The Stepping Stones to Developing a Small Scale Advanced Technology Forest Biomass Facility in California.

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CLERE Inc.
California Law Empowering Renewable Energy

sponsored by:

THE WATERSHED CENTER
HAYFORK, CALIFORNIA

Funding for this project is provided in part by State & Private Forestry, Pacific Southwest Region of the U.S. Forest Service, Department of Agriculture.

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It has become readily apparent that the State of California must prioritize the fact that climate change and forest management practices have worsened wildfire risk in such a way that even urban areas are regularly covered in with heavy smoke and suffer from significantly poor air quality. Wildfires are more than natural disasters; they threaten health, lives, homes, and put into question secure water delivery *and* water quality. Beyond the problem with overstocked forests, agriculture practices and urban greening projects, as well as urban construction also produce a lot of wood waste; so much that open pile burning is on the increase, which is bad for human health due to its smoke emissions. Existing biomass-to-energy facilities are inundated with waste wood from all sectors, are often located close to heavily populated areas, and require trucking long distances, making these locations less than optimal for disposal of forest residues.

Small-scale projects under 5 MW of nameplate generator capacity can be built close to the forest to reduce emissions from transport and from open pile burning, which will enable local air districts to permit more prescribed fires and reduce the risks of both prescribed fire and wildfire. New, small-scale bioenergy projects also bring badly needed rural jobs, will not incentivize clear cut logging or land conversion (as all projects must comply with existing environmental laws) and are using technology that pollutes less than traditional combustion systems.

This document has been prepared for those entities or individuals who are interested in developing a small-scale forest biomass-to-energy facility in California to learn basic steps for the development of small scale, strategically located advanced bioenergy facilities within forested areas of California.

Part A: Early Considerations

Choosing a Location for a Forest Biomass Facility

Depending on the nature of an organization, locating a facility can be straight forward, or, quite difficult. A government agency that has designated a location, or non-profit group that owns land purchased for the purpose of a facility will make this is a moot exercise. If there are options to choose from, however, there are several factors that should be taken into consideration. Even if the location of the facility is known, the information below can help prepare for the process of preparing the site for development. The three areas of consideration described below are not listed in order of importance: all three of these topics are critical and should be treated with equal concern and effort.

What Economic Opportunities and Capacity for Business Success are Present at this Location?

Proximity to woody biomass, transportation corridors and road access, markets, customers, other economic considerations, diversity of forest landowners/managers

The first question that most projects come to naturally is, “from where will I secure my feedstock?” There are many possible sources of woody biomass material in California but acquiring a sustainable supply well into the future can be a difficult task. At first glance the US Forest Service or the BLM are the most obvious possible partners, as the Forest Service manages about 20 million acres in California, while BLM manages 15 million acres, many of which are forested. Contracting with federal agencies, however, can be difficult. Other sources of biomass could come from state agency land clearing activities through California Conservation Corp work, or fuel reduction’s activities at state parks, or other state agencies.

Another source for potential partners is the timber industry. Depending on the company, some may have residuals made available through brokers. Be aware, however, that it matters what forest practices resulted in the biomass waste. If a project wants to participate in the SB 1122 program the biomass must be produced as a result of sustainable forest management as defined by that Program. Other private landowners, including utilities like Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) could also be potential partners.

When assessing whether a project has sufficient access to feedstock, it may be that your group or agency has the capacity to make decisions about feedstock without the need to do a formal report or hire a consultant. This decision may be predicated on the particular group’s threshold for risk. For more information about feedstock procurement, there are several different feedstock assessments available for review online. When determining feedstock partners it is important to understand to what degree a guarantee of delivery is needed for financing partners. Often feedstock source agreements are needed to secure grants, loans, or other financing. Contractually bound feedstock sources are a key to the success of the development of a forest biomass project.

When considering biomass feedstock availability and accessibility, one of the factors that will be inevitably hit is the transportation network along which the site is located. Travel distances and fuel costs, road quality and weight limitations, as well as access to subcontractors who own trucks and potentially other needed equipment must be considered. The property should also be analyzed to determine whether there is sufficient Right of Way and access points from the main roads onto the property in question. Encroachment permits from the local county or city may be needed in order to properly use a site.

Distances to markets also significantly impact the potential for co-located businesses and customers for products that might be considered as an outcome of the development of a project. Other than transportation, issues related to the economies of scale at small projects affect market success. If partnerships with other businesses are needed for a project to be sustainable, it is important to enter into written agreements with such partners before too many economic assumptions are made. Also, the nature of your group, whether non-profit, public agency or private company will need to make careful decisions about how to go into business with partners, and how to structure business ventures.

How well is this project location Suited for retail sale of electricity to the grid?

Research the grid infrastructure and applicable interconnection processes

One popular business opportunity for biomass utilization is the conversion of wood into electricity. This can be done using various technologies that convert the wood into a liquid or gas, or through direct combustion. In order to export the electricity produced off site and sell it, the site must be interconnected with the California grid. Regardless of technology, bioenergy projects use synchronous generators to produce electricity. These generators produce electricity differently than solar or wind power projects, and as of the time this paper was drafted, there was no clear way to use the fast track process within the Public Utilities Commission for interconnection of the synchronous generation systems used in biomass projects.

This interconnection process can be very complicated, but centers on the need for an understanding of the status of the nearest substation to the property. Also, to some degree whether there are sufficient power lines to the property from that substation. It is highly recommended that a project consults with an electrical engineer as early as possible in the process to determine the general feasibility of interconnection at your site. Note: There is a relatively cheap "first review" that Investor Owned Utilities (IOU) make available. There is also an alternate interconnection pathway through CAISO and the WDAT process for some projects. This will be discussed further below.

In conclusion, when investigating opportunities and limitations, strive to get as much information you can in writing and know that ultimately when considering economics, your group must decide whether the goal of the project is to cover its own costs, including the payment of local labor and stimulation of the local economy, or if the goal is to additionally turn a profit. Then, the partnerships needed to meet this goal should be explored, cultivated, and documented before too much sweat equity is put into these projects.

What is the physical condition of your site location?

Project geography, previous uses and resource constraints can significantly impact the success of a project.

Locations for small forest biomass facilities are often in rural, forested places in high elevation with variable temperatures that can dip below freezing. Certain types of equipment react differently at higher elevations, colder or hotter temperatures, and even differences in relative humidity. Location conditions should be discussed with possible technology providers.

Another static factor that will affect the usefulness of the property is water. First, access to water and the associated water rights could be critical for some technologies that need water to run their systems. And of course, making sure that there is water that is accessible via a good producing and permitted well, and that it is not contaminated, are also important. Another key water factor is whether there are streams or wetlands on your property. If there are such areas, special setbacks or take other actions to comply with federal law may be needed.

An issue that is often overlooked is waste water disposal. First there is the standard waste water issues around the fact that humans will be working at the site, so standard septic or sewer services will be needed. Also, many technologies have some degree of

waste water associated with their technology. Understanding the septic options on the property are essential, and whether or not large areas will be needed for evaporation ponds for the technology is another critical part of a property assessment for one of these projects. Also, storm water run-off is highly regulated and will likely require a permit.

Another key environmental factor is determining which air basin where the project is located. Property located in an area that is in a nonattainment area (an area considered to have air quality worse than the National Ambient Air Quality Standards as defined in the Clean Air Act Amendments of 1970) for Ozone or Particulate Matter (PM) it may be more difficult to obtain the needed air permits for your project. Determining the expected air emissions from the chosen technology and activities will greatly impact acceptable locations for a project. Maps that show where air basins are located in California can be found online.

Finally, an issue that plagues many of these project sites is soil contamination. Toxic chemicals in soil, abandoned structures, or debris left from previous activities are often an issue because ideal locations for these facilities are frequently in industrial areas or abandoned mill sites (i.e. brownfields). The first step is to check the CA Department of Toxic Substances Control and determine if they have flagged your potential site as a site of concern. Some planning departments of local agencies could also have reason to ask for a “phase one” soil assessment; be sure to fully explore whether that is necessary with an expert. Also note that some regional water boards expand their issues into the realm of soils if there is a chance they could become waterborne. Professional consultants are generally needed if there is any indication of soil contamination.

What is the Legal Condition of the Property?

Ownership

The easiest way to move a project forward is to control the location at which it is located outright. Purchasing real property can be a complex matter. Developers are strongly encouraged to work with a real estate professional who is experienced in industrial site purchases. Fee title ownership ensures control and clear decision making regarding the project. It will also make issues relating to participation in the California Public Utility Commission’s (CPUC) BioMAT (Bioenergy Market Adjusting Tariff) SB 1122 program, a Bioenergy Feed-in Tariff Program, and associated interconnection requirements, much easier. When considering purchasing real property, a title report is needed to understand potential liens, mortgages, other encumbrances, as well as taxes associated with holding the property. Also remember that future taxes will need to be paid on both the land and the value of the facility itself. Other than public entities or a religious organizations, taxes will need to be built into the economic model.

Another path forward is leasing property. Drafting a lease must be done carefully. Specific uses of the property must be described, and understand that while certain uses can be restricted to particular areas, leases cannot be drafted in a way that subdivides land in a way that would be contrary to the Subdivision Map Act. It is important to cover a broad array of issues within a lease. To name a few key items: access to the property, any rights of entry retained by the property owner, and costs associated with the

property such as taxes, utilities or other fees. Of course, rent and term must also be covered. Generally, in California the law is very friendly to the tenant, but one should nevertheless be cautious and detail oriented when entering into a lease.

It could also be that an organization wishes to create a partnership of some kind with another group who owns property who plans to use the property as an asset of the new third entity. If this is the case the liability of the asset should be carefully assessed.

Restrictions on Property Use: Zoning and Permitting

When considering a property, an essential early step is determining how the local government has classified the uses that can occur on the site. This can be found on the city or county zoning maps and affiliated tables that will describe whether an industrial activity like a bioenergy facility and its associated wood storage, would be acceptable at that location. Note that some zoning codes may distinguish between the types of wood product business, especially pertaining to the production of electricity, which often will be specifically listed as a use that is allowed, or not. Zoning designations can be changed, but that can take significant time and expense, and as such should be considered in terms of the time and economic constraints of a project.

Within the zoning code will also be information about which kind of "use permit" will be needed for the project. In some cases, such as property located in an industrial center may not need a permit. In some cases, a simple administrative process that can be approved by a local government official will be enough. In other cases, the project will need reports drawn up and approval from a local board, called the Planning Commission, in order to approve the project, and in some cases, it will even need to go before the governing body of that jurisdiction for approval. This is a key factor in evaluating whether a site is going to work for a project.

