report of the Green Power Institute, December 2006.

7.2 OUTLOOK

7.2.1 How Much More Agricultural Material Do We Anticipate?

Figure 7-5 Map of Annual Agricultural Burn Tons in the San Joaquin Valley Air Basin



Current analysis indicates that of the crops that may possibly be prohibited from further open burning activities, three of those crops would most likely be sent to biomass facilities as an alternative to open burning. The three crops include fig orchard removal, <20 acre orchard removal reduced to <15 acre orchard removal, and citrus orchard removal. Based on this information, District staff analyzed the current burn tons of material for each crop type and activity to determine how much more agricultural material would be generated and sent to the biomass plants as a result of prohibition of open burning.

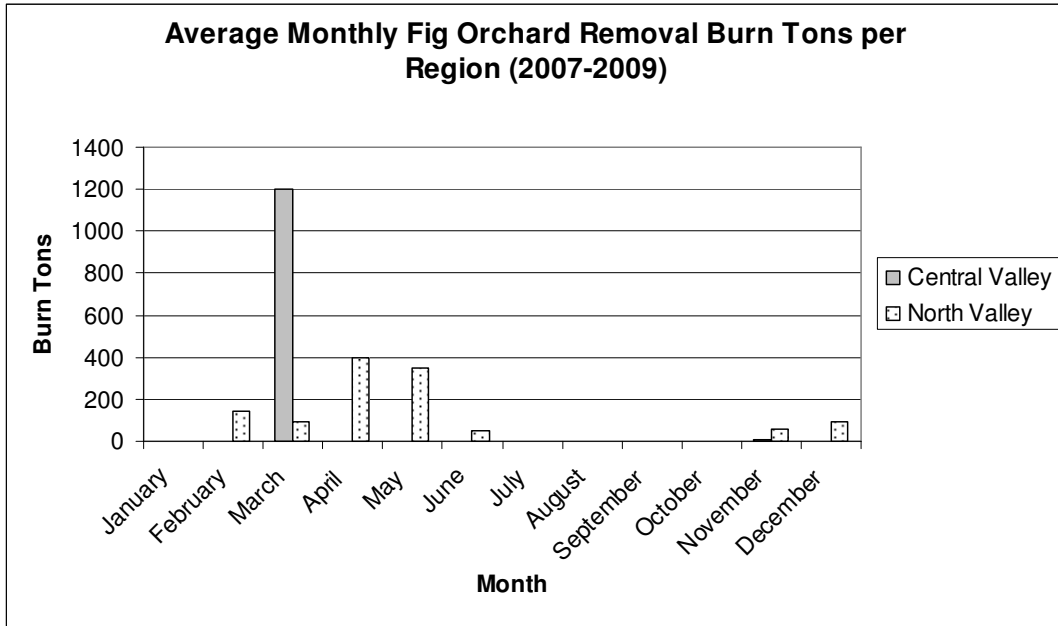
For purposes of this analysis, staff reviewed a three-year history of each crop and activities with those crops using the best available information from the District Smoke Management System (SMS). The reviewed information included the acreage and tonnage of material open burned. Staff averaged the three-year data to create an outlook as to crop and burn activities. Staff assumes the three-year average to be indicative of future activities.

Fig Orchard Removal

Staff is recommending that fig orchard removals would be prohibited from open burning acreage greater than 15 acres. Staff assumes that the total annual tonnage of material previously burned at amounts greater than 15 acres will be sent to biomass facilities as fuel.

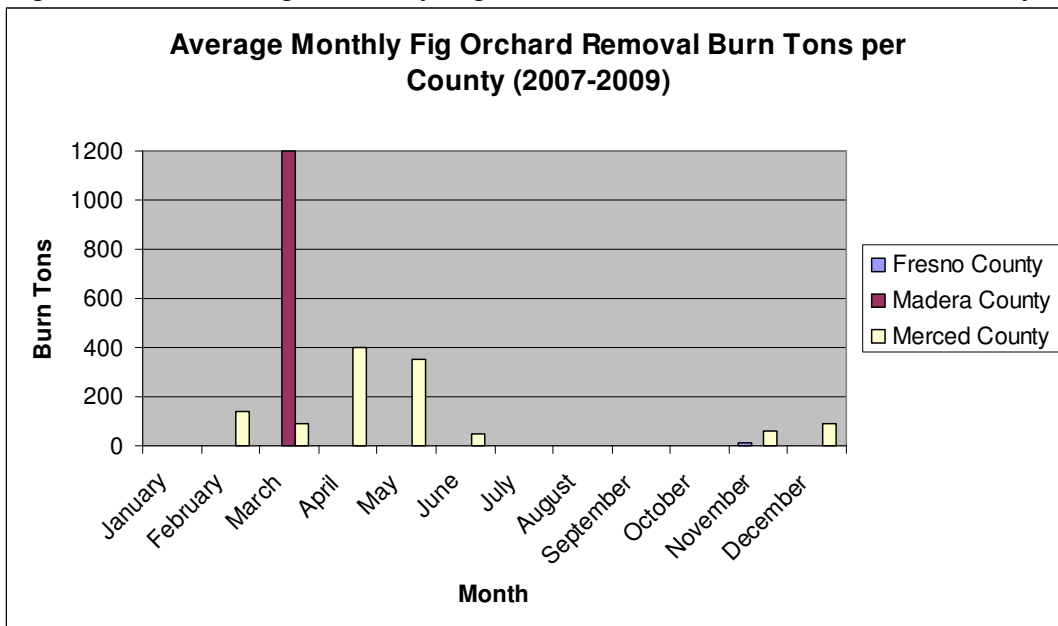
The trend for the burning of fig orchard removal material appears to be from November through June in the North SJVAB and November through March in the Central SJVAB. There is no data indicating fig orchard removal burning in the South SJVAB for the three years averaged for this analysis. The Central SJVAB region peaked for fig orchard removal tons burned in the month of March at 1,200 tons of material burned, with ten tons burned in October. The North SJVAB peaked for fig orchard removal tons burned in April at 400 tons of material burned. Little to no burning of fig orchard removal material occurs in the late summer months and early fall months of July through October. Figure 7-6 is an illustration of the average monthly fig orchard removal burn tons in the SJVAB, distributed by region, for the years of 2007 through 2009.

Figure 7-6 Monthly Fig Orchard Removal Burn Distribution



To further analyze the quantity and location of fig orchard removal material burned the chart below illustrates the monthly average fig orchard removal material burn tons by county (2007-2009). As seen in the chart below, Madera County has the highest average quantity of burn tons of fig orchard removal materials at 1,200 tons for the month of January.

