Arnold Schwarzenegger
Governor

EVALUATION OF POLICY IMPACTS ON THE ECONOMIC VIABILITY OF CALIFORNIA-BASED COMBINED HEAT AND POWER FROM A PROJECT OWNER'S PERSPECTIVE

PIER FINAL PROJECT REPORT

Prepared For:
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Evaluation of Policy Impacts on the Economic Viability of California Based CHP from a Project Owner's Perspective Final Report

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Legal Notice

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Abstract

The California Public Utilities Commission and the State of California have expressed an objective of increasing the application of Combined Heat and Power (CHP) in the state. The high efficiency and distributed nature of CHP offer a variety of societal and economic benefits. In many cases, however, policies impacting the economics of CHP ownership have conflicted in the ways that they provide incentives and disincentives to parties who would consider investing in, owning and operating a CHP project. Employing a suite of advanced software products for the analysis of CHP economics, this study will focus on the economics of CHP ownership from an investor's perspective, concentrating on the incentives and disincentives to CHP as a result of:

- Rate making policy and utility tariffs
- The Self Generation Incentive Program
- Financing alternatives available to CHP owners
- Market related factors including gas prices and the linkage of gas prices to electric rates

The study focused on the following market analyses. Each of the reference appendices includes the detailed reporting for the associated tasks.

- Appendix A – Commercial Building Applications - Market conditions prevalent in May of 2005
- Appendix B - Update – Two Parts
    - Commercial Building Applications - Market conditions prevalent in January 2006 with attention to variations in electric tariffs and gas prices
    - Potential Impacts of Federal Production Tax Credits (PTCs), Greenhouse Gas Emissions Reduction Credits and Transmission Deferral/Offset Credits on CHP economics
- Appendix C - Dairy-based anaerobic digester applications - Market conditions prevalent in January/February 2006

The goal of this study will be to assist policy makers, utilities and industry stakeholders to obtain a better understanding and to make better informed decisions relative to policies impacting and investments in CHP.

Preface

The Public Interest Energy Research (PIER) Program managed by the California Energy Commission supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings Energy Efficiency End Use
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration

What follows is the Final Report Agreement Number 500-04-015 conducted by Competitive Energy Insight, Inc. (http://www.CEInsight.com), Inc. The report is entitled Evaluation of Policy impacts on Economic Viability from a Project Owner's Perspective of California Based CHP in Commercial Buildings.

This project contributes to the PIER Energy Systems Integration Program.

For more information on the PIER Program, please visit the Commission's Web Site at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at (916) 654-5200.

Executive Summary

Introduction

This report entitled Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California-Based CHP was prepared under a contract with the California Energy Commission under the Public Interest Energy Research (PIER) Program under California Energy Commission Contract No. 500-04-015. The results and recommendations of the analysis are described in three Appendices, each which provides the analysis details for the referenced tasks.

The subject contract was subdivided into a work breakdown structure and task as outlined below:

- Task 1 – Administrative. Includes Meetings, Progress Reports and Final Report
- Task 2 – Interviews of CHP Industry Stakeholders (Reported in Task 3 Report)
- Task 3 - Appendix A - Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP in Commercial Buildings - Market conditions prevalent in May of 2005
- Task 4 - Appendix B – Two Parts
    - Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP in Commercial Buildings - Market conditions prevalent in January/February 2006
    - Potential Impacts of Federal Production Tax Credits (PTCs), Greenhouse Gas Emissions Reduction Credits and Transmission Deferral/Offset Credits on CHP economics
- Task 5 - Appendix C – Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based Dairy Digester CHP Projects

Competitive Energy Insight Inc., based in San Diego, California was contracted by the California Energy Commission under contract number 500-04-015 to prepare a series of evaluations of the economics of ownership and operation of Combined Heat and Power facilities from the perspective of independent and non-utility affiliated owners and operators of these facilities.

The analyses were performed over the period of January 19, 2005 – March 31, 2006.

It is important to note the following in the context of all of the studies described herein:

- Economics of CHP ownership are highly site specific. General assumptions based on "proxy" installations were applied to facilitate the understanding of how regulatory policies, operating considerations, market gas prices and externalities such as net emissions reductions might impact the relative economics of CHP ownership. While in certain instances findings for the "proxy" installations were dramatic enough to indicate whether or not CHP ownership may be generally economic, the study is not intended for this purpose.
- Substantive conclusions and recommendations are provided relative to the impacts on tariffs and rate making policy on the economics of CHP ownership. These conclusions and recommendations are expressed solely from the perspective of the non-utility CHP owner and do not address the reasonableness or justification of electric rates from the perspective of the electric utilities or from that of other rate payers on the system.

Background

The California Public Utilities Commission and the State of California have expressed an objective of increasing the application of Combined Heat and Power (CHP) projects in California because of the clear benefits of CHP to the state and society. While policy makers in California have agreed that CHP applications offer substantive benefits to the public and to the State, the decision to install and operate CHP facilities ultimately resides with the private owners of commercial business facilities that are candidates for CHP. Those business owners' objectives are primarily to save enough money relative to purchases of electricity and gas to justify the associated capital investment costs and risks of installing and operating an on-site generation facility.

This study complements the recent California Energy Commission publication CEC-500-2005-173 which addresses an assessment of the market for CHP in California by focusing on the considerations of the site specific economics of CHP ownership. This study will not address the appropriateness or justification of tariffs from utility, rate payer or rate-making perspectives other than to isolate the specific impacts that tariffs and other policies have on incentivizing or disincentivizing private CHP investment and operations.

Objectives and Approach

The objectives of this study are to focus specifically on the economics of CHP from project owner's perspective. The same methodology was applied in each of the analyses. Initially a series of interviews were conducted with key industry stakeholders including representatives of the CHP Community and the Electric Utilities. This was followed by detailed computer modeling of the economics of ownership and operation of the respective facilities from the perspective of facility owners taking into account the technical performance, investment costs, operating costs, financing considerations, income tax considerations and respective savings an owner of these facilities might achieve as a result of the on-site production of electric and thermal energy under prevailing electric utility tariffs.

Results and Key Findings

Key results and findings are summarized by task and report below. The respective reports appear in Appendices A, B and C.

Results and Key Findings for Commercial Building Applications
Market Conditions as of May 2005

The initial analysis was performed at market conditions prevalent in May of 2005, just prior to the steep rise in natural gas prices that resulted from gas supply shortages after the very active summer 2005 hurricane season. During the Task 3 interviews with industry stakeholders, there was a dramatic contrast in the perspectives of the utilities and CHP industry relative to the fairness of electric rates. Stakeholders in the CHP community expressed frustration with what they view as conflicts between incentives provided under the Self Generation Incentive Program and what they viewed to be disincentives under current electric rate structures. Their concerns included:

- There are significant inconsistencies between the rate approaches and methods of cost recovery used by the three California utilities. The rate structures are each also quite complex. This provides inconsistent and difficult to interpret pricing signals to the CHP market place.

- While rates are not structured in a consistent manner, there seems to be a trend in CA electric rates towards shifting cost recovery from energy rates to demand and standby rates, even in a market of increasing fuel prices. This is a substantive disincentive to CHP projects for which fuel is their most significant cost factor and which under current rate structures can usually only capture demand savings if the CHP facility operates flawlessly over an entire billing period.
- CHP owners appear to have a common perception that the rate-making process is heavily influenced by the utilities in the utilities' self-interest and a sense of frustration feeling that the CHP community does not have the means and resources to provide input to the process
- Rapidly rising gas prices are a serious concern for CHP owners who must rely on energy rates as the tariff component to recover CHP facility fuel costs. CHP owners expressed a sense of concern that it appears that recovery of increases experienced by the utilities in their fuel costs may sometimes be reflected though demand charge or other cost mechanisms in the tariffs.

During Task 3 Interviews, the electric utilities, on the other hand, emphasized:

- They are making serious efforts to be available to customers to assist them in understanding and applying rates
- Revenue recovery often times does not reflect the true costs of service. Savings to CHP owners can ultimately lead to higher electric rates for other rate payers
- Ratemaking policy is often times dictated by other complex factors that are unrelated to impacts on CHP ownership and operation

It was observed in Task 3 that SDG&E's ALTOU rate and PG&E's E20 rates provided relatively attractive economics for CHP under the right conditions while SCE's TOU-8/standby tariff is clearly <u>not</u> attractive for CHP applications. Supporting findings during Task 3 included:

- Very low off-peak power rates are disincentives to CHP. The benefits of the high efficiency of CHP are difficult to capture if off-peak energy rates are very low. Because off-peak rate periods typically comprise 50 – 60% of the hours of the year, CHP is most viable if savings can be produced during off-peak periods. SCE's tariffs tend to have the lowest off-peak rates.
- CHP are sometimes penalized though tariffs for optimizing operations and savings. Owners of CHP facilities can sometimes substantively improve their economics by operating facilities in a manner that accounts for time-related load and energy price changes. Components of tariffs like non-coincident demand charges and higher off-peak standby rates penalize CHP owners for this type of optimized operation.
- Gas costs are the single most important component of CHP operating costs. CHP economics depend greatly on savings generated from the energy component of the tariff so it is important that recovery of gas costs by the utilities be fully and promptly reflected in the energy component of the tariff.
- A shift in cost recovery from energy to demand charges in the tariffs penalizes CHP

- Demand charge structures that emphasizes on-peak operations better incentivize CHP owners to try to achieve high on-peak reliability. Conversely, high “non-coincident” demand charges and ratchets disincentivize emphasis on on-peak power production.

- Standby charges are a substantive disincentive to CHP. Exemptions allowed from standby charges often times impose even more severe penalties on CHP through other mechanisms in the tariffs. This was especially true under SCE’s tariffs and to some extent in SDG&E’s tariffs under rate structures applied in May of 2005.

- Exempting only projects sized less than 1000 kW from the DWR bond component of departing load charges creates an arbitrary breakpoint in the incentives/disincentives to CHP ownership

- The SGIP program is critical to CHP economics in the current scenario. It does not, however, provide incentives to align owners to effectively operate their facilities in a manner that supports the needs of the grid and the interest of the public once they are installed.

Recommendations that resulted from Task 3 included:

- The structure of tariffs in the state should be standardized and simplified. If tariffs can not be standardized and simplified across the board a CHP specific standardized tariff structure, if properly architected, might further encourage CHP development.

- Demand charges assessed on 15 or 30 minute operating intervals are punitive to CHP. As an alternative, these charges when applied for determining demand charge savings associated with CHP related demand reductions, should be assessed on a much longer time interval, perhaps daily or weekly.

- Demand charges assessed to CHP facilities for outages or non-performance should be assessed based on the pool benefits of many CHP facilities on the grid rather than assigning each facility individual responsibility as a single demand increment

- Energy rates in tariffs should fully and promptly reflect changes in fuel costs experienced by the utilities

- Tariffs should emphasize on-peak and part-peak demand relative to non-coincident demand charges

- Benefits offered to CHP such as the exemption from the DWR bond charges should be provided to the first increment of production by the facility rather than based on the rated capacity. This would minimize artificial incentives to non-optimal design and operating practices

- Standby charges are a substantive disincentive to CHP and should be fully waived for all CHP facilities in classes that are deemed to be of societal benefit, without other mechanisms of penalties being imposed (such as higher replacement energy costs or demand rates than would otherwise occur) when demand charges are waived.

- SGIP incentives should be restructured to include both up-front rebates and production-based incentives

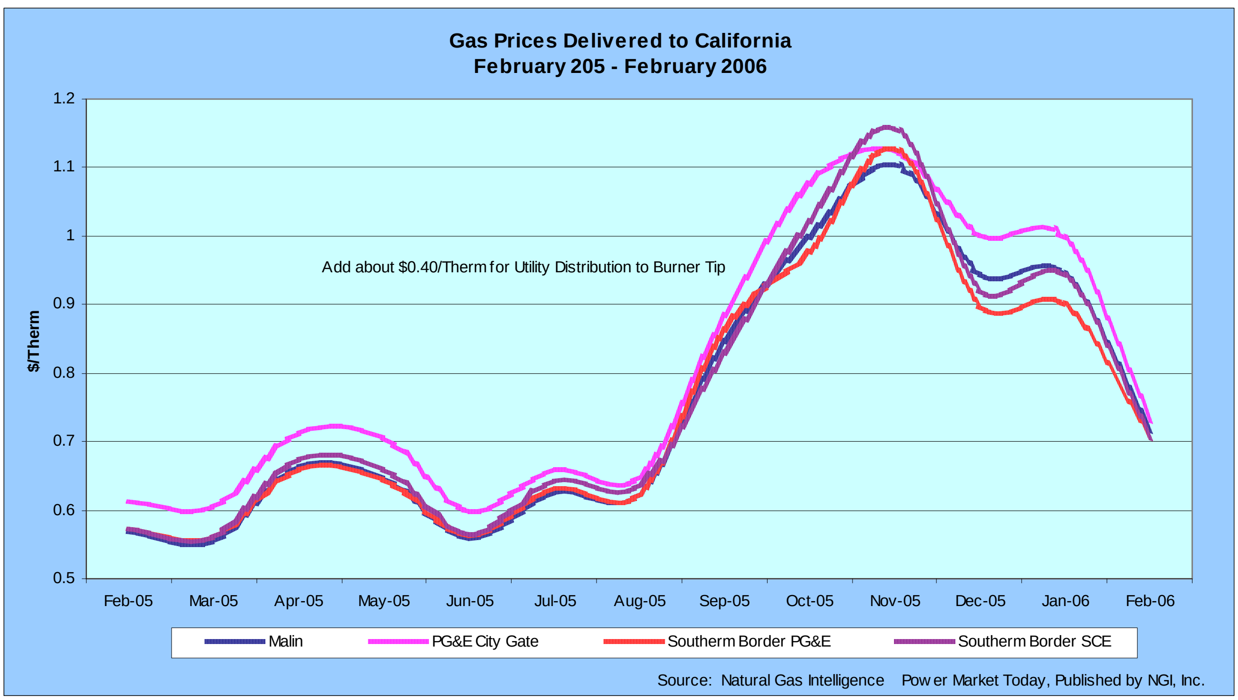
- As indicated in the CHP Market Assessment Report, incentives to CHP project owners for externalities, including net CO_2 or other emissions reductions would provide further incentives for CHP to support broader societal benefits

- Future studies and planning efforts performed by the California Energy Commission and the California Public Utilities Commission should include analysis from the CHP owners' perspectives

Task 4 Results and Key Findings for Commercial Building Applications
Market Conditions as of January/February 2006 and Potential Impacts of Externalities

Following the completion of Task 3 a very volatile period for natural gas prices occurred. Figure 61 provides an illustration of the volatility of gas prices that occurred over the period of the Spring of 2005 through the Winter of 2006. Over the period, gas rates at the CA border ranged from a low of about $0.57 - $0.65/Therm in the Spring of 2005 to a high of over $1.10/Therm in late fall of 2005, and then settled back down to the range of $0.70/Therm by the Spring of 2006. (Note that about $0.04/Therm is typically added to these prices for local distribution to the burner tip). This unprecedented volatility was the consequence of high gas demand, volatile world energy prices and supply disruptions resulting from a series of hurricanes in the Gulf of Mexico during the summer and fall of 2005. A relatively warm winter across the country resulted in some declines in gas prices which by February of 2006 were about 20% above February 2005 prices.

Figure 1 - Average Gas Price at Northern California and Southern California Border, $/Therm



Over this same period, the three California Investor Owned Utilities also had new rates approved. General observations relative to the changes in rate structures of the utilities included:

- A trend of shifting cost recovery from energy to demand rates, especially in PG&E's and SDG&E's service territories, continuing even in the face of increasing gas prices. To many CHP industry stakeholders this appeared to be counter intuitive to their expectation that increasing gas prices would result not result in decreases in electric energy rates.

- The combination of higher gas prices, lower energy rates and higher demand charges, substantively degraded the economics of CHP ownership. This is most notably true in PG&E's and SDG&E's service territories. While some of that degradation has been recovered but with the current net average increase in gas prices of about 20% and net average decrease in the energy component of the tariffs of about 5-10% (while demand charges increased.

- In SCE's service territory, demand charges remained constant and energy rates increased slightly. While the economics of CHP degraded less in SCE's service territory than for other utilities, the previously unattractive economics observed in the May 2005 analysis still degraded in January/February of 2006.

The "spark spread", an industry terminology for the equilibration of the energy rate component of the electric tariff and the cost of gas prices to produce that same electric energy using CHP, is a good measure of the degradation of CHP economics from May of 2005 to January/February of 2006. During the evaluation period, gas prices increased while the energy rate component in the electric tariffs has tended to decrease. Since demand charges are not reflected in energy consumption, while they are an important cost component on the customer's electric bill, they are not a factor in the spark spread calculation or the incremental operating incentives for CHP.

A low or inverted spark spread means the energy cost component of the electric tariff is lower than the corresponding cost of gas for a CHP owner to produce power. While demand savings and the recovery of waste heat from CHP applications can offset narrow spark spreads, the substantive decline in retail spark spreads observed over the evaluation period is a strong negative for gas fired CHP.

Under gas and electric pricing scenarios evaluated in this report, investments in CHP in both PG&E's and SDG&E's service territories appeared to be marginal to uneconomic except in circumstances where most of the waste heat from the CHP facility can be used for thermal offsets. For many CHP applications, this is not practical on a 7 x 24 basis. Use of waste heat in absorption chillers is much less attractive under scenarios of low energy and high demand rates. It is always worth noting that special circumstances at a particular site or facility might overcome these obstacles.

To complement analysis of volatile gas prices described above, analysis was also performed of the potential enhancements to CHP economics that might be realized as a result of other generating credits (i.e. externalities) that CHP facilities often provide and yet are not compensated for. These can include transmission offsets, net reductions in greenhouse gas emissions and benefits available under the Federal Energy Policy Act of 2005 for facilities that utilize renewable based fuels and/or micro turbines.

In a report titled Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs issued by the California Energy Commission on October 25, 2004 estimates were provided relative to the potential weight averaged value of avoided transmission and distribution costs and CO_2 offset credits that might be justified in a market trading system.

- A representative value of $40.00/kw year for transmission and distribution offsets.
- A representative value of $8.00/ ton for CO_2 emissions reduction credits.

- For renewable energy based projects, a Production Tax Credits of 0.95 ¢/kwh hour escalating at 1.5% for five years.
- For projects using micro turbines an Investment Tax Credit of 10% of the micro turbine price with a limit of $200/kw.

Due to the significant uncertainty and sometimes site specificity in the market values pf greenhouse gas emissions credits and transmission and distribution offsets, sensitivities were performed on the indicated rates.

In general, these upside benefits have be potential to add on the order of 2% to 7% to the after tax return on investment realized in these applications. While these amounts do not appear to be sufficient to incentivize projects faced with gas prices on the order of $1.00/Therm or higher and electric rate structures prevalent in the state in January/February of 2006, with moderation in gas prices and better equilibration in the energy component of electric rates with the real impacts of higher gas prices on electric rates, these incremental benefits could mean the difference between a marginal and a profitable investment for the CHP plant owner.

Task 5 Results and Key Findings Dairy Based Anaerobic Digesters
Market Conditions as of January/February 2006

Task 5 focused on the economics of ownership of dairy based Anaerobic Digesters. Stakeholders in the digester community interviewed during Task 5 expressed frustration with what they viewed as unfair and insufficient net metering rates paid under the NEM BIO (net metering) tariff schedules. Their concerns included:

- Most digester projects installed to date have not proven to be cost effective
  - NEM BIO net metering rates are generally insufficient to cover the operating costs of the digester, engine and generator leaving the owner with little or no margin to cover capital investment and fixed costs.
  - The NEM BIO net metering rates are based only on the generation component of the energy rate and exclude all other related costs included in retail rates. Owners find themselves in a position where they are simultaneously purchasing power from the utility at a substantially higher rate than they are selling power back to the utility.

The electric utilities, on the other hand, expressed concerns that revenue recovery from dairy farms implementing digesters often times does not reflect the true costs of service incurred by the utility to serve the dairy. The result is that the utility and rate payer are incurring direct and indirect costs as a result of the installation and operation of these privately owned facilities.

The results yielded by the study indicate that at current NEM BIO rates, a reasonably attractive return on the investment in a digester and associated engine and generator can only be achieved if:

- The bulk of the energy (greater than 75%) generated by the digester is used on-site, behind the meter and minimal energy is net metered, and
- A substantial portion (greater than 50%) of the waste heat from the engine is efficiently utilized on site

These two objectives can be difficult for a dairy farm to achieve because of the dispersed nature of energy uses on the dairy farm. While farms typically use enough electric energy to meet the first criteria, that energy use is generally metered through multiple electric meters dispersed around the farm. Only a small percentage of the total power needs occur at the meter where the digester, engine and generator are interconnected. The majority of the power produced by the digester is treated as export energy at low net metering rates while at the same time energy is being purchased at higher retail rates through other meters on the farm.

In dairy applications, waste thermal energy from the engine can be difficult to utilize in many cases because of the difficulties in moving heat from the location of the digester, engine and generator to where it is needed. It appears, however, that opportunities to use waste heat in current digester projects may not have been fully addressed, detracting from the economics of those projects. Better designs are needed which might include locating the engine and generator nearer to the dairy facilities and piping the gas from the lagoon to that location. This could allow more complete use of the electric and thermal energy from the engine for on-site uses. Also, with more complex digester designs, waste heat from the engine could be used to heat the digester, improving its performance digester performance. These considerations are always site specific.

All of the cases studied in Task 5 showed potentially attractive digester economics at equivalent retail electric rates for the generated power when a sufficient amount of waste thermal energy generated by the engine is captured and utilized. However, the NEM BIO rates for exported power were generally insufficient. Relatively, the NEM BIO rates paid under the respective tariffs studied compared as follows:

- PG&E's NEM BIO rates as of January/February 2006 (under Ag5C) were the least attractive of any of the utilities. The effective net metering rates, even during on-peak periods, are generally at or below the costs of operating the digester, engine and generator, leaving little or no margin to cover fixed and investment costs in the facilities. Projects in PG&E's territory only showed attractive economics when all of the power was used behind the meter and the majority of the waste heat is used on-site.

- SCE's NEM BIO rates (under the TOU-PA) were substantially more attractive during on-peak than they are during off-peak periods. Projects in SCE's territory can be attractive if the majority of the energy produced is used behind the meter and sufficient waste thermal energy from the engine is captured and utilized on site.

- SDG&E's NEM-BIO rates (under the EECC schedule) provided the best incentive of any of the utility rates in California. This is true because the EECC schedule most clearly isolates the fuel cost component in the electric rates and so provides the highest net metering payment. Unfortunately, SDG&E's service territory has by far the fewest potential applications because of the limited number of livestock farms in the SDG&E service territory.

Other Task 5 findings included:

- Operating costs are a key consideration for digester applications. While the fuel (manure) is essentially free or can even converted to a salable byproduct, maintenance of the digester , engine and generator can be expensive, as high as 4 ¢/kwh or more

- Federal Production Tax Credits (PTC) are important for these projects but unless they involve a third party owner, will apply only to the portion of the energy that is exported. It appears that under the Energy Policy Act 2005 that the PTC rates can be reduced as a result of funding received from sources like the USDA. All analyses in this study included available PTC benefits to the owner.

- Incentives like the SGIP and USDA programs are critical to digester economics. While alone these incentives are not adequate to make these capital intensive projects economic, without these incentives the economics of digesters would be clearly unattractive without very substantial increases in electric rates.

Recommendations of the Task 5 study included:

- The PUC should review net metering rates and should allow credits more equivalent to the retail rates that farm owners are simultaneously paying for separately metered farm uses.

- Digester applications should make more efficient use of waste heat from the engine. At current gas prices, thermal uses such as milk pasteurization, processing and other thermal uses should be given highest priority followed by chilling uses such as refrigeration and space conditioning. Some of these might be more easily accomplished if the engine and generator are located near the dairy facilities and the gas is piped from the lagoon to the engine.

- As indicated in the CHP Market Assessment Report, incentives to digester project owners for externalities, including net CO_2, methane or other emissions reductions would provide further incentives for digester to support broader societal benefits.

- Future studies and planning efforts performed by the California Energy Commission and the California Public Utilities Commission should include analysis from the digester owners' perspectives to ensure that the impacts of tariff decisions on project economics are fully understood during the policy making process.

Competitive Energy Insight Inc. would like to express it thanks to the California Energy Commission for its support and sincere interest in understanding and evaluating the practical realities of the economics of ownership and operation of these technologies from the perspective of business owners that policy makers rely on to implement these systems. If you have questions or comments about this report, please feel free to contact the Energy Commission or Competitive Energy Insight Inc. at (855) 566-0221 or http://www.CEInsight.com.

Introduction

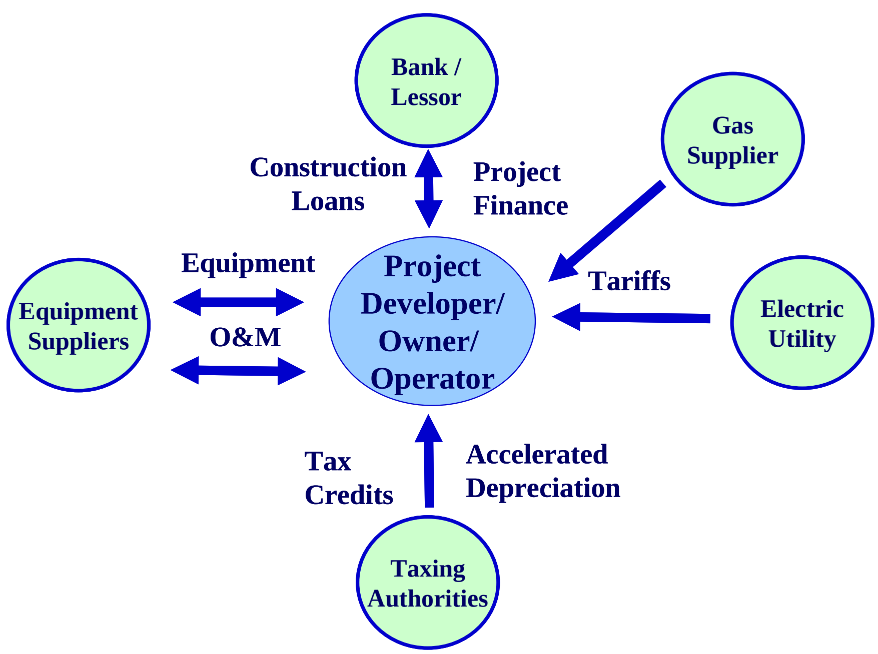
The California Public Utilities Commission and the State of California have expressed the objective of increasing the application of Combined Heat and Power (CHP) in the state. This is motivated by several factors which include:

- Efficiencies that can be gained through the utilization on-site of waste heat produced during the generation of on-site power and avoidance of transmission losses
- Peak load reductions and deferral of additions of generation capacity
- Deferral of electric transmission upgrades and expansions
- System security and diversity of a distributed generation mix
- Short lead times to installed capacity
- Reductions in emissions and global warming resulting from efficiency benefits and new technologies
- Economic benefits to the site host and society as a whole
- Improved homeland security by implementing a diverse base of generating resources

The objective of this study is to frame the analysis from the perspective of customers of the electric utilities who would invest in and operate CHP facilities at their respective commercial building sites. Ultimately, the decisions to install CHP resides with each individual project developer and owner who seeks a means to save or make money relative to what it would have otherwise cost them to purchase electricity and gas from the utility to support their building HVAC and business needs.

The tradeoff between purchasing and generating energy results in a “make versus buy” analysis that leads to the determination of the economic attractiveness of installing CHP facilities. Key to performing this analysis is recognizing that the economics of CHP investments and the associated risks undertaken by the various stakeholders in these projects are ultimately linked to one another. Figure 2 illustrates these linkages showing how changes in factors that affect any one stakeholder will ultimately affect the opportunity and risk profiles of the others. At the center of the figure is the owner of the CHP asset and/or site.

Figure 2 - The Economic Opportunities and Risks Afforded to CHP Stakeholders are Linked



Behind each of the circles representing the various stakeholders in a CHP project are the parameters that impact the cash flows between those stakeholders, and their associated economic incentives. These parameters are the primary inputs to this analysis and include:

- The host's time-related energy use profiles including electric, chiller and thermal generation
- Fuel prices and fuel price fluctuations
- The investment cost, operating costs and operating characteristics of CHP facilities as a function of load, hours of service and ambient weather conditions
- Alternative financing approaches and transaction structures

* The pricing signals imposed electric tariffs
* Incentive programs
* Income tax benefits and income taxes

Items identified by an asterisk (*) are those that can be directly influenced by policy makers, while the other factors relate to markets that are often times influenced by policy.

It is very important to note the following in the context of this study:

- The objective of this study is directed purely at understanding how policy impacts the economics of investments from the CHP project owner's perspective. It is not part of the scope of this effort to provide commentary or analysis of the basis or justification for those factors. For example, an important aspect of this study addresses how various components of the electric tariffs impact the economics of CHP. Any conclusions reached relate solely to the objective of studying CHP economic viability without judgment or commentary on the reasonableness tariffs from the utilities' or Public Utility Commission's perspectives.

- The economics of CHP development, installation, ownership and operation are highly site specific and so will always require site specific analysis. This study is not intended to illustrate the economic viability of CHP for any particular site or installation. The most important findings to be derived from this analysis are the relative impacts of the factors studied on CHP economics.

- Premises used in this study were reflective of market conditions prevalent at the time that the analysis was performed. Market volatility, especially gas and electric prices, can have a significant impact on the results derived herein. Sensitivities were performed to address how changes in these market factors might impact the findings.

To perform the analysis, the California Energy Commission contracted with Competitive Energy Insight Inc. (CEI – http://www.CEInsight.com) a San Diego based consulting firm and licensor of specialty computer software for the evaluation of energy project economics. This study was performed utilizing CEI's EconExpert™ software suite, a commercially proven toolkit for evaluating the technical and economic aspects of ownership and operation of power generation projects, both large and small. The analysis applies classic economic principals to measure the return on investment from the perspective of an owner/operator of CHP facilities. While this analysis is technical in nature, we have made a sincere effort to place the economic results in context so that the non-technical reader can understand and apply the associated conclusions and recommendations. Parties should consult their tax advisor relative to the information contained in this report as it pertains to any specific project or investment.