In situations where a discretionary permit is needed to build a project, an analysis under the California Environmental Quality Act (CEQA) is needed. This analysis will determine the impact of a project on the environment. Projects could be considered eligible for an exemption, or a "Negative Declaration" or an "Environmental Impact Report" might be required. In some cases, a project could use a previous environmental document if there is one that has been done relatively recently, in which case it might be possible to only prepare an "addendum" to that document. In any case, one should expect at least six months to prepare the documentation required by the lead agency to approve a project that needs a CEQA document. These documents do not have to be prepared by anyone with special credentials, but generally consultants are hired to prepare them.

During the CEQA process a lead agency is likely to identify the other permits needed from other agencies after the local agency discretionary approval such as air permits, water permits, grading permits and building permits. This thorough procedure will align your project with development milestones for the duration of the development and construction period.

Summary

Determining where to locate a project is a crucial step that must take into consideration the economic potential, geography, and physical attributes and limitations, as well as

regulatory application. Rest assured that careful planning and due consideration about the location of the project will be time well spent.

How to Contract for Success During Project Development

Projects need many types of relationships to make a project work, and many of them will need to be in writing. Some do not, however, like one-time purchases of goods like office supplies or other items, or one-time service arrangements like site clean-up, fence construction, or other one-time deals, which can be made through a verbal arrangement, or using an invoice. For most circumstances, however, a written agreement is best. Also, financing arrangements, whether public or private require careful written documentation. This Section will cover the details of contracting for such Projects.

Rules of the Road when Contracting: General risk management strategies within contracts

Contract format can vary, expect the unexpected. Most contracts have general terms and conditions in the body of the agreement, with specifics like project deliverables, timing, and payment within an attachment or exhibit. Some agreements, however, often for goods, have a small central component in the agreement with specifics, and then attach an "Exhibit" entitled "General Terms and Conditions", often in small print. These attachments are enforceable no matter whether in the main body of the agreement, and no matter the size of the font- be sure to read them carefully.

Clear Scopes of Work (SOW) are essential. Make sure sufficient time and attention is given to the development of an SOW. Understanding the expectations of both parties, deliverables, reporting (for grants most often), timelines, payments, invoicing/billing, and other details belong in a SOW. Generally, a lawyer will rely on you, or your contractor, to draft most of this document: consider it the place where the business points are illustrated.

There can be several different licenses that any contractor should possess. First the legal entity should be properly licensed with the California Secretary of State, if it is any kind of business or non-profit. If someone is working as a sole proprietor, they do not need any special license from the state, but they should have a business license from the local jurisdiction where they work. Second, if the individual is providing professional services, one should always check that they have an active license to provide such services; many professionals have industry related credentials that should be verified. Examples include architects, lawyers, general contractors and some engineers.

Review insurance. An often overlooked issue is, that a contract is only as enforceable as its insurance provision is valid. If a contractor or vendor is not insured, even if they blatantly breach the contract, it may be difficult to get reimbursed for loss. With each contract, carefully consider what losses might be, account for that in financial terms, and then check what limits exist on their policy. Also, the underwriters who work for insurance companies can be a good source of advice on contract matters. In some cases, if there is high risk involved in the contract, such as felling trees or removing toxic soil, an organization may consider becoming an "additionally insured". General types of insurance include Auto, Business, and Errors and Omissions. Additionally,

attorneys must carry malpractice insurance. Finally, most all entities in California must provide workers' compensation insurance. Proper insurance is critical.

Consider how to resolve disputes before they happen. No one wants to imagine that the deal they are working on will go bad, but just in case, it is prudent to clarify how disputes are handled. First, decide how the parties will notify one another if one party feels the contract terms are not being met, and then decide whether or not informal efforts, such as requiring parties to meet to discuss conflicts, will be required. The next consideration is whether professional mediation will take place, which is often used before binding arbitration. Binding arbitration is an alternative final step to a matter ending up in court, and is often chosen to save on litigation fees (although arbitration fees are often significant in their own right). Finally, if matters do end up in court, remember to choose which state law and courts will be used to resolve the dispute. This is particularly important if either party is located outside California.

Consider indemnification clauses. These clauses require one party to cover the legal costs of the other. Some clauses cover the costs of disputes between the parties themselves, and others are limited to costs of third-party claims. Indemnification is often required from private parties who contract with public entities (which will be discussed further below). If there is a circumstance where one party is far more likely to expose both parties to legal risk, a request for indemnification may be made. Generally, however, most private party contracts end up using some kind of mutual indemnification language, which requires that each party pay any share of costs that a court or arbitrator attributes to that party- this is known as "mutual indemnification".

Financial Commitments of Parties. Whatever obligations you are under for the project you are working on, especially grant requirements, should be mentioned in a contract that will be paid for through that source. If there are any pass-through provisions or other specifics, be sure they are clearly referenced, if not attached to your contract.

Finally, carefully consider cancellation provisions. Generally, a mutual contract clause with thirty days' notice provision is standard. If a party is owed money for services provided, they generally must be paid within a reasonable time of cancellation. In some cases, however, if a party cancels the contract there will be substantial harm to the other party. In such cases, "Breach of Contract" provisions will often include a "liquidated damages" clause that will set damages amounts if an arbiter or a court find that a contract has been breached. It is always a good idea to be explicit in a contract when early termination of a contract is not acceptable to at least one party.

Special Considerations when Contracting for Services

Seeking out a company or individual to provide services can be a daunting task. Often times publicizing your needs can be essential. These "Requests for Proposals" (RFP) are often a key part of finding the right service provider. Describing expectations to potential partners is very important, as well as describing the metrics to measure success. It is critical to mention any constraints on the work that might be expected by any outside funding source, especially if there are other parties that must have input in measuring the success of the implementation of the contract.

Often RFP processes are not used for highly skilled professional services such as CPA, lawyer, or realtor. When considering hiring for those types of services, references and

personal interviews are generally the norm. They will generally also provide the type of contracts needed to retain their services.

As mentioned above, carefully investigate whether service providers have the proper accreditation, insurance, and experience for the job. When only a certain company, or individual can provide the specific work needed, a provision prohibiting the re-assignment of your work product to others should be incorporated. Otherwise, it is up to the discretion of the contractor to subcontract out some, or all, of the work within the contract.

Special Considerations for Equipment and Other Goods Sales Contracts
Contracts for equipment or high-priced goods must be reviewed carefully. There are many pitfalls for the wary purchaser. To begin, a contract should be clear about who bears the liability of damage of goods through the delivery process, and what the requirements are upon "acceptance" of the goods. Defects that cannot be observed upon inspection at the time of delivery are a justifiable basis for refusal of payment, and that processes are in place for dealing with that scenario. Receipt of damaged goods are one of the most common areas of contract disputes.

This issue is not to be confused with the issue of warranties and performance guarantees. Once a product has functioned properly for some time, it is no longer an issue of a 'latent defect', but rather an issue of warranty. Warranties are made to make a purchaser whole if equipment stops working in a way that was represented within a specified period of time. Be very wary of entering into contracts that include any waiver of the "implied warranty of merchantability", or fitness. This warranty is implied in all goods contracts in California, unless waived, and protects you by requiring that sellers repay you if they sell you defective products. In the case of novel technology, a seller may demand a waiver. If such waiver is demanded, be sure to get some type of warranty provision that spells out expectations. Do not waive the implied warranties without alternative provisions.

Another specific type of provision that can be very helpful when dealing with emerging technologies are "performance guarantees". These are like warranty provisions, but they go beyond the standard provisions and include technically measured output and results to trigger financial obligations (often percentages of payments). Work with third party engineers or other consultants to best develop such provisions for your goods contracts.

Finally, note that sometimes services are needed during the delivery or installation of equipment. Complicated equipment often requires technical support. If possible, keep services provisions separate in an exhibit to the contract, or at least in a distinct section, and be sure there is an understanding as to which provisions of the contract apply to the services sections of the contracts. Be sure the expectations for the services provided are very clear (they can often be overlooked within contracts that are primarily drafted as a sales contract).

Construction contracts: special considerations
Contracts to construct have special provisions and traps for the unwary. First, note that the California Constitution gives mechanics' lien rights to contractors, workers, and material suppliers. Design professionals are also afforded mechanics' lien rights, but only after construction begins. Prior to construction they have design professional lien

rights. This is specific only to licensed architects, engineers, and landscape architects. These liens can be filed if those who hired them are not paying the invoices they have submitted under a contract. While recording a mechanics' lien is a straightforward and easy process for the contractors, the laws for enforcing mechanics' liens are complicated and often confusing. To enforce a lien (try to collect against it), a competent attorney that understands mechanics' liens must be consulted. Note that by the nature of the mechanics' lien, the property owner runs the risk of having his property sold to pay the lien, so very often enforcement involves very challenging, technical legal battle.

Also, a contract should be clear about who and how subcontractors are chosen and at which points of the project they are engaged. Depending on a relationship with the general contractor, a greater level of specifics about subcontractors may be needed. Note that in California, subcontractors have a great deal of deference and rights under contract law.

Finally, the handling of cost overruns or stalled progress (project delays) should be described. In most constructions projects some unpredictability can be expected. By coming up with terms to deal with these externalities ahead of time, problems can be avoided down the line.

It should be noted that public agency projects or those using public funds, or building on publicly owned land, have significant layers of rules that apply to the project, the most significant of which is the application of "Prevailing Wage". This requires that some people who are working at a construction site are paid specific wage amounts. It is essential that to understand the cost impacts of these wage requirements. There are some other specifics about contracting with public agencies in any context, which is the final section below.

Entering into agreements with local, state, or federal entities

There are several circumstances when projects may find themselves contracting with public agencies.

First, understand that to partner, or receive even indirect support from a public agency they will require insurance, assurance that partners are a properly recognized legal entity by the state, and that such an organization can provide indemnity for their staff. This is because local agencies are run on tax dollar money, and as such it is considered a public benefit to ensure that agencies are generally held out of harm's way to the extent possible. That is why government agreements are so difficult to negotiate, but sometimes concessions can be made, and generally the smaller the public entity, the more room there is for negotiation. There is little to no room to change state or federal contract templates, but nevertheless changes might be considered on a case by case basis. Generally, changes to those types of contracts must be done on a systemic level, but it is always worth asking and at least bringing the issue to the attention of the government agency partner.

Another important aspect of public contracting is to understand the privacy limitations in public contracting. All documents shared with public agencies are considered 'available to the public' in most circumstances. In California, the Public Records Act governs the small group of documents that can be considered confidential. Generally, health information, property assessments, legal enforcement matters and data pertaining to

children is protected, but not much else. Proprietary data or other intellectual property that needs to be kept private will require special effort: be sure to engage with an agency's counsel to see what kind of non-disclosure agreement (NDA) can be worked out, and never assume anything shared with a public employee is confidential, unless advised by an attorney.