Figure 7-7 Average Monthly Fig Orchard Removal Burn Distribution by County

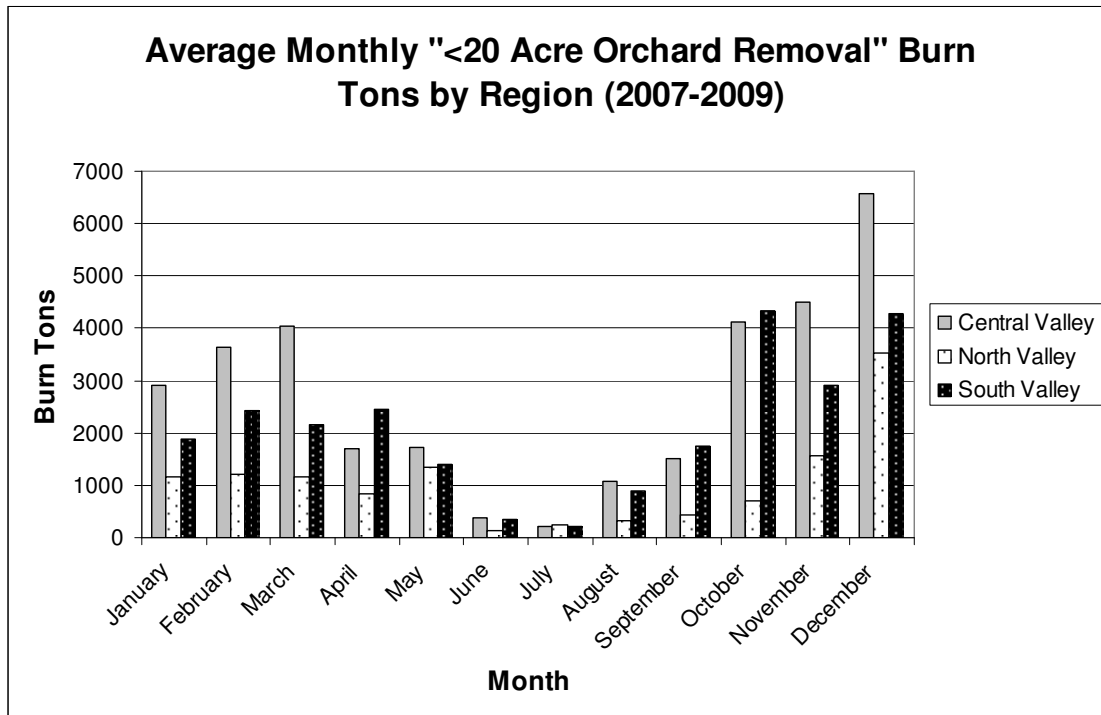


For purposes of this analysis, staff assumes the fig orchard removal acreage that was burned that were greater than 15 acres in size would no longer burn, but would find an alternative method of disposal of the material. Staff added each individual approved burn of fig orchard removal from the three years (2007-2009) to determine the average number of burns greater than 15 acres. Of the average 80 burn acres, 61 acres would no longer be allowed to burn. Converting acres to tons, translates into 1,830 tons of fig orchard removal material that would be forwarded to the biomass plants per year for the entire SJVAB.

<20 Acre Orchard Removal

Staff analyzed the average monthly burning of <20 acre orchard removals to illustrate a comprehensive look at this crop category. The burning trends were calculated using a three-year average of the best available information from the District SMS. The trend for the burning of <20 acre orchard removal appears to occur throughout the year, through out the SJVAB with peak times ranging from October to May. The Central SJVAB region peaks for <20 acre orchard removal burning in the month of December at 6,582 tons of material burned. The South SJVAB region peaks for <20 acre orchard removal burning in the month of October at 4,331 tons of material burned. While the North SJVAB peaks in December 3,531 tons of material burned. Figure 7-8 illustrates the average monthly <20 acre orchard removal burn ton distribution by region of the SJVAB.

Figure 7-8 Average <20 Acre Orchard Removal Burn Distribution



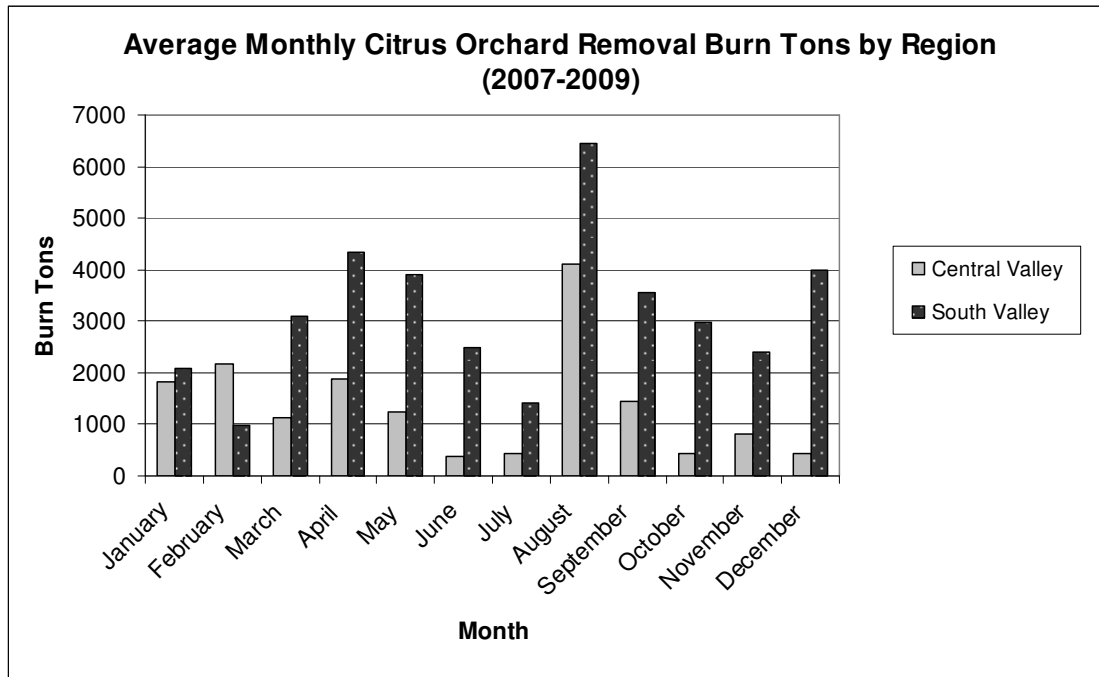
Current analysis indicates that it would be feasible to reduce burning of orchard removals from <20 acres to <15 acres. Staff determined the increase in agricultural material sent to the biomass plants by first calculating the amount of crop burns that occurred in sizes ranging from 15 acres to 20 acres. Staff did this by reviewing the SMS database for approved burn sizes and quantities for a three year average from 2007-2009.

For purposes of this analysis, staff assumes the crops that were burned that were greater than 15 acres in size would continue to burn in the future, but at 15 acres. Staff subtracted the 15 acres from each approved burn greater than 15 acres to determine the quantity of acres that would no longer be approved for burning. For example, a burn that in the past would have been for 50 acres would be allowed to burn 15 acres in the future, leaving a difference of 35 acres that would no longer be allowed to burn and would be sent to the biomass power plants as fuel. Staff applied this methodology to each burn over 15 acres during the three years (2007-2009) to determine the average. Of the average 2,334 burn acres, 254 acres would no longer be allowed to burn. Converting acres to tons, translates into 7,620 tons of orchard removal material that would be forwarded to the biomass plants per year for the entire SJVAB.