Project Objectives

The objectives of this study are:

- To provide an objective analysis of the impacts of policy in California including rate making policy and utility tariffs and the Self Generation Incentive Program (SGIP), on the economic viability of ownership and operation o CHP facilities in California including commercial buildings and dairy based anaerobic digesters.

- To perform sensitivity analyses to evaluate how various factors impact the economic viability of CHP.

- To provide recommendations to the California Energy Commission and the California Public Utilities Commission regarding policy approaches that might further encourage the deployment of CHP in California.

Project Approach

Each of the analysis performed during the study was initiated with interviews of industry stakeholders including representatives from the three California-based Investor Owned Utilities and from developers, engineers, owners and operators of CHP facilities in California. In advance of each interview, a questionnaire was provided to the parties. Key areas discussed during the interviews included:

- Feedback from the parties regarding what aspects of California Tariffs and Regulatory Policy have the greatest impact on CHP economics for commercial building applications

- Feedback on impacts of economic factors such as gas prices, financing options, state and federal tax policy on CHP economics

- Comments on the structure, benefits and limitations of the California Self Generation Incentive Program

Following the interviews, site thermal and electric usage profiles were developed for the respective applications from available metering data and from a database of building thermal and electric profile data. Using that information energy usage and production profiles were modeled for each respective application and the results were assimilated into after-tax discount case flow analyses. Scenario and sensitivity analyses were then performed to isolate and quantify the impacts of policy factors on the economics of CHP ownership from the project owner's perspective.

Project Outcomes

The analyses performed in Tasks 3 and 4 (Appendices A and B) were based on the three selected commercial building profiles (a hotel, a college and a hospital) in each of the three utility service territories. The analysis performed in Task 5 (Appendix C) were based on adjusted load profiles from actual dairy facilities.

It is very important to note the following in the context of this study:

- The objective of this study is directed purely at understanding how policy impacts the economics of investments in CHP from the project owner's perspective. It is not part of the scope of this effort to provide commentary or analysis of the basis or justification for those factors. For example, an important aspect of this study addresses how electric tariff components in California impact the economic viability of investments in CHP. Any conclusions reached relate solely to the objective of studying CHP economic viability without judgment or commentary on the reasonableness of those tariffs from the utilities' or Public Utility Commission's perspectives.

- The economics of CHP development, installation, ownership and operation are highly site specific and so will always require site specific analysis. This study is not intended to illustrate the economic viability of CHP for any particular site or installation. The most important findings to be derived from this analysis are the relative impacts of the factors studied on CHP economics.

- Premises used in this study were reflective of market conditions prevalent at the time that the analysis was performed. Market volatility, especially relative to steel and construction costs, gas prices and electric prices can have a significant impact on the results derived herein. Sensitivities were performed to address how changes in market factors might impact the findings.

Conclusions and Recommendations

The findings of the referenced reports were broad based and included a series of specific recommendations regarding tariff and regulatory policy which could encourage the implementation of CHP in California. The analyses indicated that there are currently serious policy barriers that tend to discourage CHP investment and provided insights and recommendations to how those barriers might be overcome. Individual findings are detailed in the Appendices which discuss each of the tasks performed during the analysis:

Task 3 Conclusions and Recommendations for Commercial Building Applications
Market Conditions as of May 2005

The primary finding of the Task 3 study was that SDG&E's ALTOU rate and PG&E's E20 rates provided relatively attractive economics for CHP. These attractive economics occurred under current and historical gas rates under conditions where waste heat from the CHP facility was efficiently utilized and where the facility achieved sufficient operating reliability to capture the majority of potential demand charge savings. SCE's TOU-8 tariff were clearly <u>not</u> attractive for CHP even under the conditions that were attractive in the other service territories. Supporting findings as of May 2005 included:

- Complexities of and inconsistencies between the tariffs inhibited efficient business practices for potential CHP owners and suppliers in the state

- Very low off-peak power rates, such as those under the SCE TOU-8 tariff, are severe disincentives to CHP. CHP projects are capital intensive and so are best suited for applications where the equipment can be operated at the high load factors. Because off-peak rate periods typically comprise 50 – 60% of the hours of the year, CHP is most viable if savings can be produced during off-peak periods.

    - The benefits of the high efficiency of CHP are difficult to capture if off-peak energy rates are very low. One of the primary efficiency benefits of CHP, the capture and use of waste heat, can not be economically applied during off-peak periods if the energy rate is very low. Cycling operation, while perhaps the best option under certain tariff structures, is ultimately not the preferred option for CHP owners.

- SDG&E's high "non-coincident" demand charges and ratchets under the ALTOU-DER rate are a disincentivize to CHP, opposing the potentially attractive economics for CHP projects in SDG&E's service territory. This was because of the potential for loss of demand savings that would result from any brief outage of the CHP facility, even during off-peak periods.

- PG&E's demand charge structure emphasized the importance of reliable on-peak CHP operations because of higher "coincident" (on-peak) demand charges. This type of structure better incentivizes CHP owners to try to achieve high on-peak reliability.

- CHP projects should not be penalized though tariffs for optimizing operations and savings. Hourly and seasonal variations in site thermal and electric uses, electric rates and gas prices result in a continuously changing economic environment for CHP owners. Owners of facilities can sometimes substantively improve their economics by operating facilities in a manner that accounts for these changes. Examples of this are:

- If the utility's "marginal" cost of energy during off-peak periods is truly as low as those reflected in the SCE TOU-8 tariff, CHP owners should be permitted to drop load or shut down CHP facilities during these low pricing periods without incurring reversals of non-coincident demand savings or having to pay a higher cost for replacement power than if they did not have CHP
- During low site thermal load periods (which usually coincide with off-peak electric rates) owner's can also benefit from dropping load to match CHP production to site thermal needs and minimizing the amount of waste heat exhausted.
- When gas prices rise in disproportion to electric rates or during off peak rate periods, CHP owners can benefit substantially by shifting the use of waste heat from CHP facilities to hot water or steam uses rather than using the waste heat to displace electric load with absorption chillers

  Current components of tariffs like non-coincident demand charges and higher off-peak energy rates under standby tariffs penalize CHP owners for this type of optimized operation

- Gas costs are the single most important component of CHP operating costs
  - CHP can be economic at high gas prices, subject to full and efficient use of waste heat generated by the CHP facility at the site
  - CHP economics depend greatly on savings generated from the energy component of the tariff. It is important that recovery of gas costs (and increases in gas costs) by the utilities be fully and promptly reflected in the energy component of the tariff. Time lags in passing these costs through in energy rates, or allocation of some of these costs to demand or fixed charge components of the tariffs inhibits CHP viability by distorting market pricing signals and risk associated with CHP investment and operation.

- A shift in cost recovery from energy to demand charges in the tariffs penalizes CHP
  - Realization of demand charge savings by the CHP owner can be eliminated by only a brief outage in a facility. If tariffs are heavily weighted towards demand charges then the corresponding portion of savings incentives to the owner is at risk due to a single brief outage of the CHP facility.
  - High non-coincident demand rates further worsen this effect because brief off-peak outages will result in loss of demand charge savings.

- Standby charges are a substantive disincentive to CHP. SDG&E and SCE apply these charges to CHP owners while PG&E does not.
  - SDG&E's ALTOU-DER rate exempts owners from these charges then adds costs through loss of non-coincident demand charge savings (if only one 15-minute outage occurs) and ratchets that can extend this loss of savings for as long as year, make the ALTOU-DER rate an unwise choice for most CHP owners in CEI's view.
  - SCE's higher standby energy rates also impose a higher cost on owners for replacement power than they would otherwise pay for the same power under the TOU-8 tariff.

- Exempting only projects sized less than 1000 kW from the DWR bond component of departing load charges creates an arbitrary breakpoint in the incentives/disincentives to CHP ownership. For example, while a facility rated at 999 kW is exempt from these charges a facility rated at 1001 kW or greater must pay these charges on all of the respective generation. This can lead owners away from designing and operating facilities in the most efficient manner.

- The SGIP program is critical to CHP economics in the current scenario. It does not, however, provide incentives to align owners to effectively operate their facilities in a manner that supports the needs of the grid and the interest of the public once they are installed.

- A CHP project is a small power plant, carrying with it all of the issues and complexities of power plant ownership and operation, compounded with the overlay that the facility must operate in a manner that supports the needs of a business that has nothing to do with power generation. Many commercial building owners don't have the know-how to operate and maintain these facilities and consider it to be a distraction from their core business. This provides motivation for third party ownership which some policies discourage.

Recommendations from Task 3 included:

- The structure of tariffs in the state should be standardized and simplified. Stakeholders in the CHP industry are confused by the complexity and inconsistency of tariffs amongst the 3 utilities. This confusion reduces productivity and can also lead to CHP projects that are incorrectly engineered to fully capture the potential benefits, contractual disagreements between parties in the industry, and malcontent by facility owners with both the CHP industry and the utilities.

- If tariffs can not be simplified across the board a standardized and simplified CHP tariff might provide an alternative solution.

- Credits for demand charges offsets provided by CHP should be assessed on a substantively longer time interval than 15 or 30 minutes, perhaps based on daily or weekly averages. In this way the economics of a CHP facility that operates very reliably will not be as severely penalized when a brief outage occurs, and a facility that experiences multiple or extended outages will be penalized more severely than one that might have only a single brief outage in a billing cycle.

- Demand charges assessed to CHP facilities for outages or non-performance should be assessed based on the pool benefits of many CHP facilities on the grid rather than assigning each facility individual responsibility as a single demand increment. Amongst the benefits of CHP is the diversity and redundancy that a large number of small facilities simultaneously operating on the grid provide. It is virtually impossible that all such facilities or a substantial portion of them will experience simultaneous outages. This benefit should be recognized and apportioned in the demand charge structure and the reversals of demand savings that result from CHP outages. It should be noted that the utilities expressed concern that the pooling benefits may not be not system wide and can be isolated to a specific circuit.

- Energy rates in tariffs should fully and promptly reflect changes in fuel costs experienced by the utilities so that the pricing signals for ownership and operation of CHP are truly reflective of current market conditions and associated costs of CHP operation

- Tariffs should emphasize on-peak and part-peak demand relative to non-coincident demand charges. This will also provide a pricing signal to the market to encourage conservation and reliability during on-peak periods when the power is most needed and will allow CHP facilities a time for planned maintenance during off-peak periods to ensure better reliability.

- Benefits offered to CHP such as the exemption from the DWR bond charges should be provided to the first increment of production by the facility rather than based on the rated capacity. This would minimize artificial incentives to non-optimal design and operating practices. For example, applying the exemption to the first 8,760,000 kwh of generation produced by a facility rather than only to facilities sized less than 1000 kw would mean that all CHP facilities would receive this benefit but as intended the benefit would be capped.

- Standby charges are a substantive disincentive to CHP and should be fully waived for all CHP facilities in classes that are deemed to be of societal benefit. While CEI is not prepared in this report to recommend specifically what classes of facilities this exemption should apply to, we believe it should go beyond renewables to include CHP facilities in all utility service territories that meet an established efficiency and reliability criteria, and perhaps that are located in areas where local power provides other measurable benefits. When standby charges are waived the customer should not then be imposed with other forms of charges like ratchets, higher replacement power costs or different mechanisms for demand charges than they would otherwise pay without the standby charge.

- SGIP incentives should be restructured to include both up-front rebates and production-based rebates. A production-based rebate would provide additional incentives to operators of CHP facilities to maximize production, and could be structured to encourage production during on-peak periods when energy is viewed to be most important.

- As indicated in the CHP Market Assessment Report, incentives to CHP project owners for externalities, including net CO2 or other emissions reductions would provide further incentives for CHP to support broader societal benefits.

- Future studies and planning efforts performed by the California Energy Commission and California Public Utilities Commission should include analysis from the CHP owners' perspectives. This includes characterization and reporting of how provisions in rates and tariffs affect CHP economics and better integration of objectives like those of the SGIP program with rate making policy.

Task 4 Conclusions and Recommendations for Commercial Building Applications
Market Conditions as of January/February 2006 and Potential Benefits of Externalities

As market conditions changed from May of 2005 – January of 2006, gas prices varied dramatically while the three California Investor Owned Utilities also had new rates approved. In the cases of SDG&E and PG&E, the changes in the rates were highlighted by general increases in demand charges and declines in energy rates, even in the face of substantial increases in the price of natural gas.

General observations relative to the changes in rate structures allowed to the utilities in January/February 2006 rates included:

- A trend of shifting cost recovery from energy to demand rates especially in PG&E's and SDG&E's service territories is continuing even in the face of increasing gas prices. To many CHP industry stakeholders this appears to be counter intuitive to their expectation that increasing gas prices would result not result in decreases in electric energy rates.

- The combination of higher gas prices, lower energy rates and higher demand charges, substantively degraded the economics of CHP ownership. This is most notably true in PG&E's and SDG&E's service territories. While some of that differential has been recovered but with the current net average increase in gas prices of about 20% and net average decrease in the energy component of the tariffs of about 5-10% (while demand charges increased

- In SCE's service territory, demand charges have remained constant and energy rates have increased slightly. While the economics of CHP have degraded less in SCE's service territory than is the case for other utilities, the previously unattractive economics in SCE's territory have still degraded.

Over the subject evaluation period there have been dramatic swings, and in some cases even inversions of the retail "spark spread". The "spark spread" is an industry terminology for the equilibration of the energy rate component of the electric tariff and the cost of gas prices to produce that same electric energy using CHP. During the evaluation period, gas prices have increased dramatically, while the energy rate component in the electric tariffs has tended to decrease. Since demand charges are not reflected in energy consumption, while they are an important cost component on the customer's electric bill, they are not a factor in the spark spread calculation or the incremental operating incentives for CHP.

A low or inverted spark spread means the energy cost component of the electric tariff is lower than the corresponding cost of gas for a CHP owner to produce power. While demand savings and the recovery of waste heat from CHP applications can offset narrow spark spreads, the substantive decline in retail spark spreads observed over the evaluation period is a strong negative for gas fired CHP.

Under gas and electric pricing scenarios evaluated in this report, investments in CHP in both PG&E's and SDG&E's service territories appear to be marginal to uneconomic except in circumstances where most of the waste heat from the CHP facility can be used for thermal offsets. For many CHP applications, this is not practical on a 7 x 24 basis. Use of waste heat in absorption chillers is much less attractive under scenarios of low energy and high demand rates. It is always worth noting that special circumstances at a particular site or facility might overcome these obstacles.

To complement analysis of volatile gas prices described above, analysis was also performed of the potential enhancements to CHP economics that might be realized as a result of other generating credits (i.e. externalities) that CHP facilities often provide and yet are not compensated for. These can include transmission offsets, net reductions in greenhouse gas emissions and benefits available under the Federal Energy Policy Act of 2005 for facilities that utilize renewable based fuels and/or micro turbines.

In a report titled Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs issued by the California Energy Commission on October 25, 2004 estimates were provided relative to the potential weight averaged value of avoided transmission and distribution costs and CO_2 offset credits that might be justified in a market trading system.

- A representative value of $40.00/kw year for transmission and distribution offsets.
- A representative value of $8.00/ ton for CO_2 emissions reduction credits.
- For renewable energy based projects, a Production Tax Credits of 0.95 ¢/kwh hour escalating at 1.5% for five years.
- For projects using micro turbines an Investment Tax Credit of 10% of the micro turbine price with a limit of $200/kw.

Due to the significant uncertainty and sometimes site specificity in the market values pf greenhouse gas emissions credits and transmission and distribution offsets, sensitivities were performed on the indicated rates.

In general, these upside benefits have be potential to add on the order of 2% - 7% to the after tax return on investment realized in these applications. While these amounts do not appear to be sufficient to incentivize projects faced with gas prices on the order of $1.00/Therm or higher and electric rates prevalent at the start of 2006, with moderation in gas prices and better equilibration in the energy component of electric rates with the real impacts of higher gas prices on electric rates, these incremental benefits could mean the difference between a marginal and a profitable investment for the CHP plant owner.

Task 5 Conclusions and Recommendations for Dairy Based Anaerobic Digesters
Market Conditions as of January/February 2006

Conclusions from the Task 5 analysis of Dairy Based Anaerobic Digesters included:

- Digester technologies appear to be commercially viable, proven to offer substantial opportunities for environmental benefits to dairy and other livestock applications

- Digester projects installed to date at dairy farms have not been cost effective
    - NEM BIO net metering rates are generally insufficient to cover the operating costs of the digester, engine and generator leaving the owner with little or no margin to cover capital investment and fixed costs.
    - The NEM BIO net metering rates are based only on the generation component of the energy rate and exclude all other related components of retail tariffs. Digester owners often find themselves in a position where they are simultaneously purchasing power from the utility at a substantially higher rate than they are generating and selling power back to the utility.
    - Applications installed to date do not appear to take advantage of all potential opportunities to use electricity or waste thermal energy produced by the engine on the dairy farm. These opportunities can offer substantial improvements to the project's economics.

At current NEM BIO rates, a reasonably attractive return on the investment in a digester and associated engine and generator can usually only be achieved if:

- The bulk of the energy (greater than 75%) generated by the digester is used on-site, behind the meter capturing full retail value and little or no energy is net metered, and

- A substantial portion (greater than 50%) of the waste heat from the engine is fully and efficiently utilized on the farm

These two objectives can be difficult to achieve because of the dispersed and non-continuous nature of energy uses on the dairy farm. While farms overall often use enough electric energy to meet the first criteria, that energy use is disseminated around the farm and usually metered through multiple electric meters. At the meter where the digester, engine and generator are interconnected, usually only a small percentage of the generated power can be used behind the meter. As a result, the majority of the power is treated as export energy and valued at relatively low net metering rates while at the same time energy is being purchased at much higher retail rates through other meters on the farm. thermal energy can also be difficult to harness in many cases because of the difficulties in moving and storing thermal energy across the distances where they are needed on the farm.

Other specific findings of Task 5 included:

- Dairy farms typically operate in a competitive commodity market with relatively low profit margins. Imposing investments like digester plants on them without sufficient incentives could be damaging to the industry in California

- The NEM BIO net metering rates currently offered by PG&E are lower than the cost of operating the digester, engine and generator. Projects in PG&E's territory only appear to show attractive economics when all of the power can be used behind the meter and the majority of the waste heat can be used on-site.

- The relatively high on-peak generation rates under SCE TOU-PA and NEM BIO tariff resulted in economically more attractive digester applications in SCE service territory than PG&E's. Still, attractive returns were subject to use of a majority of the electric power used behind the meter or at equivalent retail-credited net metering rates, and substantive use of waste heat from the engine on the farm.

- SDG&E's NEM-BIO, PAT-1 and EECC schedules provide the best incentive of any of the utility rates in California for digesters. This is true because the EECC schedule most clearly isolates the fuel cost component in the electric rates and provides the highest net metering payment. It appears that digester-like projects in SDG&E's service territory have the best potential to be economically attractive if a substantial portion of the electric energy is used on-site and achieves retail energy rate benefits and a substantial portion of the waste heat is captured and used. Unfortunately, SDG&E's service territory has by far the fewest potential applications because of the limited number of livestock farms in its service territory.

- Operating costs are a key consideration for digester applications. While the fuel (manure) is essentially free or can even be valued as an eliminated or now-salable waste product, maintenance of the system can be expensive, as high as 4 ¢/kwh or more. In addition owners have to cover fixed costs, capital investment costs and earn a rate of return. This dictates that net metering rates have to be on the order of retail electric rates to encourage these types of investments.

- Capture and use of thermal energy is an important economic driver for any CHP application, including digesters. It appears that many projects implemented at dairy farms to date may not have fully taken advantage of these thermal energy opportunities.

- Production tax credits are an important potential benefit for these projects but unless they involve a third party owner, will apply only to the portion of the energy that is exported. It appears under the Energy Policy Act of 2005 that the PTC rates will also be reduced as a result of funding received from sources like the USDA.

- Incentives like the SGIP and USDA programs are critical to digester economics. While alone these incentives are not adequate to make these capital-intensive projects economically feasible, without these incentives the economics of digesters would be poor unless there is a very substantial increase in electric rates.

Recommendations from Task 5 included:

- The PUC should review net metering rates and should allow credits like those charged for retail energy. The structure of tariffs in the state should also be standardized and simplified.

- Designers and developers of these projects should make more effort to capture and efficiently utilize the waste heat from the engine. It appears that in some of the recently installed projects, some of these opportunities may have been missed, detracting from project returns. Suggested approaches to help better accomplish this include:

- o Locate the engine and digester nearer to the dairy facilities. The gas from the digester could be piped to a engine located in close proximity to the milking, storage and pasteurization facilities. This might better allow the power and heat from the facility to be more effectively used on site for applications like pasteurization, refrigeration, space conditioning and sanitization of facilities, and the power to be used for lighting, pumping and other electric uses
- o In some cases, the efficiency and production of digester operations can be enhanced by heating the digester. This requires more complex equipment and controls, however, and adds the capital and operating costs of the facilities.
- o Ultimately, every case is site specific so suggestions like these may or may not be realistic for a given project.

- As indicated in the digester Market Assessment Report, incentives to digester project owners for externalities, including net reductions in $CO_{2,}$ methane or other greenhouse gas emissions would provide further incentives for digester to support broader societal benefits.

- Future studies and planning efforts performed by the California Energy Commission and California Public Utilities Commission should include analysis from the digester owners' perspectives to ensure that the impacts of tariff decisions on project economics are understood during the policy making process.

Appendix A – Task 3

Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP in Commercial Buildings (Market Conditions as of May 2005)

Executive Summary for Task 3

Background

The California Public Utilities Commission and the State of California have expressed an objective of increasing the application of Combined Heat and Power (CHP) projects in California because of the clear benefits of CHP to the state and society which can include:

- Efficiencies that can be gained through the utilization on-site of waste heat produced during the generation of on-site power and avoidance of transmission losses
- Peak load reductions and deferral of additions of generation capacity
- Deferral of electric transmission upgrades and expansions
- System security and diversity of a distributed generation mix
- Short lead times to installed capacity
- Reductions in emissions and global warming resulting from efficiency benefits and new technologies
- Economic benefits to the site host and society as a whole
- Improved homeland security by implementing a diverse base of generating resources

While policy makers in California have agreed that CHP applications offer substantive benefits to the public and to the State, the decision to install and operate CHP facilities ultimately resides with the private owners of commercial business facilities that are candidates for CHP. Those business owners' objectives are primarily to save enough money relative to purchases of electricity and gas to justify the associated capital investment costs and risks of installing and operating an on-site generation facility.

This study complements the recent California Energy Commission publication CEC-500-2005-173 which addresses an assessment of the market for CHP in California by focusing on the considerations of the site specific economics of CHP ownership. This study will not address the appropriateness or justification of tariffs from utility, rate payer or rate-making perspectives other than to isolate the specific impacts that tariffs and other policies have on incentivizing or disincentivizing private CHP investment and operations.

Objectives and Approach

The objectives of this Task 3 study are:

- To focus specifically on the economics of CHP from a CHP project owner's perspective based on market conditions and tariffs prevalent at the time of the study, May of 2005.

- To provide an objective analysis of the impacts of rate making policy, utility tariffs and the Self Generation Incentive Program (SGIP) on the economic viability of ownership and operation of CHP facilities servicing commercial buildings in California

- To perform sensitivity analyses to evaluate how factors including tariff components, incentive programs, natural gas prices, the reliability of the CHP facilities and other factors might impact the economic viability of CHP and so influence the penetration of CHP in the California marketplace

- To provide guidance and recommendations to the California Energy Commission and California Public Utilities Commission to further improve the structuring of policies to encourage broader investment in CHP

Phases of the study included:

- Interviews with industry stakeholders
- Computer modeling of CHP applications in various regions of the state and under various tariffs
- Evaluation of associated costs, savings and investor rates of return
- Compilation of scenario and sensitivity analyses to isolate and quantify how individual aspects of policy either encourage or discourage investments in CHP

To perform the analysis, the California Energy Commission contracted with Competitive Energy Insight Inc. (CEI – http://www.CEInsight.com) a San Diego based consulting firm and licensor of specialty computer software for the evaluation of energy project economics. This study was performed utilizing CEI's EconExpert™ software suite, a commercially proven toolkit for evaluating the technical and economic aspects of ownership and operation of power generation projects, both large and small. The analysis applies classic economic principals to measure the return on investment from the perspective of an owner/operator of CHP facilities. While this analysis is technical in nature, we have made a sincere effort to place the economic results in context so that the non-technical reader can understand and apply the associated conclusions and recommendations.

Results and Key Findings

During the Task 3 interviews with industry stakeholders, there was a dramatic contrast in the perspectives of the utilities and CHP industry relative to the fairness of electric rates. Stakeholders in the CHP community expressed frustration with what they view as conflicts between incentives provided under the Self Generation Incentive Program and what they viewed to be disincentives under current electric rate structures. Their concerns included:

- Significant inconsistencies between the rate approaches and methods of cost recovery used by the three California utilities. The rate structures are each also quite complex. This provides inconsistent and difficult to interpret pricing signals to the CHP market place.

- While rates are not structured in a consistent manner, a trend in CA electric rates towards shifting cost recovery from energy rates to demand and standby rates was observed, even in a market of increasing fuel prices. This is a substantive disincentive to CHP projects for which fuel is their most significant cost factor and which under current rate structures can usually only capture demand savings if the CHP facility operates flawlessly over an entire billing period.

- CHP owners appeared to have a common perception that the rate-making process is heavily influenced by the utilities in the utilities' self-interest and a sense of frustration feeling that the CHP community does not have the means and resources to provide input to the process

- Rapidly rising gas prices, even prior to the increases observed later in 2005, were a serious concern for CHP owners who must rely on energy rates as the tariff component to recover CHP facility fuel costs. CHP owners expressed a sense of concern that it appears that recovery of increases experienced by the utilities in their fuel costs may sometimes be reflected though demand charge or other cost mechanisms in the tariffs.

The electric utilities, on the other hand, emphasized:

- They were making serious efforts to be available to customers to assist them in understanding and applying rates

- Revenue recovery often times do not reflect the true costs of service. Savings to CHP owners can ultimately lead to higher electric rates for other rate payers

- Ratemaking policy is often times dictated by other complex factors that are unrelated to impacts on CHP ownership and operation

It was observed in this study that SDG&E's ALTOU rate and PG&E's E20 rates could provide attractive economics for CHP under the right conditions while SCE's TOU-8/standby tariff is clearly <u>not</u> attractive for CHP applications. Supporting findings of the study include:

- Very low off-peak power rates are disincentives to CHP. The benefits of the high efficiency of CHP are difficult to capture if off-peak energy rates are very low. Because off-peak rate periods typically comprise 50 – 60% of the hours of the year, CHP is most viable if savings can be produced during off-peak periods. SCE's tariffs tend to have the lowest off-peak rates.

- CHP are sometimes penalized though tariffs for optimizing operations and savings. Owners of CHP facilities can sometimes substantively improve their economics by operating facilities in a manner that accounts for time-related load and energy price changes. Components of tariffs like non-coincident demand charges and higher off-peak standby rates penalize CHP owners for this type of optimized operation.

- Gas costs are the single most important component of CHP operating costs. CHP economics depend greatly on savings generated from the energy component of the tariff so it is important that recovery of gas costs by the utilities be fully and promptly reflected in the energy component of the tariff.

- Shifts in cost recovery from energy to demand charges in the tariffs penalizes CHP

- Demand charge structures that emphasizes on-peak operations incentivizes CHP owners to try to achieve high on-peak reliability. Conversely, <u>high "non-coincident" demand charges and ratchets disincentivize emphasis on on-peak power production.</u>

- Standby charges are a substantive disincentive to CHP. Exemptions allowed from standby charges usually impose even more severe penalties on CHP through other mechanisms in the tariffs.

- Exempting only projects sized less than 1000 kW from the DWR bond component of departing load charges creates an arbitrary breakpoint in the incentives/disincentives to CHP ownership

- The SGIP program is critical to CHP economics in the current scenario. It does not, however, provide incentives to align owners to effectively operate their facilities in a manner that supports the needs of the grid and the interest of the public once they are installed.

Recommendations that result from the Task 3 study included:

- The structure of tariffs in the state should be standardized and simplified. If a general tariff standardization can not be effected, development of a properly architected state-wide tariff structure for CHP would improve the potential for CHP market penetration.

- Credits for reductions in demand charges should be assessed on a much longer metering period than 15 or 30 minutes, perhaps daily or weekly.

- Demand charges assessed to CHP facilities for outages or non-performance should be assessed based on the pool benefits of many CHP facilities on the grid rather than assigning each facility individual responsibility as a single demand increment

- Energy rates in tariffs should fully and promptly reflect changes in fuel costs experienced by the utilities

- Tariffs should emphasize on-peak and part-peak demand relative to non-coincident demand charges

- Benefits offered to CHP such as the exemption from the DWR bond charges should be provided to the first increment of production by the facility rather than based on the rated capacity. This would minimize artificial incentives to non-optimal design and operating practices

- Standby charges are a substantive disincentive to CHP and should be fully waived for all CHP facilities in classes that are deemed to be of societal benefit.

- SGIP incentives should be restructured to include both up-front rebates and production-based rebates

- As indicated in the CHP Market Assessment Report, incentives to CHP project owners for externalities, including net CO2 or other emissions reductions would provide further incentives for CHP to support broader societal benefits

- Future studies and planning efforts performed by the California Energy Commission and California Public Utilities Commission should include analysis from the CHP owners' perspectives

II. Project Approach for Task 3

This section overviews the approach used in the Task 3 study.