The final issue to keep an eye on is Conflicts of Interest. There are several laws in California that prohibit entities from providing services, or entering into any contract with a public agency if that private or non-profit entity includes a director, partner or other leader who is also a political representative of that local agency, or even department head or other agency decision maker. Also, even low level staff may have a conflict if they were working on a contract, and also will receive some financial benefit from the making of that contract. Personal financial relationships between public agency officials and members of organizations that are contracting with such agencies can be problematic and lead to automatic voidance of a contract, and personal liability for the parties involved.

Feedstock Contracts: the lynchpin of project success

Establishing a steady supply of feedstock is a crucial part of obtaining financing for a project, and setting the stage for steady income. When contracting for feedstock, it is important to look for business partners who understand wood markets and the complexities of contracting with the US Forest Service. The US Forest Service, as the largest forest landowner in California, has a significant amount of timber sales that could lead to steady streams of biomass for a facility (that being said, it's the most risky as there is little incentives and accountability with developing these sales). In general terms, local government or non-profit organizations can enter into "Master Stewardship Agreements" with the US Forest Service. These Agreements are general road maps for working in collaboration with the agency, and do not have binding terms for actual sales of biomass. In the context of these broad-based collaborations, specific "timber sales contracts" can be established, which are actual enforceable contracts that specify terms and conditions of work on federal land for the removal of biomass and also could have commercial wood sales components. Note that timber sales contracts can be developed outside the context of Master Stewardship Agreements.

Working with other public land owners, like counties, special districts, utilities, and others can also lead to contracting opportunities. In any of these circumstances, the advice above relating to public contracting applies. Most critically, carefully consider the length of the term of such agreements, taking into consideration that local governments must carefully work around long-term commitments.

Another approach is to contract with a company who deals with timber suppliers and acts as a middle man, so to speak. These companies contract with land owners and then have staff who remove the wood and transport it to a facility. The decline in California's timber industry has reduced the number of such companies, but some still do exist. Finding these companies and establishing a relationship takes strong local on the ground knowledge and connections to the local community must be established.

Conclusion
Moving forward with Wood Utilization Projects, be sure to consider how to make sure relationships, in the long run, will support the successful development of a project. Contracting is an essential part of the success of a project.

Part B: Participation in the BioMAT program

The Bioenergy Feed-in Tariff Program or the Bioenergy Market Adjusting Tariff (BioMAT) is a feed-in tariff program for small bioenergy renewable generators less than 5 MW in size. The BioMAT program offers up to 250 MW to eligible projects through a fixed-price standard contract to export electricity to California's three large investor owned utilities (IOUs). Electricity generated as part of the BioMAT program counts towards the utilities' RPS targets. Small-scale bioenergy projects can be procured in three categories including urban, agricultural and dairy waste, and forest biomass residuals.

In November 2017, in accordance with the program rules established by the Commission in 2014, Energy Division initiated a BioMAT program review and capped the Forest Category 3 offer price at the them current level of $199.72/MWh unless a seller is committed to using a least 60% high hazard zone fuel. This program review and temporary price cap do not affect other aspects of the program, and the IOUs continue to offer their proportionate share of remaining BioMAT capacity within each technology category and execute contracts according to existing program rules. The temporary price cap was ordered to remain in effect during the BioMAT program review, which will assess program performance to date and recommend programmatic and procedural changes to simplify the BioMAT procurement process, enable expanded program participation, reduce ratepayer expenditures; and help achieve statewide goals.

To obtain a Power Purchase Agreement through this program, several steps must be taken. Those steps are outlined below.

Step One: Obtain an Interconnection Study

How to Navigate Interconnection Under Rule 21

Electricity Rule 21 (the Rule) is the process by which an electricity generating facility can export its energy to a utility company that will distribute that energy to its customers. This Report is focused on this process as it pertains to a project participating in the feed-in-tariff program called the BioMAT (Bioenergy Market Adjusting Tariff). For the purpose of this report (and within the Rule itself), the utility company is referred to as the "distribution provider," and refers to PG&E, due to the fact that forest biomass projects under the BioMAT program are almost exclusively mandated to be within PG&E territory. Please note this report is intended to serve as an overview of this extensive Rule, and one should always consult a professional engineer when embarking on the interconnection of an electrical generation facility to the grid.

The purpose of Rule 21, which is maintained by the California Public Utility Commission (CPUC), is to provide detailed guidelines for the approval for the interconnection of

renewable energy projects into the utility's network. Rule 21 increases transparency in the interconnection process, reducing the possibility of arbitrary decision making on the side of the utility. The review process to determine if a proposed generation unit will cause negative impacts in the distribution network and the mitigation strategies are harmonized in the rule according to IEEE 1547, which is the "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems".

If a project will only produce energy "behind the meter", i.e. for onsite use, then there is no need to go through the interconnection process given that there will be no interaction with the network. If a project would like to sell energy to consumers that are contiguous property owners to the power generating facility, it can enter into "over the fence" agreements under California Public Utilities Code Section 218, and use the Rule 21 process to analyze the interconnection requirements. If a project would like to sell its energy to more than one utility company, or prefers to deal with FERC (Federal Energy Regulatory Commission) instead of the CPUC, then the project should use another interconnection process that is not covered in this Report, known as the Wholesale Distribution Tariff (WDT).

Projects can also choose to directly interconnect to the CAISO (California Independent System Operator) transmission system. CAISO manages the flow of electricity across the high-voltage, long-distance power lines that make up 80 percent of California's and a small part of Nevada's grid. The nonprofit public benefit corporation keeps power moving to homes and communities. The ISO opened its two California control centers in 1998 as the state restructured its wholesale electricity industry. While utilities still own transmission assets, the ISO controls the operation of the system, maximizing efficiency of the electric power grid resources, managing reliability and supervising maintenance of the lines. As the nerve center for the power grid, the ISO matches buyers and sellers of electricity, facilitating over 28,000 market transactions every day to ensure enough power is on hand to meet demand.

Distributed Generation (DG) projects like the ones covered under the BioMAT program (below 3 MW) rarely connect directly to the transmission grid, since connecting directly would require voltage levels to be above 60 kV; CAISO's Fast Track process (sub-5MW project size) is designed to avoid requiring a new interconnection study with PG&E (other than the screens run by CAISO). However, the upfront electrical engineering on the applicant side is greater. When connecting through CAISO the applicant has to design and develop a mini-substation for a plant rather than paying PG&E to study their own substation and lines. Currently, the BioMAT program tariff, which provides specific instructions related to the BioMAT program. This document states that a Project must be interconnected to PG&E's electric system via a distribution line or an existing PG&E transmission line, and the Project's most recent Interconnection Study or Interconnection Agreement must affirmatively support the Project's ability to interconnect within twenty-four (24) months of the execution of the BioMAT power purchase agreement (PPA).

Beginning the Interconnection Process

Obtaining basic information about what type of interconnection will be needed at a project site is critical. A Pre-Application Report provides essential, basic information that a qualified electrical engineer can then use to estimate a project's interconnection needs. If basic information about the location has been obtained, the interconnection for the site is straightforward, and within the project budget, then an "Electrical Generator Interconnection Request" can be submitted, (which is the application that must be filed to interconnect a generator to the California grid).

To apply for a pre-application report, at a minimum are required, (1) the precise location point of interconnection on the property, (2) type of fuel used ("biomass" is specific enough), and (3) deployed technology, as specific as possible; but a general description is usually sufficient, as the Power Flow Analysis, overload protection schemes, and voltage limit can be performed with decent accuracy, even if the exact technology is not known. Note that at this stage proof of ownership of the property analyzed is not required (but the owner's permission should be obtained).

The proposed Point of Interconnection must be defined by latitude and longitude, site map, street address, utility equipment number (e.g. pole number), meter number, account number or some combination of the above to sufficiently identify the location of the Point of Interconnection. For more information about the specific information required, and what to expect back from these reports, PG&E has developed a useful 10 page document that describes the three different types of Pre- Application Reports, which in summary are:

• Standard Pre-Application Report – Provides a readily available level of Distribution System data that requires little to no analysis on the part of distribution engineer providing the report. The cost of this report is $300 and takes 10 days to process by the Distribution Provider.
• Enhanced Pre-Application Report - *Primary Service Package* – Provides a detailed level of Distribution System data that requires analysis on the part of the distribution engineer providing the report. The fee for this report is $325 and takes 10 days to process.
• Enhanced Pre-Application Report - *Behind the Meter Interconnection Package* – Provides distribution system level data that is relevant to a "Behind the Meter" interconnection, as well as Secondary or Primary service characteristics that are confirmed in the field. The cost of this report is $800, or $900 if a standard report has not yet been completed, and this report takes 30 days to complete.
• An *enhanced primary service* and *behind the meter report* can also be requested for $1,025, or $1,125, respectively, and this report takes 30 days to complete.

Filing an Application for Electrical Generator Interconnection Request "EGI"

After the Pre-Application Report has been received and reviewed with an engineer, the next step is to complete an Electrical Generator Interconnection Request "EGI". This application requires collecting several technical documents and information gathering.

Once the information collection is completed, an interested party needs to create an account on the Distribution Provider website home page[1] and submit an Application online.

To begin, the applicant needs to decide whether the facility will apply for Rule 21 Export or wholesale market, as well as the decision whether or not to apply for "Fast Track" processing. Realistic dates for trial and in-service operation need to be provided. The applicant should make the best efforts to estimate this dates properly to avoid penalties later. Additionally information about the technology needs to be supplied, with the most detailed description as possible of the facilities' equipment. If the generator is over Rule 21's 3-5 MW limit, it is important to include details about the control in the *general description of the equipment* box. Remember projects can generate up to 5 MW, but only 3 MW can be exported, and how this will be achieved must be explained.

The project location information boxes is comprised of two parts: 1. The Project's address and Lot/Lang. coordinates. 2. Localization of the point of interconnection (POI), this information is the same as the previously supplied to obtain the pre-application report. Additionally proof of a lease or ownership of the project location is required. In order to move forward with interconnection and file the EGI Request, the Distribution Provider will require proof that Site Exclusivity has been achieved, which essentially means Documentation reasonably demonstrating:

(1) For private land: (a) Ownership of, a leasehold interest in, or a right to develop property upon which the Generating Facility will be located consisting of a minimum of 50% of the acreage reasonably necessary to accommodate the Generating Facility; or (b) an option to purchase or acquire a leasehold interest in property upon which the Generating Facility will be located consisting of a minimum of 50% of the acreage reasonably necessary to accommodate the Generating Facility.

(2) For public land, including that controlled or managed by any federal, state or local agency, a final, non-appealable permit, license, or other right to use the property for the purpose of generating electric power and in acreage reasonably necessary to accommodate the Generating Facility. The demonstration of Site Exclusivity, at a minimum, must be through the Commercial Operation Date of the new Generating Facility or increase in capacity of the existing Generating Facility.

If you can demonstrate this, then you should also have no problem demonstrating "site control" requirements under the BioMAT application process, as well. Definitions and explanations of additional terms can be found on Sheets 15-32 of the Rule.

