CALIFORNIA ENERGY COMMISSION

Market Transformation for Combined Heat & Power Systems in California

(REPORT DATE: DECEMBER, 1999)

CONSULTANT REPORT

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Market Transformation for Combined Heat and Power Systems in California

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What is Market Transformation?

The term "Market Transformation" came into wide use in the 1990's as a way to describe public programs designed to "increase the share of energy-efficient products and services within targeted markets."[1] Despite its wide use, the term is often vaguely defined. In this paper, Market Transformation is defined as a change in laws, regulations and/or utility practices intended to stimulate lasting increase in market share of combined heat and power (CHP) through reduction or elimination of market barriers to CHP in California.

Introduction

Combined heat and power (also known as cogeneration or CHP) is the process of both creating electricity and using heat from the process for other useful purposes. The heat is typically used to create steam for industrial processes, heating and cooling systems, in industrial, commercial and institutional facilities. CHP creates cost savings and environmental benefits by extracting and using more energy from each unit of fuel than a traditional stand-alone electric generator.

CHP has been used in industry for over 100 years. However, energy policy-makers have renewed interest in CHP as a way to gain energy efficiency benefits, lower consumer energy costs, and reduce our country's contribution to the world's atmosphere of global warming gases such as carbon dioxide. Energy service companies in the new competitive market are also interested in providing customers more choices in energy supply, including self-generation, steam and hot water capture for on-site thermal and cooling needs, back-up power for reliability and enhanced power quality.

The market for CHP systems in California may naturally expand in the future due to many factors, including advanced engine designs to improve energy efficiencies, reduced environmental impacts and reduced costs compared to utility system power. However, the speed and extent of CHP market penetration will depend on how the installation and operation of CHP units is treated in the regulatory environment of the emerging restructured energy markets. The goal of "market transformation" is to create policies or provide targeted incentives that will lead to self-sustaining improvements in the market. The transformation may arise from technology innovations, increased customer awareness or regulatory changes that eliminate uncertainties and encourage customers to consider CHP.

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[1] Energy Center of Wisconsin, *A Discussion and Critique of Market Transformation, Challenges and Perspectives*, June 1999. The term is taken from the context of demand-side energy efficiency and applied here to CHP.

In this paper we will explore the nature of the energy regulatory environment and how it impacts a decision to install and operate CHP units in a market where customers have many energy supply choices. Specifically, we will discuss changes in law, regulations and utility practice that would best serve to transform the energy market and to reap the benefits of CHP.

The laws, regulations and utility practices that now influence a decision to install and operate CHP in California fall into five topic areas:

1.0 Local Utility Economics
(There are competing economic interests between the utilities, CHP generators, and other utility customers under current tariffs and regulations.)

2.0 *Energy Market Issues*
(CHP generators face both opportunities and risks in the restructured energy market.)

3.0 Interconnection Rules and Practices
(A significant technical and regulatory hurdle for CHP and other self-generators comes from the need to interconnect and operate within the electric utility system.)

4.0 Environmental and Land Use Regulations
(Small generation plants located in cities and towns raise health and safety concerns at the local government level.)

5.0 Government Tax Policies and Incentives
(Government has a role to play in promoting policies such as CHP that protect the environment and enhance energy security.)

1.0 Local Utility Economics

1.1 Introduction

A CHP unit on a customer site can serve the customer's electric power needs with no connection to the local utility distribution or transmission system. However, the cost-effectiveness of a CHP project usually depends on its ability to physically interconnect with the local utility system. The grid interconnection allows the project owner to purchase energy during outages or routine maintenance of the CHP plant, and with appropriate interconnection protective equipment, to sell energy back to the grid.

The local utilities in California impose charges for this access to the electric grid in standby, backup and distribution wheeling tariffs. Other utility tariffs and current law limit a customer's ability to avoid these costs by circumventing the utility distribution network and constructing a private distribution system or aggregating customer loads and coming between the local utility and the ultimate consumer of electricity. Utilities are also considering a "wires bypass charge" or "exit fee" to pay for distribution investment they believe could be stranded by the creation of new private power parks. Utilities don't want to lose the revenue that would have been collected from a full-requirements customer not benefiting from self-generation or nearby generation. They suggest that customers remaining on the network would have to pick up the tab for such investments unless the self-generator pays for their share.

Therefore, a local distribution utility currently has no incentive to offer low standby or backup charges, or to encourage customer aggregations or self-generation. On the contrary, under traditional regulatory schemes, utility revenues are maximized when all customers pay full costs for utility distribution service and do not pursue self-generation and thus reduce those revenues. This issue is very important to utilities since restructuring because they are now more dependent on earnings from distribution and transmission rather than the generation of electricity. They have a vital interest in maintaining revenue from the "poles and wires" charges for delivery of electricity.

1.11 Legal Standards for Utility Practices

The Public Utility Code provides that "all charges demanded or received by any public utility… shall be just and reasonable. Every unjust or unreasonable charge…is unlawful. (Section 451). In addition, "no public utility shall…make or grant any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage." (Section 453(a)). The fairness standard applies to both publicly owned utilities and investor-owned utilities but are enforced differently. The local board of directors governs the publicly owned utilities; the California Public Utility Commission (CPUC) governs investor-owned utilities.

Proponents of CHP and other types of on-site generation may argue that utility tariffs, practices, and/or market rules discriminate against CHP, are unfair or unreasonable. At the same time utilities may argue that a proposal to reform a rule or tariff is unreasonable or discriminates against other customers. A review of how the standard has been enforced in the past may help illustrate how it may be enforced in the future.

The CPUC has recently wrestled with the application of allegedly discriminatory policies in a variety of proceedings. It has overseen the restructuring of the telecommunications industry where competitive local exchange carriers must be given fair and equal access to utility facilities. It has issued rules on affiliate-utility transactions so that utility-affiliates and competitors have equal access to customer information, billings, and other valuable information. The CPUC regularly decides utility rate cases on the basis that rates must fairly allocate costs among customers based on the cost to serve that customer. Rates that do not adequately collect the cost of service from one class of customers discriminate against other customers who must make up the difference.

The following outlines three principles that help describe what issues are considered when the regulators are trying to develop fair, reasonable and nondiscriminatory utility policies.

First, a nondiscriminatory policy should treat "similarly situated" customers or parties equally. For example, in the context of CHP, this would suggest that all types of small generation should have the same interconnection requirements. It would also suggest that a utility would not be able to impose more requirements on a small generator than it would on itself in a similar circumstance. In order to differentiate between the treatment of CHP and any other distributed generation (DG) installation, there would need to be a rational relationship between the difference in policy and the difference in technology.

Second, a nondiscriminatory policy will appropriately allocate costs to the parties for whom those costs are incurred. This is often expressed as not allowing "cross-subsidization" between customer classes, as well as requiring a fair recovery of costs by the utility. This requirement pre-dates restructuring, but is even more relevant today as suppliers in a competitive market will take advantage of opportunities for cream-skimming. This is the practice of offering lower prices to customers who are being charged above the cost of service by the utility, thus reducing utility revenues and potentially increasing the cost burden on the remaining utility customers.

Third, where there is a policy that does not expressly favor one group over another, but nevertheless operates to exclude or hamper a party's participation in the market, the policy is said to be "discriminatory" or "anti-competitive." These policies lead to arguments for a more level-playing field and proposals to remove regulatory barriers or to impose affirmative action policies in favor of the injured party.

A proposed regulatory policy in support of CHP should be able to withstand scrutiny under these three guidelines. It should treat CHP the same as other generators unless there are exceptional reasons for different treatment. It should fairly attribute costs to encourage development of an efficient marketplace. It should not discriminate in favor of CHP over other generators except if such discriminatory treatment is required to overcome other barriers to a level-playing field. However, applying these concepts in an actual policy decision is very difficult. It is hard to know the true costs of serving a customer, how new technologies will affect those costs, and how customers will respond to new market opportunities. This is the ongoing challenge for policy-makers in the energy industry.

1.12 Local Utility Rate Regulation

Before restructuring, electricity was generated and delivered through vertically integrated generation, transmission and distribution utilities. Traditional "cost-of-service" ratemaking allowed the local utility to earn a regulated rate of return, or profit, on invested capital. Regulators designed rates that gave utilities the revenue required for generation and delivery functions. Now restructuring has made the energy supply portion of the utility service competitive, and the local utility remains regulated for only the delivery (transmission and distribution) portion. Yet, despite the efforts of policy-makers to take local utilities out of the energy supply business, many aspects of local utility rates continue to link the volume of energy sales to each customer with the amount of revenue earned by the local utility.

Prior to restructuring, and even now, local utility rates are designed to collect some fixed costs related to the transmission and distribution network through the "per kWh" charge for energy. Therefore, customer payments that go toward these fixed costs decline when the customer reduces the amount of electricity they buy. Customers can reduce demand through energy efficiency measures or by generating their own power. Under this regulatory framework, a local utility has no incentive to encourage customer generation or demand side management, and may promote policies that protect the revenue stream still associated with the volume of energy sales.

Regulators have explored various ways to de-couple the level of utility profits from the amount of energy flowing through the system. For example, revenue cap regulation is a rate design that limits the total amount of revenue a utility may receive as a function of energy sales. Knowing that electric service revenues cannot exceed this capped amount, a utility has the incentive to operate as efficiently under the revenue cap as possible, rather than increasing energy sales. Performance-based rates further adjust the incentives for utility behavior by increasing profits to local utilities that improve customer service, make only cost-effective investments and run the distribution utility efficiently.

If local utility profitability were not linked to the amount of energy purchased through the system, a cooperative, rather than a competitive attitude, could be fostered between self-generators and the local utility. The disagreements about interconnection standards, the costs of standby service, and conflicts about how the energy market should operate would be eased where the parties both benefit from cost-effective customer energy purchasing decisions. This could help lower the market barriers to CHP and other customer-side small generation.

1.2 Standby and Backup Charges

1.21 Current utility tariffs in California

There are two services provided by utilities to protect customers in the case of a generator outage. The first is a standby service, which is a charge for the right to take energy off the utility system at any time in the future. The customer must pay this fixed charge to reserve wires capacity for the entire month, even if standby service is not activated at all or for only a short time period.

The second service is a backup charge for the energy actually consumed during the time the customer takes energy off the grid. This is a charge per unit of electricity (per kWh), that will vary depending on the tariff schedules, the market price of power or other calculation. Appendix A summarizes the current standby and backup charges of SCE, PG&E and SDG&E. Each differs on the pricing and implementation of standby/backup service.

In SCE's tariff, the charge for standby demand is based on either the nameplate capacity of the customer's generating facility or SCE's estimate of the customer's peak demand, whichever is lower. This full charge must be paid even if standby service is not activated or is activated for only a short time. Backup energy is provided at the customer's otherwise applicable tariff (OAT), including demand and energy charges.

For PG&E, the charge for standby service is based on 85% of the "reservation capacity" contracted for by the customer. If the customer needs more standby service than the contracted amount, the higher standby demand becomes the new contracted capacity amount for 36 months (a 3-year ratchet). The cost of energy to meet backup requirements is in included in Schedule S, Standby. There is not an OAT, so there is no additional demand charge.