A. Stakeholder Interviews

A series of interviews were conducted with representatives of the industry including:

- California Investor Owned Utilities (IOUs)
  - Southern California Edison - Bob Levine - Customer Service
  - San Diego Gas and Electric - Bonnie Baily – Supervisor Rate Support, Sally Muir – Project Mgr – SGIP, Joe Kloberdanz – Regulatory Affairs Mgr
  - Pacific Gas and Electric - Chris Tufon – Senior Tariff Analyst, Dan Pease – Electric Rates Manager, Dennis Keane – Service Analysis Manager

- Regulatory/Utility Consultant
  - Energy and Environmental Economics, Inc. - Snuller Price – Partner

- Owners, Developers and Engineers of CHP Projects in California
  - Saddleback College - John Ozurovich – Director or Facilities and Maintenance
  - Real Energy - Kevin Best – Chief Executive Officer, Steve Smith – Structured Transactions
  - Honeywell Building Solutions - Barry Voigt - Performance Contracting Engineer, Kevin Cross - Performance Contracting Engineer, Dave Gralnik - Sales Executive

In advance of each interview, a questionnaire was provided to the parties. A copy of the questionnaire is included in the appendix as are the formal notes from each interview, which were reviewed following the interviews and included edits by the interviewees to ensure that their positions were accurately represented.

Key areas discussed during the Task 3 interviews included:

- Feedback from the parties regarding what aspects of California Tariffs and Regulatory Policy have the greatest impact on CHP economics for commercial building applications

- Feedback on impacts of economic factors such as gas prices, financing options, state and federal tax policy on CHP economics

- Comments on the structure, benefits and limitations of the California Self Generation Incentive Program

The interviews tended to focus on electric rates and rate making policy. Not surprisingly, there was a dramatic contrast in the perspectives of the utilities and the CHP investment community relative to the appropriateness and fairness of rates. This study will not focus on the validity of these alternative positions but rather will concentrate on how energy rates, demand rates, standby rates, departing load charges and other factors influence the economics of CHP ownership.

i. Key Points and Observations from Interviews Stakeholders in the CHP Community

Provided below is a summary of the findings reached from discussions with the developers, engineers and operators of CHP facilities during Task 3.

- Most felt that to date CHP markets have not developed as many had projected. High gas prices, the lack of a coherent state and national energy policy, and inconsistent signals at the state levels (relative to regulatory policy and incentive programs) are impediments to broader penetration of CHP. Most observers felt hopeful that the Federal Energy Policy Act would have positive impacts on the furtherance of these markets but observed that it is unclear in the act what those benefits might be, if any, relative to gas fired CHP.

- The tariff structures of the three California IOUs were all very complex and constantly changing. Most customers seem to feel that they do not have a clear understanding about how the tariffs work and how alternative energy strategies available to them result in benefits or added risk.

- There was little consistency between the tariffs of the three California IOUs. This not only creates uncertainty for customers and potential CHP investors but also complicates CHP transactions, adding both cost and perceived risk.

- Departing load charges added to costs of operation. Many users don't understand the reasons for them. The demarcation of 1000 kW for the DWR bond component of the departing load charges is arbitrary and can incentivize inefficient design and operation of facilities.

- Owners and investors felt that they do not have (and can not financially afford to have) an adequate voice in the rate making process. In general, they feel that the utilities have control of the process.

- Gas prices were a serious concern to CHP investors and owners. The effects of increasing gas prices are often not represented in electric rates in a manner that parallels or reflects the costs of CHP ownership and operation.

- The rate making process is often contradictory with programs such as the Self-Generation Incentive Program. Customers perceive that the PUC is simultaneously encouraging CHP through the SGIP program and discouraging it through rate making policy.

- The SGIP program was easier to understand and administer from a user's perspective than it was previously. This appeared to streamline the process of obtaining funds though resulting awards under the new structure appear to be lower than they were previously.

- Production Incentives including options such as State Production Tax Credits or rate incentives based on CHP energy production could provide additional incentives for CHP facilities to be operated in a manner that supports grid needs. This might also more effectively offset risks to CHP owners associated with variations in gas prices.

ii. Key Points and Observations coming from the interviews with the California Investor Owned Utilities and Utility Rate Making Consultants

Discussions with the utilities focused largely on the interpretation and application of the tariffs. Provided below is a summary of those discussions. Note that a more detailed overview of the respective tariffs, based in part on the interviews, is provided in Section 6.vi on Page xvii of this report.

- The three California IOUs were each making visible efforts to try to be available and responsive to customers questions and inquiries about their tariffs. Each of the utilities had assigned staff dedicated to answering questions and to providing insight to customers with questions.

- There seemed to be a common opinion amongst the utility personnel that rates don't often accurately reflect or allocate the true costs of service. This may sometimes lead to inappropriate pricing signals to the CHP marketplace and may not always appropriately reflect the relative costs and savings experienced by the utilities when CHP projects are implemented. A more fair allocation of costs from the utility's perspective, however, might not necessarily provide greater incentives to CHP owners.

- The representatives of the utilities tended to feel that the grants under the Self-Generation Incentive Program may not be structured in a way that incentivizes CHP owners to design and operate their facilities to best support the needs of the grid. Some felt that operational incentives rather than up-front payments might provide better motivation to owners to achieve better reliability.

iii. The Factors that Affect CHP Economics from an Owner's Perspective – Premises Used in this Analysis

In essence, a CHP project is a small power plant, carrying with it all of the issues and complexities of power plant ownership and operation. This is then compounded with the overlay that the facility must operate in a manner that supports the electric and thermal needs of an enterprise whose central business model usually does not involve electric power generation or power plant know-how.

The impacts of policy on CHP economics were analyzed using CEI's EconExpert software suite. The goals achieved using this suite of Excel-based software tools include:

- Fully understanding the dynamics of the thermal and electric uses at the site
- Effectively integrating the operation of the CHP facility with the needs of the host business
- Properly modeling the economics of the development, financing and operation of the facility and
- Taking full advantage of all of the potential financial benefits available to the project including:
  - Efficient use of energy from the facility
  - High reliability
  - Savings under the applicable tariff
  - Efficient use of grant funding and available tax benefits
  - Effective financing and contracting structures
  - Risk allocation and management

This section describes the primary factors to consider when modeling the economics of a CHP investment and identifies the corresponding premises used in this study.

iv. Building Site Electric and thermal Usage Profiles

Understanding the profiles of electric, electric chiller and thermal usage of a facility where CHP will be applied is essential to appropriate sizing of equipment and to maximizing the return on investment. Continuous changes in site energy consumption, the balance of opportunities for electric and thermal displacement, and the value of the energy displaced all play into these considerations. In this analysis, hourly profiles were evaluated over the full 8760 hours of the year.

These energy profiles are affected by many factors including:

- Weather conditions
- Facility design including conditioned space, insulation, windows, HVAC efficiency, etc.
- The operating model of the associated business occupying the facility including hours of operation, building and equipment use and occupancy levels, etc.
- The applications for electricity and heat at the site and the "addressability" of those applications for offset by a CHP installation
- The operating characteristics of the installed CHP equipment

The result of these combined factors is the time dependent profile of electric and thermal use at the facility and the optimum match to reliably and efficiently displace those uses with on-site generation.

For the purposes of this study, characteristic or "proxy" hourly total electric, electric chiller and thermal load profiles were developed for each of three commercial building types using the EconExpert-EnergyShape load profiling tool developed by CEI (described further in Section 1.B.i). These building profiles were each configured in the three California IOU service territories for a total of nine base case scenarios. Individual site uses that contributed to these proxy profiles included:

- Addressable Electric Uses – These types of uses can only be offset by direct electric generation from the CHP facility and can not be addressed by waste heat.
    - Office Equipment
    - Inside Lighting
    - Exterior Lighting
    - Mechanical Equipment

- Addressable Chiller/Refrigeration Uses – These types of uses can be offset by the use of waste heat to produce chilled water (using absorption chillers) and/or by direct electric generation.
    - Building space cooling
    - Refrigeration

- Addressable Gas/thermal Uses – These types of uses can be addressed by waste heat. In instances where either thermal energy has sufficient value or during off-peak electric pricing periods when electric prices are lower, priority is given to apply waste heat to thermal uses as opposed to chilling. Examples of addressable thermal loads in commercial buildings include:
    - Space heating
    - Hot water uses typically including facilities such as laundry, dish washing, showers, pool heating, etc. as applicable.

- Other process uses for hot water or steam

- Non-Addressable Uses - In addition, often times there are other uses of electric power or thermal energy at a site that for physical or mechanical reasons cannot be addressed by the CHP facility. Examples of non-addressable uses can include:
  - Cooking (using natural gas)
  - Remote electric uses that are separately metered
  - Etc.

A. Characterization of Building Load Profiles Used in this Study

Figure 11 - Figure 59 in the Appendix provides the respective proxy profiles that were generated for the 3 commercial buildings in each of the three respective California IOU service territories. Annual and seasonal profiles are displayed, complemented by load duration curves which show the distribution of the respective loads as hours of use at each level over the entire year. Table 1 below provides a summary the primary characteristics of these profiles:

Table 1 - Summary of Building Load Profile Characteristics

Building Type	**Hospital**		**College**		**Hotel**	
Interconnection	**Primary**		**Primary**		**Secondary**	
Peak Electric Demand, kw	**Q1**	**Q3**	**Q1**	**Q3**	**Q1**	**Q3**
PG&E	1599	1796	1131	1523	765	922
SCE	1867	2108	1511	2085	1076	1475
SDG&E	1692	1899	1291	1564	827	1005
Season Electric Use, 1000 kwh / Quarter						
PG&E	2126	3012	1282	1549	1215	1459
SCE	2200	3474	1430	2225	1422	2097
SDG&E	2146	3357	1382	1849	1305	1719
Season thermal Use, 1000 Therms / Quarter						
PG&E	170.2	140.3	68.7	38.9	98.7	71.6
SCE	133.6	98.9	51.2	27.4	78.4	58.8
SDG&E	150.2	123.5	49.8	27.6	81.3	59.5
Notes						
PG&E Location	San Francisco – Northern California Coastal					
SCE Location	San Bernardino – Southern California Inland					
SDG&E Location	San Diego – Southern California Coastal					
Q1 Months are - January – March, typically represented of Winter conditions						
Q3 Months are July – September typically representative of Summer conditions						

Three building types were evaluated, intended to represent a cross section of commercial buildings with differing business and energy usage profiles. In order to normalize the comparison, 500,000 square feet of conditioned space was assumed for all cases.

The load profiles developed for each of the buildings is representative of both the building type and the climatic conditions in the selected utility service territories. It is recognized that throughout California, and within a particular utility's service territory, varying micro-climatic conditions will impact site needs and the resulting economics of CHP.

(a) Primary Features of the Respective Building Profiles

Table 2 below provides a relative comparison of the respective load profiles.

Table 2 – Primary Features of Commercial Building Profiles used in the Task 3 Study

	Hospital	College	Hotel
Business Operating Profile	**12 Mos** **7 days x 24 hours**	**12 Mos** **5 Days x 12 hours** 1 Day x 8 hours Closed on Sundays	**12 Mos** **7 days x 24 hours**
Intensiveness of Electric Demands	Highest		Lowest
Variability of Electric Demand	Lowest	Highest	
Intensiveness of thermal Demands,	**Highest**	Lowest	
Variability of thermal Demands	Lowest	Highest	
Sq Ft of Conditioned Space-all cases	**500,000 sq ft**	**Electric Chillers for Cooling, Gas Boilers for Space Heat**	

The Intensiveness represents the electric and thermal usage (in kWh or Therms) per square foot of conditioned building space. The Variability represents the percentage difference between the maximum and minimum electric and thermal loads. As a rule of thumb, facilities with the highest level and most continuous usage of electric and thermal consumption are the best candidates for CHP. Such facilities can benefit most from economies of scale, high load factors and the greatest efficiency of electric and thermal utilization.

(b) Weather and Climate Influences

The three regions that were studied in Task 3 are shown in Table 3. The Southern California Inland (SCE) region had a higher influence of summer cooling than did the other regions, and so the most significant absorption chilling loads during the summer. This also resulted in greater variability in electric loads during the summer and winter periods. The Northern California Coastal (PG&E) region had a higher influence of winter heating needs and the greatest relative influence of waste heat use for thermal offsets.

The magnitude and frequency of variation of thermal and electric loads will have a substantive impact on the optimum sizing, performance and operating profile of CHP installations, all which directly impact economics. The influence of tariffs and the related time-of-day electric prices were also strongly influenced by the load profile shapes and extremes. Using the EconExpert computer models, the electric generation capacity, chiller capacity, thermal offsets and the operating profile for each application were individual sized to maximize the resulting return on investment.

Table 3 - Relative Influences of Climatic Conditions on the Economics of CHP in Each Studied Region

	Northern California Coastal PG&E Cases San Francisco	**Southern California Inland SCE Cases San Bernardino**	**Southern California Coastal SDG&E Cases** San Diego

Influence of Summer Chilling requirements		Highest	Lowest
Influences of Winter Heating requirements	Highest		Lowest

v. Base Case Scenario Technical and Economic Premises

Table 4 - Table 6 illustrate the Economic, Gas Price and Technical premises used in the base case scenarios. An installed cost of $2,300 – 2,500 / kW was assumed for the applications, corresponding to the installation of 1, 2 or 3 x 333 kW engine(s) and associated auxiliary equipment for the Hotel, College and Hospital cases respectively. In addition to the installed cost the following amounts were added to account for other costs that are typically experienced by projects of this type. While site and project specific, these are illustrative of costs that are oftentimes overlooked or missed by owner's or developers.

- $25,000 for project development expenses
- 20% of annual fixed operating costs for start-up
- One month of CHP facility gas costs for working capital
- One month of debt payment costs for debt reserves
- 50% of fixed O&M costs for spare parts
- 0.75 % of the amount financed for loan origination fees
- Interest expenses at an annual rate of 8.0% annually for funds borrowed during construction

The net resulting as-built cost of the facility ranged from $2,400 - $2,600 / kW to which a credit of $600/kw was applied for incentive funding under the Self Generation Incentive Program (SGIP). Sensitivities were performed to evaluate how project economics would be impacted by higher or lower capital costs.

A very important premise in the analysis is the price of natural gas. At the time the modeling was performed (in the spring of 2005) delivered gas prices were generally in the range of $0.60 - $0.70/Therm. In the early fall of 2005 following Hurricanes Katrina and Rita, gas prices had risen to over $1.25 / Therm. Sensitivities were also performed to analyze how these market variations in gas prices would impact CHP economics, accounting for both the higher costs of gas and the net benefits associated with higher associated value of electric and thermal offsets that also result from higher gas prices. Items in

Table 4 - Table 6 with an asterisk (***)** represent those that were studied under alternative scenarios or against which sensitivity analyses were performed.

Table 4 – Basic Economic Premises

Factor	Premise
General Inflation Rate	2.5% / yr
Inflation Rate for Gas and Electric Prices	2.8% / yr
Discount Rate	8.0%
Construction Term	4 Months
Start-of-Operations	1/1/06
Project Life	10 years
Cost of Equipment and Installation*	$2300 – 2500 / kw (Economy of scale corresponding to 3, 2 or 1 x 333 kw Internal Combustion Engine(s) and Related Equipment)
Total Capital Cost (incl. working capital, start-up, spare parts, fees and construction interest) *	$2400 - $2600 / kw
SGIP Rebate*	$600 / kw
Annual Fixed Operating Costs	$44 / kw
Variable Operating Costs (incl. allowance for major Maintenance)	2.2 ¢ / kwh
Interest Rate on Borrowed Funds	8.0% / yr Fixed
Loan Term	10 years
Federal Income Tax Rate	35%
Debt / Equity Ratio*	60 % / 40 %
California State Income Tax Rate	8.84 %
Type of Business	For-Profit. Adequate taxable income to efficiently utilize all tax benefits.
Tax Depreciation	10 year MACRS

Table 5 - Gas Price Premises, 2005$ (as of 3/2005)

Month of the Year	Gas Price, $/Therm Delivered**
January	0.70
February	0.70
March	0.68
April	0.65
May	0.60
June	0.60
July	0.60
August	0.60
September	0.60
October	0.65
November	0.68
December	0.70
Annual Average	**0.65**

** Sensitivities were performed to address substantively higher gas prices experienced following hurricanes in the summer of 2005.

Table 6 – Basic Technical Premises

Factor	Premise
Efficiency of host's existing boilers	80 %
Minimum Electric Import	5 % of gross hourly demand
Engine Specifications / Manufacturer	Cummins
Base Fuel	Natural Gas
Rated Capacity	333 kw net
Number of Engines	Hotel – 1, College – 2, Hospital - 3
Minimum Load / Engine	60% = 200 kw net
Full Load Heat Rate (HHV, Net)	11,067 Btu/kwh
Minimum Load Heat Rate (HHV, Net)	12,000 Btu/kwh
Percent of input heat available for beneficial uses at full load	58.7%
Forced + Planned Outage Rate*	5.0% Minimum Downtime / Engine
Absorption Chillers / Manufacturer	Trane or like
Chiller Capacity	125 Tons / Engine
Electric Chiller Offset at Full Load	0.80 kw/Ton = 100 kw
Electric Chiller Offset at Minimum Load	0.33 kw/Ton = 41.2 kw

vi. Utility Tariffs

It is very important to emphasize that it is not in the scope of this analysis to evaluate the basis or justification for the utility electric tariffs. This study is focused exclusively on evaluating how various factors, including electric tariffs, influence the economic viability of California based CHP from a CHP project owner's perspective.

As regulated entities, Investor Owned Utilities in California are required to obtain approval from the California Public Utilities Commission for the rates that they charge to their customers. This process is complex and often times highly political with the conflicting interests of a myriad of parties participating either directly or indirectly in the rate making process. Rates paid to the utilities are intended to cover both historical and annual costs and to reward a rate of return to the utilities on invested capital. Tariffs typically include allowances for:

- The cost of installed generation, transmission and distribution facilities
- Fuel costs
- Operating costs
- Financing costs
- Costs for decommissioning of aged facilities, including nuclear projects
- Overhead costs associated with operating the utility business
- Other special accounts including public purpose funds, competitive transition charges, bond payments, energy purchases (i.e. Department of Water Resources), etc.

This analysis will focus on the resulting time-of-use tariffs (and where applicable the standby rates) paid by the commercial building owners with CHP facilities with peak site demands prior to installing CHP of over 1,000 kW.

In general, all of the tariffs applied by the California IOU's include the following components:

- Basic Service Fees - Fixed fees that do not vary with demand or energy use.
- Coincident Demand Charges – Fees based on the maximum demand (kW) in one or more specific rate periods.
- Non-Coincident Demand Charges – Fees based on the maximum demand (kW) without consideration of at what time of day or in what rate period that demand occurs.
- Energy Charges – Fees tied to the amount of energy use (kW) in each rate period.
- Other cost components and fees such as power quality adjustments and franchise fees, etc.

Utilities may also apply a standby charge assessed against the CHP owner to account for facilities that the utility has installed on their system which must be available to provide replacement power in the event that the CHP facility goes off line. SCE and SDG&E have standby rates that can include:

- Standby Reservation Charges – Fees for capacity generally designated by the utility as backup for the CHP facility.
- Standby maintenance and backup, energy and demand fees - Associated with demand and energy purchased as replacement power when the CHP facility is not available (Currently SCE Only)
- Ratchets - For those who elect exemption from the standby rate demand ratchets - Charges imposed on the user in a given month that are actually based on demand use in prior periods. (Currently SDG&E Only)

These rate components are then further broken down by each utility based on the level of service associated with the type of interconnection to the site. Service levels for the commercial building types evaluated in this study were assumed to be Secondary (standard utility service) or Primary (customer owned transformer).

Table 7 provides a simplified comparison of the respective tariffs evaluated in this report effective on May 1, 2005. Particular features of the tariffs that have most consequential impacts on the economics of CHP are highlighted in **boldface**. For simplification and comparative purposes the table includes rounding of certain rates. The actual rates were used in the financial modeling. In PG&E's and SCE's service territories, where franchise fees vary from municipality to municipality, an average franchise fee of 4.5% was assumed. In SDG&E's service territory the system wide franchise fee of 5.78% was used.

While at this level, the tariffs applied by the three California IOUs exhibit some similarities, the allocation of rates and cost recovery into the various categories listed above differ dramatically from one CA IOU to the other. These differences ultimately have a very direct influence on the relative economic viability of CHP in the three respective utility service territories.

Table 7 provides a simplified comparison of the tariffs evaluated in this report submitted or effective on May 1, 2005. The actual rates were used in the financial modeling. In PG&E's and SCE's service territories, where franchise fees vary from municipality to municipality, an average franchise fee of 4.5% was assumed. In SDG&E's service territory the system wide franchise fee of 5.78% was used.

Following Table 7 is a discussion of the key features of each of the tariffs, including insights derived from the interviews with utility personnel. It should be noted that the tariffs are complex and there are many exceptions and special conditions that can apply under specific circumstances; for the purposes of this study a common set of assumptions was applied across the various cases. The reader is advised to consult their utility representative with respect to the specific conditions of the applicable tariff as they apply to a site specific application.

Table 7 –Bundled Rates for Commercial Buildings with Peak Demand over 1,000 kw Studied in Task 3 [1, 3, 7]

Utility	PG&E		SCE		SDG&E	
Tariff – All Shown are Primary Interconnection	E20		TOU8 and Standby Base Case Scenario reservation fees on full CHP capacity		AL-TOU-DER, AL-TOU, EECC and Standby	
Applicable to Peak Loads Over	1000 kw		500 kw		20 kw	
Basic Service Fees[6]	$13.22 / Meter/Day (~$400 / Meter / Mo)		~$330 / Meter / Mo		$194 / Meter / Mo	
Standby Rate	Exempt		~$4		~$5 Exempt under AL-TOU-DER	
Demand Charges, $/kw[6]	General Service	Standby Power	General Service	Standby Power[2]	General Service	Standby Power
Metering Interval	30 Min	Same	15 Min	Same	15 Min	Same
Non-Coincident	$3.22	“	**$8.85**	**$1.80**	**$12.25**	“
Mid-Peak[4]	$3.70	“	$4.24	**$2.00**		“
On-Peak[4]	**$13.59**	“	**$27.40**	**$10.50**	$4.05-$5.91	“
Energy Charges, ¢/kwh[6]						
Off-Peak[4]	8.0¢	“	**4.6– 4.8 ¢**	**6.7 – 6.9¢**	9.0 – 9.4 ¢	“
Mid-Peak[4]	8.8 – 9.3 ¢	“	7.7 – 9.5 ¢	**9.8 – 11.6¢**	9.1 ¢	“
On-Peak[4]	**15.4 ¢**	“	**12.9 ¢**	**15.4 ¢**	11.8–11.9 ¢	“
Departing Load Charges for SGIP Projects Under 1000 kw, ¢/kwh[5]	0.51 ¢		0.55 ¢		0.67 ¢	
Additional Departing Load Charges for Projects over 1000 kw, ¢/kwh[5]	0.48 ¢		0.48 ¢		0.48 ¢	
Ratchets	CHP Exempt		CHP Exempt		For the non-coincident demand charge the customer pays pm the current months peak or 50% of highest peak established during the preceding 11 Months. If standby is paid CHP capacity amount is exempted from ratchet.	
Franchise Fees (Incl. Above)[7]	Varies 4.5% Assumed		Varies 4.5% Assumed		5.78%	

1. The rates shown are those effective on 5/1/2005. SCE rates were filed in April of 05 and effective in July of 05.
2. The SCE Standby rate is based on the amount of capacity reservation elected by the owner.
3. Bundled rates are rounded for illustrative comparisons. In the modeling analysis, the actual seasonal, time and transmission level specific rates were used without any rounding using the values shown in Table 8 - Table 15

4. The three utilities all use different nomenclature to designate rate periods. PG&E uses Peak, Part-Peak and Off-Peak, SCE uses On-Peak, Mid-Peak and Off-Peak, and SDG&E uses On-Peak, Semi-Peak and Off-Peak. For the purposes of comparison the general categories of On-Peak, Mid-Peak and Off-Peak are used reflecting the three respective rate periods.
5. Departing load charges for SGIP qualified projects less than 1000 kW include Nuclear Decommissioning Charges and Public Purpose Funds. Those over 1000 kW also include DWR Bond Charges.
6. Customers in SDG&E service territory can option for the AL-TOU rate which will also require them to pay standby charges in the amount of ~$5.00/kw but will exempt them from the demand ratchet that is applied to non-coincident demand charges and reversal of non-coincident demand charge savings as a result of CHP outages.
7. All rates include estimated franchise fees.

(a) PG&E E20 Tariff Overview

The PG&E tariff evaluated in May of 2005 was the E20 which generally applies for customers with a maximum demand of greater than 999 kW, at primary or secondary interconnection service levels respectively. After installing CHP, a customer previously subject to the E20 tariff could stay on that tariff if their demand is reduced to less than 999 kW with the CHP facility in operation.

The E20P schedule is summarized in Tables 8 and 9 below. The E20S rate structure is similar with generally higher energy and demand rates which tend to be more favorable to CHP where applicable.

Table 8 - PG&E E20P and E20S Rate Periods

	Demand	Energy	Period 1		Period 2		
Name of Period	$/kw/Mo	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Summer	May - October						
Weekdays							
Peak	13.59	15.39	12:00 PM	6:00 PM			6
Part-Peak	3.77	8.76	8:30 AM	12:00 PM	6:00 PM	9:30 PM	7
Off-Peak		8.03	12:00 AM	8:30 AM	9:30 PM	12:00 AM	11
Weekends/Holidays							
Off-Peak		8.03	12:00 AM	12:00 AM			24
Non-Coincident	3.22						
Winter	November - April						
Weekdays							
Part-Peak	3.72	9.32	8:30 AM	9:30 PM			13
Off-Peak		8.01	12:00 AM	8:30 AM	9:30 PM	12:00 AM	11
Weekends/Holidays							
Off-Peak		8.01	12:00 AM	12:00 AM			24
Non-Coincident	3.22						

The bundled rates above include typical Franchise Fees of 4.5%.

Table 9 - PG&E E20S Rates - Unbundled

Typical Franchise Fee 4.50% **Customer Charge (Incl. Franchise Fee)** $/Meter Day $ 13.22

Demand Charges, $/kw mo

	Generation	Distribution	Transmission	Reliability Service	Total	Add Franchise Fees	Bundled Total
Summer						4.5%	
Maximum Peak	7.07	5.93			13.00	0.59	13.59
Maximum Part-Peak	1.95	1.66			3.61	0.16	3.77
Maximum Demand (Non-Coincident)	(3.68)	2.14	2.44	2.18	3.08	0.14	3.22
Winter							
Maximum Part-Peak	1.92	1.64			3.56	0.16	3.72
Maximum Demand (Non-Coincident)	(3.68)	2.14	2.44	2.18	3.08	0.14	3.22

Energy Charges, c/kwh

	Generation	Distribution	Transmission	PPP	NDC	CTC	DWR Bond Charge	ECRA	Bundled Rate w/o Franchise Fee	Add Franchise Fees	Bundled Total
Summer										4.5%	
Peak	11.410	1.383	0.016	0.454	0.035	0.434	0.459	0.534	14.725	0.66	15.39
Part Peak	5.532	0.916	0.016	0.454	0.035	0.434	0.459	0.534	8.380	0.38	8.76
Off-Peak	4.952	0.798	0.016	0.454	0.035	0.434	0.459	0.534	7.682	0.35	8.03
Winter											
Part Peak	5.981	1.006	0.016	0.454	0.035	0.434	0.459	0.534	8.919	0.40	9.32
Off-Peak	4.936	0.795	0.016	0.454	0.035	0.434	0.459	0.534	7.663	0.34	8.01

Filed May 27, 2005 - Effective June 1, 2005
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

Observations concerning PG&E's E20 Tariff effective in May of 2005 included:

- PG&E metered electric demand on a 30 minute interval basis
- Rates were more heavily weighted towards energy costs than demand costs compared with the other CA IOUs
- Rates were more weighted towards on-peak period energy prices compared with the other CA IOUs
- Non-coincident demand rates (which tend to penalizes CHP facilities) were lower in PG&E's service territory and less severely penalize CHP projects for off-peak outages. High on-peak demand rates tend to encourage CHP owners to ensure that capacity is available during on-peak periods.
- SGIP qualifying CHP facilities were exempt from standby charges and PG&E does not impose any ratchets
- PG&E was currently in rate hearings for a new tariff anticipated to be effective on 1/1/06

(b) SCE Tariff Overview

The SCE tariff evaluated in May of 2005 was the TOU8 which applied for customers with a maximum demand of 500 kW or greater. As of May 1, 2005, SCE also applied a Standby Tariff for CHP applications. Under the standby schedule, customers pay a reservation fee and any reservation energy or demand used by the customer is billed under separate time-of-use demand and energy rates.

The TOU8 primary rate and respective standby rates effective in May 2005 are summarized in Tables 10 – 13 below. The TOU8 primary and secondary service level rates are similar. Grey shaded areas in Tables 12 and 13 show where standby rates differ from TOU8. Note that amounts include an estimated average 4.5% franchise fee in the bundled rates.