Citrus Orchard Removal

Staff analyzed the average monthly burning of citrus orchard removals to illustrate a comprehensive look at this crop category. The burning trends were calculated using a three-year average of the best available information from the District SMS. The trend for the burning of citrus orchard removal appears to occur throughout the year, through out the Central and South SJVAB. The Central SJVAB region appears to peak for citrus orchard removal burning in the month of August at 4,120 tons of material burned. The South SJVAB region appears to peak for citrus orchard removal burning also in the month of August at 6,442 tons of material burned. Data indicates that there was no burning of citrus orchard removal materials in the North SJVAB during the three years that were averaged for this analysis. Figure 7-9 illustrates the average monthly citrus orchard removal burn distribution through the SJVAB by region.

Figure 7-9 Average Monthly Citrus Orchard Removal Burn Distribution



7.2.2 Could the Current Biomass Power Plants Physically Handle the Increase in Materials?

The 2010 and future capacity of biomass fuel rate, from nine biomass power plants located in the SJVAB, is estimated to be between 1,409,360 and 1,909,141 bone dry tons (BDT's) per year¹. These estimates were calculated using the following assumptions:

1. Size of each boiler unit, in MMBtu/hr, is based on the district permitted solid fuel-fired boiler units subject to Rule 4352.
2. The lower bound capacity is calculated using Biomass heat content value of 0.008805 MMBtu/lbm Higher Heating Value (HHV). The value is based on ultimate analysis from 1999 source testing (page 47 in a technical support document submitted with project S-1010053). Using the 1999 ultimate analysis, nitrogen was lower, heat content value of the fuel was higher. This results in considerably less fuel consumed with a higher yield of airflow.

¹ It should be noted that the CBEA estimates that the capacity of the biomass power plants (including those plants just outside the Valley) is estimated to be 945,000 BDT to 1,000,000 BDT with an average availability ranging from 80% to 85%. Since the CBEA's estimates are less than the District's estimate, the District will utilize the District estimates as the more conservative values.

- The heat content value of 0.0065 MMBtu/lbm (HHV) is used to estimate the upper bound fuel rate capacity. The value is based on heat content values reported in the Phyllis database, the United States Department of Energy, Energy Efficiency and Renewable Energy (DOE/EERE) feedstock database, and selected literature sources.

District staff acknowledges that the use of difference heat content values will result in differences, particularly when fuel rate capacity is calculated. The following table illustrates the calculations used to determine the lower and upper bound capacities of the facilities based.

Table 7-7 Illustration of Calculations Used to Determine Annual Boiler BDT Capacity

Facility ID	Power Production	Permitted Output Capacity	Lower Bound				Upper Bound			
			0.008805 ¹	0.0005	24	365	0.0065 ²	0.0005	24	365
	(MW)	(MMBtu/hr)	(lb/hr)	(ton/hr)	(ton/day)	(ton/year)	(lb/hr)	(ton/hr)	(ton/day)	(ton/year)
A	12.5	185	21,011	11	252	92,027	28,462	14	342	124,662
B	30	317	36,002	18	432	157,690	48,769	24	585	213,609
C	56.5	715	81,204	41	974	355,673	110,000	55	1,320	481,800
D	11.5	189	21,465	11	258	94,017	29,077	15	349	127,357
E	28.5	460	52,243	26	627	228,825	70,769	35	849	309,969
F	13	185	21,011	11	252	92,027	28,462	14	342	124,662
G	28.5	352	39,977	20	480	175,101	54,154	27	650	237,194
H	9.4	171.2	19,443	10	233	85,163	26,338	13	316	115,362
I	20.5	259	29,415	15	353	128,838	39,846	20	478	174,526

Total: 1,409,360

Total: 1,909,141

1. The value was based on ultimate analysis from 1999 source testing. Using the 1999 ultimate analysis, nitrogen was lower, heating value of the fuel was higher. This results in considerably less fuel being consumed with a higher yield of air flow.

2. The value is based on 6500 Btu/lb in the past project for biomass facility C.

For purposes of determining if the biomass power plants have the capacity to accept the additional agricultural materials that would be generated by the prohibition of open burning of specific crops, District staff analyzed the agricultural material increase by region of the SJVAB rather than by county. To analyze if the biomass power plants have the capacity to accept the additional agricultural material, staff made the following assumptions:

- The average monthly burn tons per region (2007-2009) will remain constant in future years.
- The biomass facilities would burn 100% of agricultural materials received each month.

Data presented in Table 7-7 indicates that the biomass power plants in the Central SJVAB have a combined capacity ranging from 653,643 BDT/yr to 885,439 BDT/yr. Historical data shows that these facilities have been operating at 590,401 BDT/yr. If the Central SJVAB biomass plants increase use of the boilers up to the potential capacity, as presented in Table 7-7, they could increase biomass fuel consumption by up to 295,038 BDT/yr. Divided into monthly increments, the biomass plants have the ability to increase fuel consumption by up to 24,586 BDT per month. Another option for biomass power plants would be to increase the percentage of agricultural materials accepted and burned instead of increasing overall consumption and energy production.

Data presented in Table 7-7 indicates that the biomass power plants in the North SJVAB have a combined capacity ranging from 220,865 BDT/yr to 299,188 BDT/yr. Historical data shows that these facilities have been operating at 287,040 BDT/yr. If the North SJVAB biomass plants increase use of the boilers up to the potential capacity they could increase biomass fuel consumption by up to 12,148 BDT/yr. Divided into monthly increments, the biomass plants have the ability to increase fuel consumption by 1,012 BDT per month. Another option for biomass power plants would be to increase the percentage of agricultural materials accepted and burned instead of increasing overall consumption and energy production.

Data presented in Table 7-7 indicates that the biomass power plants in the South SJVAB have a combined capacity ranging from 534,853 BDT/yr to 724,519 BDT/yr. Historical data shows that these facilities have been operating at 639,055 BDT/yr. If the South SJVAB biomass plants increase use of the boilers up to the potential capacity they could increase biomass fuel consumption by up to 85,464 BDT/yr. Divided into monthly increments, the biomass plants have the ability to increase fuel consumption by 7,122 BDT per month. Another option for biomass power plants would be to increase the percentage of agricultural materials accepted and burned instead of increasing overall consumption and energy production.

Fig Orchard Removal

Decreasing allowed open burning of fig orchard removal materials to <15 acres would generate an increase of 1,830 tons of agricultural material throughout the SJVAB to the biomass plants per year. The following analysis was performed assuming the 1,830 tons of agricultural material from fig orchard removal would be forwarded to the biomass power plants. Because there are no historical burns in the South SJVAB for this crop category staff assumes the additional tonnage would be sent to biomass power plants in the Central and North SJVAB.