For SDG&E, the customer and the utility establish a level of standby service, and like PG&E, if the customer requires more standby service than the contract demand, the increased demand becomes the new contract demand for 12 months (a 1-year ratchet). Backup service is provided at the customer's OAT, including demand and energy charges. Scheduled outages that must occur during the summer peak period may avoid on-peak demand charges at the utility's discretion.

Standby demand charges and backup energy charges should reflect the total cost of interconnecting with and supplying power to a self-generation customer during an outage. Other states, such as Illinois and Texas, have determined that monthly per-kW backup demand charges are inappropriate for self-generators. In those states utility charges are prorated over the on-peak downtime of the self-generator. Charges that would otherwise apply as a "$ per kW-month" charge are converted to a "$ per kW-hour" charge and the customer pays based on the number of hours the outage lasts. The amount the utility recovers is less than would be recovered under a pure demand charge. Appendix B illustrates the different economic results of the different sets of charges.

1.22 Market Transformation

1.221Reassessing the Necessary Level of Standby and Backup Service

Utility standby and backup charges are based on the assumption that a utility must stand ready at all times to provide 100% capacity support all DG customers. This is a questionable assumption. Self-generating customers may require far less standby support than the utility claims to maintain for that purpose.

A simple example shows how this level of support may not be required. If there are 100 1-MW CHP units sharing transmission and distribution line capacity, and each are available 92% of the time, the expected demand on the system at any one time is 8 MW. Yet each member of this class of customers would now pay for 100 MW of standby capacity. It is extremely unlikely that more than 18 of these 100 generators would be down at the same time—in fact, the chance of this is occurring is so remote that the 100 units would meet a reliability level of 99.97%. This is comparable to the reliability level expected from a well- managed utility generating system.

The likelihood that more than 25 units would need support at the same time is zero. Therefore, it would be difficult to justify a requirement that on-site generation pay more than 18% to 25% of the current charges for standby service.

The reality of self-generation in the utility system is more complicated. Not all generation will necessarily share the same distribution feeders, or be located in such way that the combined reliability can be leveraged to reduce the total standby demand required by all the units. Thus, the utility's costs to provide standby will vary between generators. However, as more customers adopt self-generation technologies (and real-time energy pricing and other demand-side management options) utilities should be encouraged to build flexibility in tariffs that purport to collect the "cost of service" to take these realities into account.

1.222 Flexible Firm Service Standby Levels

Many customers would like to opt for no standby service or for a level of standby service less than their peak demand or the nameplate capacity of the generating facility. However, in the SCE Schedule S, Standby, the customer is not allowed to select the level of standby service. This is contrary to SCE's interruptible program (Schedule I-6), where customers are given a rate discount in exchange for allowing the utility to interrupt their electric service during system emergencies. In that tariff, a customer can select a level of firm service below which they would not be interrupted. A similar ability to specify how much outage protection is required for a self-generator is not available under the standby tariffs.

In addition to the requirement to take standby service without the option of selecting the level of firm service, a customer cannot provide its own standby capability. For example, a customer may have a CHP system capable of meeting their normal load and use an emergency generator to maintain only the necessary portion of the load. The customer would not require utility standby for the entire load, just the load greater than that covered by the emergency generator. Because the utilities do not allow a customer to select their desired firm service level, this is not an option.

In fact, SCE's tariffs do not allow a customer to use customer-owned generating equipment for auxiliary, emergency or standby purposes unless SCE's service is not available. This is a common problem for waste treatment facilities. Many waste treatment facilities have CHP systems using digester gas as fuel to create electricity to run pumps. State regulations require the waste treatment facility to have emergency generation to maintain service in the event of an electric outage. Even though these facilities have their own emergency generation as required by law to back up their CHP units, the utility tariffs require them to take standby service from the utility as well.

Allowing customers to choose their desired level of standby service would reduce costs and alleviate this barrier to entry. Requiring customers to pay for standby service above their needs is unjustified, and policies that require duplicative standby systems are not logical.

1.223 Flexible Pricing Options

California utilities do not provide flexible options for standby and backup energy pricing. Customers must take a predetermined amount of standby service and pay energy charges as established by the rate schedules. The reliability of the unit and the frequency of outages are irrelevant and the standby service commitment is fixed.

In reality, customers vary in the amount of risk they are willing to take and how often they believe they will rely on the utility grid for backup energy. They may be willing to suffer interruptions, or they may have backed up their own self-generation system. For example, a CHP generator may have a small standby generator for emergency backup service. The generator may not need outage support unless the outage lasts more than a certain number of hours, when the air quality permit does not allow the diesel generator to run, or when energy prices on the grid are attractive compared to the costs of running the standby generator.

One rate structure that could give such customers a more appropriate price signal would be higher backup energy prices and a lower fixed standby charge. In this way the customer could choose grid support only when necessary but pay a fully loaded cost if and when the outage occurs. This structure would also encourage the CHP industry to develop more reliable units. The higher costs of actually experiencing an outage would justify more costs to avoid that outcome.

The same risk might encourage the customer to alter the size and number of units installed to meet a load. For example, instead of installing a 50-megawatt generator to meet load, an energy service provider might install three 25-megawatt generators, with a guarantee to always meet the customer's load. When market signals were appropriate, the surplus generation could be delivered to the grid. Through these actions, the risk of imposing burdens on the utility system during generator outages would be significantly reduced or eliminated and a lower standby charge or a zero standby charge would be justified.

1.224 Modify the default rate schedule

In California, a customer installing self-generation must purchase standby and backup service with no optional tariffs. Utilities in other states (Michigan, Illinois and Texas for example) offer self-generating customers more choices for standby/backup rates.

For example, some rates could differentiate between planned maintenance outages and unscheduled outages. Planned maintenance outages justify a lower rate because the burden on the utility is less where the outage is known in advance and can occur in off-peak times for that particular feeder.

1.3 Customer Service Rules

1.31 Introduction

Under traditional utility regulation, the local utility had the exclusive right and obligation to generate and deliver electricity to all the customers in the service territory of the utility. This has been modified significantly under industry restructuring; now competitors can generate and deliver electricity over utility lines to customers. The local regulated utility maintains control only over the delivery of electricity.

In some cases the ability to deliver and sell CHP generated power to nearby customers at retail rates help make a project cost-effective. For example, CHP generation comes in many sizes, with larger units generally less expensive per unit of electricity produced than smaller units. Thus, in order to make optimum use of a large CHP unit, a developer may wish to aggregate and serve the electric loads of many nearby customers. This is allowed now only under limited circumstances, as described in more detail below.

In addition, current master-metering rules may make customer aggregations or other shared energy arrangements in new industrial parks or commercial/shopping malls uneconomic or impractical. For the most part, these various rules act in concert to preserve the local utility control and management over all aspects of local utility service, even when a developer and the occupants of the development want to benefit from building, managing or retrofitting their own utility service in a particular area.

1.32 Master Metering and Sub Metering

Master-metering is the practice of consolidating the load of various different customers into a single master-meter through which the utility, or other energy service provider, provides electric service. The customer in charge of the master meter typically collects funds to pay the electric bill through rent or utility fees that do not reflect the actual usage of each customer. Sub-metering occurs when a customer in charge of the master meter actually measures and bills the amount of electricity used by each tenant.

This issue is governed by Rule 18 for SCE and PG&E and Rule 19 for SDG&E. The rules, titled "Supply to Separate Premises and Resale," do not allow sub-metering for commercial customers. Sub-metering is allowed for residential customers only in limited circumstances, such as in older mobile home parks, boat marinas and recreational vehicle parks. Current rules limit sub-metering due to fears of consumer abuse by the manager of the main account. In addition, utilities resist modification of this rule in order to keep direct contact with the ultimate customer and continue to control the terms of their electric service.

The limitations on sub-metering negatively impact CHP developers who wish to serve many different loads. This may be in the context of a new development of mixed commercial and industrial use, or where an energy service provider wishes to install CHP or make energy efficiency investments in a building that serves many different loads. Long-term energy service aggregation, including metering and billing, is necessary to making multi-tenant energy projects cost effective. Individual tenants are understandably reluctant to invest in energy efficiency or other energy equipment in a building they do not own, yet owners have been reluctant to make these same investments because the tenants would get all the benefits through lower electric bills.

1.32 Market Transformation

With more flexible metering and load aggregation options, a property owner could assume responsibility for the energy consuming characteristics of the entire complex. The property owner would be more inclined to undertake efficiency projects such as lighting and HVAC improvements, or even the installation of CHP generation, if they could realize the savings of such projects, and bill tenants for electric service under contracts that are agreeable to all parties. The manager's of the main account may need to be regulated in order to protect consumer's interests, especially residential consumers. However, there is less justification for strict rules for more sophisticated commercial and industrial customers. They can protect their rights through contracts and redress to the court system.

Current limitations on customer aggregation perpetuates a condition of traditional utility regulation that grants low prices to large customers who take utility service at higher transmission level voltages and impose fewer costs per unit of energy consumed than smaller customers. If small customers in a local region were able to aggregate, purchase energy at higher voltage levels, manage and maintain their own metering and billing systems, many costs associated with small customer accounts could be avoided by the utility. Customers would choose aggregation if they could self-provide these services at lower cost than the local utility. In fact, long before industry restructuring, the right of a local government to create a public utility and buy-out the local private system has encouraged investor-owned utilities to keep rates low to avoid this result. Policy-makers should expand customer aggregation rights to maximize these beneficial effects of competition and eliminate the cost-advantages of large customers.

1.4 Regulation of power suppliers as "utilities"

The Public Utility Code provides that private companies selling electric service to the public are "utilities" and may fall under the jurisdiction of the California Public Utilities Commission or subject to other laws governing utility service. (Section 216(b)). Other provisions of the law provide exemptions to this, including generators who sell to the Power Exchange or to customers in direct transactions. Section 216(I). CHP operators also enjoy exemptions under Section 218 which allows the CHP operator to distribute energy "over-the-fence" (sales of electricity or steam to an adjacent facility) to no more than two other customers, and only so long as the seller does not cross a public street.

The Section 218 exemption for CHP was created in the late 70's to enable CHP generators to distribute excess generation to adjacent loads using privately owned lines as well as sell electric power to the utility. During that time, CHP operators could sell generation to the local utility at high prices so there was little need to find additional nearby customers to purchase excess energy. Now there is interest in building "power parks" and other privately owned utility systems that distribute self-generated power within localized areas and interconnect with the transmission grid or to the local utility at the distribution level. The exemption of Section 218 is not broad enough to allow this, and the "direct transactions" exemption of Section 216(I) may only refer to distribution of energy over utility owned lines.

Utilities are concerned that building private networks violates their exclusive right to serve customers in their allocated territories. They argue that allowing competing distribution utilities would create inefficiencies in the network and create cost burdens on existing utility customers. In addition, in exchange for the exclusive right to serve, the utilities have an "obligation" to serve all customers in their service territories. This obligation could become a burden if new customers with attractive load profiles and ability to pay for electric service do not choose to take public utility distribution service.

1.41 Market Transformation

The utilities are no longer offering high prices for capacity and energy under PURPA. Wholesale energy prices are too low today to sustain a project. In addition, restructuring legislation allows all investor-owned utility customers to seek direct access to energy supplies. It would therefore be logical for the legislature to limit the definition of "utility" and clarify the rights of CHP facilities to sell power to nearby customers. This would encourage developers to install CHP units that are cost-effective and sized to best serve the on-site load and distribute energy to nearby customers without fear of becoming a "utility" and therefore subject to rate regulation and other regulatory restrictions now imposed on the local investor-owned distribution utilities.