Table 10 - SCE Rate Periods (Bundled Rates used in analysis also included a 4.5% Franchise Fee)

	Demand	Energy	Period 1		Period 2		
Name of Period	**$/kw/Mo**	**Rate ¢/kwh**	**Hr Start**	**Hr Finish**	**Hr Start**	**Hr Finish**	**Hours/Day**
Summer	June - September						
Weekdays							
On Peak	27.37	12.89	12:00 AM	6:00 PM			6
Mid-Peak	4.24	7.68	8:00 AM	12:00 PM	6:00 PM	11:00 PM	9
Off-Peak		4.63	12:00 AM	8:30 AM	9:30 PM	12:00 AM	11
Weekends/Holidays							
Off-Peak		4.63	12:00 AM	12:00 AM			24
Non-Coincident	8.85						
Winter	October - May						
Weekdays							
Mid-Peak		9.47	8:00 AM	9:00 PM			13
Off-Peak		4.80	12:00 AM	8:00 AM	9:00 PM	12:00 AM	11
Weekends/Holidays							
Off-Peak		4.80	12:00 AM	12:00 AM			24
Non-Coincident	8.85						

Table 11 – SCE TOU8 Rates

Typical Franchise Fee **4.50%** **Customer Charge (Incl Franchise Fee)** **$/Mo** **$332.27**

Demand Charges, $/kw mo	Generation	Distribution	Total	Bundled Rate with Franchise Fee
Summer				
On-Peak	16.94	9.25	26.19	27.369
Mid-Peak	3.28	0.78	4.06	4.243
Facilities (Non-Coincident)	1.87	6.60	8.47	8.851
Winter				
Facilities (Non-Coincident)	1.87	6.60	8.47	8.851

Energy Charges, c/kwh	Delivery Service						Generation		Bundled Rate prior to Franchise Fees	Bundled Rate with 4.5% Franchise Fee
	Transmission	Distribution	NDC	PPP	DWR Bond Charge	Sub Total	URG 70% Avg.	DWR 30% Avg.		
Summer										
On-Peak	0.063	0.186	0.054	0.500	0.459	1.262	12.400	7.981	12.336	12.891
Mid-Peak	0.063	0.186	0.054	0.500	0.459	1.262	5.280	7.981	7.352	7.683
Off-Peak	0.063	0.186	0.054	0.500	0.459	1.262	1.110	7.981	4.433	4.633
Winter										
Mid-Peak	0.063	0.186	0.054	0.500	0.459	1.262	7.725	7.981	9.064	9.472
Off-Peak	0.063	0.186	0.054	0.500	0.459	1.262	1.341	7.981	4.595	4.802

Filed April 11, 2005 - Retroactive subject to interpretation rulings.
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
DWR Bond Charge = Department of Water Resources Bond Charge
URG - SCE Generation
DWR - Department of Water Resources Generation

Table 12 - SCE Standby Rates - Maintenance Service

Capacity Reservation Charge $ 4.16 /kw mo

Demand Charges, $/kw mo	**Generation**	**Transmission**	**Distribution**	**Total**
Summer				
Peak	11.60			**11.60**
Part Peak	1.95			
Facilities (Non-Coincident)	1.87			**1.87**
Winter				
Facilities (Non-Coincident)	1.87			**1.87**

Energy Charges, c/kwh	Delivery Service						Generation		**Bundled Rate prior to Franchise Fees**	**Bundled Rate with 4.5% Franchise Fee**
	Transmission	**Distribution**	NDC	PPP	DWR Bond Charge	Sub Total	**URG 70% Avg.**	DWR 30% Avg.		
Summer										
Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**15.160**	7.981	**14.670**	**15.330**
Part Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**8.023**	7.981	**9.674**	**10.110**
Off-Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**3.851**	7.981	**6.754**	**7.058**
Winter										
Part Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**10.466**	7.981	**11.385**	**11.897**
Off-Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**4.083**	7.981	**6.916**	**7.228**

Table 13 - SCE Standby Rates – Back up Service (Demand rates are the same as Maintenance Service - Subject to SCE advance approval of outage)

Energy Charges, c/kwh	Delivery Service						Generation		**Bundled Rate prior to Franchise Fees**	**Bundled Rate with 4.5% Franchise Fee**
	Transmission	**Distribution**	NDC	PPP	DWR Bond Charge	Sub Total	**URG 70% Avg.**	DWR 30% Avg.		
Summer										
Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**15.160**	7.981	**14.670**	**15.330**
Part Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**8.023**	7.981	**9.674**	**10.110**
Off-Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**3.851**	7.981	**6.754**	**7.058**
Winter										
Part Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**10.466**	7.981	**11.385**	**11.897**
Off-Peak	0.063	**0.588**	0.054	0.500	0.459	1.664	**4.083**	7.981	**6.916**	**7.228**

Observations concerning SCE's TOU and Standby Tariffs include:

- SCE metered electric demand on a 15 minute interval basis
- New rates were approved by the CPUC effective April of 2005. Customers who use CHP were subject to three different energy and demand charge schedules:
  - General Service under TOU-8
  - Maintenance service for scheduled outages approved in advance by SCE under the Standby Rate
  - Backup service for unscheduled outages under the Standby Rate

These new rates were more heavily weighted towards demand costs than energy costs when compared to previous SCE rates.

- Under the Standby Schedule:

  - Customers elect the amount of a reservation capacity. The reservation standby charge applied is $4.32/kw/month for secondary service and $4.16/kw/month for primary service (plus associated franchise fees)
  - With a physical assurance agreement committing that in the event of a CHP outage the customer will provide alternate capacity or will shed equivalent load, customers can elect to reduce or be exempt from the reservation amount.
  - If as the result of an outage the customer exceeds the elected reservation amount, SCE has the option to impose a reservation amount up to the full capacity of the CHP facility.
  - Charges for energy and demand associated with reservation amounts are assessed under two separate time-of-use billing structures.
    - Maintenance Service for demand and energy supplied during periods when SCE has pre-approved the outage, typically for planned maintenance
    - Backup service for replacement power during all other non-approved outages
    - Backup service rates are higher than maintenance service rates.
  - Both Backup and Maintenance rates have lower demand rates (post payments of reservation fees) and higher energy rates than TOU8

- SCE breaks out utility generation (URG) from DWR generation purchased on a monthly basis. The factoring of these rates varies monthly but is generally in the range of 70% URG / 30% DWR proportions

- SCE's off-peak energy rates are quite low, when bundled with DWR rates they are generally in the range of 4.6¢/kWh. These low off-peak rates are a substantive disincentive to CHP, which at current or recent historical gas prices produces electricity at a cost that is higher than this rate. This condition would normally incentivize customers to shed load or shut down the unit during off-peak but if the customer does this they now must pay a higher rate for the energy they use off peak under the standby rate than they would have paid under the TOU8 rate. It also eliminates the benefits of use of waste heat during these uneconomic electric pricing periods.

- SCE's primary and secondary interconnection rates differ only minimally from one another with the most substantive difference being that the primary interconnection blended summer on-peak energy rate is about 0.35¢/kWh higher than the corresponding secondary interconnection rate. All other differences in the rates are less consequential.

- Demand ratchets no longer apply under the new standby tariff structure

- At the time of the analysis, implementation of these rates was still pending interpretation rulings by the CPUC. The final rates became effective on July 1, 2005 with the only change being an upwards adjustment of about 0.1¢/kwh in the delivery charges.

(c) SDG&E Tariff Overview

The SDG&E tariffs used in this Task 3 study were the AL-TOU-DER and AL-TOU rates which generally applied for customers with a maximum demand of 20 kW or greater. In SDG&E territory, all CHP projects had the option to elect the AL-TOU-DER rate which exempts them from standby charges or the AL-TOU rate under which standby rates would still apply.

Table 14 – SDG&E Rate Periods (Includes a Franchise Fee of 5.78%)

	Demand	Energy	Period 1		Period 2		
Name of Period	$/kw/Mo	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Summer	May - September						
Weekdays							
Off-Peak	5.91	9.39	12:00 AM	6:00 AM	10:00 PM	12:00 AM	8
Semi-Peak		9.13	6:00 AM	11:00 AM	6:00 PM	10:00 PM	9
On-Peak		11.92	11:00 AM	6:00 PM			7
Weekends/Holidays							
Off-Peak		9.39	12:00 AM	12:00 AM			24
Non-Coincident	12.25						
Winter	October - April						
Weekdays							
Off-Peak	4.05	9.06	12:00 AM	6:00 AM	10:00 AM	12:00 AM	8
Semi-Peak		9.13	6:00 AM	5:00 PM	8:00 PM	10:00 PM	13
On-Peak		11.82	5:00 PM	8:00 PM			3
Weekends/Holidays							
Off-Peak		9.06	12:00 AM	12:00 AM			24
Non-Coincident	12.25						

Table 15 – SDG&E ALTOU-S and ALTOU DER-S Rates – Unbundled

Typical Franchise Fee 5.78% **Customer Charge (Incl. Franchise Fee)** $/Meter Mo $ 205.28

Demand Charges, $/kw mo

	Generation	Transmission	Distribution	CTC	Reliability Service	Total	Total w/ Franchise Fee
Summer							
On-Peak			4.09	1.50		5.59	5.91
Maximum Demand (Non-Coincident)		2.65	6.26	0.34	2.33	11.58	12.25
Winter							
On-Peak			3.48	0.35		3.83	4.05
Maximum Demand (Non-Coincident)		2.65	6.26	0.34	2.33	11.58	12.25
Standby Rate under ALTOU							
On-Peak		1.31	2.80	0.25	0.32	4.68	4.95

Energy Charges, c/kwh

	Generation See EECC Schedule	Transmission	Distribution	PPP	NDC	CTC	DWR Bond Charge	Reliability Service	Bundled Rate w/o Franchise Fee	Bundled Rate w/ Franchise Fee
Summer										
Off-Peak	6.987	(0.157)		0.576	0.056	0.578	0.459	0.378	8.877	9.390
Semi-Peak	6.987	(0.157)		0.576	0.056	0.330	0.459	0.378	8.629	9.128
On-Peak	9.389	(0.157)		0.576	0.056	0.563	0.459	0.378	11.264	11.915
Winter									-	
Off-Peak	6.987	(0.157)		0.576	0.056	0.264	0.459	0.378	8.563	9.058
Semi-Peak	6.987	(0.157)		0.576	0.056	0.331	0.459	0.378	8.630	9.129
On-Peak	9.389	(0.157)		0.576	0.056	0.471	0.459	0.378	11.172	11.818

ALTOU Rate Filed January 11, 2005 - Effective February 1, 2005
Standby Rate Filed January 27, 2005 Effective February 1, 2005
EECC - Electric Energy Commidity Cost Rate Effective April 21, 2005
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

Observations concerning SDG&E's rates included:

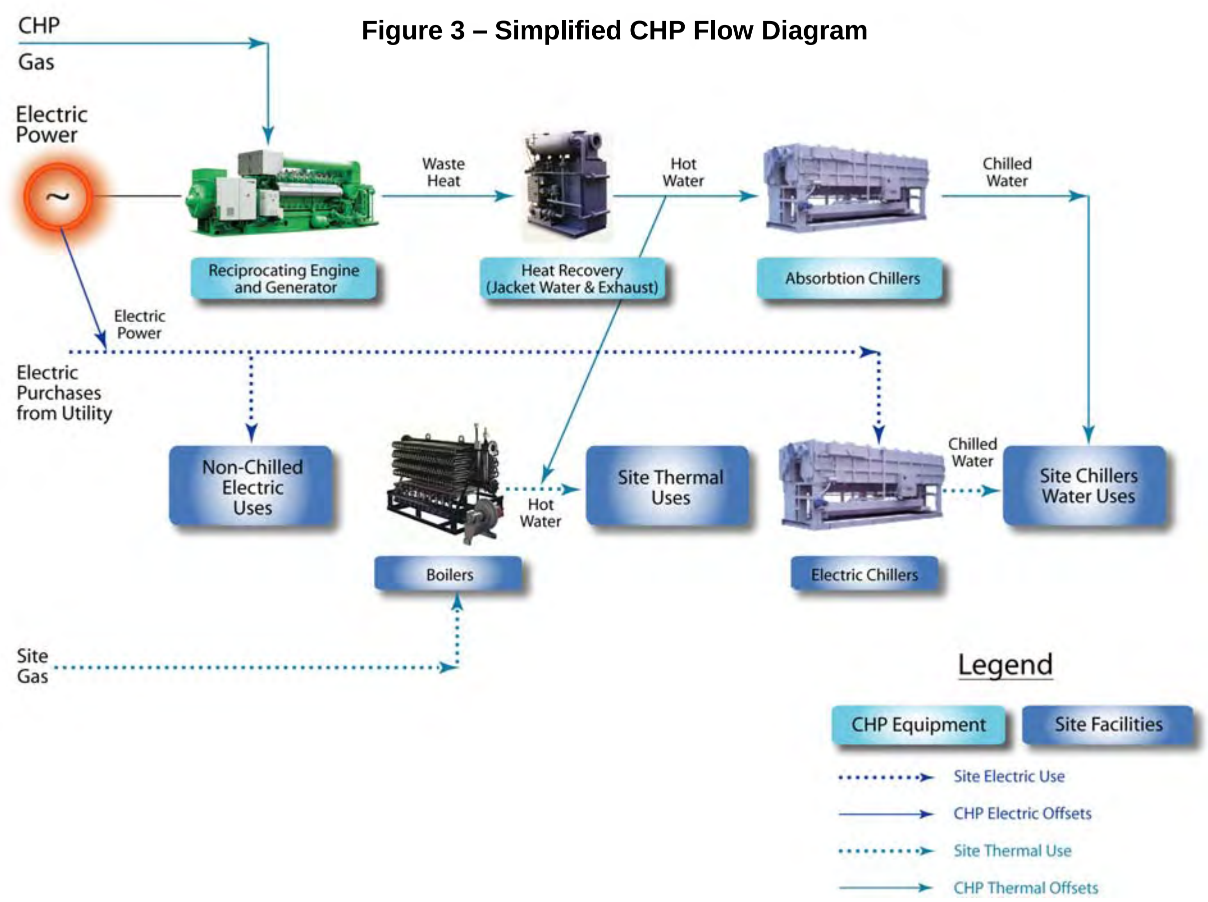
- SDG&E metered electric demand on a 15 minute interval basis
- Under certain conditions described below, SDG&E assessed a Demand Ratchet. If a customer elected the AL-TOU-DER rate and they exceed their allotted General Service demand then non-coincident demand charges were computed as the maximum of the current monthly demand and 50% of the highest monthly demand over the previous 11 months. The other utilities did not generally apply ratchets.
- SDG&E's rates emphasized non-coincident demand charges compared to the other utilities. Non-coincident demand charges assess payments for maximum energy demand independent of the time of day that that maximum usage occurs. Thus, any 15 minute CHP outage that occurs within a calendar month can result in loss of the associated non-coincident demand savings for that entire month. Since SDG&E also ratchets demand charges, the result of a single 15 minute outage can be a loss of demand savings for the entire year where the demand ratchet applies.
- The AL-TOU rate assessed CHP customers a standby reservation charge of about $5.00/kw month (including franchise fees). Under the AL-TOU standby rate the customer was exempt from both the non-coincident demand charges and the associated 11 month / 50% of demand ratchet on the amount of reserved capacity.
- Certain CHP customers had the option to elect the AL-TOU-DER rate which exempts them from the standby charge but subjects them to both reversal of non-coincident demand charges in the event of any outages and to the demand ratchet.
- SDG&E separately billed commodity (fuel) costs under the Electric Energy Commodity Cost (EECC) schedule which is adjusted monthly. For the purposes of this study the EECC rate effective 4/21/05 was used for both summer and winter commodity rates, consistent with the gas prices assumed for CHP. This tends to more frequently equilibrate bundled energy rates with gas prices than do the other utilities.
- SDG&E's bundled energy rates (including AL-TOU and EECC components) exhibited a much smaller range from on-peak to off-peak than do the other utilities' rates. This was because the EECC component comprises most of the energy rate and does not typically vary as significantly from rate period to rate period.
- SDG&E's primary and secondary interconnection rates differed only minimally from one another

vii. CHP Equipment Performance

The internal combustion engine used in this analysis was the Cummins 334GFBA Engine fired on natural gas. Detailed engine performance data for the Cummins Engine is provided in Figure 60 – Specifications for Cummins 334GFBA 2G Engine in the Appendix. For the purposes of this study it was assumed that this engine has a rated capacity of 333 kW (which is 1 kW below the vendor assigned nameplate rating of 334 kW) for the purposes of illustrating the impact of the elimination of the DWR bond fund exemption for projects sized over 1000 kW. Applications studied applied 1, 2 or 3 engines.

Figure 3 provides a simplified flow diagram of the CHP configurations used in this analysis. Basic technical premises used in the analysis, including engine and chiller specifications are provided in Table 6. Available waste heat from the exhaust, and low and high temperature circuits is assumed to be first used applied to absorption chilling with any remaining heat used for hot water uses at the site. Once both of those needs are fully met any residual heat is exhausted though radiators or in the exhaust gas to the stack. It is assumed that each engine can support up to 125 tons of absorption chilling when all available waste heat from the engine is devoted to chillers. It should be noted that each of the proxy profiles used in this study had substantive electric chiller demand and so in this analysis the propensity of waste heat was applied to absorption chilling. A minimum power import requirement of 5% of demand was assumed in all cases.

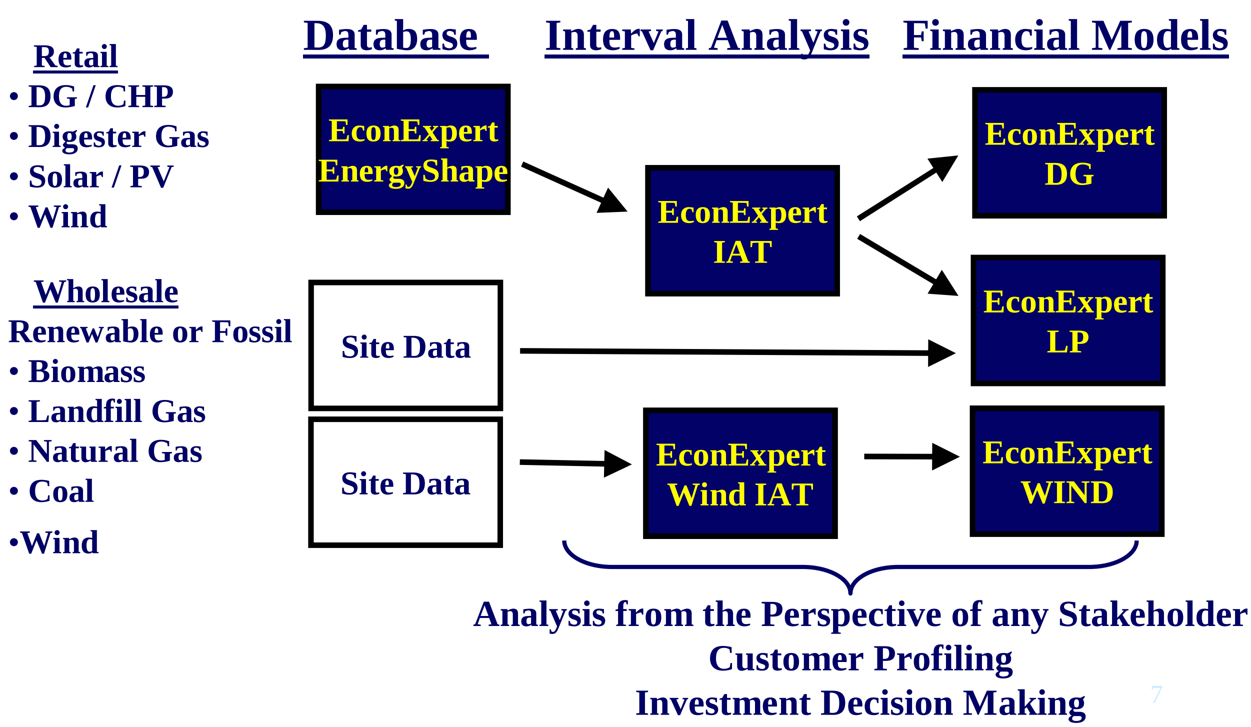
Figure 3 – Simplified CHP Flow Diagram



B. Discussion of the Modeling Approach

The analyses provided in this study were performed using the EconExpert™ modeling suite developed by Competitive Energy Insight, Inc. Figure 4 provides a schematic overview of the available components of the EconExpert software suite which include interoperable database, interval analysis and financial modeling modules.

Figure 4 - Schematic Diagram of the Software Models Used in the Analysis



The primary steps performed during modeling portion of the study are described below:

i. Develop Proxy thermal and Electric Building Load Profiles

The first step in the study was to develop hourly thermal and electric profiles for each scenario using the EconExpert-EnergyShape database.

Figure 11 - Figure 59 in the Appendix provide graphical views of the respective profiles that were used in the analysis. An overview of the respective building characteristics is provided in Table 1 on page xi.

Three characteristic commercial building types were evaluated including a hospital, a college building and a hotel, each with approximately 500,000 square feet of conditioned space. Analysis for the three respective utility tariffs was performed based on locations of these facilities in coastal San Diego (SDG&E), San Bernardino County (SCE) and San Francisco (PG&E). While every building has its own site-specific profile of thermal and electric uses, buildings within a particular category and climatic zone will tend to have similar characteristics that relate to similar building designs, common business models and building use and associated regional weather conditions that influence that building's energy needs. It is recognized that within the service territories of each of the three utilities, micro climate conditions can substantially change the energy usage profiles for their customers.

ii. Interval Analysis Modeling

Following the development of the load profiles, the results were imported into the EconExpert-Interval Analysis Tool for hourly operations and savings analysis. Using the standard templates provided in the model, the respective PG&E, SCE and SDG&E tariffs (see Table 16) were modeled. Details associated with these tariffs are also provided in section 1.A.vi on page 8.

Table 16 – Tariffs Modeled in the EconExpert-IAT Model

Building Type	**Engine Rated Capacity and Number of Engines**	**PG&E**	**SCE**	**SDG&E**
Hotel	333 kw / 1 Engine	E20 Secondary	TOU8 less than 2kV	AL-TOU-DER Secondary
College	666 kw / 2 Engines	E20 Primary	TOU8 2kv – 50 kV	AL-TOU-DER Primary
Hospital	999 kw / 3 Engines	E20 Primary	TOU8 2kv – 50 kV	AL-TOU-DER Primary

The Cummins 334GFBA 2G Engine was modeled using the premises outlined in section 1.A.vii.

Gas prices for site uses and CHP firing were also entered as specified in section . .0. . . Sensitivities were performed to illustrate how changes in gas prices will impact CHP economics from both the cost and savings perspectives.

Though each of the building types selected had 500,000 square feet of conditioned space, because of the difference in the respective load profiles, based on maximizing the return on invested capital, the selection of the number of 333 kW engines was different for each. For the hotel, which had the lowest peak energy usage, one engine provided the maximum IRR. The college, while using higher loads, was closed on Sundays and was best fit with two engines. The hospital, which had the most level load profile, had its optimum economic fit at thee engines.

The CHP facility optimum hourly load point was calculated based on the objective of maximizing the hourly savings for the owner. That load point could be full load operation or in circumstances where electric demands, thermal demands or minimum import requirements dictated that part load operation was required the facility was cycled to part load to match the economic optimum. Under SCE's Standby Tariff where the rate paid for replacement power is higher than the rate under the TOU8 tariff, forced dispatch was required in order to avoid paying the premiums for replacement power and so the facilities were assumed to run during off-peak periods though it is uneconomic to do so. In all cases, load levels reflected maximizing net savings.

iii. Financial Modeling

Results from the interval analysis were imported into the EconExpert-DG financial model which was used to perform life of project discounted cash flow analysis. Discounted cash flow is the investment mechanism that large institutional investors including industrials, utilities and banks apply to make investment decisions. All analyses were performed from the perspective the site host as the project owner.

The primary analysis metrics utilized were:

- Discount Rate - The Discount Rate is the interest rate that is used to bring a series of future cash flows to their present value in order to state them in current or in constant dollars. Use of a discount rate removes the time value of money from future cash flows. The discount rate is typically the weighted average cost of capital of an institution.
- IRR – The Internal Rate of Return of a project is the discount rate at which the present value of the future cash flows of an investment equals the cost of the investment. When the IRR is equal to the discount rate, the Net Present Value is 0.
- NPV – The Net Present Value can be defined as the future stream of benefits and costs converted into equivalent values today. This is done by assigning monetary values to benefits and costs, discounting future benefits and costs using an appropriate discount rate, and subtracting the sum total of discounted costs from the sum total of discounted benefits.

In all cases the owner's of the facility were assumed to be for-profit entities, subject to state and federal income taxes and able to take advantage of available tax benefits and incentives.

While many in the distributed generation industry still rely on simple payback as their primary metric to gauge a project's economic viability, CEI does not believe that this is a reliable metric for this type of analysis. Some of the factors not appropriately addressed by simple payback which are addressed by IRR and NPV included:

- Inflation and differentiation of escalation rates including variations in electric and gas prices
- The cost of capital
- The timing of cash flows
- Key aspects associated with financing and repayment of debt
- Working capital and inventory considerations
- Annual costs that vary over the life of the asset
- Costs that might occur on a multi-annual basis such a major maintenance
- Equipment life and equipment salvage values
- Changes in annual site electric or thermal demand or conditions
- Degradation in the performance of the equipment over the life of the project
- Partial years of operation
- Accelerated depreciation schedules
- Investment and production tax credits
- Income taxes

The IRR and NPV associated with an attractive investment will vary from owner to owner depending on their whether their enterprise is for-profit or not-for-profit, their access to capital, alternative opportunities for investment of that capital and their perception of the risk associated with CHP. For this purposes of this study, the general rules of thumb that we will apply for target hurdle rates are listed in Table 17.

Table 17 – Illustrative Target Hurdle Rates for Typically Attractive Investments in CHP

Investor Type	Target 10 yr IRR After Tax	Discount Rate	Target 10 year NPV After Tax
For-Profit Enterprise	**10% - 20% or higher**	**8 – 10%**	**~25% or greater of the initial equity investment**
Not-for-Profit Enterprise	**5% - 10% or higher**	**4 – 7%**	**A Positive Value**

The economics of CHP development, installation, ownership and operation are highly site specific and will always require site specific analysis. This study is not intended to illustrate the economic viability of CHP for any particular site or installation. The most important findings to be derived from this analysis are the relative impacts of the factors studied on CHP economics. Results of these discount cash flow analyses were compared to isolate and illustrate the relative impacts of the various policy factors on CHP economics.

iv. Scenario and Sensitivity Analyses

Following completion of the discounted cash flow analyses, alternative scenarios were evaluated complemented by a series of sensitivity analyses to measure how changes in premises would affect the economics of CHP investments. The scenarios and sensitivities performed included:

- Effects of individual components of the tariffs were isolated including:
  - Time related energy charges
  - Departing load charges
  - Coincident demand charges
  - Non-Coincident demand charges
  - Standby charges including reservation fees, standby demand and standby energy
  - Alternative service levels including primary and secondary interconnection rates

- Effects of rebates from the SGIP program
- Gas prices and electric price escalation
- Changes in CHP plant operating reliability
- Alternative mechanisms and approaches to financing

C. Descriptions of Scenarios

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Table 18 provides a matrix of the scenarios and cases that were modeled in this study. For each scenario, 3 - 9 cases were modeled reflecting the applicable 3 utility tariffs and 3 building configurations. The first column of the table lists the scenarios designated by roman numerals ***A – L***. **Scenario *A*** is the base against which all of the other scenarios were compared. It is important to note that in the cases studied it was assumed that waste heat available from the CHP facility would be applied first to absorption chilling uses and then to thermal offsets. Under scenarios where gas prices increase at a higher rate than do electric rates, this tradeoff may favor the reverse and could improve project returns by on the order of 4 – 5% after tax.

i. Scenario *A* – Base Case Scenario

The base case scenario premises are summarized in section 1.A.iii,

Table 4- Table 6. Key premises in the base case scenario include:

- Each CHP facility is rated under 1000 kw and eligible for exemption from the DWR Bond Fund departing load charges
- The CHP facilities are operated in a manner such that all potential coincident and non-coincident demand charge savings are realized (note that losses in these savings due to facility outages will be analyzed in the alternate scenarios)
- All owners were assumed to be for-profit entities with sufficient taxable income to efficiently use all project related tax benefits
- For facilities in SCE territory, the site owner pays reservation fees on the full capacity of the CHP facility
- Each CHP engine is off line at least 5% of the year for maintenance. In the case of the hotel which only had one engine a 5% reduction in annual production was assumed in the base case. In the other cases it was assumed that the maintenance was performed during periods when site demand was low enough such that one or more engines could be brought off line for maintenance without penalizing energy offsets.
- Each project qualifies for and receives the SGIP rebate of $0.60 / watt
- The applicable interconnection rates for the respective buildings were:
  - Hotel – Secondary
  - College – Primary
  - Hospital – Primary

ii. Scenario*s* ***B*** – Energy Charges

Scenario ***A*** assumed a minimum downtime of 5% (430 hours/year) on each engine for maintenance. Scenario ***B*** studied the isolated impacts of higher outage rates on reducing <u>energy</u> savings. Impacts of outages on demand savings are evaluated in a later scenario.

Table 18 - Case Study Matrix

Scenario	Base Case Scenario *Assumption*	Alternate Scenario *Assumption*	Comments
A Base Case Scenario	See Below		The base case scenario premises are provided in Table 4 - Table 6.
B Energy Charges	Facility meets all site load requirements that it can with a specification of a minimum of 5% downtime on each engine.	10% additional lost production to due equipment derating or outages.	This scenario addresses only the energy component of the savings. Demand and standby related components are isolated in other scenarios.
C Departing Load Charges	Hospital CHP Facility Sized at 999 kw	Departing load charges Hospital CHP facility sized at 1001 kw	Increase rating of hospital CHP facility to 1001 kw results in higher departing load charges associated with adding 0.459 ¢/kwh for DWR bond charges on the entire kwh output.
D All Demand Charges	All coincident and non-coincident demand charge savings realized	Demand charges Outages result in reversal of all demand savings, coincident and non-coincident	Site experiences CHP outages during both coincident and non-coincident periods resulting in all demand savings being reversed.
E Coincident Demand Charges	All coincident and non-coincident demand charge savings realized	Demand charges Outages result in reversal of non-coincident demand savings	Site experiences CHP outages in only during coincident demand periods isolating the contributions of coincident demand savings to CHP economics.
F Non-Coincident Demand Charges	All coincident and non-coincident demand charge savings realized	Demand charges Outages result in reversal of coincident demand savings	Site experiences CHP outages in only during non-coincident demand periods isolating the contributions of non-coincident demand savings to CHP economics.
G SDG&E Standby Rate	Customer of SDG&E Elects ALTOU-DER and is exempt from Standby Charges	SDG&E Standby Rate Customer opts out of ALTOU-DER Rate and elects to pay Standby Charges	Under ALTOU-DER non-coincident demand is subject to the demand ratchet. If customer elects the Standby Rate he/she pays ~$5.00 / mo Standby Charges as is exempt from the reversal on non-coincident demand charges and the associated ratchet. Coincident demand charges are still billed monthly based on meter measured demand and so will be higher if the CHP goes off-line during these rate periods.
H SCE Standby Reservation Rate	Customer Elects 666 kw SCE Standby Reservation Fee	SCE Standby Rate Customer Elects 333 kw SCE Standby Reservation Fee	Evaluated only to the SCE Hospital 999 kw and College Cases 666 kw
I SCE Standby Reservation Rate	Customer Elects 999 kw SCE Standby Reservation Fee	SCE Standby Rate Customer Elects 333 kw SCE Standby Reservation Fee	Applies only to the SCE Hospital case
J SGIP Rebate	$600 / kw SGIP Rebate	No SGIP Rebate	
L SGIP Rebate	$600 / kw SGIP Rebate	$900 / kw SGIP Rebate	
M Service Level	Interconnection Hotel – Secondary College – Primary Hospital - Primary	Alternate Interconnection Hotel – Primary College – Secondary Hospital - Secondary	
N Most Likely Scenario	Base Scenario	25% Loss of Coincident and Non-Coincident Demand Charges	This is an example of the average combination of the factors above that might apply to a typical project

Shaded items indicate parameters that provide insight relative to the impacts of electric rates and tariffs on CHP economics.