Analysis, as illustrated in Figure 7-6, indicates that 51% of the fig orchard removal burn tons occur in the Central SJVAB. Staff assumes the burn acreage from this crop category above 15 acres is distributed throughout the SJVAB

parallel to the total acreage from this crop category. Therefore, staff applied the 51% to the 1,830 tons of material to determine the increase of agricultural material forwarded to the biomass plants (1,830 BDT x 0.51).

Staff estimate by reducing allowed burns of fig orchard removals to <15 acres results in an increase of 933 tons of material to be forwarded to the biomass plants in the Central SJVAB per year. Therefore, staff believes the biomass facilities have the capacity to accept the additional agricultural biomass fuel generated by decreasing the allowed open burning of fig orchard removal materials to <15 acres in the Central SJVAB.

Analysis, as illustrated in Figure 7-6, indicates that 49% of the fig orchard removal burn tons occur in the North SJVAB. Staff assumes the burn acreage from this crop category above 15 acres is distributed throughout the SJVAB parallel to the total acreage from this crop category. Therefore, staff applied the 49% to the 1,830 tons of material to determine the increase of agricultural material forwarded to the biomass plants (1830 BDT x 0.49).

Staff estimate by reducing allowed burns of fig orchard removals to <15 acres results in an increase of 897 tons of material to be forwarded to the biomass plants in the North SJVAB per year. Therefore, staff believes the biomass facilities have the capacity to accept the additional agricultural biomass fuel generated by decreasing the allowed open burning of fig orchard removal materials to <15 acres in the SJVAB.

Less Than 20 Acre Orchard Removal

Decreasing allowed open burning of orchard removals from <20 acres to <15 acres would generate an increase of 7,620 tons of agricultural material throughout the SJVAB to the biomass plants per year.

Analysis indicate that 46% of the <20 acre orchard removal burn tons occur in the Central SJVAB. Staff assumes the burn acreage from this crop category above 15 acres is distributed throughout the SJVAB parallel to the total acreage from this crop category. Therefore, staff applied the 46% to the 7,620 tons of material to determine the increase of agricultural material forwarded to the biomass plants. Staff estimate by reducing allowed burns of orchard removals from <20 acres to <15 acres results in an increase of 3,505 tons of material to be forwarded to the biomass plants in the Central SJVAB per year.

Analysis indicate that 18% of the <20 acre orchard removal burn tons occur in the North SJVAB. Staff assumes the burn acreage from this crop category above 15 acres is distributed throughout the SJVAB parallel to the total acreage from this crop category. Therefore, staff applied the 18% to the 7,620 tons of material to determine the increase of agricultural material forwarded to the biomass plants. Staff estimate by reducing allowed burns of orchard removals

from <20 acres to <15 acres results in an increase of 1,371 tons of material to be forwarded to the biomass plants in the North SJVAB per year.

Analysis indicate that 36% of the <20 acre orchard removal burn tons occur in the South SJVAB. Staff assumes the burn acreage from this crop category above 15 acres is distributed throughout the SJVAB parallel to the total acreage from this crop category. Therefore, staff applied the 36% to the 7,620 tons of material to determine the increase of agricultural material forwarded to the biomass plants. Staff estimate by reducing allowed burns of orchard removals from <20 acres to <15 acres results in an increase of 2,744 tons of material to be forwarded to the biomass plants in the South SJVAB per year.

Based on the analysis presented above staff believes the biomass power plants have the capacity to accept the additional tonnage of agricultural material generated by the reduction of allowed burns of orchard removal materials from <20 acres to <15 acres in all three regions of the SJVAB.

Citrus Orchard Removal

Assuming the total citrus orchard removal burn tons would be forwarded to the biomass power plants rather than be burned, this would cause an increase of citrus orchard material to the biomass power plants of more than 54,000 tons per year. More specifically, in the peak citrus orchard removal burn month of August, the quantity of agricultural material forwarded to the biomass power plants would increase by up to 4,120 tons in the Central SJVAB and by 6,442 tons in the South SJVAB. This would be an increase that is above and beyond what the power plants are currently accepting.

It is important to note citrus is a unique crop that faces unique challenges regarding biomass consumption. Biomass facilities consider citrus material to be the least desirable of all fuel types. Due to the stringy nature of the material, biomass power plants do not burn citrus material by itself. Rather, they blend it with other biomass fuels. Citrus material is blended with other biomass fuels in ratios up to 25%.

Additionally, comments from the California Citrus Mutual stated that not all biomass facilities accept citrus materials. Staff reviewed quarterly reports submitted to the District by the biomass plants, and could only confirm definitively that two of the nine biomass plants in the SJVAB accepted citrus wood products in the past five years. The California Citrus Mutual comments, mentioned a third biomass facility that accepts citrus wood material. Based on this information, staff can verify that three biomass facilities accept and use citrus material as biomass fuel. One facility is located in each region of the SJVAB. However, CBEA has indicated that all 12 biomass power plants have very broad acceptance policies for wood fuel, which include citrus orchard and vineyard removals.

Based on best available data at the time, staff has analyzed the capacity of the facility in the South SJVAB that staff can definitively verify accepts citrus material. In order to analyze a worst case scenario, this analysis is specific to the month of August, which is the peak burn month for citrus orchard removal materials. The facility in the South SJVAB is known to blend up to 30% of citrus material into its fuel blend. This is the only facility in the SJVAB to blend at this high a level. This facility has advertised on its website that it has a rated capacity of 1,293 tpd of biomass fuel. The five-year historical data indicates that the boilers at this facility are operational on an average of approximately 25 days per month of the third quarter of each year. District staff assumes the average of the historical data is indicative of future activities. Therefore, staff assumes this facility is operational 25 days for the month of August giving it a biomass fuel capacity of 32,325 tons.

For purposes of this analysis, staff conservatively estimated that the plant will use a fuel blend with 15% citrus material during all hours of operation and will accept the corresponding amount of citrus material for storage, since a fuel blend using 30% of citrus material could vary by amount and availability of the material. Using the previously stated assumptions, staff estimates the biomass plant could use 4,848 tons of citrus material in the month of August. The five-year historical data indicates that this facility accepts an average of 24,265 tons of non-almond agricultural orchard material each August. Assuming 15% of that orchard material is citrus orchard material, staff would assume this plant is currently accepting 3,637 tons of citrus material each August. As previously stated, each August the South SJVAB biomass plant would see an increase of 6,442 tons of citrus orchard removal material in addition to what is currently being accepted.

Using the data above for the following analysis. Each August, the plant has a capacity of 4,848 tons of citrus material, and is currently accepting about 3,637 tons of citrus material resulting in an available capacity of 1,211 tons of additional citrus material. Meaning, there would be a surplus of 5,231 tons of citrus material in the South SJVAB if citrus orchard removal burning is prohibited.