All the property control ownership documentation needs to be uploaded in the last stage of the application process along with the technical details of the facility. The additional technical information recommended is:

1. Single Line Diagram (SLD) of the facility showing the proposed protection equipment, transformer and auxiliary services.

[1] https://www.pge.com/ccoweb/

2. Generator Parameters and type of generator. For instance, synchronous or induction generator, Short Circuit Ratio (SCR), rate power MVA. All of this information is usually found in the manufacturer's specification sheet.
3. Protection equipment specification, manufacturer and model number of protection devices to be installed in the facility.

After the application has been submitted, the Distribution Provider has 10 days to notify the developer if the application is complete, or 20 days if the "Cost envelope" option, which is discussed below, is selected. Then, the application will either be deemed complete, or if anything is missing, the Distribution Provider will deliver a Notice of Deficiency, at which time the Applicant has ten days to respond. A second Notice can be issued, and at which time the Applicant has 5 days to respond. Note, however, that after either of these notices an Applicant may request one 20-day extension to respond. If the Application is still inadequate, after the Distribution Provider notifies Applicant two times, the Applicant has only 2 business days to request dispute resolution for the matter.

Once the application is deemed complete, PG&E will determine whether a project qualifies for Fast Track or a Detailed Study process, which are discussed below. Further fees and deposits will be dependent on this determination.

The Cost Envelope Option

Before describing the different interconnection pathways, it is important to mention that the CPUC has adopted a program to help support cost certainty throughout the interconnection process called the "Cost Envelope" option. If an applicant would like to take advantage of this new financial management tool, a $2,500 administrative fee must be paid with the EGI. This option is available to projects on the Fast Track or those that will do both, an Independent Study and a Facilities Study, which are explained later.

The cost controls work as follows: An Applicant shall only be responsible for the actual cost of the portion of interconnection facilities and/or distribution upgrades subject to the Cost Envelope within the range of plus or minus twenty-five (25) percent of the estimated cost of such facilities identified in the Cost Envelope estimate. Applicant's cost responsibility for that portion of the interconnection facilities and/or distribution upgrades subject to the Cost Envelope shall be capped at 25% above the estimated cost, and applicant shall not be responsible for the portion of the actual cost of such interconnection facilities and/or distribution upgrades that exceeds 25% of the estimate.

Correspondingly, applicant's cost responsibility for the portion of the interconnection facilities and/or distribution upgrades subject to the Cost Envelope shall not be less than the amount determined as 25% below the estimated cost, and any portion of the actual cost of such interconnection facilities and/or distribution upgrades that is below 25% of the estimate shall not be refundable to the applicant.

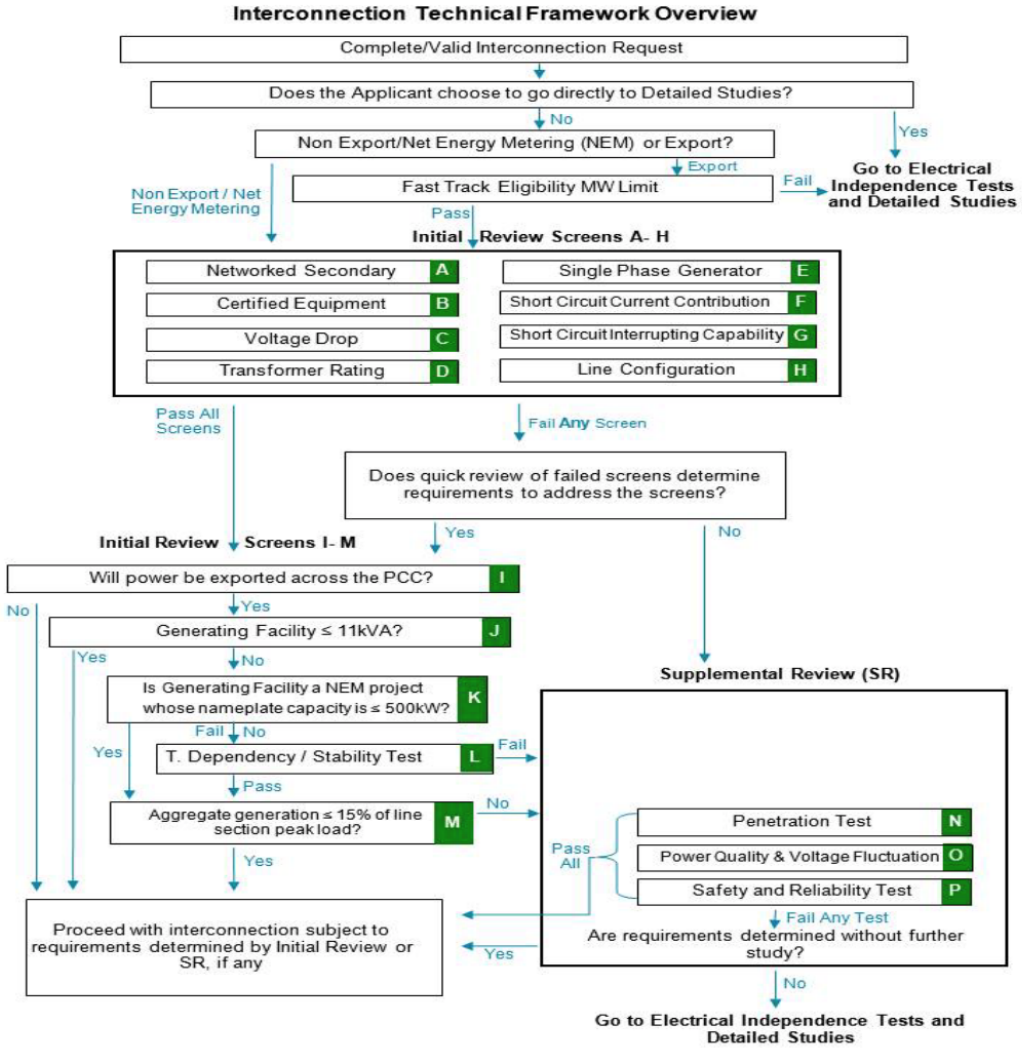
Concerns were raised that this process would lead to higher initial estimates. In order to address this potential problem, the CPUC required the utilities to prepare cost unit guides that would help explain the basis for certain costs. As this is a relatively new

program, there is still some uncertainty how well this approach will work out. Note that this is considered a 'pilot' program that will be in place for five years, at least initially.

The equipment price tables developed by PG&E contain costs related to the electrical equipment necessary to handle potential overloads, such as new transformers and line segments. Also, it includes guidance on the costs for metering devices and telemetry to perform remote control of the facilities. The guide also accounts for potential costs on the implementation of a Direct Transfer Trip (DTT) scheme; however, these costs usually change depending on the design and implementation of the solution. DTT tends to be one of the biggest cost components of interconnection, and is an issue recognized by utilities in other jurisdictions such as New York State.

What is Fast Track, and how do I qualify?

Sheet 137 in Rule 21 shows a block diagram of the screens and technical parameters relevant to the eligibility for Fast Track. The figure is replicated in this report to further clarify the process.



Projects that have a Gross Nameplate Rating of 3 MW or less and are on a 12kV or higher interconnection voltage point (at the Distribution Provider location) are eligible for

Fast Track, depicted in the figure with the block *"Fast Track MW Eligibility Limit".* Even though when Fast Track is selected on the application and the associated fee of $800 is paid, there is no guarantee that the Fast Track review will be successful. Utilities review an application for Fast Track by running the project through a series of engineering processes called "Screens".

Generally, proposed forest biomass projects have not been able to pass these screens because in most of the cases the challenges begin within the analysis of screen I, *"Will power be exported across the PCC?"* A positive answer to screen I triggers a requirement to pass Screen J, which basically limits generation facilities to those below 11 kVA. Forest biomass proposed facilities are larger than 11 kVA (the three facilities closely reviewed within this document were approximately 3,000 kVA) and so most projects are required to continue through screens K, L, and M. Furthermore, screen K allows only facilities with a size of 500 kW or smaller to continue through Fast Track, so most projects, again, do not pass. The last two screens in the process are Screens L and M, the first one is related to transmission stability problems, which for most projects will not be a concern. **It is Screen M that all the projects fail to complete the Fast Track given that the proposed installed capacity is above 15% of the Line Section peak load, thus, triggering a supplemental review.** The relative size of many of the proposed projects compared to the load in the feeders at their local substations raises concerns about the operation of the system. Namely, loading of the assets, power quality issues related to voltage, protection coordination and islanded operation of the power stations. Generally speaking, forest biomass projects cannot pass Fast Track.

Timing of Fast Track review if a Project passes Fast Track

The Distribution Provider must provide a response to a validated application for Fast Track within 15 business days. Then, within 15 days of the notice of the outcome of the review, if the review for Fast Track is successful, the Distribution Provider will provide a template Generator Interconnection Agreement (GIA). If the "Cost Envelope" option has been selected, the Distribution Provider will provide that non-binding cost estimate (essentially a draft estimate), instead of a GIA. Within 10 business days of receiving the non-binding estimate, the project developer will need to put down the cost envelope deposit of $2,500. The Distribution Provider will then provide the "Cost Envelope Estimate" within 20 days of receiving the deposit. The project then has 15 business days after receiving the Cost Envelope estimate to notify the Distribution Provider if they plan to move forward, or withdraw. If they decide to continue, the Distribution Provider will then provide a draft GIA within 15 days of such notification by the project.

Once a project receives a draft GIA from the Distribution Provider, whether they chose the cost envelope option or not, they must return an executed draft of the agreement within 90 days. After GIA execution, the interconnection process through Fast Track is complete.

What is Supplemental Fast Track?

Projects that fail to pass Fast Track are given a written technical justification with the opportunity for a "results review meeting," and a chance to proceed under Supplemental Review. Projects larger than 3 MW that agree to the installation (at Applicant's costs) of the Distribution Provider's listed protection devices to ensure net export never exceeds 3 MW, can be processed through supplemental Fast Track. Within 10 business days of

notification of failure to pass Fast Track, applicants must notify the Distribution Provider whether they would like to have a results review meeting, or directly proceed with Supplemental Review. The fee for a supplemental review application is $2,500. After the deposit is made, the Distribution Provider has 20 business days to complete review. Also, the Applicant has the option to request a "fault current study", which costs $1,000 and takes an additional 20 days to prepare by the Distribution Provider. It is recommended to discuss with an electrical engineer whether the project needs this additional study.

In general terms, the "fault current study is a good idea when the proposed installed capacities in the feeder surpass the 15% of peak load penetration limits (failed Screen M, as discussed above). The information about the feeders can be obtained from PG&E Renewable Auction Mechanism maps, made available on-line as discussed earlier. Even though these maps were originally developed for solar power penetration, they provide important information about the feeder where the plant will be located and increase the likelihood of a proper sizing. Moreover, they will provide information to inform the expected interconnection process.