1.5 Delivery of Excess Electricity

Some customers may have multiple facilities located within the service area of one utility and may wish to install a CHP plant large enough to supply all the locations. Or a CHP plant may wish to supply energy to nearby customers unrelated to the CHP owner. In order to do so, the local utility would have to provide wheeling over its distribution system from the generator to the various locations.

The Public Utility Code provides that in order to achieve meaningful wholesale and retail competition in the electricity generation market, it is essential to "provide customers and suppliers with open, nondiscriminatory, and comparable access to transmission and distribution services." (Section 330(k)).

Currently, if a generator wants to wheel its power to a customer located on the same distribution circuit, the customer who wants the electricity from the generator must pay both transmission and distribution charges under a Wholesale Distribution Access Tariff (WDAT). Some proponents of on-site generation argue that it is unfair to charge for transmission level service when the energy is flowing only on the low voltage distribution system (distribution wheeling). These parties recommend that the transmission charges be pulled out of the rates charged to these customers.

In addition, the charges in the WDAT tariff are based on the total generating capacity of the generating unit on a "$ per kW" basis. Thus, a large CHP plant must pay for the highest level of capacity it will provide, even if actual deliveries of energy are not that large on a continuous basis. A different pricing method is used by the Independent System Operator (ISO) to collect revenues for the of the ISO-controlled transmission grid; in that case, charges are based on energy actually delivered ($ per MWh).

After paying WDAT charges and providing extra generation to make up for line losses, the CHP generator must calculate its generation and load requirements and communicate this information to the grid through a scheduling coordinator. The current costs of wheeling, energy losses and schedule coordination just to dispatch excess generation generally make distribution wheeling uneconomic.

1.51 Market Transformation

A proposal for a distribution-only wheeling service is currently pending before the Federal Energy Regulatory Commission (FERC Docket ER 97-2358). The ISO and some California utilities object to the establishment of the service because any activity on the distribution grid affects the transmission grid. The utilities argue that avoiding costs related to constructing, operating and maintaining the transmission grid would shift these costs to other customers.

FERC has jurisdiction over the outcome of this debate if FERC determines that wheeling over distribution lines is either a wholesale transaction (a delivery to an entity who will then resell the energy to a customer) or is an interstate transaction. If FERC decides the issue should be decided at the local level, such as may be the case for retail distribution wheeling wholly within California, then state legislators and the CPUC could make distribution wheeling charges conform to a standard appropriate for the California market.

Whoever has jurisdiction over the size of distribution wheeling charges, the imposition of high wheeling charges to nearby loads will encourage generator's to bypass these charges by building private distribution lines, to undersize CHP units to avoid wheeling, or to abandon the project altogether as unfeasible.

A wise wheeling policy will encourage energy deliveries that make productive use of the existing investments in the network and encourage more volume of deliveries to reduce costs on a per kWh basis. An unwise policy will over-price wheeling, keep volumes low, push developers to install duplicative networks and keep the cost per kWh delivered relatively high.

1.6 Stranded Utility Investments

1.61 Introduction

California utility customers pay a Competition Transition Charge (CTC) to cover the costs of generating assets that are too expensive to compete in the energy markets. The bulk of these charges may last as long as March 31, 2002, then decline over time until about 2010. The CTC charge is based on volume of energy consumed by each customer, so CTC decreases when a customer uses less utility energy through conservation or by reducing load in other ways. However, AB1890 limits a customer's ability to avoid CTC by installing on-site generation and thereby taking less utility-supplied energy, unless a specific exemption applies.

Customers using CHP energy can avoid CTC through several exemptions. First, no CTC applies if the CHP system was substantially committed to construction as of December 20, 1995 and was substantially operational on or before January 1, 1998. Second, no CTC applies to CHP after June 30, 2000. Third, no CTC applies if the system comes on line between December 1995 and June 2000 and has the ability to start up and run without any support from the grid. If a system comes on line between January 1998 and June 2000 and cannot be started without power from the grid, CTC must be paid through the calculation of a "departing load" charge from the time the unit is operational through June 2000. The departing load charge is the amount of CTC the utility would have otherwise collected from the customer had it remained on the system.

Even if one of these exceptions applies, customers remain responsible for CTC charges contained in other utility tariffs, such as standby tariffs, and all other non-bypassable charges in any "otherwise applicable tariff." Those tariffs will reflect CTC and other restructuring related charges that decline and then disappear altogether around 2010.

Utilities have raised the possibility of a new "wire-bypass charge" to recover what they perceive will be stranded distribution charges in the event a customer installs self-generation and standby charges are insufficient to fully compensate the utility for the investment it has made to serve this customer. At this time there is no such charge. The utilities believe that the standby charge should be high enough to avoid the necessity for an additional wires-bypass charge for self-generators. The public policy dilemma is how to price standby charges low enough to encourage self-generators to stay interconnected to the grid, yet not so high that they choose to isolate themselves and thus completely eliminate this revenue source for the utility.

1.62 Market Transformation

The importance of the issues raised by AB1890 will decline as the stranded costs related to uneconomic utility generation are paid off. However, the general issue of stranded costs will continue to come up whenever the regulated utility perceives that a competitive threat will reduce revenues associated with a regulated utility investment.

As noted above, in AB 1890 there were special provisions to limit the applicability of CTC to CHP generators and provide an early retirement for some CTC charges. Policy-makers recognized that customers should be allowed to take control of their own electric power needs and reduce demands on the electric system without penalty through energy efficiency improvements, fuel-switching and other customer activities on the customer "side of the meter."

Some market participants believe that the issue of stranded distribution investment due to self-generation is without merit. They argue there is no evidence that the revenues for distribution services will decline due to self-generation. They believe that economic growth in the state, more efficient use of the system and the grid benefits of interconnected self-generation will more than make up for any theoretical loss of revenue from self-generation. In the meantime, the threat of a wires-bypass charge or extraordinarily high standby charges will stifle competition and slow the rate of innovation in the market. All consumers would be the losers in this scenario.

1.7 Utility Customer Retention Programs

1.71 Introduction

SCE and SDG&E currently have economic development/customer retention rates that provide some customers discounts off the tariff that would otherwise apply to direct access purchases from a competitor. In SCE's program, in exchange for a seven-year commitment from the customer to remain a full-service customer of SCE, SCE provided discounts for the first five years beginning at 25% and decreasing 5% each year (25% the first year, 20% the second year, etc.) In its 1999 General Rate Case, PG&E requested approval for economic development/customer retention rates. SCE also recently filed a petition with the CPUC to expand its program.

Discounts for large customers were originally designed in the 1970's and 80's to encourage new customers to locate in the service territory of the utility or keep a current customer from relocating to another state or providing their own power through self-generation. The discounted rates charge the customer enough to cover any incremental costs associated with that service and some of the utility's fixed costs. This means at least some incremental revenue goes toward fixed costs that would have been assessed on other customers if the targeted customer did not take utility service. In order to qualify for the discounted rate, the customer had to show that their threat to leave utility service was bona fide—such as an offer by a marketer to install self-generation.

1.72 Market Transformation

Marketers believe the utilities now use these programs to unfairly compete with independent suppliers, including those who are promoting CHP. They believe the regulated utility should not be allowed to undercut competition through these mechanisms. They argue these programs are inappropriate in the restructured market and should not be allowed. The main concern relates to the distribution utility using market power to offer lower prices and other energy services outside its limited role in the market. The regulated distribution utility enjoys an exclusive franchise to be the delivery agent in a certain territory and should not be able to use that status to gain, or retain, market share in the competitive arena.

The energy delivery function of the utility remains fully regulated because of the market power that exists in being the only network in a region. On the other hand, the regulated utilities are encouraged to reduce costs, keep service levels high, and otherwise act as if there is competition in the market for their services.

The CPUC is in the process of adopting "performance based rates" to reward utilities for cost-efficient service. However, offering discounts to keep customers from leaving utility service are, on their face, an inappropriate response to market threats. They are not generally available to all customers, they do not collect all the costs of providing service to that customer, and they are not funded out of increased efficiencies or other true savings.

1.8 Grid Enhancement Credits

1.81 Introduction

The electricity network consists of generating stations, often located in remote locations, linked to one another and to customers through transmission and distribution lines. The size and transfer capability of the lines determines how much power can flow from the generators to the customers. It is possible to relieve pressure on constrained electric power lines by locating new generation close to customers and thereby reduce the amount of power that must flow through the network. This practice allows the utility to defer or avoid upgrades to the electric network, the cost of which would have been borne by all customers through higher rates.

The cost of the transmission and distribution network is a large portion of the total cost of delivered electricity—approximately 52% of each customer's bill[2]. However, at this time, a customer installing on-site generation would not receive any payment or other credit from the utility for T&D costs avoided through installation of local generation. There is no requirement that a utility notify local area customers that there exists an opportunity for grid enhancement services through on-site generation and that they could receive fair compensation for that investment. Nevertheless, utilities agree that local generation can offer local grid benefits and can be a sensible alternative to more expensive line upgrades.

1.82 Market Transformation

All customers would benefit from generators being encouraged to site where grid benefits could be realized. A process for identifying these opportunities, communicating them to the market and choosing the most cost-effective options should be developed. The payment for the grid

[2] Richard Counihan, Green Mountain Energy, "Breaking Down the Barriers to a Truly Competitive Market", presentation to CMA Summer Energy Conference July 23, 1999.

enhancement could be based on the lowest amount bid in a competitive market solicitation or through a valuation methodology that accounts for actual cost savings to the grid, or a "standard performance contract" patterned after California's energy efficiency incentive program. In addition, the operation of the units to provide the most grid benefits as well as provide energy to customers may require well-designed contracts and advanced dispatch controls. These are technical and legal issues that can be solved with the right incentives for both the utilities and the generators.

The value of locating and operating cost-effective generation where it is needed could be reflected in lower standby rates or facilities charges for the local generation. On the flip side, customers taking service in areas wholly dependent on costly utility infrastructure could bear a proportionately higher cost of utility distribution system costs. This approach could be applied to new construction by imposing close to marginal costs of utility system expansion on developers. Accurate price signals should lead them to install the most cost-effective combination of local generation and distribution network infrastructure.

2.0 Energy Market Issues

2.1 Introduction

In the last few decades the electricity market has been evolving to allow more competition among utilities and other energy suppliers. Prior to industry restructuring, utilities could withhold transmission services in order to keep other utilities from getting cheap energy supplies from distant locations. This practice also kept their own customers captive and unable to gain cheaper energy supplies from outside the local utility system. Utilities sold energy only from their own plants and promoted tariffs and policies to discourage customers from installing their own generation or purchasing power from other sources.

Three key events highlight the transition from pure monopoly services to an almost completely open market in California. In 1978, Congress passed the Public Utilities Regulatory Policies Act which required utilities to interconnect with and purchase energy at fair prices from generators who operated on renewable fuels and/or used CHP technologies. In 1992, the Federal Energy Regulatory Commission adopted rules requiring transmission-owning utilities to allow other generators access to transmission under cost-based and non discriminatory rates. Finally, in 1996 California adopted legislation to allow retail customers to purchase energy supplies in the competitive market. (The restructuring rules apply in many respects to both public and investor-owned utilities, but the public utilities are on a longer timeline for compliance. The most notable difference in California is that municipally-owned utilities remain vertically integrated distribution, transmission and generating utilities while investor-owned utilities have sold off generation and no longer operate the transmission grid.)