According to CBEA, this biomass power plant currently has the capacity to accept approximately 130,000 BDT of citrus annually, but only took in 34,000 BDT for the year of 2009. CBEA also stated that biomass plants are seeking additional agricultural material at this time. The accepted 34,000 tons of citrus material for 2009 supports the staff analysis that the plant is accepting about 3,637 tons of citrus material each August. CBEA has also indicated that citrus handling and grinding practices have changed resulting in a wood product that may be used in higher percentages than in past years. For example, Covanta Delano alone may now burn up to 100,000 Bone Dry Tons (BDT's) of this fuel in any one year. Rio Bravo Fresno and Covanta Mendota are capable of burning up to 40,000 BDTs and 20,000 BDTs of citrus annually, respectively. It is important to note, however, that all these facilities received considerably less than 10,000 BDTs of citrus in 2009. All of the facilities continue to fall short of their goals for

more citrus orchard waste, where a number of plants continue to be extremely short of wood fuel and are currently curtailed or operating at reduced loads. The Biomass plants are in need of more fuel at this time. The District looks forward to working with the biomass industry to achieve long-term commitments toward the extensive use of agricultural biomass.

7.2.3 Policies for Renewable Energy

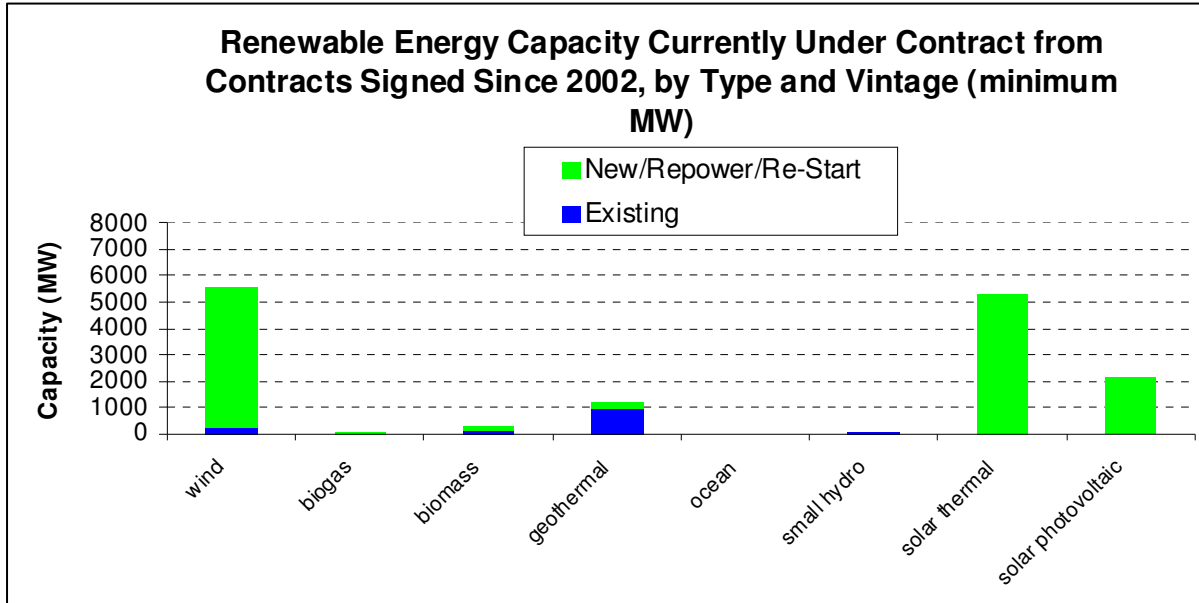
The California Renewable Portfolio Standard (RPS) program was established by Senate Bill 1078, effective January 1, 2003. It requires that a retail seller of electricity such as Pacific Gas and Electric (PG&E) purchase a certain percentage of electricity generated by Eligible Renewable Energy Resources (ERR). Each utility is required to increase its total procurement of ERRs by at least 1% of annual retail sales per year so that 20 percent of its retail sales are supplied by ERRs by 2017.

The State's Energy Action Plan (EAP) called for acceleration of this RPS goal to reach 20 percent by 2010. This was reiterated again in the Order Instituting Rulemaking (R.04-04-026) issued on April 28, 2004, which encouraged the utilities to procure cost-effective renewable generation in excess of their RPS annual procurement targets (APTs), in order to make progress towards the goal expressed in the EAP. On September 26, 2006, Governor Schwarzenegger signed SB 107, which officially accelerates the State's RPS targets to 20 percent by 2010. The bill took effect on January 1, 2007.

According to CBEA, there are current developments in increasing the requirement to 33%. The Governor's Executive Order S-21-09, September 2009, directs the ARB, under its AB 32 authority, to adopt a regulation consistent with the 33 percent renewable energy target established in Executive Order S-14-08 by July 31, 2010. The Legislature is also actively pursuing its own 33% RPS policy with SB 722 (Simitian). There is a high likelihood that one of these two policy making bodies will have enacted a 33% RPS standard into law by the end of this year.

ERRs include such sources as wind power, biogas, biomass, geothermal, ocean, small hydro, solar thermal, and solar photovoltaic. Charts on the CPUC website indicate that biomass is one of the smallest contributors of ERR utilized by electric companies to meet the RPS standards.

Figure 7-10 Renewable Energy Capacity Currently Under Contract



CPUC.ca.gov. Renewable Energy Capacity Currently Under Contract from Contracts Signed Since 2002, by Type and Vintage.

District staff explored the specific PPA contracts that PG&E currently has to determine the distribution of ERRs in the SJVAB. Biomass power plants make up approximately 2% of PG&E’s RPS portfolio. The ERRs contracted with PG&E as a larger portion of the RPS portfolio include solar thermal power (38%), solar photovoltaic power (23%), and wind power (26%).

According to CBEA, Biomass actually represents 30% of PG&E RPS existing RPS procurement portfolio, more than any other utility in the State.

7.2.4 Contracts with Utilities

District’s staff’s analysis below was based on the nine biomass facilities in the SJVAB and did not account for the three facilities located outside of the SJVAB at the time. Of those nine facilities, seven have contracts with investor owned utility (IOU) companies. District staff surveyed the California Public Utilities Commission (CPUC) website and found the following facilities have approved projects online as a part of the RPS program. Power Purchase Agreement (PPA) Contracts that were scheduled to terminate, per contract agreement have been extended through additional terms with the utility companies. At the time of this report, staff was unable to confirm if the Delano contract has also been extended to more terms.

Table 7-8 Approved Operational Projects for Contracts

Projects Approved and Online	Investor Owned Utility	Min Expected GWh/yr	Contract Term (years)	Term Number	Online Date/ Contracted Delivery Date
AES Delano	SDG&E	386	5	unknown	1/1/2003
Madera Power	PG&E	160	5	2	7/9/2009
Dinuba Energy	PG&E	90	5	3	7/9/2009
Sierra Power Corp.	PG&E	75	5	3	7/9/2009
AES Delano	SDG&E	365	10	1	1/1/2008
Global Common's Chowchilla	PG&E	72	15	1	12/12/2008
Global Common's El Nido	PG&E	72	15	1	2/21/2009

The table above indicates that at least six biomass power plants have PPA contracts with IOUs for up to fourteen years in the future. Historical data indicates that PG&E will continue to extend its five-year PPAs with Dinuba Energy and Sierra Power Corp, for as long as the RPS requires renewable energy to be a part of its portfolio.