All cases assume application of waste heat from the CHP facility to chilling first. In many instances, after tax returns can be improved by 4 – 5% or more by applying waste heat to thermal uses first, especially under scenarios of high gas prices.

iii. Scenario *C* – Departing Load Charges

Departing load charges are charges the customer must pay to the utility for generation by the CHP facility. The funds are used to pay for special public purpose programs, decommissioning of nuclear facilities and amounts owed to the Department of Water Resources to retire bonds from energy crises of 2001. All CHP facilities in California are required to pay the Public Purpose Funds and Nuclear Decommissioning Fund components of the departing load charges. Facilities rated under 1000 kW that qualify for the SGIP program are exempted from paying the DWR bond fund component (currently 0.459 ¢/kwh), but facilities rated over 1000 kW must also pay that charge on the full production from the facility.

This scenario investigated the impacts on CHP economics of a step jump in departing load charges for any facility sized over 1000 kW. The comparison was performed only for the Hospital cases illustrating the impact on CHP economics of increasing the rated capacity of the facility from 999 kW to 1001 kW.

iv. Scenario*s D – F -* Demand Charges

An area of substantive concern expressed by CHP suppliers and owners during the interview process was the methodology of how demand charges are applied in event the CHP facility experiences either planned or unplanned outages.

All three of the evaluated tariffs distribute demand charges into two categories, coincident and non-coincident.

- Coincident demand charges are costs billed to the customer associated with the maximum monthly energy demand measured during a designated rate block. For example, in PG&E's service territory customers under the E20 tariff pay peak rates during the hours of 12:00 pm and 6:00 pm on weekdays during the months of May – October. In each of these months the peak demand that is measured occurring during these intervals is used to calculate the monthly peak demand charge. Another coincident demand charge may also be applied during the mid-peak period.

- Non-coincident demand charges are those that do not depend on the time of day that the maximum demand is established

The relative amounts of the coincident and non-coincident demand charges applied in the three utilities' tariffs are very different. The reason that this is important to CHP owners is that outages of the CHP facility that result in a higher peak being established, and a reversal of some or all of the demand savings in that rate category.

It is important to note that just as the base case represents the extreme of no outages resulting in losses of demand charge savings, these scenarios study the opposite extreme of no associated demand charge savings being realized over the life of the asset. While the reality is likely in between this approach provides insight to the relative impacts of these demand charge categories on CHP economics.

v. Scenario *G* – SDG&E Standby Rates

Scenario G is specific to SDG&E. As an alternative to electing the ALTOU-DER rate which exempts customers from the SDG&E standby tariff, customers can opt out of ALTOU-DER and elect the standard AL-TOU rate. In this case they would then be required to pay a monthly standby charge of about $5.00 / kW month on the rated capacity of the CHP facility. Under this condition, since reservation fees have been paid on the CHP facility capacity, none of the resulting non-coincident demand charge savings will be reversed in the event of outages of the CHP facility. Coincident demand charges would still be paid based on the actual demand measured in each month such that the associated demand savings in these rate categories could be lost. Also under the standby rate, no ratchet is applied.

vi. Scenario*s H* and *I* – SCE Standby Reservation Fees

Scenarios ***H*** and ***I*** are specific to the SCE standby tariff which allows the customer to elect a reservation fee of up to the amount of the rated capacity of the CHP facility. As opposed to the base case which premised the owner would only pay reservation fees on all of the rated capacity of the CHP system, these cases studied the reduced costs of electing to pay a lower reservation fee amount. If after electing a lower reservation amount, the reservation is exceeded, SCE ultimately has the option to impose the full reservation fees on the customer.

vii. Scenario *J* and K - SGIP Rebate

These scenarios studied the impacts of eliminating or increasing the SGIP rebate relative to the base case rebate of $0.60 / watt up to $600,000.

viii. Scenario *L* – Alternate Interconnection

This scenario evaluated the relative impacts on CHP economics of sites that were subject to the alternate interconnection rate assumed in the base case scenario. The respective service levels were:

Building Type	Base Case Scenario	Scenario *L*
Hotel	Secondary	Primary
College	Primary	Secondary
Hospital	Primary	Secondary

ix. Most Likely Case

Typically a CHP project will experience some degree of outages resulting in a reversal or loss of some or all of the demand savings attributed to the project, but not all of those savings. This “most likely” case is intended to illustrate typical returns that might be experienced by the project that as a result of outages in the facility experiences a reversal of 25% of the potential annual demand savings. While the actual losses realized are project and site specific depending on the timing, frequency and duration of outages, these results are intended to illustrate what returns a project with a reasonably reliable design my observe.

It should be noted that this case is completely hypothetical and may not fairly represent a comparison between the utilities. This is true largely because of the relative difference in weighting of on-peak, mid-peak and non-coincident demand charges under the respective tariffs. An assumption that outages will be equally distributed between these respective time periods is arbitrary. In practice, non-coincident periods would have a higher weighting probability than coincident periods and so this approach is somewhat favorable to SDG&E relative to PG&E.

D. Summary of Results

Table 19 provides a summary of the Internal Rates of Return (IRRs) calculated for each respective scenario and case. Table 19 illustrates the respective IRRs calculated for each case and Table 20 illustrates the change in the IRR for each case relative to the base case scenario *A*. Similarly, Table 21 provides a summary of the Net Present Values (NPVs) calculated for each respective case. And, Table 22 shows the differences in NPVs from the base case scenario.

Table 19 - Comparison of IRRs Calculated for Each Case

(For-Profit Entity – Owner Assumed to be Taxable)

IRR Summary, 10 Years, After Tax

Scenario	Building Configuration	Hotel			College			Hospital		
	Utility	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
	CHP System Capacity	333 kw	333 kw	333 kw	666 kw	666 kw	666 kw	999 kw	999 kw	999 kw
	Interconnection	Sec	Sec	Sec	Pri	Pri	Pri	Pri	Pri	Pri
Scenario	Description									
	Target Hurdle Rate, %	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
A	Base Scenario	13.8%	-8.2%	28.4%	21.7%	0.0%	33.1%	15.4%	-10.2%	40.1%
B	Energy Charges - 10% Lost Production	12.3%	-9.7%	25.3%	18.5%	-1.3%	29.1%	12.6%	-14.1%	36.2%
C	>1000 kw - DWR Departing Load Charges Apply							9.3%	-14.2%	32.3%
D	All Demand Savings Reversed	-15.1%	-35.0%	-9.1%	-24.7%	-33.6%	-12.1%	-15.9%	-58.2%	-4.0%
E	Only Coincident Demand Savings Reversed	-6.9%	-23.0%	18.0%	-13.2%	-10.9%	21.6%	-5.9%	-22.6%	28.0%
F	Only Non-Coincident Demand Savings Reversed	6.9%	-20.9%	1.9%	13.3%	-12.2%	0.2%	7.1%	-29.5%	7.5%
G	Customer Opts Out of SDG&E ALTOU-DER and Pays Standby Charges			20.1%			23.9%			22.2%
H	Customer Elects 333 Below Capacity kw SCE Standby Reservation Fee					1.6%			-6.1%	
I	Customer Elects 666 Below Capacity kw SCE Standby Reservation Fee								-2.5%	
J	No SGIP Rebate	3.5%	-9.0%	14.9%	8.9%	-2.4%	17.5%	3.6%	-10.7%	21.8%
K	$900/kw SGIP Rebate	21.4%	-7.6%	39.1%	31.8%	1.8%	46.3%	24.6%	-9.9%	56.7%
L	Opposite Interconnection Rating (Primary vs Secondary)	3.1%	-7.7%	28.4%	17.6%	-0.6%	33.1%	24.4%	-10.6%	40.1%
M	Most Likely Case	6.6%	-14.9%	19.0%	10.1%	-8.4%	21.8%	7.6%	-22.2%	29.1%

Table 20 - Difference in IRRs Calculated vs. the Base Case Scenario

Difference vs Base Case - IRR Summary, 10 Years, After Tax

Scenario	Building Configuration	Hotel			College			Hospital		
	Utility	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
	CHP System Capacity	333 kw	333 kw	333 kw	666 kw	666 kw	666 kw	999 kw	999 kw	999 kw
	Interconnection	Sec	Sec	Sec	Pri	Pri	Pri	Pri	Pri	Pri
Scenario	Description									
A	Base Scenario	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
B	Energy Charges - 10% Lost Production	-1.5%	-1.4%	-3.1%	-3.2%	-1.4%	-4.0%	-2.8%	-3.8%	-3.9%
C	>1000 kw - DWR Departing Load Charges Apply							-6.1%	-4.0%	-7.8%
D	All Demand Savings Reversed	-28.9%	-26.8%	-37.5%	-46.4%	-33.6%	-45.2%	-31.3%	-48.0%	-44.1%
E	Only Coincident Demand Savings Reversed	-20.7%	-14.8%	-10.3%	-34.9%	-10.9%	-11.4%	-21.3%	-12.4%	-12.1%
F	Only Non-Coincident Demand Savings Reversed	-6.9%	-12.7%	-26.5%	-8.4%	-12.2%	-32.9%	-8.3%	-19.3%	-32.6%
G	Customer Opts Out of SDG&E ALTOU-DER and Pays Standby Charges			-8.3%			-9.2%			-17.9%
H	Customer Elects 666 kw SCE Standby Reservation Fee					1.6%			4.2%	
I	Customer Elects 999 kw SCE Standby Reservation Fee								7.7%	
J	No SGIP Rebate	-10.3%	-0.8%	-13.5%	-12.8%	-2.4%	-15.6%	-11.8%	-0.5%	-18.3%
K	$900/kw SGIP Rebate	7.6%	0.6%	10.7%	10.1%	1.8%	13.2%	9.2%	0.4%	16.6%
	Opposite Interconnection	-10.7%	0.5%	0.0%	-4.1%	-0.7%	0.0%	9.0%	-0.4%	0.0%

Table 21 - Comparison of NPVs (1000$) Calculated for Each Case

(For-Profit Entity – Owner Assumed to be Taxable)

NPV Summary, 10 Years, 8% After Tax - in 1000$

	Building Configuration	Hotel			College			Hospital		
	Utility	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
	CHP System Capacity	333 kw	333 kw	333 kw	666 kw	666 kw	666 kw	999 kw	999 kw	999 kw
	Interconnection	Sec	Sec	Sec	Pri	Pri	Pri	Pri	Pri	Pri
Scenario	Description									
	Initial Equity Investment (60% Debt / 40% Equity)	$282	$282	$282	$550	$550	$550	$814	$814	$814
	Target Hurdle Rate	$71	$71	$71	$138	$138	$138	$204	$204	$204
A	Base Scenario	$64	($438)	$224	$276	($445)	$502	$211	($1,240)	$909
B	Energy Charges - 10% Lost Production	$47	($465)	$189	$210	($510)	$423	$130	($1,402)	$801
C	>1000 kw - DWR Departing Load Charges Apply							$36	($1,438)	$711
D	All Demand Savings Reversed	($232)	($879)	($179)	($561)	($1,421)	($379)	($618)	($2,608)	($343)
E	Only Coincident Demand Savings Reversed	($156)	($671)	$112	($392)	($912)	$278	($380)	($1,705)	$582
F	Only Non-Coincident Demand Savings Reversed	($12)	($646)	($67)	$107	($955)	($155)	($27)	($1,908)	($16)
G	Customer Opts Out of SDG&E ALTOU-DER and Pays Standby Charges			$134			$323			$577
H	Customer Elects 333 Below Capacity kw SCE Standby Reservation Fee					($363)			($1,020)	
I	Customer Elects 666 Below Capacity kw SCE Standby Reservation Fee								($803)	
J	No SGIP Rebate	($62)	($584)	$98	$24	($736)	$250	($161)	($1,677)	$531
K	$900/kw SGIP Rebate	$127	($365)	$287	$402	($300)	$629	$397	($1,022)	$1,098
L	Alternate Interconnection Rating (Primary vs Secondary)	($122)	($428)	$224	$194	($496)	$502	$468	($1,310)	$204
M	Most Likely Case	($10)	($548)	$123	$67	($689)	$282	$4	($1,582)	$596

Table 22 - Difference in NPVs (1000$) Calculated vs. the Base Case Scenario

Difference vs Base Case NPV Summary, 10 Years, 8% After Tax - in 1000$

	Building Configuration	Hotel			College			Hospital		
	Utility	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
	CHP System Capacity	333 kw	333 kw	333 kw	666 kw	666 kw	666 kw	999 kw	999 kw	999 kw
	Interconnection	Sec	Sec	Sec	Pri	Pri	Pri	Pri	Pri	Pri
Scenario	Description									
A	Base Scenario	$0	$0	$0	$0	$0	$0	$0	$0	$0
B	Energy Charges - 10% Lost Production	($17)	($27)	($35)	($66)	($65)	($80)	($82)	($162)	($108)
C	>1000 kw - DWR Departing Load Charges Apply							($175)	($197)	($198)
D	All Demand Savings Reversed	($296)	($441)	($403)	($837)	($976)	($882)	($829)	($1,368)	($1,252)
E	Only Coincident Demand Savings Reversed	($220)	($233)	($112)	($668)	($466)	($224)	($591)	($465)	($327)
F	Only Non-Coincident Demand Savings Reversed	($76)	($208)	($291)	($169)	($509)	($658)	($238)	($668)	($925)
G	Customer Opts Out of SDG&E ALTOU-DER and Pays Standby Charges			($90)			($180)			($332)
H	Customer Elects 333 Below Capacity kw SCE Standby Reservation Fee					$83			$220	
I	Customer Elects 666 Below Capacity kw SCE Standby Reservation Fee								$437	
J	No SGIP Rebate	($126)	($146)	($126)	($252)	($291)	($252)	($372)	($437)	($378)
K	$900/kw SGIP Rebate	$63	$73	$63	$126	$146	$126	$186	$218	$189
L	Opposite Interconnection Rating (Primary vs Secondary)	($64)	$438	$0	($276)	$445	$0	($211)	$1,240	$0
M	Most Likely Case	($74)	($110)	($101)	($209)	($244)	($220)	($207)	($342)	($313)

E. Comparisons between the Base Case Scenarios – Impacts of building type, climate and tariffs

The section discusses the results for the scenarios and cases listed above. To complement the scenarios studied, various sensitivity analyses were performed to further study the impacts of other important parameters on CHP economics like fuel price, alternative financing approaches, etc. The discussion of the sensitivity analyses follows in a later section.

i. Impacts of Building Configuration and Climate on the Economics of CHP Ownership in the Base Case Scenario

Since the goal of this study was to focus on policy related factors as they impact CHP economics from an owner's perspective, the analysis only briefly addresses the impacts of factors such as weather conditions, building configurations and business models on CHP economics. The intention of including these factors was both to ensure that any findings related to policy were not prejudiced by the specific profiles or building types that were developed and to analyze the tariffs in the context of the reasonable applicable climatic conditions in each respective utility service territory. Still, there are valuable insights that can be derived from the analyses of the various building types and the different climatic conditions on CHP economics. The guiding principal for CHP is that the economics of CHP are highly site specific.

Section 1.A.iv and Table 1 - Table 3 illustrate the relative comparisons of the electric, chiller and thermal load profiles and the influences of the different building types, business models and weather on the profiles. The most prominent factors that influenced the profiles were:

- The hospital had the most consistent electric and thermal demands over the course of the four seasons of the year as well as the highest peak thermal and electric demands. This was characteristic of the 7 x 24 operation of hospitals and their facilities.
- The hotel had the lowest peak energy demands
- The college had both the highest relative variability in loads (peak vs. minimum) and the lowest overall thermal use

The dominating weather related influences on the profiles were:

- The facilities in San Bernardino (SCE territory) exhibited the highest chilling requirements for summer air conditioning
- The facilities in San Francisco (PG&E territory) had the highest thermal use for winter heating
- Facilities in San Diego (SDG&E) had the lowest relative chilling and thermal use relating to San Diego's more moderate climate

Daily, weekday vs. weekend and seasonal variations in thermal and electric use were the most important profile related factors impacting CHP economics affecting:

- The optimal size of the CHP facility (i.e. the number of engines applied)
- The economic operating profile of the CHP facility including cycling operation to follow site thermal and electric loads
- The time of day and seasonal value of the thermal energy, electric energy displaced and fuel

All three building applications showed the potential for attractive CHP economics. In general, the hospital tended to show the most attractive economics which benefited from economies of scale and a relatively consistent 24 x 7 electric and thermal loads. The hotel, which was the smallest installation, has the least attractive economics but the range from best to worst was not as large as for the other cases.

ii. Impacts of Utility Tariffs on the Economics of CHP Ownership Base Case

This section will focus on the tariffs and their impacts on the economic viability of CHP installations. An overview of the features of the individual tariffs is provided in section 1.A.vi. Underlying the general similarities in the structures of the respective time-of-use tariffs of the three California IOUs are dramatic differences in how the tariff rates are allocated between energy costs, coincident and non-coincident demand charges and standby charges.

Impacts of the tariffs on CHP economics included:

- CHP Economic Viability - Direct impacts on the savings and resulting rates of return. Scenario ***A*** in Table 19 and Table 21 provides the insight relative to differences in the impacts of the tariffs on overall economic viability of CHP

- Owner's Risk that achievable savings might not be realized. Later Scenarios address the second point illustrating how changes in CHP facility operating approaches and/or differences in the availability of CHP facilities can result in very different impacts on savings and resulting economics between the three tariffs.

<u>Most notable is that in PG&E and SDG&E service territories exhibited potentially attractive returns but SCE's service territory returns for CHP investments were all unattractive.</u>

Table 23 provides a comparison of SCE's TOU 8 tariff (primary) filed on April 11, 2005 with that in effect on September 1, 2003. Under SCE's new rates demand charges were increased and generation charges were reduced. Standby charges were also reintroduced into the tariff. These changes resulted in four important disincentives to CHP.

- Energy rates were reduced under the new tariff in all time blocks and demand rates were increased

- The most significant changes for CHP were in the off-peak energy rates. Under the prior TOU-8 tariff, bundled off peak energy charges were in the range of 7.2 ¢/kwh. Under the new tariff they are in the range of 4.6 – 4.8 ¢/kwh (when including DWR charges), meaning that CHP facilities are likely uneconomic to operate during off-peak periods (about 60% of the hours of the year).

- The off-peak rate difference is further exacerbated by the fact that under the standby tariff, owner's installing CHP are required to pay a higher costs for replacement energy than they would have otherwise paid under TOU8. This effectively forces the CHP facility to operate in order to avoid these higher off-peak rates though the owner is not realizing savings during the off-peak period.

- The standby tariff also requires owners to pay annual monthly standby charges for elected reservation amounts. This adds fixed costs to CHP ownership and detracts from the economics.

Table 23 - Comparison of SCE Tariffs Filed July 23, 2003 and April 11, 2005

(Bundled Rates Including Franchise Fees)

Tariff	Effective 9/1/03	Filed 4/11/05
Demand Charges, $/kw mo		
Summer		
Peak	**17.95**	**27.37**
Part Peak	**2.70**	**4.24**
Facilities (Non-Coincident)	**6.60**	**8.85**
Winter		
Facilities (Non-Coincident)	**6.60**	**8.85**
Energy Charges, c/kwh		
Summer		
Peak	**14.311**	**12.891**
Part Peak	**8.598**	**7.683**
Off-Peak	**7.218**	**4.633**
Winter		
Part Peak	**9.407**	**9.472**
Off-Peak	**7.294**	**4.802**

Table 24 – Comparison of Relative Savings to a CHP Facility under SCE's Current TOU-8 Tariff and the Tariff that was Effective on September 1, 2003

	Contributions to Savings				Contributions to Variable Operating Expenses			Total
Tariff Effective 9/1/03	Electric Savings	Thermal Savings	Demand Charge Savings	**Total Savings**	Fuel Costs	O&M and Standby Costs	**Total Operating Costs**	**Net Annual Savings**
Non-Coincident			$ 102,881	**$ 102,881**				**$ 102,881**
Off-Peak	$ 450,755	$ 11,823		**$ 462,578**	$ 341,872	$ 124,213	**$ 466,084**	**$ (3,507)**
Mid-Peak	$ 335,000	$ 4,924	$ 3,170	**$ 339,924**	$ 199,845	$ 73,085	**$ 272,930**	**$ 66,993**
On-Peak	$ 95,822	$ 459	$ 93,268	**$ 96,280**	$ 33,658	$ 13,400	**$ 47,058**	**$ 49,223**
Incremental Demand Charges for Outages						$ 170,373	**$ 170,373**	**$ (170,373)**
Total	**$ 881,577**	**$ 17,205**	**$ 199,319**	**$ 1,001,663**	**$ 575,374**	**$ 381,071**	**$ 956,445**	**$ 45,217**
Tariff Filed on 4/11/05								
Non-Coincident			$ 132,030	**$ 132,030**				**$ 132,030**
Off-Peak	$ 306,307	$ 12,450		**$ 318,757**	$ 354,306	$ 143,106	**$ 497,413**	**$ (178,655)**
Mid-Peak	$ 308,951	$ 4,296	$ 21,096	**$ 313,247**	$ 187,410	$ 75,490	**$ 262,900**	**$ 50,347**
On-Peak	$ 86,458	$ 459	$ 136,083	**$ 86,917**	$ 33,658	$ 14,843	**$ 48,501**	**$ 38,416**
Standby Charges, Backup and Maintenance Service Charges						$ 122,192	**$ 122,192**	**$ (122,192)**
Total	**$ 701,716**	**$ 17,205**	**$ 289,209**	**$ 850,952**	**$ 575,374**	**$ 355,630**	**$ 931,005**	**$ (80,053)**
Difference 2005 vs 2003 TOU 8 and Standby Tariffs								
Non-Coincident Demand Savings			$ 29,150	**$ 29,150**				**$ 29,150**
Off-Peak	$ (144,448)	$ 628		**$ (143,820)**	$ 12,435	$ 18,893	**$ 31,328**	**$ (175,149)**
Mid-Peak	$ (26,049)	$ (628)	$ 17,926	**$ (26,676)**	$ (12,435)	$ 2,404	**$ (10,030)**	**$ (16,646)**
On-Peak	$ (9,364)	$ -	$ 42,815	**$ (9,364)**	$ -	$ 1,443	**$ 1,443**	**$ (10,806)**
Change in Replacement Power Costs						$ (48,181)	**$ (48,181)**	**$ 48,181**
Total	**$ (179,860)**	**$ -**	**$ 89,891**	**$ (150,711)**	**$ -**	**$ (25,440)**	**$ (25,440)**	**$ (125,270)**

Table 24 provides a relative comparison of the savings over a 12 month period under the 2004 and 2005 TOU rates for the hospital case. Findings of this comparison are:

- Under the tariff filed on 4/11/05, the same facility is projected to generate about $125,000 less annual savings with the propensity of the difference (~$178,000) associated with the difference lower off-peak energy rates

- At an outage rate of 5% (averaged across the rate blocks), the standby charge rate resulted in about a $50,000 higher net demand related savings but this difference would be reversed at an outage rate of over 10%

- In the end, under SCE's current rate structure it appears that most CHP projects, including those that qualify only for SGIP incentives, will probably be uneconomic without some additional sweetener to offset the impact of the revised rates. Examples of sweeteners could include:

- Gas procurement savings associated with the CHP project that might bring an overall lower gas rate to the site associated with combining the gas purchases for the CHP facility with any residual amounts of gas needed for site uses
  - Additional grant funding including showcase or other funding
  - Tax benefits available for renewable energy applications or for micro-turbines
  - Higher SGIP grants available for renewable energy or fuel cell applications
  - Other tariff benefits or modifications of the TOU 8 or Standby tariffs that provide additional incentives for CHP installations

F. Alternate Scenarios and Their Impacts on CHP Economics

(a) Scenario *B* – Energy Charges

These scenarios focused on only the energy component of the tariffs as they relate to the number of annual kWh produced by the CHP facility and the resulting energy savings. Demand related savings are separately isolated in scenarios ***H, I*** and ***J***.

Reduced production from the CHP facility will result in both less energy savings and in lower variable operating and fuel costs. The base case scenario assumption was that each engine would be off-line for maintenance at least 5% of the time (430 hours). The base case shows the maximum potential energy savings that the CHP project could realize with the only limitations being planned maintenance and reductions in realized savings associated with drops in thermal and electric usage at the site.

Scenario ***B*** premises that the facility would a generate 10% less annual production than occurred in the base case scenario with corresponding reductions in respective on-peak, mid-peak and off-peak energy offsets. The differences in IRRs and NPVs shown in Table 20 and Table 22 illustrate the relative weighting of the energy rates in the tariffs and the relative amounts of on-peak, mid-peak and off-peak electric and thermal energy produced.

In general, over the range of 0 – 10% forced outage rate, the difference in the energy component of the savings was not a major contributing factor to economic viability. For the hospital facility, which had the most level usage profile, the highest peak demand and which was matched with 3 x 333 kw CHP units, the SCE case showed the greatest relative impact on returns.

Table 7 compared the energy rates, by period, charged under the three utility tariffs. All three tariffs have a relatively similar on-peak energy rate ranging from 11.9 – 12.9 ¢/kwh. The SDG&E energy rates, which are driven primarily by the EECC (commodity component), vary little between mid-peak and off-peak.

SCE's energy rates are characterized by the very low off-peak rates described above and the higher energy rate assigned to replacement power under the Standby tariff.

(b) Scenario *C* – Departing Load Charges

CHP projects with a rated capacity of less than 1000 kW and that qualify for SGIP funding are exempt from paying the DWR Bond component of the departing load charges. The corollary to this exemption is that facilities with a rated capacity of over 1000 kW must pay the DWR component of the departing load charges on the entire production from the facility. This means that a CHP facility rated at 1001 kW must pay these charges (~$38,000/year = 0.459 ¢ / kWh) where as a facility rated at 999 kW would not. This can ultimately lead to an arbitrary incentive to the facility owner to size a facility under 1000 kW though that might not be the optimum solution to efficiency, net emissions or energy savings.

Scenario ***C*** isolates this sensitivity. The impact reversing the exemption just for exceeding the 1000 kW capacity rating is to reduce the project's IRR by as much as 6 – 8% and to reduce the net present value of the project investment by on the order of $170,000 at an 8% discount rate. This is equivalent to a 28% reduction in SGIP rebate for a project sized at 999 kW compared to one sized over 1000 kW.

As an alternative to this "exemption" approach, CEI recommends that a fairer and more aligned approach could be to have the first 1000 kw (or equivalently the first 8.76 MM kwh or similar amount of annual generation) exempt from the higher departing load charges, thus not penalizing the entire output of the CHP facility in the event the rated capacity exceeds 1000 kw.

(c) Scenarios *D - F* – Demand Charges

These scenarios isolate the relative contributions of savings associated with displacement of demand and the relative risk to the CHP owner that these savings will be reversed in the event that the CHP facility goes off-line either for planned or unplanned reasons. Table 25 provides an excerpt from Table 7, isolating the standby and demand charge components of the respective tariffs.

Table 25 - Comparison of Demand Charge Rates

Tariff	E20 Primary		TOU8 and Standby Base Case Scenario reservation fees on full CHP net capacity Primary		AL-TOU-DER, AL-TOU, EECC and Standby Primary	
Standby Rate	Exempt		~$4		~$5 –Exempt under AL-TOU-DER	
Demand Charges, $/kw[6]	General Service	Standby Power	General Service	Standby Power[2]	General Service	Standby Power
Metering Interval	30 Min	Same	15 Min	Same	15 Min	Same
Non-Coincident	$3.20	"	**$8.50**	**$1.80**	**$12.20**	"
Mid-Peak[4]	$2.60	"	$4.10	**$2.00**		"
On-Peak[4]	**$11.50**	"	**$26.20**	**$10.50**	$3.70-	"

					$5.80	

Under all three of the tariffs, the monthly demand charges are billed based on the kW demand that is measured during the indicated metering interval. This means that in any monthly billing cycle a single outage in the CHP facility during mid-peak or on-peak period will likely result in a higher measured demand during that period, even if the outage is very brief, and in the case of non-coincident demand charges an outage at any time of the month will result in reversal of all non-coincident demand savings. In the case of the SDG&E ALTOU-DER rate and its associated ratchet, a single outage can result in loss of non-coincident demand savings for an entire year.

Another anomaly from the viewpoint of the CHP industry is that once an outage occurs during any period in a billing cycle additional outages in that same period will not have any impact on savings. The net consequence of this is a CHP customer who has only one very brief outage in a month (or in the case of the AL-TOU-DER tariff in a year) can suffer the same reversal of demand charge savings as a another CHP customer who experiences many or extended outages.

SDG&E's AL-TOU rate has the highest non-coincident demand charges on the order of $12/kw mo and a relatively low on-peak demand rate of about $4 in the winter and $6 in the summer. These non-coincident demand can account for as much as 70 – 80% of the monthly and annual demand charges under the AL-TOU rate. Unless the customer chooses to pay standby charges, any outage of 15 minute duration or greater will result in reversal of the non-coincident savings for up to 1 year.

Table 19 and Table 22 illustrate this showing that loss of the non-coincident portion of demand savings would reduce the after tax IRR of a CHP project in SDG&E's service territory by project by 26 – 32%, wiping out all of the project's potential benefits for the owner.

(d) Scenario *G* – SDG&E Standby Rates

An alternative available to CHP customers in SDG&E's service territory is to opt out of the ALTOU-DER rate and to pay standby charges. This then insulates the customer against incremental non-coincident demand charges associated with outages of the CHP facility but adds a monthly cost of about $5.00 / kW mo for standby charges.