California created an Independent System Operator (ISO) to manage generators access to the transmission grid. California also requires investor-owned utilities to purchase energy from the Power Exchange (PX), into which generators bid energy and from which energy could be purchased for ultimate delivery to the customer. Under restructuring, management of the local distribution utility remains with the local utility. There is no independent "distribution grid manager" comparable to the ISO.

CHP projects may want to interconnect and transmit energy at the distribution level or the transmission level. The costs and rules vary depending on which route is chosen. In addition, the ability to reach customers for sale of energy, the price that must be paid and the amount that may reasonably be charged for the energy may differ for large and small generators. Policies that level the energy marketplace for small generators will encourage customers to install them and take advantage of the energy markets for surplus energy sales.

2.2 Transmission Policies

The ISO manages the flows of energy on the transmission grid to ensure system reliability. The schedules for deliveries must balance so that no part of the system is over-committed for energy deliveries. When generators request more energy to flow on a transmission line than the line can accommodate, the ISO holds an auction to determine the congestion price for access to that line. The price is what a generator or customer must be paid to generate power (or reduce demand) on the load side of the congestion point and thus relieve the congestion.

The ISO is also charged with planning for transmission system upgrades to meet load growth and enhance operation of the energy markets. As noted above, transmission constraints can limit the ability of generators to access customer loads, as well as increase the value of generators on the customer side of a congestion point. Some current ISO transmission planning activities concern the constrained area of the San Francisco Bay and the system stability problems that may occur if San Onofre nuclear station shuts down in the next few years with no replacement generation at that site.

As part of its grid management functions, the ISO purchases "ancillary services" to ensure that loads will be met with adequate supply when and where demand for energy exceeds the scheduled supply. A heat wave, unanticipated generator outages, and transmission line failures require immediate access to generators that are ready within minutes or even seconds to provide service. The price of ancillary services is set in an auction conducted by the ISO. During the summer months the prices paid for ancillary services can be very high, which has caused the ISO to request FERC to allow them to temporarily "cap" the amount they must pay for such services. The reason for the price spikes is a combination of high demand and short supply of ancillary services, which may be very location specific and limit the market to only a few generators that can therefore "name their price" on occasion.

2.21 10MW rule

Localized generation can add significant value to the transmission grid. Where there is insufficient transmission to deliver sufficient supplies to a load, local generation must be called upon to fill the need. In addition, ancillary services are often in short supply and can be bid at very high prices. However, since the ISO is concerned with transmission level system events, it has set a 10MW minimum bid amount for services. Anything smaller than this is administratively too expensive to consider.

The 10MW level is larger than CHP units that might be installed by small commercial and even industrial customers. If it is true that small generation may not be interconnected at the transmission level, it would follow that it is not within the operational purview of the ISO. Interested parties are discussing with the ISO the potential to aggregate the operation of many small generators in order to meet the 10MW threshold, or to modify the threshold to accommodate more small generators. The distinction between transmission-level and distribution-level interconnection of CHP is artificial from the standpoint of its effect on the system. The ISO is reviewing whether aggregated CHP can be recognized as relieving congestion from the distribution system up to the transmission system.

2.22 System Planning Practices

ISO is charged with planning for system upgrades and ensuring system reliability into the future. As described above, some transmission problems can be solved by the appropriate installation of generation on the load side of a congestion point. ISO planners are now exploring the ways in which it can encourage the cheapest and most reliable combination of transmission upgrades and generation siting. This could include CHP projects or other generation in areas with too little generation, or extra charges to new generators located in areas in need of transmission upgrades.

It is unclear at this time how the ISO will perform this planning function. It has only been in existence for 18 months and many other agencies have an interest in transmission reliability – the California utilities, the Western Region Reliability Council and the Electricity Oversight Board. The Federal Energy Regulatory Commission has final jurisdiction on any tariffs, fees or access charges proposed by the ISO. The California Energy Commission has siting jurisdiction over large (50MW and above) generating plants and associated facilities to the first point of interconnection, and is thus interested in the ability of new generation to interconnect and operate in the current transmission network.

The "size" issue may come into play in this planning process. It may not be cost-effective for the ISO to plan for many small generators if one or two large generators in a constrained area could provide the same reliability services. It may be up to energy planners to make it easier to aggregate the loads of many small generators and thus compete on an equal basis with the larger units in addressing the needs of the transmission system.

2.23 Market Transformation

The cost-effectiveness of CHP and other small generation may depend on how it can or cannot participate in many of the new markets established by restructuring. Policy-makers should attempt wherever possible to identify and overcome barriers associated with the small size of many advanced generating units. In addition, transmission and distribution planners must include in their forecasts that customers may install local generation at an accelerated pace for their on-site purposes, and that the need for network upgrades may be affected by these customer activities. In a restructured market, policy makers will need to consider the complex interaction of transmission and distribution investment decisions, power plant siting and customer choices to install local generation.

2.3 Market Power Issues

2.31 Introduction

The restructured electricity market is designed to provide customers a choice of electricity providers from many companies offering service at competitive prices. There are now many companies registered as Energy Service Providers selling electricity to California consumers. The generation to fulfill these contracts can flow to California from as far away as Canada, Utah and Mexico. It is hoped that competition and customer choice in this large and dynamic energy market will result in lower prices, wise-investment in new generation, and technical innovations to improve service and further reduce prices.

There are some serious threats to successful operation of the restructured market. The competitive prices and environmental benefits of technology will not be realized where one or more market participants can assert market power to limit competition. For example, where a customer is limited to one or only a few providers, that provider may be able to extract an above market price for the service. On the other hand, if the same company has the ability to extract high-prices from some customers and pass along the premium to other customers as a discount, the company can undercut and force other competing providers out of business. Another example of market power in the electric industry occurs where a utility distribution company uses their status as the only "poles–and-wires" company to undercut ESPs in providing electric service to customers.

Traditional utility regulation rewarded utilities for making investments and expanding their customer base by allowing utilities to recover the costs of such investments plus a reasonable rate of return through customer rates. This fueled the expansion of generation and utility networks in the last 100 years. Now "performance-based rates" to be adopted by the CPUC will diminish the link between making investments and earning a profit. The utility will also be rewarded for cost-efficiencies, customer service, reliability, and other positive attributes of utility service. However, the link between investment and profits is not completely severed. Utilities naturally do not want to lose revenues to competitors and they would like to maximize revenues for any new investment they make. This is appropriate so long as they do not use their status as monopoly service providers to unfairly compete in the market.

Much of the restructuring legislation in California is devoted to reducing the chance that market power can be exerted by local distribution utilities in the electric industry. However, the following discussion outline some areas where the market power issues are not yet resolved and which could limit the ability of CHP to expand in California.

2.32 Utility Ownership and Control of Distributed Generation

Restructuring of the electric industry was designed to separate the business of generating electricity from the business of delivering electricity from the generator to the customer. Customers can now choose their electricity supplier and are only limited to the local utility for distribution services. This separation of functions was created to both free up the electricity market and to better regulate the remaining delivery functions of the utility.

Many market participants argue that the goals of restructuring would be compromised if local utilities were allowed to own and operate local generation. They maintain that if a local utility wants to locate generation on a distribution feeder to reduce grid congestion, the grid enhancement benefits should be contracted for in the competitive market, provided by customers or energy service providers who offer the lowest bids to provide the service. On the other hand, local utilities argue that for safety and reliability purposes they should be allowed to own and operate the local generation. However, there is no evidence that non-utility owned generation is inherently less safe or reliable than utility-owned generation.

A further distinction is often drawn between generation located on the "grid-side" of the customer's meter, and generation located on the customer side of the meter. Some argue that grid-side generation should be owned and operated only by the utility, while customer-side generation could be owned and operated by the customer. This is mainly related to control and safety questions, such as who should have the ability to dispatch or shutdown the unit. The debate also arises because of a traditional assumption that customers should have freedom on "their" side of the meter to use or not use energy as they desire, while keeping the grid firmly in the hands of the local utility with the exclusive franchise to provide utility services.

No matter where on the customer's site a new generator is located, we can assume that the local utility's dominant position as the single network would give it an advantage over competitors in the marketing of energy services to that customer, including the decision to site a generation unit. Evidence to support this assumption exists in the telecommunications industry, where traditional, incumbent phone companies compete head to head with competitive carriers in the provision of telecommunications services. Under the Federal Telecommunications Act of 1996, the incumbents were not required to divest their non-network services from the network side of the business as was required of electric utilities under AB 1890 in California. The competitive telecommunications companies compete directly with the incumbent telephone companies to provide services on the incumbent's own network, requesting interconnection, customer switch-over, maintenance and support from the same company that competes with them to provide the same services. This conflict-of-interest has created an ongoing and as yet unresolved dispute at the CPUC between the incumbents and competitors, with the competitors alleging that the incumbents engage in bad faith and unfair tactics to preserve their dominant market position.[3]

2.33 Locational Pricing Practices

The electricity network does not allow unlimited amounts of generation to flow from one location to another. The transmission and distribution lines can only transport power to a certain rated capacity level. This allows some generators better access to some customers than to others due to their proximity and the limited ability of more distant generators to transport electricity over the network. This mainly occurs only at "peak" times when the transmission and distribution lines are full due to high customer demand for power. High temperatures, transmission line outages and generator outages can all contribute to constrained conditions in parts of the state.

During system emergencies and peak periods for electricity demand, being in the right place at the right time could allow generators to name their price for energy. This is not a favorable outcome to the market as a whole that depends on competition to keep prices in check. In response to this threat, some large central station generators in the position to regularly assert this type of market power in California operate under "Reliability Must Run" contracts. The contracts both ensure that the generator is adequately compensated for providing energy and reliability services to the state, while assuring that they do not extract price premiums from the competitive market. Under constrained conditions, a local CHP unit could seek high prices for energy that would not otherwise be supplied to that location. While a single unit may have market power, the presence of many local on-site generators would limit the ability of any one unit to extract monopoly profits.

[3] See staff reports and decisions in R. 93-04-003, Pacific Bell's application to enter into long distance telephone market for more a more complete description of the challenges facing competitive local exchange carriers.

2.34 Market Transformation

The combination of both market power by location and control of local generation by the distribution utilities fuels a fear of market power abuse by the distribution utilities. If strategically located generation can be owned and dispatched by distribution utilities, the utility could avoid more expensive grid upgrades, receive high prices for critically needed ancillary services, and receive a fair rate of return on the generation investment through the distribution performance based rates in effect at the time. This same opportunity would not be available to other competitive suppliers unless they knew about the opportunity and could compete to receive a grid enhancement credit related to the costs avoided by the local utility, or some other agreed upon measure of value.

The right combination of competitive bidding for grid enhancement services and mechanisms in the local utility performance-based distribution rates could theoretically dampen the incentive of local generators to exercise market power if they were allowed to own and operate local generation. However, the ongoing market monitoring and regulatory intervention that may be required to preserve a fair market may exceed the benefits of allowing the local utility to participate in the generation business.