Staff reviewed the CPUC web page regarding renewable energy capacity currently under contract for Pacific Gas and Electric. Based on information presented there it appears to staff that biomass fuel makes up a mere 2% of the total capacity of renewable energy capacity currently under contract. Staff chose to review PG&E's information because they are the primary utility company purchasing power from the SJVAB's biomass power plants, as presented in Table 7-8 above. Other technologies PG&E have under contract for renewable energy include wind, biogas, geothermal, small hydro, solar thermal and solar photovoltaic.

Table 7-9 shows additional information from CBEA for the 12 biomass power plants that use agricultural material in the SJVAB for fuel. According to CBEA, the 12 member biomass power plants generates over 240 MW of renewable capacity and are all under contract with California's investor owned utilities.

Table 7-9 Biomass Power Plants and Contracts

Facility Name	Region Served	Contracting Utility	Contract Length	Online Date
Rio Bravo Fresno	Central SJVAB	PG&E	30	7/15/88
Covanta Mendoza	Central SJVAB	PG&E	25	1/1/90
Community Recycling Madera Power	Central SJVAB	PG&E	10	6/1/01
Ampersand Chowchilla	Central SJVAB	PG&E	15	12/12/08
Covanta Delano	South SJVAB		10	1/1/08
Community Recycling Dinuba Energy	South SJVAB	PG&E	11	7/1/03
Sierra Power	South SJVAB	PG&E	15	2001
Ampersand Merced Power	North SJVAB	PG&E	15	12/12/08
Thermal Energy Tracy Power	North SJVAB	PG&E	30	3/31/90
SPI Sonora	North Valley	Merchant	n/a	1999
Covanta Chinese Station	North Valley	PG&E	30	1/31/87
SPI Lincoln	North Valley	PG&E	30	1985

Source: CBEA

7.2.5 Legislative Platform

On January 21, 2010, the District Governing Board adopted the Districts 2010 Legislative Platform. On that Legislative Platform are two 2010 Legislative Priorities that will affect biomass facilities. These legislative priorities will provide policy guidance for legislative action and recognize the unique needs of the District during the upcoming legislative session. The District supports legislation that will encourage, promote, and facilitate alternative uses for agricultural material.

7.2.5.1 Cost-Effective Alternatives to Agricultural Burning

The District has been phasing out agricultural burning based upon the schedule outlined in the CH&SC. State law specifies that if there are no economically feasible alternatives to burning, the burning can continue. In implementing the latest phase of the CH&SC, District staff has analyzed the amount of agricultural material that are currently and has been historically accepted by the biomass power plants and other related information.

District staff released a Draft Feasibility Study on Biomass Incentives in December 2008. In that study, District staff analyzed past incentive programs and determined that the programs appeared to be cost-effective; however, there was no long-term incentive funding available to support this conclusion.

7.2.5.2 Energy

The District has identified energy efficiency and renewable energy as part of its effort to attain air quality standards as expeditiously as possible. When utilized properly, biomass to generate energy is a viable alternative to open burning of these materials. The District supports policies and initiatives that encourage renewable energy and energy efficiency including supporting legislation that provides additional biomass capacity utilizing agricultural materials.

7.2.6 New Facilities

There are currently four biomass facilities undergoing the permitting process through the District. These biomass facilities are mentioned in this report for purposes of completeness of the report. The four potential facilities are spread throughout the SJVAB as illustrated in the maps presented in Section 3.1 and again in Sections 7.1 and 7.2. Conversations with an operator from one of the potential biomass facilities in the North SJVAB revealed that the facility has no intention to accept agricultural materials from orchard removals or prunings.

According to CBEA, there are additional Greenfield or new biomass plants under development, which includes San Joaquin Solar/Thermal Biomass, Modesto Bioenergy, and Buena Vista Biomass Power. These plants could require an additional 800,000 to 1,000,000 BDTs of wood fuel resources within a two to five year development timeframe.

The California Biomass Energy Alliance (CBEA) also brought to the attention of District staff that there are several existing coal fired plants in the District that are undergoing conversions to co-fire up to 50% or convert to 100%. CBEA indicated that the three plants are Millenium Mt. Poso, Stockton AP Cogen, and POSDEF. Staff researched the District database and confirmed that the Air Products plant has applied for an ATC to install and operate an ag derived biomass fuel handling system with a max amount of biomass to be received of 300 tons per day. According to CBEA, most of the fuel used in the three facilities mentioned above will be agricultural waste from the SJVAB.

At this time, staff will not include these facilities as an alternative option to open burning of agricultural materials. Future reports will reexamine if the new facilities will be a viable alternative to open burning and if they will increase the overall biomass capacities for agricultural fuel.

7.3 STATE AND FEDERAL COMMITMENTS FOR CONTINUED OPERATION

Tax credits are available to biomass power plants, and five of the nine existing plants in the SJVAB are required to have agricultural offsets. However, there are

no long-term federal or state funding commitments for the biomass facilities in the SJVAB.

District staff found that there are no long-term federal or state funding commitments for biomass power plants in place at this time. Staff was successful in identifying one short-term federal program that is currently in place, one short-term state-funding program that is currently in place, and one short-term program that is expired.

7.3.1 Renewable Electricity Production Tax Credit

The short-term federal program is called the Renewable Electricity Production Tax Credit (PTC). The PTC is a federal corporate tax credit that provides a per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The PTC offers the tax credit for short periods and the in-service deadline to qualify for the tax credit is set to expire on December 31, 2013.

The applicable sectors for the PTC tax credit are commercial and industrial using technologies such as wind, biomass, hydroelectric, geothermal electric, municipal solid waste, and hydrokinetic power among others. The tax credit amount is 2.1¢ for wind, geothermal, closed loop biomass, and 1.1¢/kWh for other eligible technologies. However, this tax credit is only available to a facility for the first ten years of operation.

Originally enacted in 1992 by the Energy Policy Act of 1992, the PTC has been renewed and expanded numerous times, the most recent amendments being in February 2009. The tax credit amount is 1.5¢/kWh in 1993 dollars (indexed for inflation) for some technologies and half that amount for others. The rules governing the PTC vary by resource and by facility type. In addition, the tax credit is reduced for projects that receive other federal tax credits, grants, tax-exempt financing, or subsidized energy financing. Table 7-10 outlines two of the most important characteristics of the tax credit: the in-service deadline and the credit amount as they apply to each type of biomass facility.