This scenario shows the impact on IRR and NPV resulting from the customer electing to opt out of the ALTOU-DER rate and to pay the standby charge. The reduction in the CHP project after tax IRR is in the range of 8 – 9% as opposed to the exposure of reversal of non-coincident demand charges described in the previous scenario which would reduce the IRR by 26 – 32%. In the cases studied, assuming that the CHP customer does not experience any additional losses in coincident demand savings the projects still meet the target IRR threshold of 15% after tax. A loss of as much as 50% of the coincident demand savings would appear to still yield a potentially attractive investment opportunity.

(e) Scenarios *H* and *I* – SCE Standby Reservation Fees

These scenarios apply only to the SCE Standby tariff. The base case scenario assumed that the client would pay reservation fees on the full capacity of the CHP facility. Scenarios H and I evaluate the impacts if the owner assumes some risk by electing a lower reservation fee in exchange for lower standby fees. As illustrated in Table 19 to Table 22, while paying lower reservations fees improves returns assuming the facility operates without outages that trigger additional reservation charges, that improvement was not sufficient to drive sufficiently profitable economics. Furthermore, owners would always be subject to the imposition by SCE of higher reservation charges if an unplanned outage occurred that resulted in the demand surpassing the lower reservation amount.

(f) Scenarios *J* and *K* – SGIP Rebate

For the class of facilities using internal combustion engines fired on natural gas, the current SGIP program allows for an incentive rebate of $0.60/watt with a cap of $600,000 rebate. Scenarios ***J*** and ***K*** illustrate the relative sensitivity to the amount of the rebate ranging from no rebate to a rebate of $0.90/watt, 50% higher than the current amount.

Scenario *J illustrates* that loss of the current $600/kw rebate would reduce project IRRs by on the order of 14% for the projects evaluated in the PG&E and SDG&E service territories. In all cases the loss of this rebate would have resulted in the project economics becoming marginal to unattractive. For the cases studied in SCE's service territory, since the projects already illustrated negative rates of return, the net impact of the rebates was not an influencing factor.

Increasing the rebate to $900/kw while increasing the attractiveness of the investments in CHP and perhaps increasing the level of tolerance that owners might have for risk, was not sufficient to overcome the tariff disincentives in SCE's service territory and appears to be unnecessary to substantiate economics in the PG&E or SDG&E territories.

(g) Scenario *L* – Alternate Interconnection

Each of the base case scenarios was evaluated based on the alternative interconnection rate relative to the base case scenario.

The differences between primary and secondary service levels in under the SCE TOU8 and SDG&E AL-TOU tariffs is minor and so results in a relatively insignificant impact on the relative economics of a CHP installation. In PG&E's service territory the difference is more pronounced and can result in a substantive difference in CHP viability.

Table 26 provides a comparison of the bundled E20S and E20P rates. The greatest differences are in the relative allocations of peak energy and peak demand charges, the E20-P tariff has a higher demand weighting, and the overall energy rates which are lower in the E20P. Projects in PG&E's service territory that qualify for the E20S tariff are better candidates for CHP applications.

Table 26- Comparison between PG&E E20P and E20S Rates, Bundled Rates c/kwh including 4.5% Franchise Fee

	E20S	**E20P**
Summer Demand		
Maximum Peak	13.59	11.63
Maximum Part-Peak	3.77	2.61
Maximum Demand (Non-Coincident)	3.22	3.23
Winter Demand	-	
Maximum Part-Peak	3.72	2.61
Maximum Demand (Non-Coincident)	3.22	3.23

Summer Energy		
Peak	15.39	12.61
Part Peak	8.76	7.69
Off-Peak	8.03	7.98
Winter Energy		
Part Peak	9.32	8.46
Off-Peak	8.01	7.59

(h) Scenario M – Most Likely Case

Scenario M was developed for the purposes of illustrating example economics for a CHP facility sited in each of the three utility service territories under a "likely scenario". In this case, modeled from the Base Case Scenario, it is assumed that as a result of forced outages that 25% of the potential demand charge savings are not realized. All other premises are the same as the base case.

Accepting that the 25% assumption is somewhat arbitrary (see explanation on page xxxv), this analysis indicates that representative rates of returns for CHP projects in PG&E's service territory are in the range of 7 – 10% after tax, and in SDG&E's service territory are in the range of 19 – 29%. Returns in SCE's service territory are all negative.

It is also worth noting that with designs effecting "most efficient heat utilization", these returns might respectively be improved by in the range of 4 – 5% after tax.

G. Other Sensitivity Analyses

The following additional sensitivity analyses were performed to illustrate how other factors, policy and non-policy related, can impact CHP economics. These sensitivities were run against a single building type and in only one utility service territory. Sensitivities included:

- Capital Investment Costs
- Gas prices
- thermal Savings
- Variable Costs Associated with Reserves for Major Maintenance Expenses
- Fixed Operating Costs
- Equity / Debt Ratio
- Interest Rates
- For-profit (taxable) and not-for-profit (non-taxable) ownership.
- Alternative tax incentive programs including accelerated depreciation, Investment Tax Credits and production tax credits
- Alternative mechanisms and approaches to financing
- Partnerships

The case selected for the sensitivities is the College located in PG&E service territory under the E20P tariff. The general assumptions for this case are presented in section 1.A.iii. The

Base Case Scenario had an IRR of 21.7% after tax and a net present value of $276,000 at an 8% discount rate.

i. Sensitivity of CHP Economics to Gas Prices and the Relative Rates of Escalation of Electric Energy Rates and Gas Rates

Table 5 lists the gas price assumptions used in the analysis. When the modeling was performed in the spring of 2005, market gas prices were in the range of $0.60 - $0.70 / Therm. As world oil prices rose in the ensuing months and following the onset of Hurricane Katrina, gas prices about had doubled by the late summer of 2005.

The cost of natural gas is a very important factor in computing the economics of CHP since gas is the most significant operating expense. The effect of rising gas prices on CHP economics does not only impact the cost side of CHP however, since the thermal and electric savings realized are also linked to gas prices.

The most direct linkage is the thermal savings since they are usually themselves based on burning of gas at the site. When a customer burns gas for thermal uses the efficiency of that conversion from gas to hot water or steam is usually in the range of 75% - 85%. As a result, 1 Therm of hot water or steam produced by the CHP facility will generally offset 1.2 – 1.3 Therms of gas use. This leveraging provides a value for the thermal energy from the CHP facility at a premium to the cost of gas burned for CHP.

The second and more indirect linkage is the electric offsets, which are tied to the electric tariff. The linkage of current gas prices to electric rates is much more difficult to predict for a variety of reasons which include:

- Utilities have a mix of generating sources including gas, coal, nuclear, hydro, etc. So, only a proportion of the cost of electricity is subject to gas prices. In California, gas currently represents about 40% of the generation base

- Often times utilities may have purchased gas under in large quantities under long term contract that can be hedged to limit gas price swings. This can result in a lag in the time frame that increases in gas prices are ultimately reflected in electric rates.

- The rate making process can further delay the response of retail electric rates to changes in gas prices. Sometimes the true up for these differences may be captured in the demand charge or some other fixed charge component of the bill. Since the CHP owners costs for gas relate to the amount of energy produced this means that the recovery of the variable costs of gas use by the utility are often not reflected in the electric bills in a manner that incentivizes CHP.

In the Base Case Scenarios evaluated in this study, displacement of electric chilling represented the most economic application for the use of waste heat from the CHP facility and that thermal uses at the site would only be addressed to the extent that all chilling uses had been exhausted. At $0.60 - $0.70 / Therm gas prices, in all cases except under SCE’s low off-peak energy rate, the use of waste heat to displace chilling is the most economic application. Since the profiles analyzed in this study included substantive chilling requirements, generally the propensity of waste heat from the CHP facility was devoted to this offset.

Under the scenario of a substantive increase in gas prices that has not yet been at fully reflected in electric rates, it can become more beneficial to dedicate the waste heat from the CHP first to thermal offsets and then to use the residual for chilling. If electric energy prices rise in response to gas price increases the situation can again reverse itself, assuming that the rise in gas prices is reflected in energy and not in demand components of the tariffs.

Of importance to CHP is that gas prices reflected accurately and promptly in energy rates as opposed to demand charges. Shifting the weight of utility cost recovery from energy rates to demand rates is a substantive disincentive for CHP.

Figure 5 - Figure 7 provide a series of sensitivity analyses illustrating the importance to CHP linking energy savings to energy costs. These figures respectively illustrate the sensitivity of CHP project IRRs over a range of gas prices from $0.30 to $0.90 / Therm under conditions where the energy component of the electric tariffs increases at a rate equal to 10%, 30% or 50% of the relative increase in gas prices. The center line of the charts is identical in all cases and corresponds to a base case rate of return of about 19% after tax and a net present value of $205,000. This case corresponds very closely to the Hospital Case in the PG&E service territory described above except:

- Seasonal gas prices variations were ignored. Gas prices were assumed to be level at the specified rate over the whole year, escalating annually at 2.8%
- The priority of waste heat from the CHP facility was applied to thermal offsets to take advantage of the disparity in increases in electric and gas rates
- The capital cost of the facility was reduced by $100 / kW to account for the reductions in chilling

The important finding in these analyses is the demonstration that if electric prices don't escalate at the same rate as gas prices, the economics of CHP ownership can remain viable. If electric rates were to increase at half the relative rate of the increase of natural gas, CHP economics can actually improve subject to the right combination of chilling and thermal energy offsets being realized.

From a CHP owner's perspective, this finding ultimately emphasizes the importance of electric energy rates correlating with fuel costs and avoiding situations where fuel cost increases are recovered by fixed or demand charge components of the tariffs.

Figure 5 - Sensitivity to Gas Prices, Energy Rates Increase at 10% of the Rate of Gas Price Increases

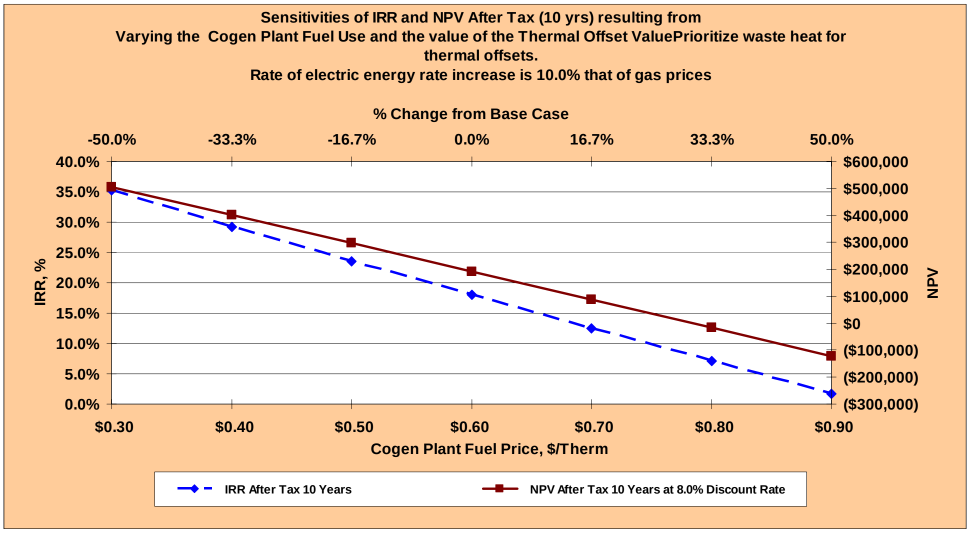


Figure 6 - Sensitivity to Gas Prices, Energy Rates Increase at 30% of the Rate of Gas Price Increases

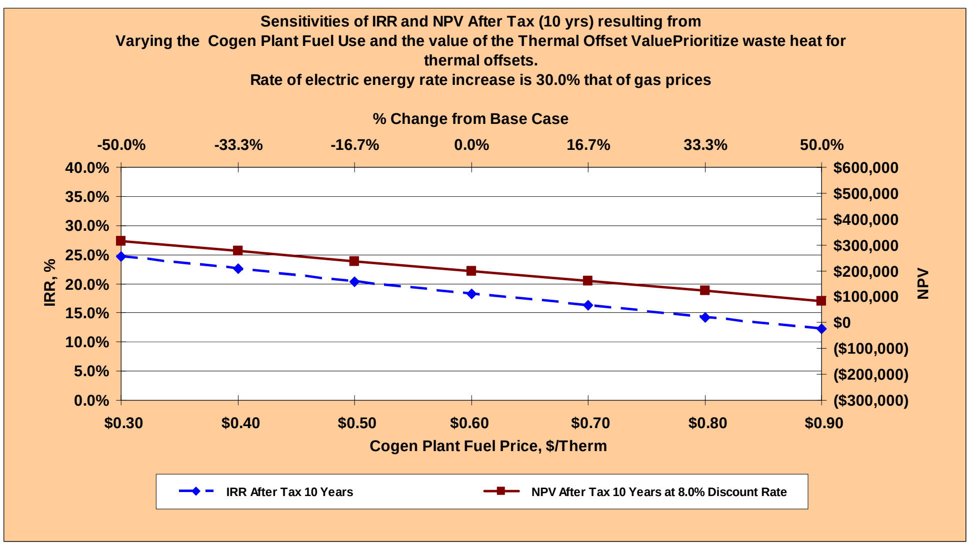
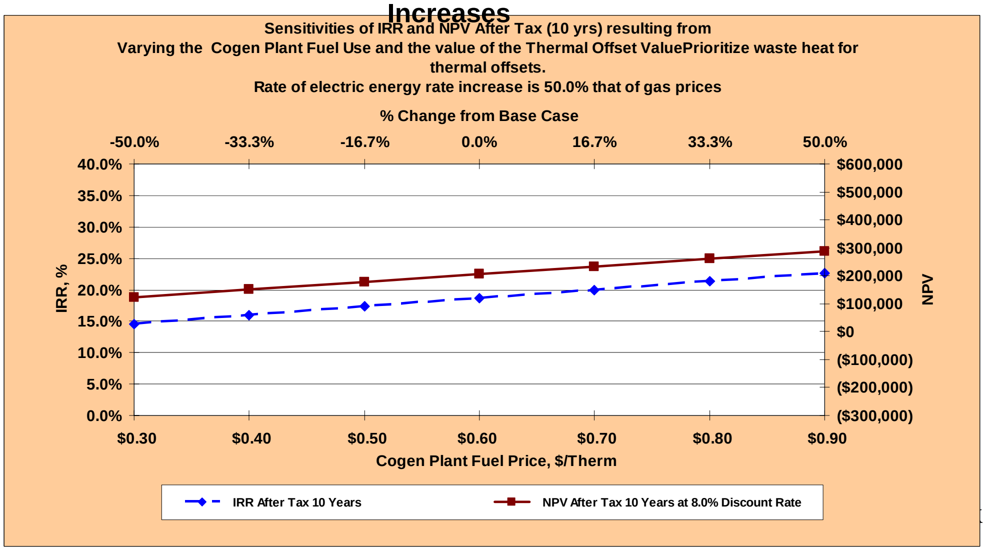


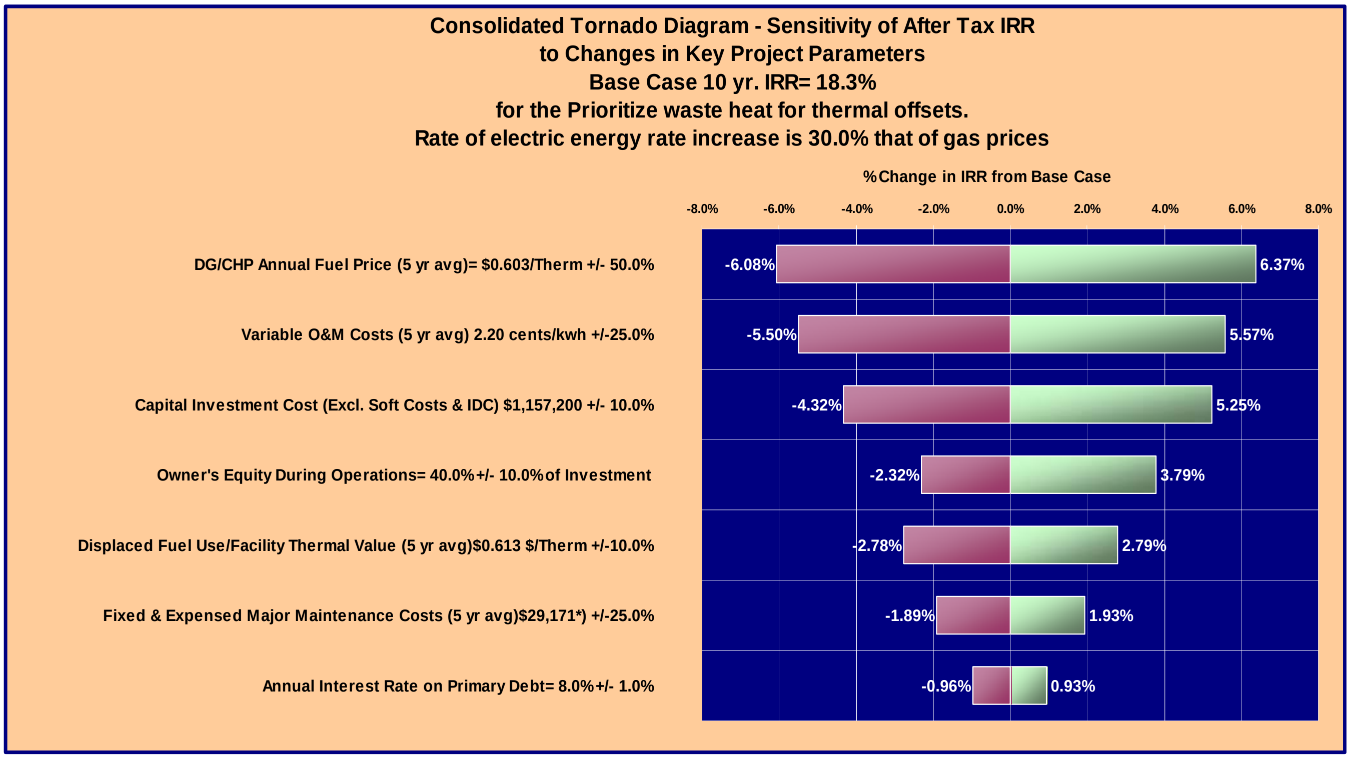
Figure 7 - Sensitivity to Gas Prices, Energy Rates Increase at 50% of the Rate of Gas Price Increases



ii. Sensitivity of CHP Economics to Other Factors

Figure 8 provides an illustration of the relative sensitivities of the PG&E hospital case described above to an array of other factors including capital costs, the owner's equity investment, thermal savings, and costs of borrowing. The red bars on the tornado diagram show the relative degradation of the after-tax IRR and the green bars show the relative enhancement to the economics resulting from an respective downside or upside influencing change. The base case gas price change corresponds to the case described in the previous section where the relative increase in electric energy rates in the tariffs is 30% of that of the relative increase in gas prices.

Figure 8 - Tornado Diagram - Sensitivity of CHP Economics to Various Factors



iii. For-Profit versus Non-for-Profit Ownership

Another factor that can be very important relative to the economics of CHP investments is the taxability of the site host or owner. A not-for-profit entity does not pay any income taxes and so can not utilize tax benefits. As a result of the Energy Policy Act of 2005, the importance of tax benefits has increased substantially with the broad application of Investment Tax Credits (ITCs) and production tax credits (PTCs) for qualifying projects and technologies, most notably those that are renewable based.

Depending on market interest rates, not-for-profit entities may also have the offsetting advantages of a lower cost of borrowing and a lower rate of return threshold. All of these factors will play into the economics and the optimum business and financing construct for the project.

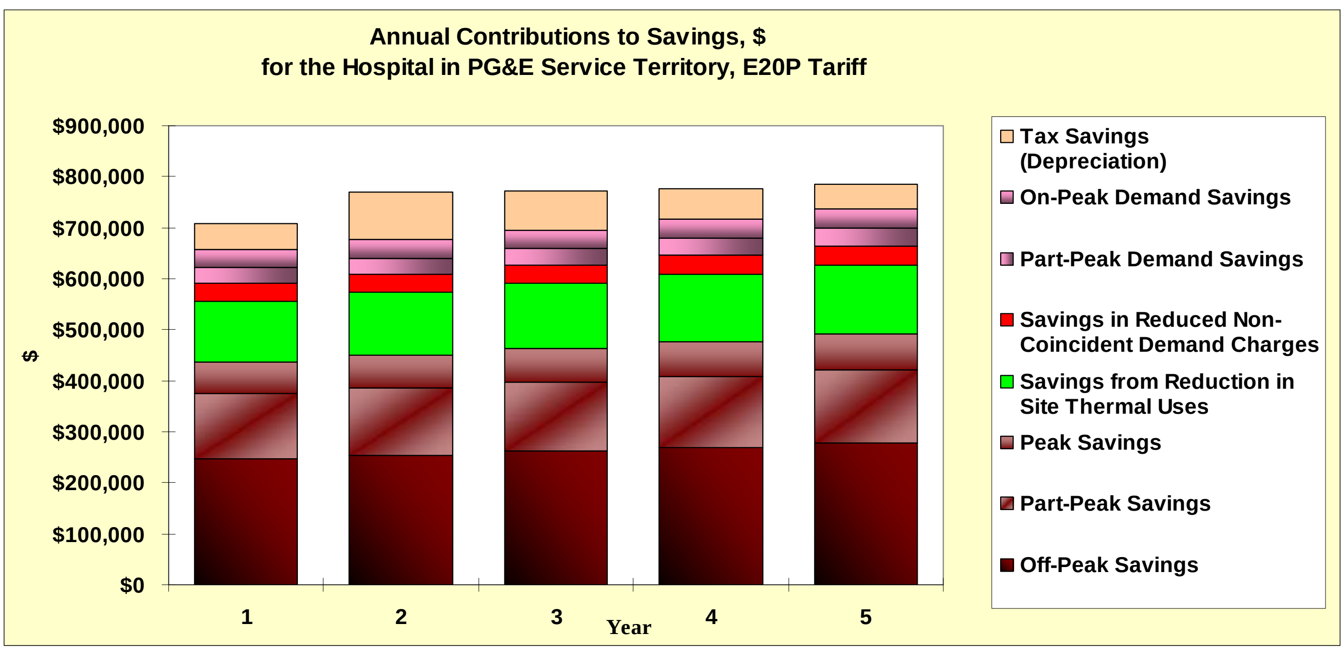
Options available to project owners and developers to deal with a range of tax situations can include:

- Owner financed projects 100% equity
- Debt / equity financing
- Operating leases
- Partnerships

Provided below is an overview of the relative contributions to savings and costs of a CHP project using the same premises as those employed in the previous section for a college located in PG&E's service territory and under the E20P tariff. Figure 9 provides an illustration of the contributions to energy savings, isolating the relative contributions of energy charges, demand charges and thermal costs. Key observations under this tariff are:

- Greater than 50% of the annual energy savings are accrued during the off-peak period
- The shift to greater emphasis on thermal offsets increased the relative amount of thermal savings when compared to the Base Case Scenario analyses performed in the study
- Coincident demand charge savings represent about double the potential on non-coincident demand charges
- Tax savings provide a substantial additional incentive. In this case tax savings represent only accelerated depreciation credits

Figure 9 - Annual Contributions to CHP-Related Savings for a For-Profit (Taxable) College



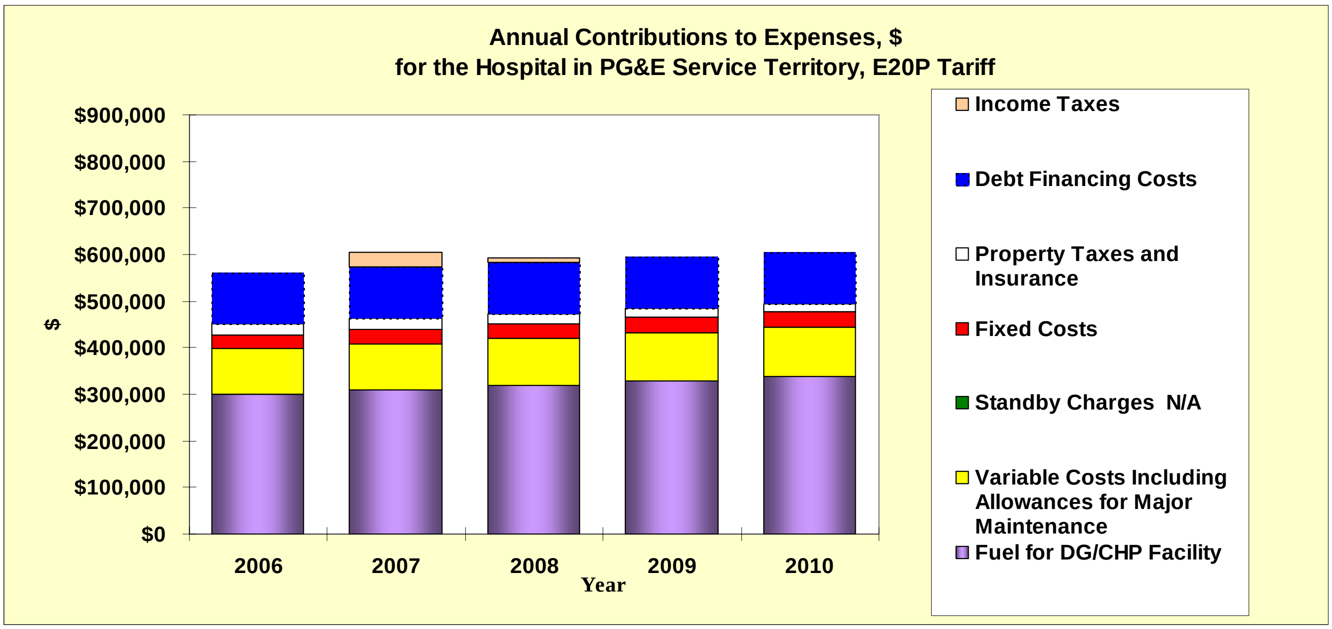
If the project owner is a not-for-profit entity, the tax component of the savings will be lost. Equivalently, if a for-profit owner does not have an adequate tax basis to use the tax deductions efficiently, they would be deferred (carried forward) diminishing their value. Other savings such as interest expenses and operating expenses are also tax deductible and can contribute to project returns, although for the purposes of this five year analysis they are assumed to be equivalent to operating expenses on the next page.

This leaves three options for the owner:

- Offset the difference with savings in expenses
- Use an innovative approach to finance or structure the project so that another party can utilize the tax benefits, or
- Accept a lower rate of return.

Figure 10 provides a similar diagram illustrating the relative expenses attributed to a CHP project including fuel, operating costs, property taxes, insurance and financing expenses.

Figure 10 - Annual Contributions to Expenses for a CHP Project



As expected, fuel is the largest contributor to operating costs, followed in this case by maintenance costs, financing costs, property taxes and net income taxes. Again, in the case of a not-for-profit owner the income tax component is eliminated unless that owner can transfer the available tax benefits to a third party.

One approach to transfer tax benefits to a third party is through an operating lease. An operating lease is equivalent to the type of lease one might assume when they lease an automobile. Under the terms of an operating lease, which is subject to special IRS tests, the following occurs:

- The Lessor (leasing company) holds title to the asset
- The Lessor retains all of the allowable capital related tax benefits which typically include depreciation write-offs and Investment Tax Credits. Typically the Lessor is not allowed to assume production tax credits.
- The Lessor finances the project and charges the Lessee (site owner or developer) an periodic lease payment. That lease payment qualifies fully as a deductible operating expense.
- The amount financed is the original acquisition price of the asset minus a “fair-market” residual value which the Lessee has the option to purchase the asset for at the end of the leasing period.

Under an operating lease the amount of up front capital required from the owner is usually minimal. The benefits of the operating lease are best realized when the owner prefers not to invest up-front capital in the project and/or can not make efficient use of the tax benefits. Often times the monthly payment due under an operating lease is less than the comparable amount of a debt payment resulting in greater monthly savings. One of the disadvantages of an operating lease is that the lease payment is burdened with the rate of return of the Lessor's investment, after accounting for their assumptions of the allowable tax benefits.

Please consult your tax advisor relative to the information contained in this report.

iv. Partnerships

Yet another approach for more efficiently capturing the value of tax benefits are Partnerships. Over the past several years the wind industry has made extensive use of partnership arrangements (some of the details are still subject to IRS interpretation rulings) that more efficiently make use of the substantial Production Tax Credits and accelerated depreciation schedule that are available to wind projects. Under the recently enacted Energy Policy Act of 2005, Investment Tax Credits and Production Tax Credits are now available for other qualifying energy investments which can include certain combined heat and power applications. Under these circumstances it is critical to have a party involved in the transaction that can make efficient use of these benefits. Appropriate partnerships arrangements may be the best mechanism to monetize tax benefits. It should be noted that for certain qualifying not-for-profit entities, provisions of the Energy Policy Act provide for alternative bond rebates that can offer equivalent benefits to the PTCs.

2. Conclusions and Recommendations for Task 3

The primary finding of the Task 3 study was that while SDG&E's ALTOU rate and PG&E's E20 rates provided attractive economics for CHP under the right conditions, SCE's TOU-8 tariff was clearly <u>not</u> attractive for CHP. Supporting findings of the study include:

- Complexity and inconsistencies in the tariffs are in general an inhibitor to efficient business practices in the state

- Very low off-peak power rates, such as those under the current SCE TOU-8 tariff, are severe disincentives to CHP. CHP projects are capital intensive and so are best suited for applications where the equipment can be operated at the high load factors. Because off-peak rate periods typically comprise 50 – 60% of the hours of the year, CHP is most viable if savings can be produced during off-peak periods.

    - The benefits of the high efficiency of CHP are difficult to capture if off-peak energy rates are very low. One of the primary efficiency benefits of CHP, the capture and use of waste heat, can not be economically applied during off-peak periods if the energy rate is very low. Cycling operation, while perhaps the best option under certain tariff structures, is ultimately not the preferred option for CHP owners.

- SDG&E's high "non-coincident" demand charges and ratchets under the ALTOU-DER rate ultimately disincentivize CHP because of the potential for loss of demand savings that result from any brief outage of the CHP facility, during off-peak periods.

- PG&E's demand charge structure emphasizes the importance of reliable on-peak CHP operations because of higher "coincident" (on-peak) demand charges. This type of structure incentivizes CHP owners to try to achieve high on-peak reliability.