Many market participants assert that the incentive of the regulated utility should be to provide reliable and cost-effective utility services, not pursue new market opportunities best left to independent suppliers or their unregulated energy services affiliates. They also believe that policy-makers should maintain the separation of delivery and generation of electric service. This issue will be debated at the PUC rulemaking on distributed generation.[4]

2.4 Net Metering

2.41 Introduction

Some generators in California have the right to sell energy to the grid for the same price they would otherwise purchase energy. This is accomplished through a meter that "runs backwards" when they are generating more energy than they are using and the excess power is flowing onto the grid. At the end of their billing period, usually a month, they only pay for the net amount of energy purchased from the utility.

Net-metering is available under Public Utility Code Section 2827(b)(3) only to small customers who use solar or wind turbines and who use the system primarily to offset their own electrical requirements. The legislation is designed to encourage private investment in renewable energy resources. Utilities argue that net metering does not reflect the true value of the energy supply when the customer takes power from the distribution system when the value of electricity is high, and only offsets that by delivering power to the grid when the value is low. Also, when the

[4] Order Instituting Rulemaking into Distributed Generation R99-10-025.

generator takes power from the grid, it receives the commodity, as well as transmission and distribution services. However, the customer receives an equivalent price when it is only supplying the commodity to the grid. Thus, the small generator is using the distribution system like an energy bank and not providing any revenue toward the cost of that service.

2.42 Market Transformation

The utilities suggest that net metering is contrary to the goal of using real time and cost-based pricing, that it subsidizes renewable technologies, and that it allows net metered customers to avoid certain costs that other customers are obligated to pay. Proponents argue that the smallest generators could not otherwise overcome the costs of installing and operating these technologies, and that the renewable technologies deserve this option to promote these environmentally beneficial technologies. In addition, a solar and wind generator does not create electricity on demand, but only when the sun is out and the wind blows. A generator cannot manipulate the energy production of these units to take advantage of energy prices.

Market transformation does not require that CHP be allowed to net-meter for energy supplies. In an ideal market, all generators would be able to sell energy in the real time energy market and all customers would have real time meters to calculate their energy purchases based on the cost of energy at each time of the day and night. In the future there also might be price signals related to the level of congestion on the distribution network. These signals would encourage consumers to reduce demand (or self-generate) at times of distribution congestion. However, at this time, most small customers pay a flat rate for electricity, varying by season but not by time of day. In addition, few small customers have the technology to automatically detect high prices and avoid purchasing energy at the most expensive times of day. This disconnect between the market price of electricity and a small consumer's ability to respond to the price is one of the most significant market barriers to small customer participation in the competitive electricity market.

Market transformation to benefit CHP and other small generators will include wide-spread adoption of technology to overcome this barrier. In the meantime, policy measures such as net-metering serve to encourage a generating technology that may not otherwise survive in the market.

3.0 Interconnection Rules and Practices

3.1 Introduction

The optimal economic use of CHP for many installations requires interconnection with the local utility for emergency backup, supplemental power needs, or delivering CHP energy to other customers. Unlike traditional emergency generators that stand alone and are only run during a utility outage to serve the on-site load, an interconnected generator runs in "parallel" with the distribution system so as to be part of the constant flow of electricity to and from the generation site.

3.11 Critical Interconnection Issues

The primary challenge facing a customer who wants to interconnect with the local distribution grid is uncertainty about the cost and time to interconnect. This uncertainty may stem ultimately from a lack of incentive for the utility to provide predictable, efficient methods for interconnection of DG. The following critical issues impede interconnection and cause uncertainty:

- The rules do not clearly establish interconnection requirements at the outset.
- The rules are not consistently applied by front-line utility personnel;
- Some interconnection equipment may not be justified for small generators (such as dedicated transformers for residential and small commercial applications);
- The need for utility studies, the high cost of studies and the time it takes to conduct studies.
- The protection requirements for small generators may be excessive.

These areas of market uncertainty each serve as a potential barrier to interconnection. The Market Transformation section will describe the nature of each of these issues in more detail and how they may be resolved to minimize their impact on CHP generation. First, we will cover the history of the current interconnection issues and the actual interconnection requirements.

3.12 History of the Current Interconnection Situation

Prior to industry restructuring, utilities owned and operated most of the generation operating in parallel on the utility network. Utility engineers designed and operated the system using standards for interconnection that made sense for large central stations. Utilities were not particularly concerned about the cost of interconnection, both because the cost was small compared to the entire plant construction budget and because the utility expected to earn a reasonable return on all prudent investments. It was not until the Public Utilities Regulatory Policies Act in 1978 that utilities were required by law to interconnect with some independently owned generators and rules had to be written to govern the terms of interconnection. The rules for utility interconnection for the three investor-owned California utilities are now in Rule 21 of their respective tariffs and in technical guidebooks published by each utility. Municipals have developed similar rules to comply with PURPA.

The passage of PURPA was the first time utilities were required to communicate their interconnection standards to third parties. However, utilities had no incentive under PURPA to make interconnection easy, inexpensive or quick. As a matter of fact, because utilities faced losing revenue whenever an independent generator could successful interconnect, the utilities had every reason to make interconnection as onerous, complicated and expensive as possible. Nevertheless, many large generators (usually 10 to 49 MW) absorbed the costs of interconnection in order to enter into a profitable power sales contract with the utility as required by PURPA.

Now small generation technologies (such as CHP) that offer environmental benefits and low energy costs are coming on the market. Restructuring has increased the incentive to operate these units in parallel on the utility system for sales to the PX or to other customers in direct transactions. The technical requirements and the application process for interconnection can be especially burdensome to smaller systems (under a few hundred kW). The costs of implementing interconnection requirements are generally the same regardless of capacity. (For example, relays for 30kW units cost the same as relays for 500kW units.) For smaller projects, interconnection costs are a higher percentage of the total project costs and at a certain point the decision to install small generation may turn on this issue alone.

3.2 Summary of Current Utility Interconnection Requirements:

The interconnection rules address three major concerns: safety, system protection and quality of service. First, the safety of utility linemen requires that CHP facilities not energize a line that has been de-energized for maintenance or as the result of a line fault. Second, CHP system operation, or failure, must not detrimentally effect the utility system to which it is connected or service to other customers. Third, the voltage and other electrical characteristics of the generator should not degrade the quality of power on the distribution system.

Each investor-owned utility is in the process of revising Rule 21. Their intent is to align Rule 21 with recent legislative mandates and to simplify interconnection. Even with the proposed changes, each utility still requires most of the following steps: an interconnection study paid for by the customer, utility review and approval of the design, facility inspections before, during and after interconnection, signed contracts, maintenance and calibration test reports, proof of insurance, and pre-parallel tests. Interconnection remains a complicated process.

3.21 General Requirements

A quick look at Appendix C shows that the five utilities covered (PG&E, SCE, SDG&E, LADWP and SMUD) have quite similar general requirements. That would seem like a boon to interconnection, because the different requirements may not result in drastic differences in hardware costs to meet the minimum. However, the real issue is that a CHP developer doesn't know what the actual requirements are going to be until it is into the process and dealing with the utility on the specifics of the site. Customer awaremess of that uncertainty keeps some projects from moving off the drawing board in the first place. The process is open-ended currently and it varies according to personnel ability and knowledge. The interconnection design and costing is essentially at the discretion of the utility, which may or may not be favorable to a project for competitive reasons, or other reasons that may be completely removed from concerns of safety, reliability or quality of service.

3.22 Specific Requirements for Small Scale Generation (1-MW or less)

The following table summarizes the minimal protection requirements of SCE, SDG&E, PG&E, SMUD and LADWP for three kW capacities: a 30kW unit, a 300kW unit and a 1-MW unit. The legend below states whether the requirements relate to technologies that use static power converters (SPC) (such as the microturbines and fuel cells) induction generators or synchronous generators.

Legend:
S= 30 kW (includes induction generator and SPC)
M= 300kW (includes. induction generator, synchronous generator and SPC)
L= 1000kW, (includes synchronous generator and SPC)
X = required.
? = assumed required, via specification for breaker or current interrupting device.

Minimum Protection Requirements: by Utility and Capacity

Function	**SCE**			**SDG&E**			**PG&E**			**SMUD**			**LADWP**		
	S	M	L	S	M	L	S	M	L	S	M	L	S	M	L
25		X	X	X	X	X	X	X	X	?	X	X	?	?	?
27	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
46					X	X									
47	X	X	X												
50	?	?	?				X	X	X	X	?	?	?	?	?
51	?	?	?	X	X	X	X	X	X	X	?	?	?	?	?
50N							X	X	X						
51N		X	X				X	X	X		X	X			
51V									X		X	X			
59	X	X	X				X	X	X	X	X	X	X	X	X
67 (or 67V)		X	X												
81	X			X	X	X	X	X	X	X	X	X	X	X	X

Device Function Numbers, re ANSI/IEEE C37.2

25	Synchronizing or synchronism-check
25A	Auto-synchronizer
27	Phase undervoltage
32	Directional power
46	Reverse-phase or phase-balance current
47	Phase-sequence voltage
50	Instantaneous phase overcurrent
51	Phase time overcurrent
50N	Ground instantaneous overcurrent
51N	Ground time overcurrent
59	Phase overvoltage
67(V)	Directional phase overcurrent, V= voltage restrained/controlled
81	Over & Under frequency

It should be pointed out that current multifunction digital relays can be programmed to cover all the above requirements using software. Compared to a protection system that uses discrete analog relays, the process is relatively simple and inexpensive. Even if the utility were to change the requirements, the cost of re-engineering and reprogramming a digital relay would be minimal, assuming the developer has full information on specific utility requirements from the utility engineering study. However, current utility requirements do not accept the new multifunction relay technologies entering the market. Utilities are still known to require discrete relays and other redundant protection equipment be installed as a back-up to new technologies, adding significant capital and labor costs, especially to small projects. In order for utilities to accept the new digital relays, they will need to time to test them, or to have credible test data provided to them either from other utilities or an independent testing authority.

3.3 Market Transformation

The market challenge for small generation is to overcome the cost and technical barriers to interconnection. The inconsistency and uncertainty of current utility requirements across California adds time and costs to projects. What is needed is a way to decrease the uncertainty now existing in interconnecting with the utilities, and a way of accelerating the acceptance and use of new technologies that offer flexible and secure protection in a single package. This section of the report will explore how current interconnection standards operate as a barrier to small generation and how the process of interconnection and technical requirements could be improved to reduce this barrier.

3.31 Uncertain Standards

Uncertainty exists because the written and published guidelines on interconnection are general, the contents are subject to change and interpretation. A developer may design a project to meet a standard and be surprised by additional requirements imposed later. Utilities are reluctant to state absolute interconnection requirements in advance of utility studies because they do not know the impact the generator will have on the local distribution system until they can perform the studies. The utility wants flexibility to account for local conditions.

This may become less of an issue as utilities gain experience from initial installations and developers become more aware of utility concerns. In the meantime, faster utility turn-around time with utility studies would help alleviate this problem because it would allow developers quicker feedback on their plans thereby reducing the cost of uncertainty.