Table 7-10 In-Service Deadline and Credit Amount for PTC

Resource Type	In-Service Deadline	Credit Amount
Closed-Loop Biomass	December 31, 2013	2.1¢/kWh
Open-Loop Biomass	December 31, 2013	1.1¢/kWh

The duration of the credit is generally, ten years after the date the facility begins service, however, there are two exceptions. (1) Open-loop biomass, geothermal, small irrigation hydro, landfill gas and municipal solid waste combustion facilities placed into service after October 22, 2004, and before enactment of the Energy

Policy Act of 2005, on August 8, 2005, are only eligible for the credit for a five-year period. (2) Open-loop biomass facilities placed in service before October 22, 2004, are eligible for a five-year period beginning January 1, 2005.

7.3.2 Existing Renewable Facilities Program

The Existing Renewable Facilities Program (ERFP) is a short-term state funding program. The California Energy Commission (CEC) has developed and currently administers renewable energy incentive programs, and the ERFP is one of several program elements within the renewable energy incentives program.

The ERFP was implemented to allocate state funds to increase the competitiveness of existing in-state renewable generating facilities and to help achieve the California Renewable Portfolio Standard's (RPS) goal of 20% of retail electricity generated from renewables by 2010.

ERFP eligible technologies include solid-fuel biomass, solar thermal electric, and wind power. Facilities must have commenced commercial operations as a renewable energy facility, consistent with the requirements of the federal Public Utility Regulatory Policies Act of 1978 and Section 292.204, Subdivision (b), of Title 18 of the Code of Federal Regulations, on or before September 26, 1996. For the purpose of the ERFP, self-sustainability refers to the ability of these facilities to continue operation without public funding by no later than December 31, 2011.

To qualify for ERFP funding, a facility's electrical generation must satisfy the following criteria:

- The energy must be generated after 1/1/07.
- The energy must be sold to customers within the State of California.
- The energy must not receive monthly energy payments at a price equal to or greater than the applicable target price as determined by the Energy Commission for the entire year.
- Eligible generation is net-metered generation.
- The energy must not be sold to customers of local publicly owned electric utilities.
- The energy must not receive incentive payments or funding from any other state program.

In addition, the facility must be located either within the state or near the state's border with its first point of interconnection to the transmission systems within the state. The facility must not be owned by an electrical corporation or local publicly owned electric utility and must be certified by the CEC as eligible for payment, the generation must not be sold at an energy price that is above the applicable target price, or be used on-site.

The existing renewable facilities are considered for incentives by the ERF based on individual need and market price. Facilities receive funding based on production incentives (cent(s) per kWh). A target price and incentive cap is assigned to each facility based on need. If the market price of energy of a facility drops below the target price, then the CEC will incentivize the facility for each kilowatt-hour generated up to a maximum incentive cap.

Funding tiers for facilities participating in the ERF have been created and are based on the facility's renewable energy resource type, average annual energy price or contract type, and utility power purchase contract under which the generation is sold.

Table 7-12 Existing Renewable Facilities Program Funding Tiers

	Energy Resource	Average Annual Energy Price	Investor-Owned Utility Contract
Tier 1	Solar Thermal Electric	Facilities with power purchase contracts receiving fixed or variable monthly average energy prices for a majority of their generation at 4.0 cents/kWh or less	PG&E, SCE and SDG&E
Tier 2	Biomass	Facilities with power purchase contracts receiving fixed or variable monthly average energy prices for a majority of their generation at 5.0 cents/kWh or less	PG&E and Sierra Pacific Power Company
Tier 3	Biomass	Facilities with power purchase contracts receiving fixed or variable monthly average energy prices for a majority of their generation at 5.0 cents/kWh or less.	SCE, SDG&E
Tier 4	Biomass and Solar Thermal Electric	Facilities with power purchase contracts receiving variable monthly energy payments based on the short-run avoided cost (SRAC) or facilities with contracts receiving fixed monthly average energy prices for a majority of their generation greater than 5.0 cents/kWh but less than or equal to 6.5 cents/kWh or facilities receiving all-in prices.	SCE, SDG&E
Tier 5	Biomass and Solar Thermal Electric	Facilities with power purchase contracts receiving variable monthly energy payments based on the SRAC or facilities with contracts receiving fixed monthly average energy prices for a majority of their generation greater than 5.0 cents/kWh but less than or equal to 6.8 cents/kWh or facilities receiving all-in prices.	PG&E and Sierra Pacific Power Company

The predetermined target prices and incentive caps for each tier are shown in the table below. The CEC may adjust the target prices and incentive caps, if appropriate, to reflect changing market and contractual conditions and to account for inflation.

Table 7-13 Existing Renewable Facilities Program Target Prices

	Target Price	Production Incentive Cap
Tier 1	6.2 cents/kWh	2.0 cents/kWh
Tier 2	6.5 cents/kWh	1.5 cents/kWh
Tier 3	6.2 cents/kWh	1.5 cents/kWh
Tier 4	6.2 cents/kWh	1.5 cents/kWh
Tier 5	6.5 cents/kWh	1.5 cents/kWh

The ERFPP appropriates 20% of deposited funds into the Renewable Resource Trust Fund per Senate Bill 1036. It is estimated that approximately \$75 million would be allocated to the ERFPP by the CEC for calendar years 2007 through 2011.

7.3.3 Biomass-to-Energy Incentive Grant Program

The Biomass-to-Energy (BTE) Incentive Grant Program was a state funded program in operation from 2000 to 2003 that promoted the increased use of agricultural materials. The State allocated \$6 to \$7.7 million per year to qualified biomass power plant applicants. The BTE incentive program allocated about ten-dollars (\$10) per ton for the qualified agricultural biomass purchased by biomass power plants. District staff estimated that emissions reductions achieved from this program were over 5,200 tons of emissions in FY 2000/2001 and over 6,400 tons of emissions in FY 2001/2002. District staff believes that the Biomass-to-Energy incentive program provided a cost-effective alternative method for the growers and contributed to the increased use of agricultural materials for biomass fuel.