In almost all cases where screen M is not satisfied, the project will have to pass Screens N, O, and P. These screens are intended as an analysis of high-penetration and can reveal costly issues that need to be resolved, e.g. distribution protection requirements and reliability problems induced by the new facility.

When the Distribution Provider delivers the results of their study, the applicant has five business days to request a Supplemental Review Results Meeting, if they have questions or want to discuss conclusions within the study. Once it has been determined that the project can proceed under Supplemental Review, the Distribution Provider has 15 days from the notice of the outcome of successful supplemental review - which could arise after a "Supplemental Review Results Meeting"- to provide a draft Generator Interconnection Agreement (GIA). Alternatively, if the "Cost Envelope" option has been selected, it will proceed as described above. This completes a project interconnection process through Supplemental Review.

If a project does not pass Supplemental Review, then the Distribution Provider will provide an explanation in writing and invite the Applicant to a Supplemental Review Results Meeting. The Rule provides that if the Distribution Provider can determine which type of detailed study the Project needs, then they will inform the applicant, and that the Applicant must respond within 15 days, or 30 days if requested by the Applicant, as to whether they want to continue with the Interconnection process.

If a Project does not pass either Fast Track Options: the Detailed Study Options.
Upon application and deposit payments, the Distribution Provider will begin to review the application to determine if the project can be studied independently, or whether it needs to be looked at as part of a group or cluster. This must be completed by the Distribution Provider within 20 days from the time the detailed study deposit of $10,000 is submitted. The Distribution Provider will then use criteria found in Screens Q and R within the Rule to make this determination. Forest biomass projects intended to operate under special feed-in-tariff programs (e.g. BioMAT) are very unlikely to be considered into screen Q because Sheet 138 of rule 21 shows that screen Q is only required if the Supplemental Review determines that a transmission protection analysis is needed or the size of the facility is over 3 MW.

A project could fail Screen R, however, if another large renewable energy project was planning on using that substation. In that case, the project would need to move forward under the Distribution Group Study Process (DGS). The details about how the DGS process works can be found in Rule F3c. Because that is an unlikely outcome for most rural projects, the following will focus on the Independent Study process.

The Independent Study (IS) Process

If the project successfully passes screens A-P, screen Q will determine whether the project has interdependencies with other facilities in the network. If the analysis of screens Q and R determine that the project is independent, it can move forward with the Independent Study process. Given the approval of screens A-P, developers have the alternative to move into an Independent Study or a Distribution Group Study process as per sheet 158 in Rule 21.

After notification from the Distribution Provider that a project must proceed with an IS, the Distribution Provider is required to contact the Applicant and schedule a "Scoping Meeting." This meeting will cover several technical items, and should be attended by an Applicant's electrical engineer. After the Scoping Meeting, the Distribution Provider has 15 business days to provide the "Detailed Study Agreement" which includes an outline of a System Impact Study, (SIS) and a Facilities Study (FAC), which will contain a non-binding good faith estimate of interconnection cost for the project. After receiving these documents, the Applicant has 30 business days to execute a contract to engage the Distribution Provider to perform a SIS. At this time, a deposit of $10,000 for such Study is required.

Once the Applicant agrees to continue, the Distribution Provider has 60 days to complete the Detailed Study Agreement, but the Distribution Provider has specific provisions to notify the Applicant about the need and justification to extend this timeframe. The Rule provides generous flexibility to the Distribution Provider.

Once an Applicant has received the final SIS study, they have 10 business days to request a "results meeting". This meeting is important because it gives the Applicant the chance to request changes to the Study. A request for changes must be made within 5 business days of the results meeting. Note that the Applicant may request all back-up materials that justify the conclusions in the Study, but the Distribution Provider may request a Non-Disclosure Agreement as to some of those materials.

While working out any changes needed to the SIS with the Distribution Provider, an Applicant must also make decisions about proceeding with a Facilities Study (FAC), and arranging to make financial deposits to cover estimated costs of interconnection.

A "Pause Button" option within the Interconnection process

This is a critical juncture within the interconnection process for a forest biomass project participating in the BioMAT program. If an Applicant foresees that they may need to wait for more than 60 days to obtain a Power Purchase Agreement (PPA) in the BioMAT procurement queue, or have not yet entered that queue, they may want to allow their interconnection process to lapse, which is now allowed under state law.

Later, when the project strikes at a price and enters into a PPA, the project must renew their Study and get back into the interconnection process within 30 days of execution of the PPA. A new deposit of $10,000 for the renewed Detailed Study Agreement will be

needed at that time, but as this is a deposit, much of this can be expected to be returned to the Applicant, as long as circumstances have not significantly changed at the substation where the project is interconnecting to the grid.

In order to enter the BioMAT queue with an expired SIS, or to maintain a BioMAT queue position when an SIS expires, a deposit must be made to show the CPUC that the project is viable. The deposit amount is equal to three times the current fee under Rule 21 for a system impact study. Using the current system impact study fee of $10,000, the deposit today would be $30,000. This is collected when a project enters the queue, or at the time it leaves the interconnection queue while remaining in the BioMAT queue (i.e., the project fails to make the first financial security deposit within 60 days of receiving the final SIS). The deposit should be refunded less the administrative fee of 10% of the system impact study fee if the project both drops out of the interconnection queue and leaves the BioMAT bidding queue (does not get a PPA). Using the current System Impact Study fee of $10,000, the administrative fee withheld would be $1,000. This deposit is refunded in full (31,000 for a three MW project, for example) to the project proponent when the project signs a BioMAT PPA.

The remaining sections below describe the next steps of the process; when an Applicant is not concerned about the length of time needed to obtain a PPA and chooses to continue with the interconnection process, or the project has obtained a PPA and is now completing interconnection requirements.

The Interconnection Facilities Study (FAC)

The Interconnection Facilities Study (FAC) is a study conducted by the utility to determine a list of facilities, the cost of those facilities, and the time required to interconnect the Generating Facility with Distribution Provider's Distribution or Transmission System. The scope of the study is defined in Section G.3.c of the Rule. Within five business days of the Results Meeting, or 25 days from the issuance of the final SIS, the Applicant and the Distribution Provider must decide together whether to waive a Facilities Study (FAC). The conditions to waive the (FAC) are defined in sheet 91 (it applies to cases where the costs of facilities' changes are negotiated between the utility and the developer or the Cost Envelope option is applied directly, hence further study is not needed). Remember, the Cost Envelope option discussed earlier is only available to facilities that undergo a FAC study. A Facilities Study requires a deposit of $15,000, which is required to be paid within 10 business days from when agreement was reached about any modifications to the SIS, or the time has lapsed to request modifications.

The Distribution Provider has a considerable amount of time to complete the FAC. In cases where no Distribution Upgrades and/or Network Upgrades are identified and the required facilities are limited to Distribution Provider's Interconnection Facilities only, the Interconnection Facilities Study shall be completed within 45 business days. The Distribution Provider has 60 business days to complete the Study if upgrades were identified in the SIS. These timelines relating to Study completion begin from when the Applicant has made their first financial security deposit for the interconnection of the project. This deposit must be made within 60 days of the final SIS delivery to the Applicant if the Applicant wants to maintain its project within the interconnection process.

Financial Security Deposits

The next step after the completion of a FAC, or if that study was waived, the SIS, is to make a series of payments towards the project's interconnection costs. As mentioned earlier, the first financial security obligation is due within 60 calendar days from the Applicant's receipt of the SIS report. Two separate Financial Security instruments are required**.** First, a Financial Security instrument in an amount equal to the lesser of (i) fifteen percent (15%) of the total cost for Network Upgrades, or (ii) $20,000 per MW of electrical output, is due. Second, a Financial Security instrument in the amount of twenty percent (20%) of the total estimated cost for Distribution Provider's Interconnection Facilities and Distribution Upgrades is due.

The second financial security obligation is due within 120 calendar days of the final FAC report (or SIS if FAC is waived). First, an Interconnection Financial Security Instrument is due for Network Upgrades, which equals the lesser of (i) $1,000,000 or (ii) thirty percent (30%) of the total cost responsibility assigned to Applicant for Network Upgrades. Second, Interconnection Financial Security Instrument for Distribution Provider's Interconnection Facilities and Distribution Upgrades equals thirty percent (30%) of the total cost responsibility assigned to Applicant for Distribution Provider's Interconnection Facilities and Distribution Upgrades.

The third and final Financial Security obligation is due on or before the Start of Construction for all upgrades. The two separate Interconnection Financial Security instruments must be modified so that they equal 100% of the total cost responsibility, or the total payments in cash must be made.

There are a series of consequences and outcomes if during this time the Applicant withdraws their application. To understand what happens to the deposits in that circumstance, see Rule F4e and more generally, F6.

Reimbursements of Deposits

According to Table E2 on Sheet 61 of the Rule, the costs associated with Interconnection Facilities and Distribution upgrades are covered by the Applicant. Costs of upgrades required for the transmission system are partially reimbursed pursuant to the "applicable CAISO Tariff", as described in Table E2 of the Rule. Currently PG&E takes the position that reimbursement is covered under Appendix DD, also known as GIDAP. Currently the maximum amount of reimbursement is $60,000 per MW. This is contrary to the current BioMAT rules that would allow for up to $300,000 total reimbursement no matter the size of the facility. As of the date of the drafting of this paper, there is still considerable confusion about this issue. Note that this reimbursement issue is referred to as "strategic location" requirements.

The General Interconnection Agreement

The Distribution Provider must offer the Applicant a General Interconnection Agreement (GIA) within 30 days of either the issuance of the FAC, or the agreement between the Distribution Provider and the Applicant to waive the FAC. Negotiations over the terms of the GIA must conclude within 90 days, or the Applicant must begin the dispute

resolution process described in Section K. Keep in mind that the timeline in place for this Agreement's execution runs parallel with the Financial Security timelines and does not impact those requirements.

Miscellaneous Questions about Interconnection Studies

What are the confidentiality provisions that affect my Study?

Section D7 of the Rule explains the confidentiality provisions applicable to the interconnection process. Confidential Information shall include, without limitation, confidential, proprietary or trade secret information relating to the present or planned business of Applicant, Customer, Producer, or Distribution Provider (Parties), including all information relating to a Party's technology, research and development, business affairs, and pricing. Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document (including electronic materials), or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential. The only exception to this is that design, operating specifications, and metering data provided by Applicant shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such. If information provided needs to be reviewed by a government agency, then the information is no longer confidential for that specific investigation or governmental purpose.

In conclusion, System Impact Studies or Electrical Generator Interconnection Requests are only as confidential as the Applicant chooses to make them, and as such the Distribution Provider must check with the Applicant before sharing any of the information deemed confidential above, or marked confidential in the files. Usually a Distribution Provider will ask for an NDA regarding any information they want to keep confidential, but if something a Distribution Provider produced is labeled "confidential" be sure to check with the Distribution Provider before you disclose it to third parties.