3.32 Inconsistency

Inconsistent requirements stem partly from different field conditions but also from a lack of clear and concise procedures and inadequate training of front-line utility personnel. Utilities recognize this is a problem and are working on in-house solutions, as shown in the appendix on PG&E's process and SCE's commitment to "define a simple process and dedicate staff to respond (to) requests." (See Appendix D for more information on PG&E's Interconnection Requirements).

Nonetheless, without an internal incentive, utilities cannot be expected to follow through with these streamlined procedures without external pressure.

3.33 The need for dedicated transformers

The need for dedicated transformers is a costly issue for smaller capacity generators, particularly in urban areas. Most large-capacity generators would either already have a dedicated service transformer or could easily absorb the cost of this equipment. (Secondary network systems pose a more complex problem and are not addressed here).

One of the main reasons utilities want a dedicated transformer is to isolate the generator from the rest of the system in case there are power quality problems, especially harmonics, created by the generator. Power quality concerns can be handled in other ways, such as having the generator itself adhere to power quality standards (IEEE 519 or IEC standards), rather than specifying a dedicated transformer. Power quality may become less of an issue when utilities gain a better understanding of how different types of generators work, especially newer inverter-based generators.

Another justification for a dedicated transformer relates to system grounding. There is debate on the proper method of grounding local generators, primarily focused on transformer winding configurations. The National Electric Code has specific requirements on grounding separately derived systems that must be resolved. This issue requires more technical analysis before acceptable solutions will be found.

3.34 Utility Studies

Utility studies are performed by electrical engineers to determine the impact the proposed power plant will have on the grid. A "study" can be a simple manual calculation relating to a specific condition, or load flow and short-circuit studies that require a complex mathematical representation of the entire utility system, or only a portion of the system. Many vendors supply "canned" software packages to perform the more complex analysis. Traditionally these software packages have been designed either for transmission-level analysis or for large facility-level electrical design. These packages cost thousands of dollars.

The time required to perform a study and the cost of the study will vary depending on many factors, including:

- the relative size (capacity) of the generator in relation to the local system capacity;
- the location of the proposed generator on the system;
- the application (sale or no sale, peak shaving, base load, etc.); and
- how the utility handles such work (how complex is the process, how well-trained is the utility engineer, how many resources are available, etc.).

Pacific Gas and Electric has estimated that studies can take anywhere from 22 hours to 60 hours to complete, with an average of 41 hours. These studies can cost between $3,000 and

$25,000 depending on the complexity of the study. The costs include personnel costs, computing time, management review, report preparation and other direct and indirect charges. (See Appendix D on PG&E's Interconnection Process for more information).

An effective way to reduce the time required for, and cost of, these studies is to have a well-established procedure for handling interconnection applications. The procedure should take advantage of tailored software packages that use existing utility databases (if they exist) to speed-up the number-crunching portion of these studies. Interpretation and analysis of results will always require experienced personnel and probably can't be hurried.

Another proposal for minimizing the impact of the cost of utility studies comes from a recent report to the National Association of Regulated Utility Commissioners.[5] The authors suggest that the costs for interconnecting generators be shared between the utility and generator. Since all distribution customers typically receive an interconnection subsidy (usually equivalent to the average embedded cost of all customer-specific distribution plants) interconnecting generators should receive similar treatment. If this proposal for sharing costs of interconnection studies were to be adopted, the utility would pay for a threshold level of studies and facilities, with the distributed generator paying for amounts above this blended level.[6]

3.35 The need for protection equipment

Utilities insure the reliability and security of the grid through system protection measures. Line faults are cleared quickly. Lines are sectionalized. Voltage and frequency are regulated within specific limits. Traditionally, utilities have been able to provide this level of service and reliability because they retained complete control over all generation and network construction standards. They could determine what level of protection was required and spread the cost over all customers.

Now, with locally owned generation, the situation is more complicated. Protection requirements, derived from past practices, are coming under fire. The risks posed by small generators may not justify the same protection system required by utilities for large central station power plants. Small generators are questioning the utility requirements for interconnection because the small generator must bear the entire cost of its installation.

Manufacturers of small generators now build protection functions within the control system of the generating unit. All of the protection functions can be programmed through software into the controls. Even though this satisfies the intent of the protection requirements, utilities still want back-up protection through a separate system, not associated with the controls of the generating unit. The back-up system insures protection will not be lost if the control system fails.

[5] R.W. Beck and Distributed Utility Associates, "Model Utility Interconnection, Tariff and Contract Provisions for Distributed Generation," NARUC (June 1999)
[6] Lehr, Ronald L., "Open Access for Distributed Resources: Regulatory Issues." September 15, 1999.

Manufacturers are particularly concerned about this requirement it unnecessarily adds to the complexity and cost of the installation.

A solution to this problem is to obtain third-party certification of integrated protection and control systems. After performing performance tests, a recognized independent testing lab could certify that the systems meet all requirements. This would be similar to the safety testing that UL and other labs do today. Once the equipment is certified, the utility would not need to impose any other protection requirements. This type of solution is a few years off, though, as performance tests and procedures have to be developed and agreed upon, and testing labs have to gear up to perform such tests. In the mean time, manufacturers are stuck with the existing requirements.

3.4 Conclusion

The solutions for interconnection challenges include both technical and procedural improvements. It is incumbent on regulators to ensure that utilities adopt the most cost-effective standards and practices for small generators. Because of pressure from market participants, the Institute of Electrical and Electronics Engineers (IEEE) has fast-tracked their process for issuing new national standards for interconnection. However, even on this fast track, the IEEE does not expect to issue new standards for interconnection until after December 2001.

Some solutions could be pursued in advance of new national standards. These include the development of interim state standards, consensus on requirements for smaller systems (under 1 MW) to minimize the impacts on small generators, and a quick and simple screening procedure to inform a developer up-front whether or not a project requires comprehensive review and studies. Policy-makers should encourage utilities to participate in and promote quick resolution of issues that do not require national standards.

4.0 Environmental and Land Use Regulation

4.1 Introduction

CHP units must comply with all applicable local zoning and health and safety requirements at the site. These include rules on air and water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety and building construction standards. For generation units 50MW and above, the California Energy Commission conducts a single siting process to ensure compliance with all local requirements. Units below 50MW avoid the CEC process and seek approval from the local agencies directly.

The local agencies interested in the siting of a CHP unit include fire districts, air districts, water districts and planning commissions. Therefore, the installer of a CHP unit may need to pay for and obtain permits, or variances from permits, inspections, and approvals from many different local agencies. In addition, one or more of the agencies may require additional equipment or impose special operating standards as a condition to granting approval for the unit. Depending on the basis for the requirements, the local agency may or may not have discretion to modify the terms of the approval or negotiate with the installer for a variance.

Both engaging in the local permitting process and complying with the technical requirements coming out of the process can impose significant costs on a CHP installation. The costs depend on the kind of CHP unit being installed, how sensitive the local area is to the environmental impact, how familiar the local agency is with the installation, and how the nearby neighbors feel about the installation. Thus it is difficult to generalize about these impacts for all CHP installations across the state.

However, two elements of the siting process regularly challenge installers of CHP in California. The first concerns air quality impacts and the second concerns the process of siting itself. California is home to some of the most constrained air sheds in the nation, often not in compliance with federal Clean Air Act requirements. Thus new emitters must pass strict tests to minimize air impacts or must install emission control technologies that use hazardous materials, such as ammonia and acid, and thus raise more public health and safety concerns at the local level. Secondly, the novelty and lack of local standards for some of the newest CHP technologies may slow down the process and make the outcome more uncertain as local officials “write the rules” for new technologies. In order to promote the installation of clean and efficient generation in California, it may be necessary to create a user-friendly CHP siting process at the local level.

4.2 Air Quality

4.21 Introduction

CHP units that rely on fuel combustion for electricity and heat production emit pollutants controlled by local air districts. Each air district has its own rules for allowable emissions based on local conditions, but all districts must ultimately comply with state and federal air quality standards. The following is a brief outline of the main issues facing installers of CHP in California and how each requirement may impact the cost and feasibility of a particular installation:

- Is the installation exempt from permit requirements? Very small generators and special technologies (fuel cells or other very clean emitters) may not require a permit.

- Is it a “major source” or a “minor source”? The answer to this question will determine the extent of compliance requirements for monitoring, record keeping, reporting, emissions testing, and maintaining a running inventory of emissions.

- What are the hours of operation of the CHP unit? Most CHP installations run as long as necessary to fulfill the on-site or district heat load, typically 50%-80% of the year. Few installations will qualify for minimal emissions controls allowed for emergency generators.

- What are the levels of each type of air pollutant being emitted? Some kinds of emissions, now called "air toxics" are subject to a special screening process to determine potential public health impacts. Other emissions that contribute to regional air quality, such as NOx, and VOC are governed under the traditional air permit process.

- Is the CHP unit a new installation or is it a modification of an existing plant? It is generally less expensive to comply with rules for minor modifications of existing plants. A New Source Review (NSR) may result in requirements for the most stringent control technologies and the necessity of purchasing NSR offsets. On the other hand, a modification at the site may create "offset credits" if the CHP unit replaces a dirtier boiler, for example.

- Is the CHP unit being installed in a non-attainment or severely constrained area? The most stringent emissions control technologies will be required, and the installer may need to purchase air credits to offset the increase in regional pollution levels caused by the unit.

- Is the control technology required by the air district cost-effective? Sometimes an air district cannot impose a control technology if the installer is thereby paying too much to reduce an additional pound of pollutants.

The air quality requirements may be sufficiently extreme to make a CHP installation not cost-effective. The control technology or offsets required for an installation may not justify the project costs. Emission limits in some air districts, particularly for high emission fuels such as wood, coal or diesel, may make some CHP units unfeasible.

4.22 Challenges for CHP

The Clear Air Act requires that each state attain national ambient air quality standards (NAAQS) for each criteria pollutant, such as NOx, CO, SO2, PM, and Volatile Organic Compounds (VOCs). When a region is out of attainment, the regulator must reduce emissions from existing and new sources. Historically, regulators have been more successful reducing emissions from major stationary sources, such as power plants, than from mobile sources, such as automobiles. The result is that the rules for stationary sources, including CHP, are much more stringent than rules for mobile sources, even though some new CHP technologies are no larger than automobile engines.

The Best Available Control Technology (BACT) standard in California for stationary sources is 5ppm for NOx at 15% oxygen for simple-cycle gas turbines; it is 2.5ppm for NOx for combined cycle and CHP installations of gas turbines[7]. In the Los Angeles air basin, where these standards were deemed BACT, actual emissions from the CHP and combined cycle units

[7] California Environmental Protection Agency Air Resources Board, *Guidance for Power Plant Siting and Best Available Control Technology*, June 21, 1999

operating below these new standards are within an order of magnitude of the cleanliness of ambient air.

There are about thirty siting cases planned or currently under review by the CEC. These are new merchant power plants that would be combined cycle gas turbines adhering to the BACT numbers above. Although combined cycle units capture heat from gas turbine exhaust to make additional electricity, they are not CHP units since they do not use the captured heat to meet a local thermal requirement. The new merchant plants are just highly efficient central generating stations.

If we compare CHP with these merchant plants on an input basis, as regulators do currently, CHP does not offer much in NOx emission reductions, and may cause NOx increases in some cases. For the same amount of input fuel, the newest merchant plants emit fewer pollutants than the best CHP units. However, if we compare CHP to the merchant plants units on a "net NOx" basis, including the power generation that is avoided through use of CHP waste heat, the benefits of CHP are more apparent. Such "output-based" standards are necessary in California in order to compete fairly with new central units.