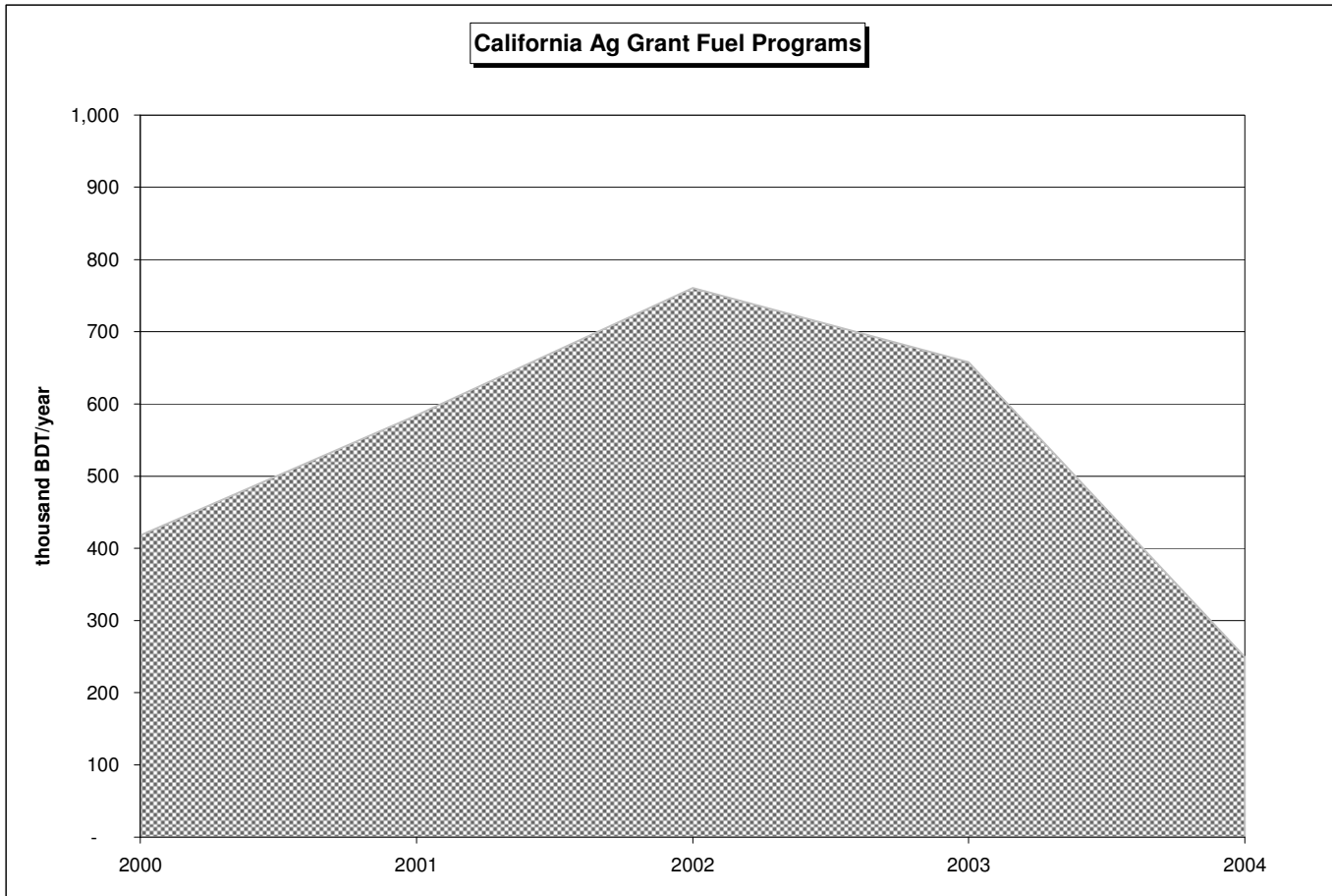
One northern SJVAB biomass power plant, while participating in the BTE incentive program, was burning 109,500 tons of agricultural material, up from around 87,000 tons of agricultural material in 1999 before the beginning of the program. As of the December of 2008, the plant has dropped back down to about 83,000 tons burned; hovering around permit offset requirements of 75-85,000 tons of agricultural material. The graph below demonstrates this shift from the end of the BTE incentive program in 2003 to 2007. At full capacity, this biomass power plant could burn up to 115,000 tons of agricultural material annually. There is a similar trend seen in a Southern SJVAB power plant that by permit is not required to offset emissions. At this facility agricultural material use went from 45,000 BDT burned in 2003 down to zero burned in 2008.

Under the BTE grant program the District saw a significant increase in the quantity of agricultural materials burned. Before the program, from 1994-1999, an average of 483,000 tons of agricultural materials was burned in the SJVAB. In 2000, the average agricultural material use increased to 636,469 tons for the year. The second year of the program (2001) showed an even bigger increase in

agricultural materials burned with an average of 961,247 tons for the SJVAB with \$7.7 million in funding.

Figure 7-11 further demonstrates this trend of more agricultural material consumed during the two years of the BTE. The figure illustrates a four-year period; the third year only had partial funding.

Figure 7-11 Agricultural Biomass from 2000 to 2004



Morris, G., *Biomass Energy Production in California 2006: Update of the California Biomass Database*, report of the Green Power Institute, December 2006.

According to CBEA, the Biomass Crop Assistance Program is also a short term incentive program, which was authorized by the 2008 Farm Bill. Under this program, owners of all types of agricultural material can receive a dollar-for-dollar matching payment for agricultural material sold to a Qualified Bioenergy Facility. This program is intended to be a direct payment to growers and chipping operators to encourage use of the material to produce bioenergy. This program does not include biomass facilities. The BCAP went into effect toward the end of 2009 and is expected to continue funding for five years.

7.4 DISCUSSION

Biomass facilities have no firm commitment for how much agricultural materials they will accept in the future. The lower cost of urban versus agricultural fuel for biomass facilities, combined with the historical overview of fuel usage, creates uncertainty for staff about biomass operators willingness increase and maintain the use of agricultural materials in the future, particularly when the construction industry recovers. Although there are regulations and policies in place for renewable energy use for the utility companies, there are several other sources of renewable energy fuels besides biomass fuel that the utility companies are using. Therefore, there is no guarantee that biomass facilities will obtain and maintain contracts with utility companies to encourage continued and increased use of agricultural materials as a renewable fuel.

Biomass power plants are unlikely to increase agricultural fuel usage to one hundred percent of their fuel usage. Historical data shows that the biomass plants accept more than fifty percent of the fuel from urban or other sources rather than from agricultural material suppliers. The recent decline in the construction industry has limited the amount of urban fuel available from that industry and which may explain why biomass facilities have increased their intake of agricultural materials as fuel. When the construction industry recovers with the recovery of the economy, it is likely that the lower cost urban waste will again cause it to increase as a larger percent of the biomass fuel source.

Renewable energy contracts between the biomass plants and utility companies exist but research was only able to find a few of the biomass facilities have such contracts. There are several other sources of renewable energy, such as wind and solar power, available to the utility companies and they are taking full advantage of those opportunities. The deadline for utilities to meet the 20% requirement for renewable energy is 2010. The utilities are meeting this requirement with a mix of renewable energies. This makes the possibility of increased biomass production to meet increased demand from utilities uncertain, at this time.

There are currently no long-term federal or state funding commitments for biomass power plants. There are currently short-term state and federal commitments that are scheduled to expire within the next few years. Research indicates that the federal Renewable Energy Production Tax Credit program is set to expire in 2013, and the state Existing Renewable Facilities Program is set to expire in 2011. District staff is unaware of any other Federal or State programs currently in place or in the planning stages. Both of these programs indirectly subsidize the growers through reduce costs for chipping and hauling the agricultural materials instead of open burning. Given the narrow operating margin common to agricultural operations, loss of such subsidies could increase the removal costs for crops that are currently banned from open burning and

those that are being considered for such a prohibition. Therefore, reliance on biomass facilities as a primary, long-term alternative method to open burning is not possible since there are no long-term federal or state funding commitments for the biomass facilities in the SJVAB.