The timelines within Rule 21 are very flexible for the Distribution Provider.

There are numerous references within the Rule that allow for the Distribution Provider to extend the timelines within the Rule. The primary one is found within Section D14. This section basically states that the Distribution Provider can extend any deadlines that apply to it, with the provision of a written explanation as to the reason for the extension. Meanwhile, Section D15 clarifies that an Applicant must get permission of the Distribution Provider for any timeline extension that it may need. There are a few extensions that an Applicant is entitled to under specific sections of the rule as described above, but the timeline provisions are generally written favorably for the Distribution Provider, rather than the Applicant. The remedy for concerns with these timeline lapses is found under F (1) (d).

Costs that are identified even after your GIA has been executed and the project is complete can still be attributed to the project.

It is worthwhile to point out Section E4c of the Rule, which states that an Applicant may be responsible for costs that are identified even after a GIA has been executed. The justification for this is that if there are projects ahead of an Applicant's that impact the same Line Section that change, then the Applicant may be responsible for unforeseen costs. It is not clear that there is any timeline restriction on the application of this rule, or any cap on the costs that could be attributed after the fact. It is a good idea to investigate with your Distribution Provider staff the state of the line sections associated with your project to determine whether there are any earlier queued projects that have not triggered the need for your project to move through the DGS process, but nevertheless could trigger unforeseen costs. Note that Section F (7) (e) specifically calls out that the Cost Envelope does not include these potential costs.

The Very Real Cost of Ownership (COO) burdens that are not discussed within System Impact Studies.

Another Rule that significantly affects the costs of the interconnection of these projects is Electricity Rule 2. While most of this Rule discusses voltages, load limitations, protective devices, and prevention of interference of system, Section I of the Rule describes how "special facilities" must pay a percentage of the cost that PG&E will incur for maintaining such a facility over time. Projects under 60 kV (BioMAT forest biomass projects fall below this cap) are required to pay a percentage of their distribution and facilities upgrade costs (not transmission upgrade costs). This payment can be made over a period of time, or may be required to be paid in one lump sum, as stated in the Rule. Note that the SIS reports do not calculate this amount, and it is not listed in the final cost charts with any specific value.

Conclusion

The Rule 21 process is a very complicated process that is best done in close consultation with an electrical engineer and assigned Distribution Provider staff. If further questions exist, contact the Distribution Provider and check online resources for the latest version of the Rule, as it changes regularly.

Step Two: Prove Site Control

Once the draft SIS has been received, further documentation proving a long term lease or fee title ownership by the business entity developing the project may be required beyond what was submitted during the Independent Study process. The Utility will ask for a copy of a deed or lease to meet BioMAT program requirements. If a lease is the option of the Project, there are many important aspects of that agreement that must be included in order to meet the requirements of the Subdivision Map Act, Zoning laws, and the terms of the PPA. Be sure to have a lease carefully reviewed by a professional.

Step Three: Partner with Experienced Project Developer

Another item that must be demonstrated for BioMAT program inclusion is participation of an experienced developer on the team. By experienced developer, this means at least one person who has experience building a similar facility, either domestically or internationally. The developer must at least be a consultant on the project, and ideally would have direct experience with whatever technology you has been chosen. Note

that this requirement is fairly broad. At this time, Projects have not been asked to submit developer agreements or other contracts to prove this involvement, but that may change.

Step Four: Getting the Project into the BioMAT Queue

Program Participation Request (PPR) Process

After gathering the information needed as described in the three steps above, it is time to consider placing the project within the BioMAT queue. First, note that there is a cost of 2,000 per MW application fee. Second, if the SIS has expired, a $30,000.00 security deposit is required, of which all but $1,000 will be refunded when the project takes a PPA or drops out of the queue.

In order to do this, a form called a Program Participation Request (PPR) will need to be filed. This form will ask for information pertaining to the three previous steps, and other items pertaining to project technology and other project details.

Primary requirements to submitting a PPR (the rest can be found on the PPR form):

1. Site control: must have direct ownership, a lease, or an option to lease/purchase

2. Developer experience: at least one team member must have completed at least one project of similar technology and capacity

3. Fuel Resource: confirm that feedstock will be derived from eligible sources

Fill out the PPR sections. An electrical engineer or EPC will be needed to fill out technical sections related to interconnection and specific technology selection (such as Operational Characteristics, Delivery Term Contract Quantity, and interpreting Interconnection details from your SIS within the relevant Information section). Other things needed include a Table of Major Components, the Facility Layout Drawing, Forecast of Useful Thermal Output, Dedication of Useful Thermal Output, and the Production Profile. The Single Line Diagram must be submitted as well.

A potentially more time consuming component of the PPR is the Fuel Resource Attestation form. A forester or representative from the entity sourcing the feedstock (such as private timber company or the US Forest Service) should be able to assist in filling out this form, including the detailed questions in Appendix A, confirming eligibility of the feedstock.

If the document is incomplete or the Utility wants more detailed information than initially provided, they will request the information through direct correspondence. Often times there are multiple communications between Applicant and Utility. When the PPR is completed, the project will receive notification and be placed in the queue.

Step Five: Entering into a Power Purchase Agreement

A General Review of the Power Purchase Agreements (PPA) version approved December 2018

The Power Purchase Agreement (PPA) that is available through the BioMAT auction process is a standard contract approved by the California Public Utilities Commission. The terms and conditions of the contract cannot be changed by the Utility or the Seller of power without going to the Commission. This report is not meant to be a comprehensive description of each and every provision of the PPA, but rather, an overview of the key provisions that need special attention by forest biomass projects.

The "Cover Sheet"

The first section of the Contract is a ten-page document in which the project has to supply extensive information about the project. This is the part of the contract in which the Seller of power fills in the information about the project. The remainder of the contract has sections that are boilerplate terms that cannot be changed. To be listed include (1) the fuel resource (which is forest biomass), (2) whether to do a 10-,15- or 20-year contract, and (3) whether the contract is for "full buy/sell" or "excess sale". Forest biomass projects will generally be "full buy/sell" because most will sell all electricity produced to the utility. "Excess Sales" contracts theoretically allow for the sale of variable amounts of electricity if co-located businesses use power onsite, or is sold to contiguous property owners. With BioMAT PPA's however, it is not permitted to sell variable amounts of electricity without paying penalties, which will be discussed further below., As such there are effectively no 'excess sales' contracts. This means that Seller of power must be sure about amounts that will be delivered to co-located businesses or over the fence sales.

Note that it is worth exploring what the choice of full buy/sell or excess sale means for a project's ability to qualify for different Time of Delivery (TOD) prices or "Resource Adequacy" as defined by CAISO.

The Cover Sheet will also require repeat Facility and Site Description information described in previous documents like the Application for Electrical Generator Interconnection Request, and for the BioMAT queue. Additionally, a more specific choice about the facility requires the choice between a "small power production facility," as described in 18 CFR §292.203(a), 292.203(c) and 292.204, or a "topping-cycle cogeneration facility," as defined in 18 CFR §292.202(d), or a "bottoming-cycle cogeneration facility," as defined in 18 CFR §292.202(e).

A small power production facility includes a set of different variables, size of the facility (maximum nameplate capacity may not exceed 80 MW, but there are exceptions) and the primary energy source of the facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources. Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass. Also, use of oil, natural gas, and coal by a facility, is limited to the minimum amounts of

fuel required for ignition, startup, testing, flame stabilization, and control uses. Basically, most forest biomass projects in the state of California are a 'small facility'. Also, most such facilities are a "topping-cycle cogeneration facility" which means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the residual heat from the electricity generation process is then used to provide useful thermal energy. These are facilities like saw mills that use the energy to generate electricity but use the waste heat for other applications like drying or heating.

For reference, a bottoming-cycle cogeneration facility is a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the residual heat from the process is then used for power production. These are facilities that use the energy sources mainly to produce heat and the residual energy is used for electricity, for example cement plants that use residual heat from the kilns to produce electricity.

The Cover Sheet also requires to reiterate information about equipment, including that used for interconnection. Additionally, the contract price will be listed and then a significant choice must be made about how much electricity the project guarantees will be generated each year of the contract. Failure to meet the quota will trigger a penalty, and conversely, the utility will only pay 75% of the PPA price for electricity produced over the contract quantity stated in the cover sheet. The full consequences for failure to meet guaranteed electricity production amounts are discussed in more detail later in this document.

There is a Collateral Requirement Payment or Letter of Credit in the amount of $20,000 per MW required to enter into the PPA. The fate of this money is described in Section 12 of the PPA, and basically says that the funds/Letter of Credit will be returned within one year after the term of the PPA has expired, less any fees or charges outstanding.

The next section of the Cover Sheet requires information about the "curtailment orders" and requests information such as (i) Minimum operating capacity per MW, (ii) Ramp Rate: MW per Minute (iii) Maximum number of Curtailment Orders per calendar day (if any such operational limitations exist), (iv) Maximum number of Start-ups per calendar day (if any such operational limitations exist, and (v) Advance notification required for a Curtailment Order (in Minutes). Other information needed include Start-Up Time (if applicable) in Minutes, Minimum Run Time after Start-Up (if applicable) in Minutes, and Minimum Down Time after Shut-Down (if applicable) in Minutes.

The next section requests that the seller sets its Milestone Calendar for the project. The Utility warns that the operator should give "maximum flexibility" to timelines given the constraint of any given technology. At the same time, the commercial operation date needs to be considered when setting project milestones. After the project milestones have been completed, there is a list of contacts at PG&E who can assist in various ways on the project, and the project is required to list their contacts, as well. To get a good understanding of how to fill out the Cover Sheet, a full understanding of the rest of the contract is required, as reviewed below.

General Terms and Conditions

The following explains and references Sections 1 – 20 in the PPA as of the date of this paper.

SECTION 1 - COMMERCIAL OPERATION DATE

The project must commit to being operational within 24 months from the date the PPA is executed, or from the date that an updated interconnection study is complete (if the project entered the queue with an expired study). There are a series of reasons that a project may get a six-month extension, but they are limited, with no extensions beyond 30 months.