At this time, as described above, the rules are generally indifferent to the efficiency characteristics of a generator. Thus a non-CHP generator is measured on the "parts per million" of pollutants just as a CHP generator, and the fact that CHP is recovering and making valuable use of the waste heat created by the combustion process is not given any credit from an air quality point of view. The preservation of fossil fuel resources and the national economic benefits of high efficiency are outside the scope of the air district's charter.

In addition, current local air rules do not focus on the production of greenhouse gases, such as CO_2, which have a global, rather than local, impact on the environment. The Department of Energy has determined that doubling the amount of CHP used to create electricity in the US by 2010 would be a significant contribution to our country's ability to comply with the terms of the Kyoto treaty on global warming. The CHP would displace some older fossil-fueled units that are major contributors to current CO_2 production in the US.

Addressing these issues on behalf of CHP is particularly challenging in California for at least three reasons. First, the state now hosts the "cleanest" electric generation in the country, due to its high percentage of nuclear and hydroelectric production. California imports electricity produced by coal plants in other western states but doesn't suffer the immediate environmental impacts of that production. Thus, there is little "dirty" generation in California to replace with cleaner, more efficient CHP generation.

Second, since industry restructuring there has been a flurry of applications to site additional large generating plants, mentioned above, using very clean and efficient natural gas-fired technologies. Not only do these plants favorably compete on a cost per kWh basis with on-site power production, they may deplete the supply of available air offset credits or drive the price of credits up to unacceptably high levels.

Third, the nature of small on-site generation often results in siting new units in the most constrained areas—cities, industrial parks, etc—rather than in the less constrained country-side where transmission lines deliver the power produced by large generating stations to load centers. While each new unit in an urban area may not create a significant impact, regulators may take a dim view of numerous small installations in urban "hot spots" and impose stricter standards for permitting.

4.23 Market Transformation

Officials in charge of environmental and energy policies at the state and federal level are aware of the challenges facing CHP in the current regulatory environment. There is progress on some fronts to address the problems.

- The Environmental Protection Agency modified the 1998 New Source Performance Standards for utility boilers from a fuel-burned basis to a useful output basis to give credit for increased efficiency. Thus, instead of being permitted on a pounds of pollutants "per unit of heat," the boiler is permitted "per unit of electricity produced." Waste heat not recovered for electricity production penalizes the unit.

- The California State Air Resources Board (CARB) is performing an economic study to project the penetration of distributed generation in California and quantify the net emission effects. This would help them develop an air quality regulatory strategy to meet the challenges described above. The final report is not yet published.

- CARB is also studying how new in-state generation (both CHP as well as merchant plant development) impacts regional CO_2 production due to displacement of out-of-state coal-fired generation from California's total electricity consumption mix.

Other options for both meeting local environmental goals as well as giving CHP some credit in the energy market could be developed by modest changes to current permitting rules. For example, emergency generators are not currently subject to the strictest permitting rules, but they may only run for very few hours in the year and only when the system power supply is interrupted. Regulators might be persuaded to allow CHP generators to run during periods of high real time energy prices and/or when the local transmission system is constrained. The number of total allowable hours may be increased, or the run time could be measured in pounds of pollutants per year, rather than hours per year. This would more accurately attribute air impacts to the responsible generator, and not penalize small efficient units.

Another way to protect the public health and encourage installation of environmentally responsible, local generation such as CHP is to reimburse the cost of some or all of the necessary air control technologies through efficiency credits. The credit could be justified when the environmental costs of energy inefficiencies through alternative generation are equal to or greater than the cost of the control technology. A model for such activities is the Renewable Resources Account credit system managed by the California Energy Commission and funded by a one-time $540 million grant established by restructuring legislation in California.

4.3 Streamlined Permitting

4.31 Current Rules

The local permitting process can be challenging for a CHP installer for many reasons. As noted above, CHP technologies must often comply with air quality, hazardous waste management, fuel storage, fire-safety, worker safety, building codes and local zoning rules. The following are a few of the reasons why the local process can add time and expense to a CHP project installation:

- It may not be known prior to permit application what standards the CHP unit must meet. It may not be clear whether the local zoning will accommodate the CHP technology and associated fuel supply systems, or how stringent the environmental mitigation requirements will be. This makes the initial economic analysis of the project's viability or financing needs less certain.

- The time between application and approval may be long, or may not be known in advance. This makes it difficult to create project installation schedules and to keep to the schedules.

- The installer may need to visit with multiple agencies on multiple issues. Where agencies do not work together to coordinate an application, the installer may need to go back and forth to different agencies, modifying an application to reflect the findings or decisions of another agency.

- Agencies may have some discretion to negotiate the terms of the permit or approval. In these cases the installer may have to hire experts to prove the reasonableness of a modified requirement. The negotiation process can require iterations of testing, reapplication and more delay.

- Even after approval to site is granted, the local agencies maintain jurisdiction over terms of the approval, sometimes requiring annual testing, record keeping, reports, fees, etc. This cost must be built up front into the economics of project feasibility.

- An intangible factor in local permitting is the political reality of neighborhood sensibilities and not-in-my-backyard reactions to development. This could include concerns about noise, vibration, visual attributes, and safety in sensitive areas such as near schools or hospitals.

Getting through the local process can take anywhere from 3 months to a year. Each installation will face it's own particular array of challenges depending on all the variables of the technologies being deployed, the qualities of the building or local area into which the unit will be placed and the personalities of the local officials involved.

The burden of siting and permitting adds to the carrying costs of the project. Of course, every CHP project will be different, but an estimate of carrying costs associated with permitting and siting could average 6.5% or more of the total project costs. These costs cannot be eliminated since siting and permitting will continue to be of concern to local jurisdictions. However, they could be lowered through streamlining. If the solutions in the next section were to eliminate six months from the time for permitting and siting a project, the carrying costs would be reduced proportionally. Assuming a simplification of this magnitude, carrying costs could shrink to 3.8% of the total project cost, from an average of \$580/kw down to \$220/kw, a sixty-two percent reduction. (See Appendix E.)

4.32 Market Transformation

There have been efforts in some areas of the state to address the problems noted above without sacrificing the legitimate health and safety concerns of local citizens. For example, many local governments in the Santa Clara Valley area have joined together to reduce the number of steps for local city and county building permits from four hundred down to eleven. The Silicon Valley Uniform Code Program improves the region's regulatory climate by promoting consistency and reducing regulations, while maintaining high safety standards in Silicon Valley. They are looking into doing the same regulatory streamlining for the siting of small generation units in the region. The San Diego Association of Governments has included generation sites in the master plan for urban development. Finally, standards agencies such as the Underwriter's Laboratories, Model Building Code, and National Electric and Fire Safety Code writers are beginning to look at the newest CHP technologies for standardized treatment.

In the fall of 1999 the California Energy Commission has received Department of Energy funding to study the local permitting process for two generation plants, one in the City of Irvine in Southern California, the other in northern California chosen by the Association of Bay Area Governments. Each site will convene an advisory committee of representatives of affected agencies to monitor the permitting process, create specific recommendations for streamlining, and a time estimate for effecting those recommendations. The results will be available to any other local government, and form the basis for workshops across the state for similar improvements.

5.0 Government Tax Policies and Incentives

5.1 Tax Policies

Tax policies can significantly effect the economics of investing in new equipment such as CHP. The availability of tax credits and/or rapid depreciation schedules can make or break a project. There are currently no investment tax credits for CHP, and CHP property falls into several tax categories with depreciation periods based on its use and capacity. Systems larger than 500kW have a cost recovery of 15 years if the electricity is used on-site and 15 to 20 years if the electricity is sold. In contrast, a similar engine used to power airplanes or equipment would have only a 5- to 7- year tax life.

5.12 Market Transformation

There are two initiatives underway at the federal level that would move toward a more fair tax treatment of CHP. DOE and EPA have been working with the Department of Treasury to review existing depreciation categories for on-site generation equipment. Treasury is considering allowing on-site equipment in buildings to qualify for a 15 year depreciation schedule, similar to on-site generation equipment in industrial applications. In addition, as a part of its 2000 budget request, the Clinton Administration has included an investment tax credit to encourage the increased application of CHP systems. The proposal would give an 8% credit for qualified systems over 50kW installed in the years 2000 and 2001.

5.2 Public Goods Charges

5.21 Energy Efficiency Programs

Under AB1890, the distribution utilities were directed to collect money from customers to support programs “which enhance reliability and provide in-state benefits” such as energy efficiency programs, low income support programs, research and development and renewable energy programs. (Section 381(b)). The municipally-owned utilities are also required to collect such charges. (Section 385.)

The dollars collected for energy efficiency through this mechanism are governed by the CPUC with the advice of the California Board for Energy Efficiency (CBEE). In 1998, approximately $270 million of public benefits monies were collected for gas and electric energy efficiency programs. These funding levels will remain until 2002 when the programs will be reevaluated. The programs are currently administered by the utilities and the CEC.

5.22 Market Transformation

At this time, the environmental benefits of CHP are not recognized or paid for in the competitive energy markets. The reduction of greenhouse emissions such as CO_2 through increased fuel efficiency is the most significant public health benefit of moving away from traditional power plants and increasing the penetration of CHP technologies.

The CBEE is investigating whether self-generation technologies, such as CHP, could be included in the definition of energy efficiency and thus eligible for public goods support. The current definition includes "Any product, service, and practice or an energy-using appliance or piece of equipment to reduce energy usage while maintaining a comparable level of service when installed or applied on the customer side of the meter."

If self-generation were included in the definition, a support program would have to meet three criteria; it would have to satisfy the "public purpose test, be capable of transforming the market so that support would no longer be needed, and be part of a balanced portfolio of programs."[8]

The CBEE performed a "1998 Study of Self-Generation for Energy Efficiency Programs." The CPUC adopted a CBEE recommended pilot for limited renewable technologies for residential new construction. Beyond that, the CBEE may consider direct subsidies or research and development programs that pursue benefits such as uninterrupted power, power quality, fuel price risk management, participation in bulk power and ancillary service markets and pricing by location.

5.23 Renewable Resource Credits

The public goods charges include support for renewable energy. Renewable energy is defined as "biomass, solar thermal, photovoltaic, wind, geothermal, small hydropower of 30 megawatts or less, waste tire, digester gas, landfill gas, and municipal solid waste generation technologies…" Section 383.5 (a) (1). The support through public goods charges is limited to renewable energy using less than 25 percent fossil fuel. (Section 381 (b)(3)).

The California Energy Commission manages the distribution of these funds to support qualified generators. The support is in the form of a 1.5cents/kWh price credit for renewable energy supplies. This incentive helps overcome the higher costs of producing electricity from these generators. The limitation on fossil fuel use disqualifies CHP technologies fueled by natural gas, a readily available fuel source for many prospective CHP generators.

5.24 Market Transformation

Policy-makers in California recognize that some energy technologies fueled by renewable resources are beneficial yet do not compete in the energy market without subsidy. The rationale for providing the subsidy is that the environmental benefits and the value of energy reliability through fuel diversity is not accounted for in the competitive market and therefore should be "purchased" by the public as a whole through these funding mechanisms. A wise policy appropriately values the benefits and then allows qualifying generators to compete for the credits, thus getting the best price for the values that are sought.