- CHP projects should not be penalized though tariffs for optimizing operations and savings. Hourly and seasonal variations in site thermal and electric uses, electric rates and gas prices result in a continuously changing economic environment for CHP owners. Owners of facilities can sometimes substantively improve their economics by operating facilities in a manner that accounts for these changes. Examples of this are:
    - If the utility's marginal cost of energy during off-peak periods is truly as low as those reflected in the SCE TOU-8 tariff, CHP owners should be permitted to drop load or shut down CHP facilities during these low pricing periods without incurring reversals of non-coincident demand savings or having to pay a higher cost for replacement power than if they did not have CHP
    - During low site thermal load periods (which usually coincide with off-peak electric rates) owner's can also benefit from dropping load to match CHP production to site thermal needs and minimizing the amount of waste heat exhausted.
    - When gas prices rise in disproportion to electric rates or during off peak rate periods, CHP owners can benefit substantially by shifting the use of waste heat from CHP facilities to hot water or steam uses rather than using the waste heat to displace electric load with absorption chillers

    Current components of tariffs like non-coincident demand charges and higher off-peak energy rates under standby tariffs penalize CHP owners for this type of optimized operation

- Gas costs are the single most important component of CHP operating costs
  - CHP can be economic at high gas prices, subject to full and efficient use of waste heat generated by the CHP facility at the site
  - CHP economics depend greatly on savings generated from the energy component of the tariff. It is important that recovery of gas costs (and increases in gas costs) by the utilities be fully and promptly reflected in the energy component of the tariff. Time lags in passing these costs through in energy rates, or allocation of some of these costs to demand or fixed charge components of the tariffs inhibits CHP viability by distorting market pricing signals and risk associated with CHP investment and operation.

- A shift in cost recovery from energy to demand charges in the tariffs penalizes CHP
  - Realization of demand charge savings by the CHP owner can be eliminated by only a brief outage in a facility. If tariffs are heavily weighted towards demand charges then the corresponding portion of savings incentives to the owner is at risk due to a single brief outage of the CHP facility.
  - High non-coincident demand rates further worsen this effect because brief off-peak outages will result in loss of demand charge savings.

- Standby charges are a substantive disincentive to CHP. SDG&E and SCE apply these charges to CHP owners while PG&E does not.
  - SDG&E's ALTOU-DER rate exempts owners from these charges then adds costs through loss of non-coincident demand charge savings (if only one 15-minute outage occurs) and ratchets that can extend this loss of savings for as long as year, make the ALTOU-DER rate an unwise choice for most CHP owners in CEI's view.
  - SCE's higher standby energy rates also impose a higher cost on owners for replacement power than they would otherwise pay for the same power under the TOU-8 tariff.

- Exempting only projects sized less than 1000 kW from the DWR bond component of departing load charges creates an arbitrary breakpoint in the incentives/disincentives to CHP ownership. For example, while a facility rated at 999 kW is exempt from these charges a facility rated at 1001 kW or greater must pay these charges on all of the respective generation. This can lead owners away from designing and operating facilities in the most efficient manner.

- The SGIP program is critical to CHP economics in the current scenario. It does not, however, provide incentives to align owners to effectively operate their facilities in a manner that supports the needs of the grid and the interest of the public once they are installed.

- A CHP project is a small power plant, carrying with it all of the issues and complexities of power plant ownership and operation, compounded with the overlay that the facility must operate in a manner that supports the needs of a business that has nothing to do with power generation. Many commercial building owners don't have the know-how to operate and maintain these facilities and consider it to be a distraction from their core business. This provides motivation for third party ownership which some policies discourage.

Recommendations from the Task 3 study included:

- The structure of tariffs in the state should be standardized and simplified. Stakeholders in the CHP industry are confused by the complexity and inconsistency of tariffs amongst the 3 utilities. This confusion reduces productivity and can also lead to CHP projects that are incorrectly engineered to fully capture the potential benefits, contractual disagreements between parties in the industry, and malcontent by facility owners with both the CHP industry and the utilities.
- If tariffs can not be simplified and standardized across the board than an properly architected standardized CHP tariff could improve market penetration of CHP.

- Credits for demand charges offsets should be assessed on a much longer metering interval than 15 or thirty minutes, perhaps daily or weekly. In this way the economics of a CHP facility that operates very reliably will not be as severely penalized when a brief outage occurs, and a facility that experiences multiple or extended outages will be penalized more severely than one that might have only a single brief outage in a billing cycle.

- Demand charges assessed to CHP facilities for outages or non-performance should be assessed based on the pool benefits of many CHP facilities on the grid rather than assigning each facility individual responsibility as a single demand increment. Amongst the benefits of CHP is the diversity and redundancy that a large number of small facilities simultaneously operating on the grid provide. It is virtually impossible that all such facilities or a substantial portion of them will experience simultaneous outages. This benefit should be recognized and apportioned in the demand charge structure and the reversals of demand savings that result from CHP outages. It should be noted that the utilities expressed concern that the pooling benefits may not be not system wide and can be isolated to a specific circuit.

- Energy rates in tariffs should fully and promptly reflect changes in fuel costs experienced by the utilities so that the pricing signals for ownership and operation of CHP are truly reflective of current market conditions and associated costs of CHP operation

- Tariffs should emphasize on-peak and part-peak demand relative to non-coincident demand charges. This will also provide a pricing signal to the market to encourage conservation and reliability during on-peak periods when the power is most needed and will allow CHP facilities a time for planned maintenance during off-peak periods to ensure better reliability.

- Benefits offered to CHP such as the exemption from the DWR bond charges should be provided to the first increment of production by the facility rather than based on the rated capacity. This would minimize artificial incentives to non-optimal design and operating practices. For example, applying the exemption to the first 8,760,000 kwh of generation produced by a facility rather than only to facilities sized less than 1000 kw would mean that all CHP facilities would receive this benefit but as intended the benefit would be capped.

- Standby charges are a substantive disincentive to CHP and should be fully waived for all CHP facilities in classes that are deemed to be of societal benefit. While CEI is not prepared in this report to recommend specifically what classes of facilities this exemption should apply to, we believe it should go beyond renewables to include CHP facilities in all utility service territories that meet an established efficiency and reliability criteria, and perhaps that are located in areas where local power provides other measurable benefits. When standby charges are waived the customer should not then be imposed with other forms of charges like ratchets, higher replacement power costs or different mechanisms for demand charges than they would otherwise pay without the standby charge.

- SGIP incentives should be restructured to include both up-front rebates and production-based rebates. A production-based rebate would provide additional incentives to operators of CHP facilities to maximize production, and could be structured to encourage production during on-peak periods when energy is viewed to be most important.

- As indicated in the CHP Market Assessment Report, incentives to CHP project owners for externalities, including net CO2 or other emissions reductions would provide further incentives for CHP to support broader societal benefits.

- Future studies and planning efforts performed by the California Energy Commission and California Public Utilities Commission should include analysis from the CHP owners' perspectives. This includes characterization and reporting of how provisions in rates and tariffs affect CHP economics and better integration of objectives like those of the SGIP program with rate making policy.

III. Exhibits to Task 3 – Appendix A

Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP in Commercial Buildings
(Market Conditions as of May 2005)

I) Questionnaire used in Task 3 - Interviews with Investor Owned Utilities, Consultants, Owners, Engineers and Developers involved in the CHP Industry

- Interview Questionnaire for Investor Owned Utilities and Utility Consultants

The following Questionnaire was provided to each interviewee in advance of their interview.

Introduction and Goals of the Study - Competitive Energy Insight Inc. is performing a study funded by the California Energy Commission of "Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP". The goal of the study is to assist the California Energy Commission and California Public Utilities Commission in better understanding how factors such as tariffs, incentive programs, income taxes and financing alternatives impact the economic incentives for stakeholders in California to invest in Combined Heat and Power Projects, primarily in the commercial building sector.

CEI has been selected by the California Energy Commission to perform an economic evaluation of three typical CHP applications in each of the three California investor owned utility service territories. The "proxy" installations are anticipated to be a hotel, a hospital and a college/university. The analysis will be performed applying CEI's EconExpert-IAT and EconExpert-DG software tools which are specifically designed to assess the economic and risk factors associated with CHP applications from the perspective of the various stakeholders in these transactions including the site or building owner and/or developers who might participate in such transactions.

We have prepared a list of questions regarding yours and your employer's perspectives on the issues affecting the economic viability of CHP. While the interview will include a list of specific questions, we anticipate an ad hoc type discussion which can be expanded to other factors as you and I deem appropriate during the discussion. The discussion is anticipated to last about an hour. All information shared will be published by the California Energy Commission and so discussions regarding proprietary information should be avoided.

1. Please describe your affiliation and role and how that role and your company are involved in Combined Heat and Power in California.

2. Regulatory Policy:
   a. Are you familiar with regulatory policy and the factors influencing regulatory policy in California? If so:
      i. What aspects of regulatory policy in California do you feel have the greatest impact on the economic competitiveness of CHP at the project level? Please describe for us how you feel each of the factors you have identified have consequential positive or negative impacts on CHP economics.
      ii. How would you go about quantifying the factors you have identified at the project level?

3. Tariffs: Our goals regarding tariffs and regulatory policy are to classify and to quantify the aspects of tariffs as they relate to incentivizing or disincentivizing CHP. This means we would like to fully understand the mechanisms of the current tariffs as they apply to how the customer is billed before and after installing a CHP facility and your views on the justification / fairness of the various provisions. Do you have specific knowledge of California Electric Tariffs? If so we would like to discuss appropriate California Tariffs with you in more detail.
    a. For Representatives of California Investor Owned Utilities. We would like to discuss with you the individual key tariffs in your service territory that typically apply to commercial buildings that could be candidates for combined heat and power including facilities like hotels, hospitals and schools, with peak demand under 1500 kw. Recognizing that this might involve a large number of different tariffs, we will be glad to orient the discussion on the classes of costs in the tariffs that apply as long as substantive issues relevant to the applicable tariffs are not missed. Classes of information that we would like to discuss will include:
        i. Billing and Rate Periods
        ii. Rate Components
        iii. Rates
            1. Customer Charges
            2. Demand Charges and components of the demand charges – both time related and non-time related.
            3. Energy Charges and components of energy charges– both time related and non-time related.
            4. Standby charges and standby rates
            5. Departing Load Fees or other fees that continue to apply after a CHP facility is placed in services including:
                a. DWR Bonds
                b. Nuclear Decommissioning
                c. Public Purpose Funds
                d. Other
            6. Adjustments and riders.
            7. Taxes and other adders.
            8. Limiters
            9. Discounts
            10. Pertinent Special Conditions that affect the customers bills

Task 3 - Interview Questionnaire for Investor Owned Utilities and Utility Consultants - Continued

4. Incentives and the Self Generation Incentive Program. The California Self-Generation Incentive Program (SGIP) was created:

   "to offer financial incentives to customers who install certain types of distributed generation facilities to meet all or a portion of their energy needs. In late 2003, AB 1685 extended the SGIP through 2007."

   a. We would like to discuss with you how the SGIP program is implemented in your service territory and what are the key provisions relevant to the utility and CHP projects that typically apply to commercial buildings facilities like hotels, hospitals and schools, with peak demand under 1500 kw. Classes of information that we would like to discuss will include:
   b. Do you feel you fully understand the current program? If so, how is the program implemented within your service territory or on projects your have or will pursue?
   c. What are the key provisions of the program as they relate to cogenerators who are applying for funds?
      i. Installation Rebates - $0.60 / watt
      ii. Operating Rebates – No Longer Applicable
      iii. Other
   d. What do you see as the main strengths and weaknesses of the current program and how could it be improved.
   e. Please provide your current perspectives on the California Self-Generation Incentive Program as you believe it relates to these objectives.

5. Other Comments:
   a. Please provide any other feedback that you feel is important for CEI to consider as we prepare this analysis of the impacts of "Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP".

Task 3 - Notes from Interview with Southern California Edison Company – March 29, 2005

Participants:

<u>SCE</u>

Bob Levine - Customer Service, Business Customer Division, Technical Support, Point of contact for issues relating to departing load and standby for customer generation

<u>Interview Notes</u>

1. Please provide you feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics, and what is SCE's role in this regard:

- SCE assists customers by providing accurate and unbiased information related energy pricing and policies. When requested by the customer, SCE is pleased to provide the customer(s) a second opinion engineering study to assist the customer in making informed decisions. SCE's is concerned that customers may not make a completely informed decision, and after installing a customer generation project may find that if completely informed would not have made that decision. SCE has observed that at times sellers of equipment or developers may provide to rosy of a picture without providing all details that may impact a project, e.g. departing load and standby charges.
- At one point in time SCE could offer customers flexible pricing options, self generation deferral rates, but today those tools are not available. SCE today tries to make sure that customers are fully informed to that customers have all information they need to make the correct decision for them. This included providing facts related to energy pricing and alternative programs like energy efficiency that may accomplish a similar result for the customer...

2. Comments on the Self Generation Incentive Program.

- Referred me to Howard Green who is responsible for SGIP Program Admin for SCE. Calls exchanged. This interview was not completed.

3. Discussions of Specifics as they relate to SCE Tariffs.

- The CPUC in March 2005 approved Phase 2 of SCE's 2003 General Rate Case filing. As part of this new tariffs for SCE were implemented effective April 14, 2005.
- Standby Rates – The new tariff will have a completely different structure from the current standby tariff which was discontinued on April 14, 2005.
- Previous Tariff
- A rider to the otherwise applicable tariff, the new standby tariff will be a completely new tariff that includes its own fixed, energy and demand components.
- In addition, the standby tariff had a Standby Demand Charge
- The level of standby demand should be reflective of what SCE will be standing by to supply should the customer generation be down.
- Standby amounts were established by SCE at gross name plate rating of the customer's generator or connected load served, which ever is less.
- Customer generation that is cogeneration and 5 MW or less was exempt from the standby demand charge providing they were interconnected prior to April 14, 2005.
- The CPUC approved an automatic extension of 6 months for standby exemptions since the new SCE tariffs were not implemented by the January 1, 2005. This extension will run through June 2005.

- Under the New Standby Tariff
    - New standby tariff is a rate schedule to it and applies specifically to the generator name plate.
    - All new generators will be metered. If the generator is down, the standby rate will apply first to the capacity that would have been otherwise been supplied by the generator.
    - Fixed, Energy, demand and time related and non-coincident demand components
    - Customer may elect the level of standby but that level should be reflective of what SCE will be standing by for.
    - If the CHP facility goes down and the resulting increase in demand does not exceed the standby level, then the standby level as set would be viewed as acceptable. Should the standby level selected by the customer be exceeded then SCE will reestablish the level at either the gross nameplate rating of the generator or the connected load that SCE would have to serve whichever was less. This would be the new standby level on a going forward basis.
    - Customers may sign a physical assurance agreement indicating that they do want to pay standby charges, or desire a limited amount of standby, but if lose on-site capacity then additional generation is not guaranteed. Also, a physical assurance agreement requires that protective electrical equipment be in place to prevent electrical delivers.
    - Customers that were previously exempt from Standby Demand Charges will continue to be exempt from the same charges either until 2006 (for non-cogeneration facilities) and until 2011 (for cogeneration facilities). All customers will be required to pay all applicable charges when they take electric service from SCE including Facilities Related Demand Charges.
    - Capacity Reservation charges vary depending on the size of the customers account and the voltage level of service. These values are identified in the new standby tariff Schedule S. Customers under the new standby schedule will pay for energy and demand charges on both a time and non-time related basis. For those familiar with SCE tariffs the new standby schedule would be similar in format to the TOU-8 tariff schedule
    - Allows customer to initially select what standby level they want relative to amount of generator output, but the level should be established at what SCE is likely to have to provide should the customer's generator(s) fail.
- A customer can change the reservation amount after initial election providing that they have not exceeded the initial election and has not established a standby demand level for the customer. With that said a customer should select the standby level to be reflective of what SCE will have to provide to the customer in the customer's generation fails.
- If exceed the level of standby selected by the customer is exceed, SCE will reestablish the standby level in the manner done under the prior tariff, i.e. at the gross nameplate rating of the generator(s) or the maximum connected load that SCE would have to serve whichever is less. This reestablished standby level will remain in place for twelve (12) months. At the end of this 12 month period the customer can request a lowering of the standby level but will have to provide justification for any adjustment.
- Tariff Schedules
    - Commercial and industrial customers typically take electric service under one of two tariff schedules, either:
        - TOU-8 (>500 kW peak)
        - GS2 (Less than 500 kW peak)

- Customers who install CHP resulting in a reduction in peak will not be obligated to change to a different tariff.
- Customers who install a CHP facility between April 14, 2005 and June 30, 2005 and are 5 MW or less have the opportunity to take standby service either under the provisions of the rates identified under the new Schedule S or can receive the standby exemption and receive standby service under their Otherwise Applicable Tariff (QAT).
- SCE's older tariffs contained demand ratchets, but the new tariffs no longer have demand ratchets.
  - Demand Ratchet – No longer applicable
  - Departing Load Charges Billable to ALL CHP Departing Load Non-bypassable Charges.
  - Public Purpose Programs Charges
  - Covers Energy Efficiency Programs
  - Rate pursuant to the customers OAT
  - Nuclear Decommissioning Charges
  - Departing Load Charges Billable to some CHP
  - CGDL-CRS – Customer Generation Departing Load – Cost Responsibility Surcharges – This money does not go to the utility, it is passed through to DWR
  - DWR Bond Charge –0.459 cents/kWh. This charge will vary year to year as DWR charges are paid off and depending on the amount of power the utility is required to buy from DWR. Certain CHP projects that received money under the Self Generation Incentive Program may be exempt if the total amount of installed generation is less than 1 MW.
  - Competition Transition Charge (CTC)
  - The tail "CTC" applies to non-cogeneration projects. Cogeneration projects would typically be exempt from this charge.
  - Historical Procurement Charge - Applies if customer had not met prior obligations. Rare except for direct access customers (2.7 c/kWh even if go off of direct access). If come back to the utility, still must pay certain requirements as direct access customer.

- Exemptions:
  - Certain w/ timing – Before Feb 2001
  - SGIP program funding and under 1 MW, exempt from DWR power and bond charges.[see above]
  - Unit with capacity name plate over 1 MW may not be exempt in SCE view.[see above]
  - SCE establishes makes an initial determination regarding a customers exemptions related to the Cost Responsibility Surcharges with the California Energy Commission making the final determination]
  - SCE believes determination is on name plate size of the generator. The determination of standby levels is based on the gross generator nameplate rating or the customer's maximum connected load that SCE would be required to serve if the customer's generator fails to operate.

- Energy Charges - tariff sheet on web site
  - URG and DWR components allocated and will change on regular basis
  - Typical blend URG and DWR rates is 30% DWR, 70% URG (i.e. February 05, ~31% DWR, ~69% URG)

Task 3 - Notes from Interview with San Diego Gas and Electric Company – March 18, 2005

<u>Participants</u>
<u>SDG&E</u>
Bonnie Baily – Supervisor Rate Support – Implementation and applicability of Tariffs
Sally Muir – Project Mgr – SGIP manager
Joe Kloberdanz – Regulatory Affairs Mgr – Manage issues and cases at state level for SDGE and SoCal Gas

<u>Interview Notes</u>

1. Please provide you feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics, and what is SDG&E's role in this regard:
   - Cost based rate design vs. social rate design – price signals should be accurate and appropriate based. Accurate price signals. Public filing – rate design window – posted on web site. Designed to improve rate design.

2. Comments on the Self Generation Incentive Program.

   - Projects need to be right sized for electric load and thermal load
   - Need full use of waste heat
   - Industry turnover has been harmful - Selection of Vendors difficult
   - Volatility of gas prices – inability for small users to hedge gas puts them at risk Income
   - CHP – up to 5 MW, applies to 1st MW
     - o Renewables – Higher ruling two weeks ago (check $1.60/watt – SDREO)
     - o Non-Renewable Microturbines - 80c/watt $800K Max
     - o Internal combustion – 60c/watt $600K Max
     - o Fuel Cells
       i. $4.50 / watt based on renewable fuel
       ii. $2.50 / watt non on non-renewable
   - Must meet emission standards – superseded CARB AB1685
     - o 0.14 lb/MW NOx going to 0.07 lb/MW (CHECK THIS)
   - Must meet waste heat requirements – 42.5%
     - o 60% efficiency requirement. New calculation – Southern Engineering (CHECK – See SDRE website – **GET Handbook**) can use some to offset NOx.
     - o Requirements get stricter in 2007.
   - Strengths
     - o Encourages CHP
     - o Encourages renewables.
   - Weaknesses
     - o Paying up front incentive
     - o If system shut down, doesn't guarantee operation when needed or meeting of waste heat requirements.
     - o No reward to plants that run when needed.
     - o Recommend "Performance based incentives".
   - ITRON Impact study for 02, 03 - How has CHP helped or not. 03 study,
     - o It is not clear that program is meeting objectives based on historic data (ITRON Study)
     - o Only .6 kW / each kW nameplate operating in 2003.

3. Discussions of Specifics as they relate to SDG&E Tariffs
    - Typically Only 1 Tariff Applies – AL-TOU for all customers over 20 kw Commercial
    - Departing Load Fees, provided a nice summary sheet
        - Public Purpose Program applies
        - Nuclear Decommissioning
        - DWR bond funds exempt under 1 MW if meet PUC exemption criteria. (~0.5c)
        - CTC's apply if project doesn't meet FERC efficiency pay CTC's on what they generate
    - Voltage definition requirements
        - Secondary - At substation 98% of customers,
        - Primary service must own switch gear to step down,
        - Transmission level own substation and receive at 69 kV.
    - Power Factor – General rule SDG&E doesn't bill for them since meters are not capable. Used to address reliability issues to encourage customer cooperation.
    - Demand Charges
        - Non-Coincident is highest rate, circuit level (~$11)
        - Reflects cost to service that customer, transformers, General. RMR, Transmission, moving costs into non-coincident demand.
        - On-Peak – System level. ($3 – 4)
        - What does system need to do to support that customer.
        - Demand ratchet based current peak or 50% of highest peak over the previous 11 months.
    - Qualifying CHP customers have option for AL-TOU CHP which exempts them from standby. Customers on AL-TOU must pay standby charge.
        - Can negotiate lower amount of standby if have multiple units. Have to be willing to curtail load in the event of an outage that exceed the standby commitment.
    - Schedule S – Standby charges – Cogen under 5 MW is currently exempt under AL-TOU-CHP subject to further PUC review.
    - Commodity Charges – SDG&E bills commodity charge under a separate rider.
        - EECC are blend of DWR power and utility retained generation.
        - Changes typically annual, can be more frequent.
        - Includes SDG&E generation and Power Purchase contracts, share of San Onofre and DWR. Ranko plant peaker.
            - New project Escondido-Palomar. Will fall into rate base.
            - Electric commodity – rate in effect based on forecast basis – trigger allowing adjustment more frequently than annually, otherwise annual even-up. Trigger is % of forecasted expenses (5%) approach commission when reaches 4% so have time to deal with it.
        - Direct Access
            - Only clients previously qualified – Legacy only
            - Customer must make arrangements with their service provider.
            - Utility not party to the contract. Replaces EEC. No added charges. No Penalty.
            - The Utility is still provider of last resort – concerns about what this means – no changes in the provisions but in front of PUC for discussion – Utilities still question it, not defined.

Task 3 - Notes from Interview with Pacific Gas and Electric Company – March 30, 2005

Participants:
PG&E
Chris Tufon – Senior Tariff Analyst responsible administering standby tariffs
Dan Pease – Electric Rates Manager – responsible for electric rates.
Dennis Keane – Service Analysis Manager – responsible for managing general regulatory policy issues as they relate distributed generation and other areas.

Interview Notes

1. Please provide your feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics:
    - Feel most of the recent regulatory policy may be “overly” favorable to CHP. Recent rate changes (in 2001, related to the energy crisis) resulted in 3 cent increase in PG&E’s energy rates which should alone enhance CHP economics, even absent other incentives.
    - The SGIP program provides additional incentives.
    - Standby exemptions also favor CHP and shift costs to other customers (since the costs of providing standby service remain, while revenues are decreased, causing rates to increase).
    - Lower Gas Transportation rates for CHP units if they meet specific efficiency standards.
    - PG&E feels that CHP is probably more economic today than it was in 2000 due to the myriad of subsidies.

2. Comments on the Self Generation Incentive Program.

    - Would prefer incentives weren’t just up-front with no incentive for actual performance of the facility.
    - Feel units specified PU Code 218.5 efficiency should be required to meet that over the life of the program.
    - Feel the supplier should be required to install what they apply for. Feel that often this is overstated. Program needs better checks and balances.

3. Discussions of Specifics as they relate to PG&E Tariffs

- Expect new rates in May or June of 05 – mainly DWR impacted.
- Standby Rates – PG&E Schedule S
    - SB1X28 provides standby exemptions. Qualifying CHP installations are exempt.
- Primary CHP requirements.
    - Meet PU Code 218.5 efficiency standards.
    - SGIP program.
    - Less than 5 MW.
    - Other conditions apply.
    - Standby exemption will eventually expire on or before June 1, 2011, if not extended by legislature or CPUC)
- Used for customers who regularly can supply **all** of their own energy use.
- A Stand alone full tariff with non-firm option.
    - Reservations charges for backup capacity supplied by the utility.
    - Customer can initially choose the amount of capacity reservation they would like to have

- If demand does not exceed the reservation amount, no additional demand charges apply during periods when customer needs reserved load.
- If exceed reservation amount, demand ratchet applies
  - Ratchets under standby/reservation charges only, qualifying CHP exempt
  - Currently 85% of highest load over prior 36 months. PG&E expects this ratcheting period to be reduced to 12 months on 1/1/06.
  - Customer can raise reservation charge at any time, but in general can not reduce it.
  - Currently applies only a single reservation charge that is non-time bearing.
- Tariff Schedules - For commercial or industrial customers 3 tariffs apply
  - E20 (>1000 kw peak)
  - E19 (500 to 1000 kw peak)
  - A10 (Less than 500 kw peak)
- Customers who install CHP resulting in a reduction in their peak load are not obligated to change to a different tariff which would disadvantage them.
- CHP customers who are exempt from standby are treated the same as customers who don't have on site generation.
- Departing Load / Non-bypassable charges.
- AB1890 – 1996 deregulation, legislature decided that certain costs should be **non-bypassable**. You can't leave and get out of it.
- Municipal departing load – disconnect and take service from muni or irrigation district. Usually all.
- Customer generation departing load – usually partial departure (i.e., the amount considered to be "departing" is the usage formerly served by the utility that is now displaced by the customer's on-site generator).
- The displaced usage (i.e., the part that used to be served by PG&E but is now served by the on-site generator) is subject to charges unless exempted by specific legislation or CPUC decisions.
- Billable to all CHP
  - Public Purpose Programs
    - Transmission level 3.26 c/kwh
    - Primary Voltage 4.02 c/kwh
    - Secondary Voltage 4.54 c/kwh
    - Solar exempted
  - Nuclear Decommissioning Charge
    - 0.35 c/kwh
  - Billable to some CHP
    - DWR bond charge
    - Qualifying cogen under 1MW is exempt (net metered or SGIP)
  - CTC – Competitive Transition Charge
    - Exempt if meet cogen efficiency standards per Section 372 of PU Code cogen efficiency standards are in Section 218.5 of PU Code
    - TTA – Transfer Trust Amount
    - Applies only to residential/small commercial, but includes small cogen [This is a separate charge, not part of TTA; thus this bullet should not be indented - Cogen Exempt subject to statewide MW Installation cap]
  - Energy Cost Recovery Amount – applies to same as power charge so cogen exempt subject to statewide cap. [This is a separate charge, not part of TTA; thus this bullet should not be indented]
  - DWR rates
    - PG&E rates are set – don't alter DWR share on forecast basis.
    - PG&E does not use proportionate share like SCE does.

- Annual or biannual corrections.
- Energy Resource Recovery Account.
    - Tracks procurement costs and revenues.
    - If get out of balance by more than 5% then PG&E can expedite Trigger filing rates change but typically annually.
    - Recovery can go to demand or energy.
    - Usually allocate to both.

- Direct Access – If Customer on DA installs a generator
- DWR charges for DA customers are capped at less then full amount currently with expectation they would defer payments make up difference later .
- Deferred / under collected amounts would have to be paid after switch to CHP.
- Still get exemptions going forward.
- ONE TIME PAYMENT of deferred amount

Task 3 Notes from Interview with Energy and Environmental Economics, Inc – March 21, 2005

Participants
Energy and Environmental Economics, Inc.
Snuller Price – Partner

Interview Notes

4. Please provide you feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics, and what is E3's role in this regard:

- E3 Background
  - E3 supports utilities and agencies on Distributed Resource Evaluations and Economics
  - Screen opportunities for CHP and DSM
  - Expertise not typically applied to individual transactions
  - Overview of Markets
  - Impacts of CHP on energy markets
  - Avoided cost impacts for utilities
  - Working with the California Energy Commission relative to costs and benefits
- E3 assists others to develop policy for Integrated Energy Policy Report (IEPR for the California Energy Commission)
  - EPRI, Energy and Environmental Analysis, Primen and E3
  - Try to be neutral – looking at impacts on owner, utility and society.
  - Biggest Impacts / Market Drivers
  - Rate design
  - Rates that result in tariffs that have the most weight in direct c/kwh are most beneficial - $/kw-mo beneficial if understood and targeted
  - Rates that have conditions on connected load / demand charges / ratchets are the biggest discouragement.
  - Departing load surcharges
  - Time of use vs. non-time-of-use
  - Importance of thermal
  - Phasing of gas and electric prices rates
  - thermal storage opportunities
  - Retail access
- Putting lid on retail access made it more difficult to export to the grid
  - Ability to sell excess generation
  - Value of that generation
  - For Big projects, this is a major impact
  - Drives owner to smaller project
  - Maybe less efficient
  - Driven by electric by thermal
  - Potential solution Net meter at wholesale rate
  - South Coast air emissions issues – may limit technology options – SCAQMD (Will send to me) NOx lb/MWH
  - Current Standard (varies, 9ppm (large) or 0.15gm/bhphr (small)
  - 2007 Standard (0.07lbs/MWh) "Ultra-Clean Technologies"

5. Comments on the Self Generation Incentive Program

- Doesn't reflect true impacts on Utility system

- Doesn't promote efficiency
- Doesn't promote peak load period generation
- Doesn't promote environmental benefits
- Doesn't promote amount of time run
- Benefits vs. ease of implementation (a trade off)
- Ideally SGIP would provide payment as service is provided.
    - $/kwh payment
    - CO2 / REC incentives
    - Operational during summer peak incentives
    - Waste heat utilization incentives
    - Need for a fair systems that has no negotiations or room for interpretation.