SECTION 2 - CONTRACT CAPACITY AND QUANTITY; TERM; CONTRACT PRICE; BILLING

Section 2 begins with the important limitation to the size of the facility; facilities can have a name plate maximum capacity of 5 MW, but the total contract capacity with the utility must be under 3 MW. Then, the Section reiterates the term of the contract based on what is filled in within the Cover Sheet (either 10,15 or 20 years). Section 2 also includes the specific list of items that must be completed to be considered operational (meeting Commercial Operation Date). Other information relating to price difference between full buy/sell and excess sale, Time of Delivery Pricing details (TOD), and what the Utility will pay when electricity generation is over or under the stated quantity is covered within Section 2, and other administrative items including details for billing and invoicing. For reference, the TOD pricing is listed within Section 2.7.3, and states:

2.7.3. The monthly payment will equal the sum of (a) the sum of the monthly TOD Period payments for all TOD Periods in the month and (b) the Curtailed Product Payment for the month ("Monthly TOD Payment"). Each Monthly TOD Payment will be calculated pursuant to the following formula, where "n" is the TOD Period being calculated:

TOD PERIOD PAYMENT = A × B × (C - D)
Where:
A = then applicable Contract Price, in $/MWh.
B = The Payment Allocation Factor for the TOD Period being calculated.
C = The sum of Energy recorded by the meter specified in Section 5.2.1 or Check Meter, as applicable, in all hours for the TOD Period being calculated, in MWh.
D = Any Energy produced by the Facility for which Buyer is not obligated to pay Seller as set forth in Section 2.7.1.

See within Appendix C of the PPA the following allocation factors:

Energy-Only Payment Allocation Factors

Monthly Period	**1. Peak**	**2. Mid-Day**	**3. Night**
July – September	1.479	0.604	1.087
October- February	1.399	0.718	1.122
March – June	1.270	0.280	1.040

Note that there is no benefit in opting for full deliverability in terms of TOD pricing (see Appendix C of the PPA - there is no difference in allocation factors), although there may be other benefits.

Another very important part of this Section fully defines “contract quantity”, which a project must set within the Cover Sheet. The contract states that the amount of energy delivered can be reduced at two different times: once within the first two years of the contract, and one additional time thereafter. There is no opportunity to increase contract capacity once the PPA has been executed.

Section 2 is important to review before setting the contract quantity, and is the most important aspect of developing the PPA. This Section should be filled out by the Experienced Developer on the project’s team. Also, review the Section 12 below on Guaranteed Energy Production for more information.

SECTION 3 - WREGIS; RESOURCE ADEQUACY BENEFITS; ERR REQUIREMENTS; QUALIFYING FACILITY STATUS

If the project is eligible for a CAISO revenue meter (check with your developer partner) there are sections within this Section 3 that relate to the Western Renewable Energy Generation Information System (WREGIS) credit issuance. WREGIS is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC), which includes CAISO. WREGIS tracks renewable electricity generation from units that register in the system by using verifiable data and creating renewable energy certificates (RECs) for this generation. If the project is less than 1 MW and ineligible for the meter, then the project is responsible for “causing and allowing” the utility to be the “Qualified Reporting Entity” and “Account Holder” (as such terms are defined by WREGIS) for the Facility within thirty (30) days after the Commercial Operation Date.

As to Resource Adequacy during the Delivery Term, the Seller grants, pledges, assigns, and otherwise commits to Buyer all of the Contract Capacity, including Capacity Attributes, if any, from the Project to enable Buyer to meet its Resource Adequacy or successor program requirements, as the CPUC, CAISO or other regional entity may prescribe (“Resource Adequacy Requirements”). Note that “Resource Adequacy” is the term used for the procurement requirements of the utility, for example the energy that is required to be purchased by the Renewable Portfolio Standard statute, and implemented by the CPUC. See the contract for more details.

The PPA also requires that the project maintain its certification as an Eligible Renewable Energy Resource or ERR, which is a process maintained by the California Energy Commission. Specific details within Section 3.6 describe the process if there are cost issues associated with this compliance.

The last certification covered in Section 3 requires the project to maintain its “Qualifying Facility” (QF) status with the Federal Energy Regulatory Commission (FERC), but the provision recognizes that the PPA will still be valid if a law changes the facility’s

status. Also, the project is not obligated to take any actions or make any filings to the extent that no action or filing is required by FERC to obtain, or maintain the Qualifying Facility status of the Facility. Check with the project developer to determine if anything is needed.

SECTION 4 - REPRESENTATION AND WARRANTIES; COVENANTS

This Section includes a number of provisions that require the project to meet standard conditions of a contract, such as proving that the company is solvent, complying with all laws, and generally has the capacity to enter into the PPA. Additionally, the section again requires compliance with ERR definitions as described above, and that the project has not participated in the Self-Generation Incentive Program in the past.

Section 4 also describes how projects that no longer have an active Interconnection Study must submit a new Interconnection Study application for the Project no later than thirty (30) days from the Execution Date of the PPA, and Seller shall notify PG&E two times in relation to the Study process; first they must submit an interconnection queue position number within five (5) Business Days from receipt of such number, and a second notice of an Interconnection Study Completion Date no later than five (5) Business Days from the Interconnection Study Completion Date.

The last part of Section 4 covers the fuel requirements as stated in SB 1122. At least 80% of the fuel used at the facility must come for sustainable forest resources and the other 20% must be fuel that would qualify under one of the other categories of the program, such as agricultural waste, or urban biomass waste. Annual attestations of biomass sources are required. Additionally, based on the state's interest in dealing with the tree mortality crisis in California, the CPUC has required that facilities keep track of any 'High Hazard Zone' fuel that gets used at the facility, with quarterly reporting requirements. Additionally, there is language in Section 4.4 for any projects that want to try to enter into a PPA for a project that uses 80% of the fuel from high hazard zones.

SECTION 5 - GENERAL CONDITIONS: CAISO AGREEMENTS, METERING REQUIREMENTS, ACCESS RIGHTS, RECORDS RETENTION, CURTAILMENT, MODIFICATION TO FACILITIES, GREENHOUSE GAS EMISSIONS, ADDITIONAL INCENTIVES, SITE CONTROL AND SAFETY PLAN

This Section goes into detail about CAISO agreements and metering data and requirements. It includes a general statement about maintaining a professional standard of care, and discusses access rights on the property. This Section also clarifies that the utility may visit the facility during normal business hours, to ensure that the facility is consistent with the PPA, and all laws.

The Section also discusses that the project must keep a daily log book that describes information on power production, fuel consumption, efficiency, availability, maintenance performed, outages, results of inspections, manufacturer recommended services, replacements, electrical characteristics of the generators, control settings or adjustments of equipment, protective devices, information and documentation related to Fuel Use and the Fuel Resource Requirements, and any other pertinent information that

affects plant operations. Within 20 days of a request, the Project must provide the utility a copy of the log books. There is also an extensive list of documents that must be retained.

Curtailment, forecasting, and telemetry are all described in the later parts of Section 5, but refer to Appendix D and later sections of the PPA for more specific information. For reference, a Curtailment order can be issued by CAISO or PG&E when there is a need for a facility to stop producing power. When CAISO issues an order, the utility will not pay for electricity production lost. If the utility issues the order, they still do not have an obligation to pay, but they may pay based on the most recent Notice of forecasted Expected Generation Output Buyer has received from Seller at the time of the Curtailment Order. In the event this forecast is not representative of past performance of the Facility, Buyer shall apply accepted industry standards in making such an estimate and take into consideration past performance of the Facility and any other relevant information. Seller shall cooperate with Buyers requests for information associated with any estimate made hereunder.

Modifications to the Facility are strictly controlled under section 5.11, require a 90-day notice to the Utility if it is planned, and written consent is at the sole discretion of the Buyer. Material modifications or alterations include, but are not limited to, (a) movement of the Site, (b) changes that may increase or decrease the expected output of the Facility (other than decrease based upon any adjustment to the Contract Capacity based on the Demonstrated Contract Capacity), (c) changes that may affect the generation profile of the Facility, (d) changes that may affect the ability to accurately measure the output of Product from the Facility, and (e) changes that conflict with elections, information or requirements specified elsewhere in this Agreement (other than, to the extent not covered by clauses (a) through (d), as specified in the Cover Sheet). Material modifications or alterations do not include maintenance and repairs performed in accordance with Prudent Electrical Practices.

The party who enters into a PPA must be the party who maintains site control. If another party obtains site control, the Utility must be notified. At this time, it is unclear what would be required of the Seller if they wanted to transfer site control to another entity, but it is likely the new party would need to assume some, or all, of the responsibilities under the PPA. What is clear is that permission must be sought from the Utility to make this change.

The Seller shall provide to the Buyer, prior to commencement of any construction activities on the site, a report from an independent engineer (acceptable to both Buyer and Seller) certifying that the Seller has a written plan for the safe construction and operation of the Facility in accordance with Prudent Electrical Practices.

SECTION 6 and 7 - INDEMNITY AND LIMITATION OF DAMAGES

The PPA template provides that each party will indemnify the other for liability that arises due to the other party's negligent or tortious act. But, consequential, incidental, punitive, lost profits or other business loss-based claims are not covered, and are waived by both parties.

SECTION 8 - NOTICES

Notices (other than forecasts, scheduling requests and curtailment (or equivalent) instructions) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail). For notices related to forecasts, scheduling requests, and curtailment (or equivalent), see those Sections or the related Appendixes.

SECTION 9 - INSURANCE

The insurance requirements are extensive. A brief summary includes the following policies that must be rated with an " A.M. Best's Insurance Rating of not less than A-: VII".

- Commercial general liability insurance, written on an occurrence, not claims-made basis, covering all operations by or on behalf of Seller arising out of or connected to the PPA with a combined single limit per occurrence and annual aggregate of not less than one million dollars ($1,000,000), exclusive of defense costs, for all coverages. This must be maintained for a period of four years past the expiration date of the PPA.
- Workers' compensation insurance with statutory limits, as required by the state having jurisdiction over Seller's employees, and employer's liability insurance with limits of not less than: (a) bodily injury by accident - one million dollars ($1,000,000) each accident; (b) bodily injury by disease - one million dollars ($1,000,000) policy limit; and (c) bodily injury by disease - one million dollars ($1,000,000) each employee.
- Commercial automobile liability insurance covering bodily injury and property damage with a combined single limit of not less than one million dollars ($1,000,000) per occurrence. Such insurance must cover liability arising out of Seller's use of all owned, non-owned, and hired automobiles in the performance of the Agreement.
- Umbrella/excess liability insurance, written on an occurrence, not claims-made basis, providing coverage excess of the underlying employer's liability, commercial general liability, and commercial automobile liability insurance, on terms at least as broad as the underlying coverage, with limits of not less than four million dollars ($4,000,000) per occurrence and in the annual aggregate.

Section 9.2 describes in detail what evidence must be provided to ensure these insurance provisions can be met, as well as timelines for proof of insurance.

SECTION 10 - FORCE MAJEURE

The provision for Force Majeure is similar to most contracts, acts of God can provide for a justifiable reason not to perform under the PPA. There are two unique provisions however, that should be noted. The provision reads:

"Neither Party shall be in default in the performance of any of its obligations set forth in this Agreement, except for obligations to pay money, when and to the extent failure of

performance is caused by Force Majeure. Nothing in this Section 10 shall relieve the Seller of the obligation to achieve Commercial Operation on or before the Guaranteed Commercial Operation Date, as may be extended pursuant to Section 1.1."