CHP projects that run on renewable fuel sources should logically qualify for both efficiency credits as well as renewable resources credits, providing that the combination of subsidies does

[8] See www.cbee.org

not overstate the environmental values and encourage projects that don’t return a fair value for the public investment.

APPENDIX A – Standby and Backup Charges for Three IOUs

Standby and Backup Charges

	Voltage Level	**Standby Charge $ per kW**	**Backup Charge**
SCE	Secondary	$6.40	@ default rate, scheduled outages may avoid on-peak charges
	Primary	$6.60	
	Transmission	$0.65	
SDG&E	Secondary	$2.67	@ default rate, scheduled outages may avoid on-peak charges
	Primary	$2.54	
	Transmission	$0.22	
PG&E	Secondary	$2.55	$0.39159 on peak summer
	Primary	$2.55	$0.36632 on peak summer
	Transmission	$0.35	$0.30168 on peak summer

The charges are based on unbundled charges, without RMR, CTC Phase 1 or 2 charges, or generation costs.

APPENDIX B – Example of Standby and Backup Charges

The economic difference between two approaches to standby and backup charges is illustrated in Table 1.2 below for an SCE industrial customer operating a 1MW CHP unit with 92% availability. The impact of the California utility's standby charges made the total average electricity costs of the customer 37% higher than the Illinois/Texas example when we assume equivalent energy charges. This could be high enough to make the CHP project more expensive than purchasing electricity from the local utility.

TABLE 2

Annual Costs		**UDC Purchase**	**California Case**	**Illinois/Texas Case**
Capital Carrying Charge			$130,000	$130,000
Fuel Cost			$157,320	$157,320
Cogeneration Heat Credit			($78,660)	($78,660)
O&M Cost			$62,928	$62,928
Maintenance/Standby Power			$203,536	$74,281
Total Cost		$441,309	$475,124	$345,869
Total Electric Generated (kWh)			5,244,000	5,244,000
Total Electric Bought (kWh)		5,847,000	603,000	603,000
Average Power Cost ($/kWh)		$0.0755	$0.0906	$0.0660
Annual Maintenance Power			California Case	Illinois/Texas Case
Summer Outage Demand Charge			$121,300	
Winter Outage Demand Charge			$52,955	
Outage Hours			456	456
Summer Outage Hours			190	190
Winter Outage Hours			266	266
Summer Outage Energy Charge			$14,668	$14,668
Winter Outage Energy Charge			$14,613	$14,613
Standby Charge*			* included in demand charges	$45,000
Total Maintenance/Standby Power			$203,536	$74,281

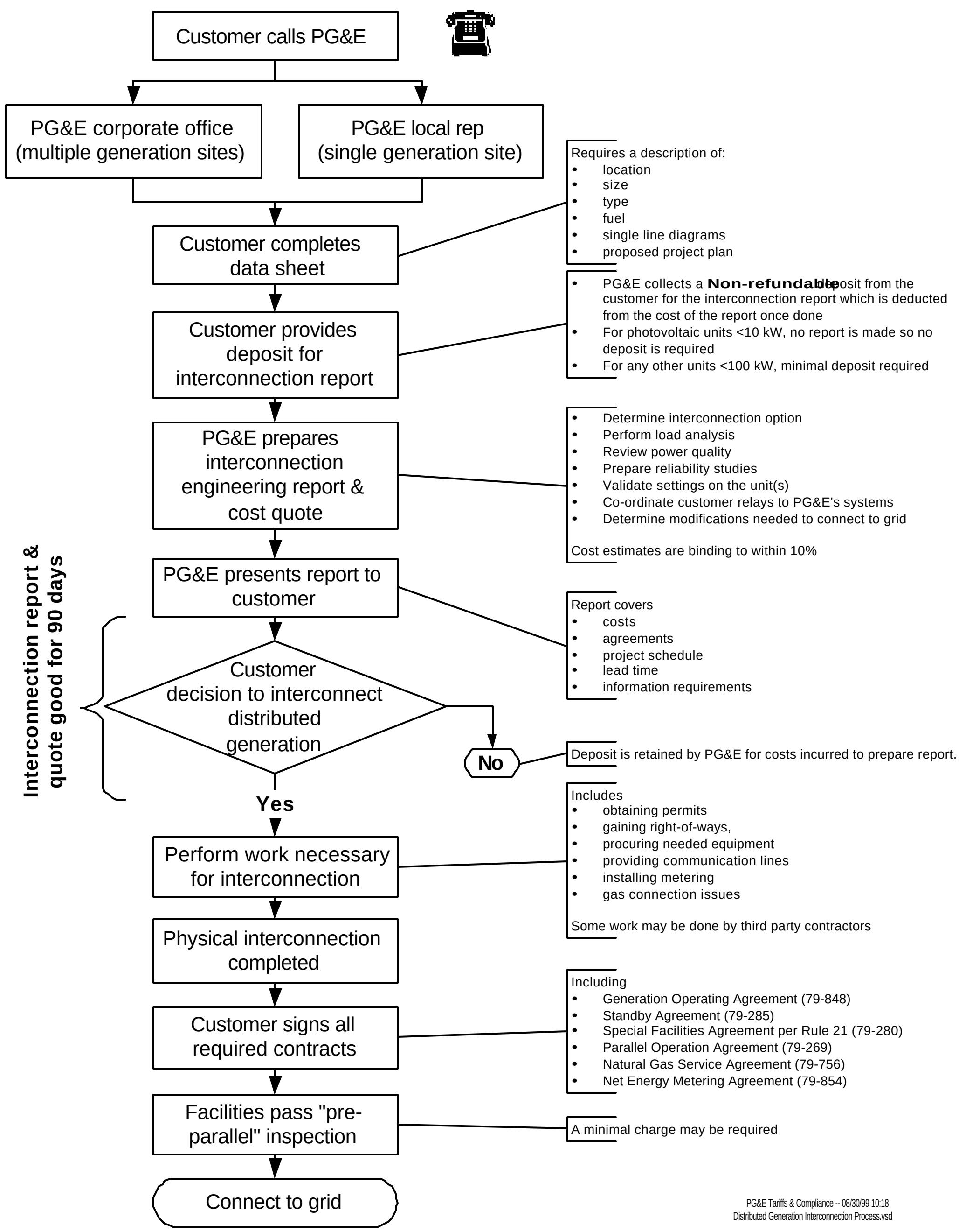
APPENDIX C – Interconnection Requirements of Five CA Utilities

The following table is an overview of the current interconnection requirements of the five largest utilities in California.

	General Requirements (as of June 1999)	SCE	SDG&E	PG&E	LA DWP	SMUD
A.	*Installation & Operation: Pre- & Post-*					
1.	Interconnection Studies Required?	Yes	Yes	Yes	?	Yes
2.	Review and Approval of Design?	Yes	Yes	Yes	Yes	Yes
3.	Right to Inspect Facilities: Pre & Post Connection?	Yes	Yes	Yes	Yes	Yes
4.	Signed Contract(s)/Agreement(s) before Connection?	Yes	?	Yes	Yes	Yes
5.	Must meet all applicable codes and requirements of other authorities?	Yes	Yes	Yes	Yes	Yes
6.	Provide Maintenance and Calibration/Test Reports and/or Witness Tests?	Yes	Yes	Yes	Yes	Yes
7.	Provide Proof of Insurance	Yes	?	?	Yes	?
8.	Conduct Pre-Parallel Tests	?	?	Yes	Yes	Yes
B.	*General Design*					
1.	Disconnect Required?	Yes	Yes	Yes	Yes	Yes
2.	Protection Requirements Vary According to Capacity and/or Voltage?	Yes	Yes	Yes	Yes	Yes
3.	Dedicated Transformer Needed?	*	*	*	*	*
4.	Utility-Grade Relays?	*	?	*	?	*
5.	Ground Fault Protection?	*	*	*	*	*
C.	General Operating					
1.	Reactive Power and Voltage Control	Yes	Yes	Yes	Yes	Yes
2.	Must meet Power Quality standards?	Yes	Yes	Yes	Yes	Yes
	Notes:					
	"?" means not specifically discussed in documents. "*" means depends on capacity, voltage, gen. type or other characteristic.					

APPENDIX D – PG&E Interconnection Flowchart

PG&E's Distributed Generation Interconnection Process



APPENDIX E – Basecase and Highcase DG Installation Costs

Basecase Inatallation Costs

Representative Onsite Generation Cost and Performance	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine
Size kW	50	100	200	800	5,000	25,000
Heat Rate (Btu/kWh HHV)	13,306	13,127	7,584	10,605	11,779	10,311
Recov. Exhaust Heat (Btu/kWh)	4498	1786		1443	5193	4522
Recov. from Coolant (Btu/kWh)		3404	3000	2750		
Package Cost ($/kW)	$500	$650	$2,000	$350	$400	$300
Heat Recovery	$150	$100	$75	$75	$75	$75
Emission Controls	$0	$70	$0	$29	$102	$100
Project management	$25	$33	$100	$18	$20	$15
Site & Construction Management	$35	$46	$140	$25	$28	$21
Engineeering	$20	$26	$26	$14	$16	$12
Civil	$50	$75	$100	$38	$15	$13
Labor/Installation	$100	$130	$120	$44	$60	$45
CEMS	$0	$0	$0	$0	$30	$20
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15
Interconnect/Switchgear	$150	$150	$75	$63	$20	$6
Contingency	$25	$33	$60	$18	$20	$15
General Contractor Markup	$164	$197	$270	$101	$81	$64
Bonding/Performance Guarantee	$33	$39	$27	$20	$24	$19
Carry Charges during Constr.	$83	$99	$192	$51	$87	$69
Basic Turnkey Cost ($/kW)	$1,375	$1,647	$3,184	$842	$998	$789
O&M Cost $/kWh	$0.010	$0.014	$0.005	$0.011	$0.003	$0.003

Highcase Inatallation Costs

Representative Onsite Generation Cost and Performance

	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine
Size kW	50	100	200	800	5,000	25,000
Heat Rate (Btu/kWh HHV)	11,741	11,147	6,205	9,382	9,125	7,699
Recov. Exhaust Heat (Btu/kWh)	4600	1600		1200	3709	2800
Recov. from Coolant (Btu/kWh)		2600	1600	2500		
Package Cost ($/kW)	$350	$500	$900	$300	$300	$300
Heat Recovery	$150	$100	$75	$75	$75	$75
Emission Controls	$0	$70	$0	$29	$51	$50
Project management	$18	$25	$45	$15	$15	$15
Site & Construction Management	$25	$35	$63	$21	$21	$21
Engineeering	$14	$20	$20	$12	$12	$12
Civil	$50	$75	$100	$38	$15	$13
Labor/Installation	$70	$100	$120	$38	$45	$45
CEMS	$0	$0	$0	$0	$30	$20
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15
Interconnect/Switchgear	$50	$75	$38	$31	$10	$3
Contingency	$18	$25	$27	$15	$15	$15
General Contractor Markup	$78	$103	$139	$57	$61	$58
Bonding/Performance Guarantee	$24	$31	$14	$17	$18	$18
Carry Charges during Constr.	$28	$				