The unique language is that the obligation to pay money cannot be avoided because of Force Majeure. Second, the contract will not allow for extensions of the Commercial Operation date due to Force Majeure; meaning if the deadline is missed, the Utility can cancel the PPA. Also, the suspension of the Claiming Party's performance due to Force Majeure may not be greater in scope or longer in duration than is required by such Force Majeure.

The contract may be terminated due to Force Majeure.

SECTION 11 - GUARANTEED ENERGY PRODUCTION

The Power Purchase Agreement (PPA) template requires that facilities commit to delivering a specific amount of energy to the Investor Owned Utility (IOU). This amount is calculated over a two-year time period based on the PPA's stated "Contract Quantity." The "Contract Quantity" during each Contract Year is the amount set forth in the applicable Contract Year in the "Delivery Term Contract Quantity Schedule", as the Developer has filled in on the Cover Sheet, which amount is net of Station Use, and, for Excess Sale arrangements, Site Host Load.

Seller shall have the option to decrease the Contract Quantity for any or all Contract Years of the Delivery Term Contract Quantity Schedule one (1) time if the Contract Capacity is adjusted based on the Demonstrated Contract Capacity within ten (10) Business Days of Buyer's Notice of such adjustment to the Contract Capacity or the date of the Engineer Report, as applicable. Additionally, Seller may provide Notice to Buyer during Contract Year 1 or Contract Year 2 of the Delivery Term to request a decrease to the Contract Quantity for any or all Contract Years in the Delivery Term Contract Quantity Schedule. Upon Buyer's approval, the adjusted amounts shall thereafter be the applicable Delivery Term Contract Quantity Schedule.

The Guaranteed Energy Production (GEP) requires that a project produce at least 90% of the amount of power listed within the PPA over a two-year period. If a facility does not deliver the contracted GEP, then a penalty is imposed based on the amount that energy production fell below the GEP. The PPA states that the Parties agree that the damages sustained by Buyer associated with Seller's failure to achieve the Guaranteed Energy Production requirement would be difficult or impossible to determine, or that obtaining an adequate remedy would be unreasonably time consuming or expensive and therefore agree that Seller shall pay the GEP Damages to Buyer as liquidated damages. In no event shall Buyer be obligated to pay GEP Damages. Appendix F of the PPA describes how to calculate the damages.

In summary, the damages are calculated by multiplying the difference between GEP and actual production and the difference between the replacement costs for the electricity that was not generated and the project contract price. The replacement cost for electricity is calculated as the sum of the " simple average of the Day Ahead Integrated Forward Market hourly price, as published by the CAISO, for the Existing

Zone Generation Trading Hub, in which the Project resides" and a $50/MWh fee. The difference between the replacement costs and the contract price can never be less than $20/MWh and cannot be greater than 75% of the contract price (in $/MWh). To determine this penalty, the CAISO price must be determined for the appropriate Generation Trading Hub.

A project may be tempted to underestimate production due to these penalties, but the PPA also punishes the project when there is over-production of electricity. Section 2.6.2. states that in no event shall Buyer be obligated to receive or pay for, in any hour, any Delivered Energy that exceeds one hundred ten percent (110%) of Contract Capacity and the Contract Price for such Delivered Energy in excess of such one hundred ten percent (110%) of Contract Capacity shall be adjusted to be Zero dollars ($0) per kWh. Section 2.6.3. says that in any Contract Year, if the amount of Delivered Energy exceeds one hundred twenty percent (120%) of the annual Contract Quantity the Contract Price for such Delivered Energy in excess of such one hundred twenty percent (120%) shall be adjusted to be seventy-five percent (75%) of the applicable Contract Price.

The combination of these provisions makes the estimation of energy production an important component of receiving full possible compensation under the PPA.

SECTION 12 - CREDIT AND COLLATERAL REQUIREMENTS

This section outlines the requirements for the Letter of Credit for $20,000 per installed MW that is described within the Cover Sheet section above, and other details pertaining to this deposit requirement, see the Contract for the straight forward requirements.

SECTION 13 - EVENTS OF DEFAULT AND TERMINATION

To begin, at the time of the writing of this Handbook, the CPUC is in the process of amending the template PPA to eliminate Section 13.2.1.1, which terminates the agreements if a party is bankrupt. It appears at this time that the utility and CPUC are attempting to maintain the viability of the program by making appropriate changes.

The PPA automatically terminates the day after the final day of the contract term. Early termination can only take place because of Force Majeure, discussed earlier, or through this Section. This Section lists the five ways the Utility's actions could lead to a cancellation, and over a dozen ways that the project's actions could lead to cancellation. If one of the parties wants to claim default, there is a specific way described to give notice, and calculate penalties.

If either Party exercises a termination right under Section 13 after the Commercial Operation Date, the non-defaulting Party shall calculate a settlement amount ("Settlement Amount") equal to the amount of the non-defaulting Party's aggregate Losses and Costs less any Gains, determined as of the Early Termination Date. Prior to the Commercial Operation Date, the Settlement Amount shall be Zero dollars ($0). If the non-defaulting Party's aggregate Gains exceed its aggregate Losses and Costs, if any, determined as of the Early Termination Date, the Settlement Amount shall be Zero

dollars ($0). The Buyer shall not have to enter into replacement transactions to establish a Settlement Amount.

Another aspect of an early cancellation of a PPA is the two year "Restricted Period" that is required under this Section. If Seller terminates this Agreement, as provided in Sections 13.10 or 10.4 (based on a Force Majeure as to which Seller is the Claiming Party), or if Buyer terminates this Agreement as provided in Sections 13.2.2.2 and 12.3.1, or due to an Event of Default of Seller prior to the Guaranteed Commercial Operation Date, neither Seller nor Seller's Affiliates may sell, or enter into a contract to sell, Energy, Renewable Energy Credits, Capacity Attributes, or Resource Adequacy Benefits, generated by, associated with or attributable to a generating facility installed at the Site to a party other than Buyer for a period of two (2) years following the effective date of such termination ("Restricted Period").

This prohibition on contracting and sale will not apply if, before entering into such contract or making a sale to a party other than Buyer, Seller or Seller's Affiliate provides Buyer with a written offer to sell the Energy, Renewable Energy Credits, Capacity Attributes and Resource Adequacy Benefits to Buyer at the Contract Price and on other terms and conditions materially similar to the terms and conditions contained in this Agreement and Buyer fails to accept such offer within forty-five (45) days after Buyer's receipt thereof.

It is important that a Project understand the consequences of early termination when entering into a PPA. A key point is that cancellation *before* the Commercial Operation Date is limited to the loss of the Collateral Requirement found in the cover sheet, which is $20,000 per MW.

SECTION 14 - SCHEDULING COORDINATOR, PENALTIES; CAISO CHARGES; GOVERNMENTAL CHARGES

This Section clarifies that the Utility pays all scheduling and imbalance fees charged by CAISO, except in some circumstances that are listed within this Section.

SECTION 15 - RELEASE OF INFORMATION AND RECORDING CONVERSATION

This Provision states that the Project authorizes the Utility to share information that it has about the Project with government agencies, and also clarifies that either Party agrees to have any and all conversations recorded.

SECTION 16 - ASSIGNMENT

Generally speaking, the PPA can be assigned by the Project (or the Utility) if the other party consents, and such consent shall not be "unreasonably" withheld. The PPA requires a series of conditions to any assignment, which generally assure that the new party will assume all obligations. There is a specific provision relating to the assignment of financing providers, which requires compliance with Appendix I of the PPA. That Appendix should be reviewed to see if such an assignment is needed. Finally, this

Section requires the Project to give notice if the controlling interest of the project changes.

SECTION 17 - GOVERNING LAW

California law is the governing law of this PPA. This section is specifically noticed as not modifiable.

SECTION 18 - DISPUTE RESOLUTION

The contract goes over what is to happen if there is a contract dispute between the Parties. The sole procedure to resolve any claim arising out of or relating to this Agreement is the dispute resolution procedure set forth in this Section 18, except that either Party may seek an injunction in a Superior Court close to the location of the headquarters of the Utility - within the state of California if such action is necessary to prevent irreparable harm, in which case both Parties nonetheless will continue to pursue resolution of all other aspects of the dispute by means of this procedure. The rest of the Section describes the Arbitration process, which can be reviewed if a dispute arises.

SECTION 19 - MISCELLANEOUS

This Section simply goes over issues related to contract interpretation and standard provisions of contract law that are relevant in contract disputes.

APPENDICES LIST FOR REFERENCE

APPENDIX A – DEFINITIONS
APPENDIX B – COMMERCIAL OPERATION DATE CONFIRMATION LETTER
APPENDIX C – TIME OF DELIVERY PERIODS AND PAYMENT ALLOCATION FACTORS
APPENDIX D – FORECASTING AND OUTAGE NOTIFICATION REQUIREMENTS
APPENDIX E – TELEMETRY REQUIREMENTS
APPENDIX F – GUARANTEED ENERGY PRODUCTION DAMAGES
APPENDIX G – FORM OF LETTER OF CREDIT
APPENDIX H – FORM OF GENERAL CONSENT TO ASSIGNMENT
APPENDIX I – FORM OF FINANCING CONSENT TO ASSIGNMENT

APPENDIX J – PROCEDURE FOR DEMONSTRATION OF CONTRACT CAPACITY

APPENDIX K-1 – QF EFFICIENCY MONITORING PROGRAM – COGENERATION DATA REPORTING FORM.

APPENDIX K-2 – FUEL USE STANDARDS – SMALL POWER PRODUCER DATA REPORTING FORM
APPENDIX L – FORM OF FUEL ATTESTATION
APPENDIX M – FUEL RESOURCE FAILURE CURE REQUIREMENTS

Conclusion

The PPA may seem like an overwhelming document, however, the only portions of this document that are filled in by the applicant is the cover sheet. Also, the main issue that should be analyzed, in partnership with the technology provider, is what the Guaranteed Energy Production (GEP) amount will be. This aspect of the PPA should be addressed carefully.

Recall from earlier discussions that if you chose to press the "pause" button on interconnection as discussed earlier, you will need to file for a renewed SIS within 30 days of signing your PPA. A project should be ready to begin making the required deposits for interconnection work to begin soon after a PPA is executed.

Steps Beyond

The next steps after review of this document is the development of basic business tools such as a business plan and Pro Forma, considering financing tools and options, public grants and subsidies, and low-cost loans that are available. Financing a biomass to energy operation is a complicated task, but is achievable; investigate models in other states, and review options with the technology provider, sometimes they offer financing on their equipment, and may have even broader financing options available for a project.

Final Words

As is the case with any emerging technology, small scale forest biomass projects offer challenges, and unique opportunities for community scale development, economic stability for rural communities and opportunities to alleviate the gross need for wood waste option in forested communities in California. The BioMAT program is one tool that can be used to open wood waste options and build that sustainable future that California desires.