6. Financing and Income Taxes
    - E3 believes there could be benefits for utility or state financing to flow through to CHP applications but has not seen substantive support for that approach.

7. Tariffs
    - E3 Approach is to simulate load shape and then determine what costs are avoided.
    - All the current rate structures will cost utilities money and therefore will increase costs to other rate payers as costs avoided by cogenerators flow to others.
    - Need for system to better define who pays, how allocate. Revenue shifting result.
    - Feel that in general the discount the customer gets is greater than the amount it saves the utility.
    - Ideally, tariff structure designed to so that CHP savings reflect true savings for the utilities.
    - Distribution charges are billed in c/kwh even though they are fixed costs.
    - Systems built to meet peak load – Demand charges are Levelized.
    - Avoiding capacity in April doesn't benefit the system
    - Avoiding capacity in August may have much greater value than current demand charges.
    - Rate structures don't match the pattern of the costs.

8. Other comments

- LADWP – Rates are significantly more adverse to CHP than are those of the IOU's

Task 3 Interview Questionnaire for Developers, Owners and Engineers of CHP Projects

Introduction and Goals of the Study - Competitive Energy Insight Inc. is preparing a study funded by the California Energy Commission of "Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP". The goal of the study is to assist the California Energy Commission and the California Public Utilities Commission in better understanding how factors such as tariffs, incentive programs, income taxes and financing alternatives impact the economic incentives for stakeholders in California to invest in Combined Heat and Power Projects, primarily in the commercial building sector.

CEI has been selected by the California Energy Commission to perform an economic evaluation of three typical CHP applications in each of the three California investor owned utility service territories. The "proxy" installations are anticipated to be a hotel, a hospital and a college/university. The analysis will be performed applying CEI's EconExpert-IAT and EconExpert-DG software tools which are specifically designed to assess the economic and risk factors associated with CHP applications from the perspective of the various stakeholders in these transactions including the site or building owner and/or developers who might participate in such transactions.

We have prepared a list of questions regarding yours and your employer's perspectives on the issues affecting the economic viability of CHP. While the interview will include a list of specific questions, we anticipate an ad hoc type discussion which can be expanded to other factors as you and I deem appropriate during the discussion. The discussion is anticipated to last about an hour. All information shared will be published by the California Energy Commission and so discussions regarding proprietary information should be avoided. If any such information is inadvertently disclosed during this discussion, please contact us and we will omit it from our reporting to the California Energy Commission.

1. Please describe your affiliation and role and how that role and your company are involved in Combined Heat and Power in California.

a. Regulatory Policy
   i. Are you familiar with regulatory policy and the factors influencing regulatory policy in California? If so:
   ii. What aspects of regulatory policy in California do you feel have the greatest impact on the economic competitiveness of CHP at the project level? Please describe for us how you feel each of the factors you have identified have consequential positive or negative impacts on CHP economics.

2. Tariffs: Our goals regarding tariffs and regulatory policy are to classify and to quantify the aspects of tariffs as they relate to incentivizing or disincentivizing CHP. This means we would like to fully understand the mechanisms of the current tariffs as they apply to how the customer is billed before and after installing a CHP facility and your views on the justification / fairness of the various provisions. Do you have specific knowledge of California Electric Tariffs? If so we would like to discuss appropriate California Tariffs with you in more detail.

a. We would like to discuss with your perspectives of what are the key issues relating to tariffs that impact combined heat and power economics. Classes of information that we would like to discuss will include:
   - i. Tariff Discussions
     1. Billing and Rate Periods - Tiered and Time of Use
     2. Rates
        - a. Demand Charges
        - b. Energy Charges
        - c. Standby charges
        - d. Non-Bypassable / Exit Fees
        - e. Nuclear Decommissioning Fees
        - f. Public Purpose Programs
        - g. DWR Bond Funds
     3. Pertinent Special Conditions that affect the customer's bills.

   - a) Do you feel you have a clear understanding of the various tariff structures that affect your business?
     1. If so, how have you gained this understanding?
     2. If not, what areas do you have uncertainty about? Do you know where to get the needed information and how to interpret it? Do you know who to contact to ask questions?
   - b) Incentives and the Self Generation Incentive Program. The California Self-Generation Incentive Program (SGIP) was created:

     "to offer financial incentives to customers who install certain types of distributed generation facilities to meet all or a portion of their energy needs. In late 2003, AB 1685 extended the SGIP through 2007."

3. We would like to discuss with you how the SGIP program is implemented in your service territory and what are the key provisions relevant to the utility and CHP projects that typically apply to commercial buildings facilities like hotels, hospitals and schools, with peak demand under 1500 kw. Classes of information that we would like to discuss will include:
   - i. Do you feel you fully understand the current program? If so, how is the program implemented within your service territory or on projects your have or will pursue?
   - ii. What are the key provisions of the program as they relate to cogenerators who are applying for funds?
     1. Installation Rebates - $0.60 / watt
     2. Operating Rebates – No Longer Applicable.
     3. What do you see as the main strengths and weaknesses of the current program and how could it be improved

iii. Please provide your current perspectives on the California Self-Generation Incentive Program as you believe it relates to these objectives.

4. Income Taxes and Financing.

a. We would also like to discuss your perspectives on the roles of federal and state tax programs on incentivizing or disincentivizing CHP. What provisions of the current Federal and State Tax Code do you feel are most influential on CHP economics and financing?

b. What actions would you like to see included in new federal Energy Legislation to encourage CHP?

c. Do you perform CHP projects in cooperation with or on behalf of not-for-profit entities such as hospitals, schools and universities or municipalities?

   i. If so, what do you see as the standard means for financing these projects?
   ii. Are you familiar with the mechanisms of Operating Leases? If so, how have you applied them and what do you see as the key benefits and disadvantages?

5. Other Comments:

a. Please provide any other feedback that you feel is important for CEI to consider as we prepare this analysis of the impacts of "Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based CHP".

Task 3 Notes of Interview with Real Energy – April 1, 2005

Participants:
<u>Real Energy</u>
Kevin Best – CEO

1. Please provide you feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics, and what is Real Energy's role in this regard:

- Independent power producer and developer
  - Seek and develop viable investments
  - Focus Hospitality, health care and waste water treatment
  - Sell to Markets and Financial Community
  - Team
    - Outsource engineering work to local contractor(s)
    - Goal 70 MW CHP in next 6 years
    - Finance – By private placement
    - Investment Fund – holding company for projects
    - Project size $2 – 3 MM each
    - Roll up to $10 MM to finance with debt
    - Hedge when achieve $40 MM with equity and long term gas
    - 17% target return for investors in fund.
    - Private investment in clean technologies will have major impact on the markets in coming years
    - Billion $ investment by Calpers and Stirs
    - Others including Renewable, thermal, scrubbers, small nuclear, CHP, fuel cells, etc.
    - Market is there if technologies can be cost competitive

2. Self Generation Incentive Program.
   - Application process has been greatly simplified, but:
   - Past got 22 – 24% of project cost = ~70c/watt including O&M
   - Now 60c/watt so rebates are smaller
   - Program Encourages further fragmentation, easy to get $ – risk that breeds lower probability of projects done right.
   - Real Energy In favor of higher rebates for renewables / solar (~$1400/kw??) Plus renewable energy credits.
   - Renewable projects now approaching single digit returns.
   - Need capacity payments
   - Hard to justify projects CHP in SCE territory, w SCE tariffs
   - California is taking the lead and has the most forward view.
   - Programs in NJ, Maine, Arizona, renewable energy portfolios are not as reliable. Need $100B year investment to meet standards that are in place.
   - Suggests that incentives and tariffs should reward when facility is available
   - Complements needs of utilities
   - Day ahead bidding

3. Regulatory Policy:

- Departing Load Charges:
- DGOIR will address departing load rules.
- Exemptions
  - QF
    - Expires when DG penetrates – 3000 MW
    - Important for Direct Access
- Standby charges
  - Exempt as long as PURPA qualified. DGOIR should extend that.
  - Demand charges only if miss.
- Demand ratchets:
  - Can be up to 12 months. Usually less than $2, $11 Non-coincident.
  - Lobbying for daily ratchet rather than monthly at CTDC
- Solar photo voltaic credit
- Industrial park or regional park.
  - Need to have density in a local area to justify spreading demand charges.
- Suggests that incentives and tariffs should reward when facility is available
  - Complements needs of utilities
  - Day ahead bidding

4. Income Taxes and Financing.

- Real Energy View
- Better to have third party own who is the expert, not core business for the site owner.
- Aggregation of supply chain, equity, debt, gas procurement, equipment procurement.
- Need to role up into portfolio.
- Very fragmented market, so lose economies and financability.
- Capital influx in the renewable market will promote higher level of investment.
- Energy bill – Real Energy Favors
- Accelerated depreciation benefits passed.
- 10 – 15% Investment Tax Credit
- Federal tax credit for renewable and CHP
- National Renewable Energy Portfolio Standard Extension of Production Tax Credit – Wind and land Fill
  - Real Energy interpretation, PTC extends to waste water treatment
  - Doesn't apply to biomass, agricultural, geothermal
  - Adds 3% to IRR.
- Financing – Important advantages of 3rd party player
- Real Energy uses "roll-up" strategy
- Project financing – needs to roll project to min $20 MM 6.5%
- Small projects can't meet that level.
- Limit equity commitments to later roll-overs and roll ups.
- Need to use financing to leverage deals to attract private equity, but to accomplish this must have aggregation.

- Working standardize supply chain

  - Steel
  - Engines
  - Small volume hurts business
  - Supply chain management to lower costs delivered
  - Gas Hedging

5. Other
    - Democrats in CA appear to want to guarantee returns for investor
    - Real Energy feels this is a bad idea
    - An Alternative safe income model could include Loan Guarantees.
    - See strong Focus moving to “Clean Technology”.

Task 3 Notes from Interview with Saddleback University – March 16, 2005

Participants:
Saddleback University
John Ozurovich – Director or Facilities and Maintenance for the Saddleback College

Interview Notes

1. Please provide you feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics, and what is Saddleback's role in this regard:

Saddleback College

- 13000 full time and 12000 part time students
- 200 acre campus, 630,000 sq ft of conditioned space
- Central plant cooling and heating
- 1000 ton and 600 ton Electric Chillers
- Hot water system
- Chilled water thermal storage system

- Owner of 1.5 MW Internal Combustion 2 x 750 Waukesha Generators
- thermal for Campus space heating and hot water for pool
- No Chillers
- Generators run 24 x 7, some part loading
- Weekdays M – F 6 am – 10 pm Both Generators at load
- Night time, charge thermal storage unit until tank charged then drop to one generator for lighting
- Reliability ~99%
- Commissioning phase had some unscheduled shut downs, now few occur.
- SDG&E Electric, SoCal gas for gas purchase non-core fm 3rd party and SoCal Trans
- AL TOU CHP Tariff

2. Comments on the Self Generation Incentive Program

- Original SGIP program took a lot of negotiation and problems.
- Feel the simplified program is much better.
- Feels that the 1500 kw limit is a negative.
- Got $880K under old program more hassle but more money. Felt they qualified for more $ but didn't get it.
- Up front they thought they would have done the program without the incentives but at current gas rates the incentives are absolutely necessary.
- Higher gas prices were a surprise to them and caught them by surprise.
- Economics of project have not panned out due to gas prices.
- Suggested improvements to SGIP – Address Gas costs
- Rebates on gas consumption would be a big incentive.

3. Financing and Income Taxes

- Saddleback is non-profit
- Understands there can be benefits of alternatives with private financing. Reluctant to bring in third parties from policy perspective. Most important is budget planning.
- Have considered alternative mechanisms such as operating leases and third party ownership
- Everything self funded to date.

- Board is resistant to third party approach but they continue to evaluate because of potential cost/investment advantages and risk sharing.

3. Tariffs

- After installing the units they had a number of surprises
- Ratchet charges - didn't understand until after had installed the facility
  - o Departing load charges on energy they generate (generation 789000 kwh, $5428.00) didn't expect them.
  - o The currently use the AL-TOU CHP tariff - No Standby charges under CHP Tariff
  - o Not familiar with special conditions
  - o Ratchet now understands
  - o Has not reviewed the utility published tariff sheets

Task 3 Notes from Interview with Honeywell Corporation – March 30, 2005

Participants:
Honeywell
Kevin Cross - Performance Contracting Engineer Role – Technical portions of performance contracts and energy reference contacts
Barry Voigt – Performance Contracting Engineer Role – Technical portions of performance contracts and energy reference contacts
Dave Gralnik - Sales Executive – Field sales and customer interface

Interview Notes

1. Please provide you feedback about what aspects of California Regulatory Policy you feel have the greatest impact on CHP economics, and what is Honeywell's role in this regard.

- Support development of projects and provide customers with turnkey solutions
- Feel that the utilities have the ear of the California Energy Commission and the California Public Utilities Commission, better than do the cogen developers and therefore wonder whether their interests are being fairly represented.
- Feel like the process is sometimes biased, and not necessarily in such a way as to encourage cogen.
- Perception / Feeling that utility structures are slightly biased against cogen.
- Feel that utility approaches are not always communicated clearly.

2. Comments on the Self Generation Incentive Program
- 60c/watt charge provides a much lower rebate amount than previous when the costs of gas have increased working against cogen.
- Simplifications are of value but incentives reduced dramatically.
- Over 1000 kw, lose both incentives and have higher departing load charges.
- Limitations at 1000 kw discourage many projects that could have greatest benefit for the state in providing on-site energy.
- Regulations that have size limits (exemptions, etc.) are arbitrary any many discourage some of the most beneficial applications.

3. Financing and Income Taxes

- Customer's responsibility - Usually don't get involved in that.
- Operating Leases – Honeywell will not do. Could add more risk to who holds title to the equipment.

4. Tariffs
- Bills are sometimes hard to interpret. Many adders and deducts. Direct access and other rules unclear on bill. Taxes, etc.
- Unclear how metering handled relative to metering gas for site and cogen, elect and cogen electric.
- Departing Load Charges
    - Power by CHP facility will be charged a rate paid to utility of ~0.5 c/kwh.
    - Tariff information is available and they know where to get it.
    - Limitations at 1000 kw discourage many projects that could have greatest benefit for the state in providing on-site energy.

- Standby Charges
  - SDG&E Option to take or not take TOU vs. TOU CHP
  - Standby based on nameplate of cogen.
  - Can Pay every month, relieves obligation of demand outage.
  - Don't feel it's a strong encourage or discouragement.
- Demand Charges
  - Don't understand why SDG&E Non-coincident demand charges higher – biases against cogen reliability of individual units rather than fleet
  - Demand charges are discouragement to cogen because of outage risk.
  - Reliability risk of individual cogen units, not fleet where risk on many units is low. Tends to push developer to multiple units but works against economies of scale.
- Sometimes get misinformation and confused information from utility sources.
- Sense a major disconnect on perceptions of stakeholders in different camps. Misunderstanding. Utility vs. Developer.
- Gas Tariffs – Don't feel understand what it takes to qualify for lower cogen transportation rate.

Task 3 Hourly Load Profiles and Load Duration Curves used in the Study

This section includes illustrations of the hourly load profiles and load duration curves used in the study. The curves were derived using the EnergyShape Database. Competitive Energy Insight Inc. has licensed the EnergyShape database from Primen, a division of EPRI Solutions, Inc. with limited rights to sub-license the EnergyShape database for use with the EconExpert-IAT model and other EconExpert software tools developed by CEI.

The hourly load profiles (shown annually and for the hospital case monthly) illustrate hourly electric use in kwh over the period of a calendar year. Dips in the curves illustrate drops in load associated with weekend or nighttime uses and with seasonal variations. Note the differences in profiles for facilities that operate on a 7 x 24 basis versus facilities that only operate during normal business hours. Each different building configuration has a different load signature.

The load durations curves provide a different view of the data, showing the number of hours in a year that a particular condition occurs. For example, in the load duration curve below shows that the for the subject hospital in a typical year the hourly electric demand is over 1500 kw about 1500 hours per year and is over 1200 kw about 5300 hours/year.

PG&E Loads are for a facility in the San Francisco Bay Area

Figure 11 – Proxy Annual Electric Load for Hospital Complex in PG&E Service Territory

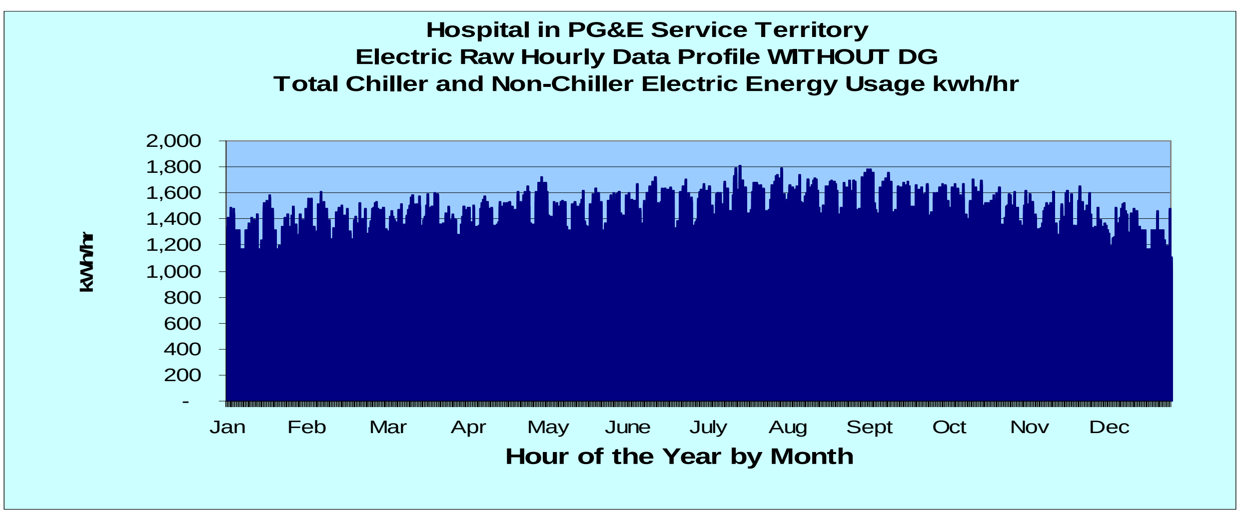


Figure 12 –Proxy Annual Electric Load Duration Curve for Hospital Complex in PG&E Service Territory

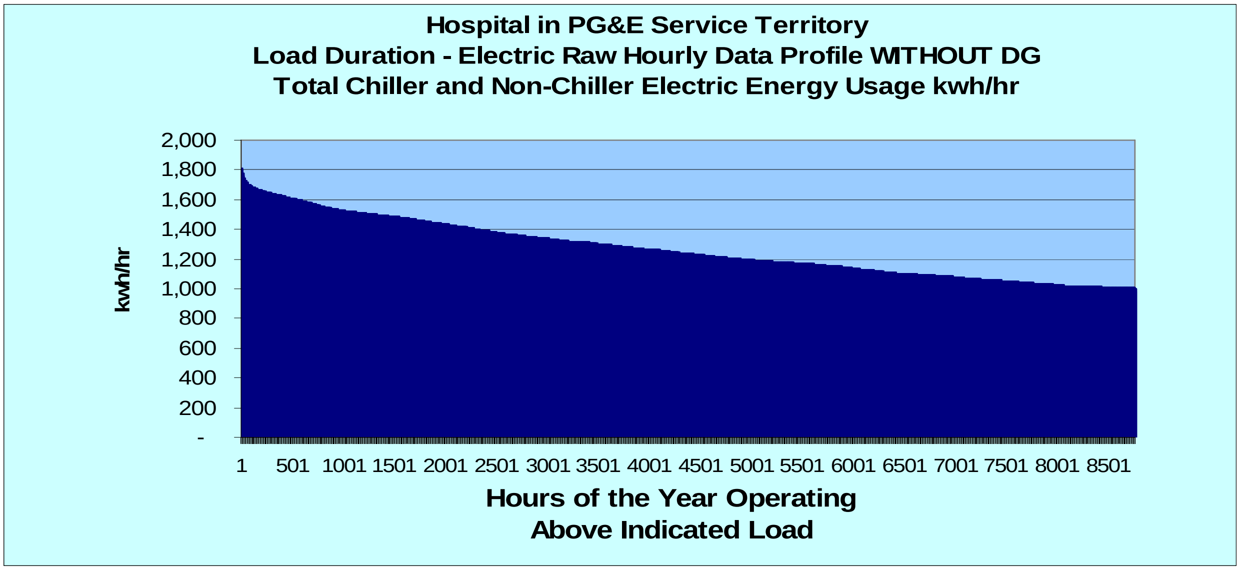


Figure 13 – January Hourly Electric Load Profile for Hospital Complex in PG&E Service Territory

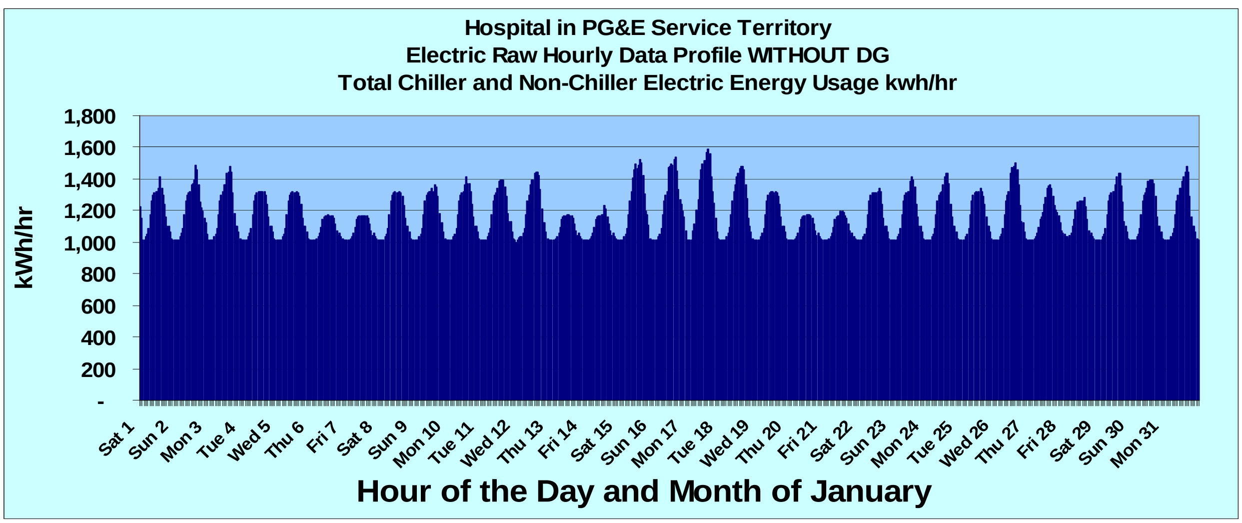


Figure 14 – January Electric Load Duration Curve for Hospital Complex in PG&E Service Territory

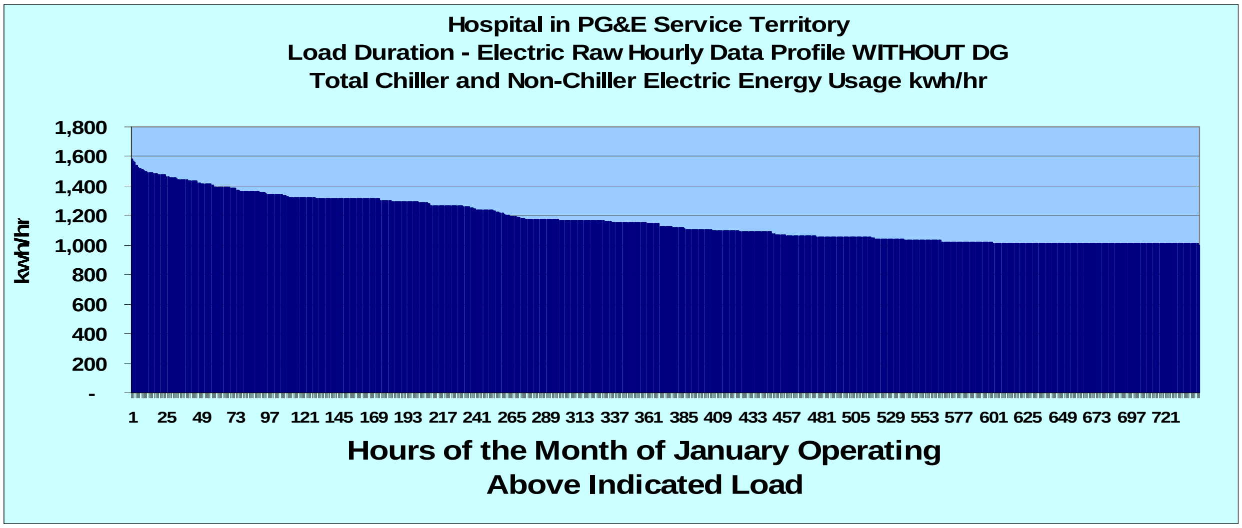


Figure 15 – July Monthly Proxy Annual thermal Load Profile for Hospital Complex in PG&E Service Territory

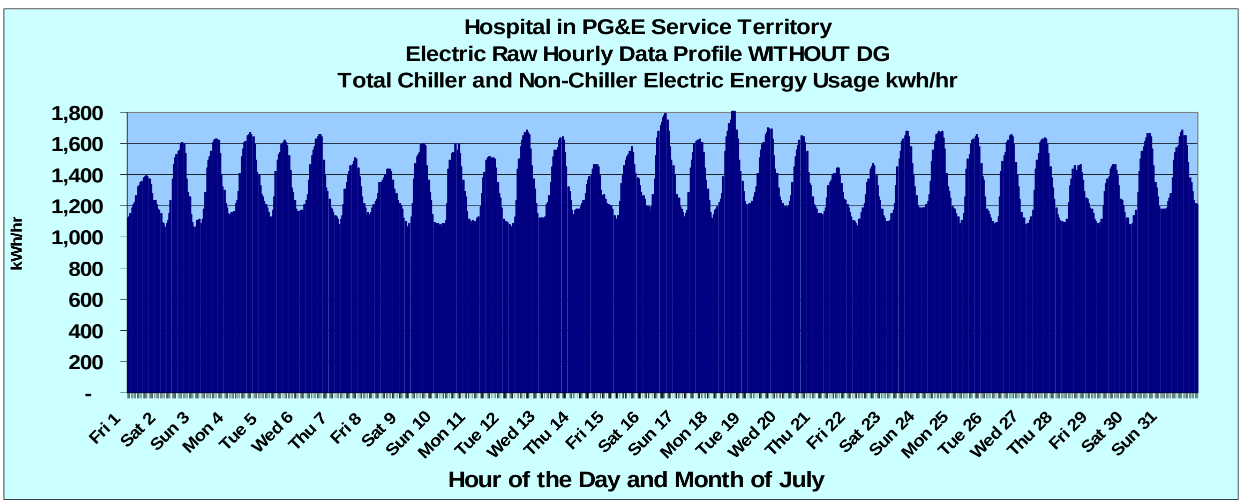


Figure 16 – Proxy Annual thermal Load Profile for Hospital Complex in PG&E Service Territory

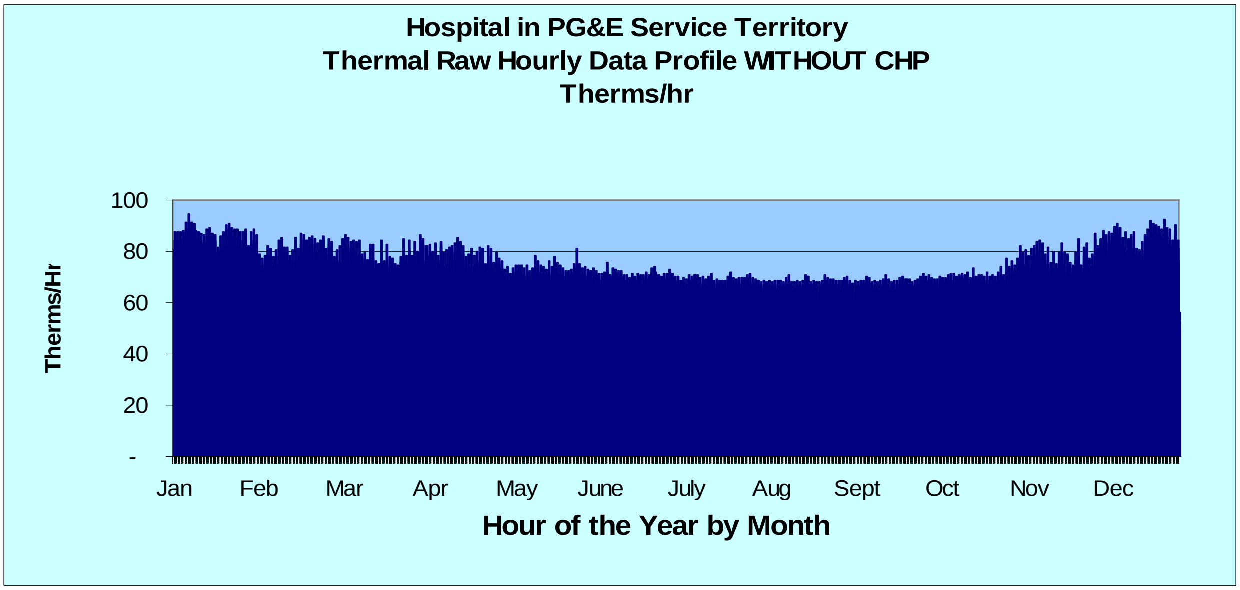


Figure 17 –Proxy Annual thermal Load Duration Curve for Hospital Complex in PG&E Service Territory

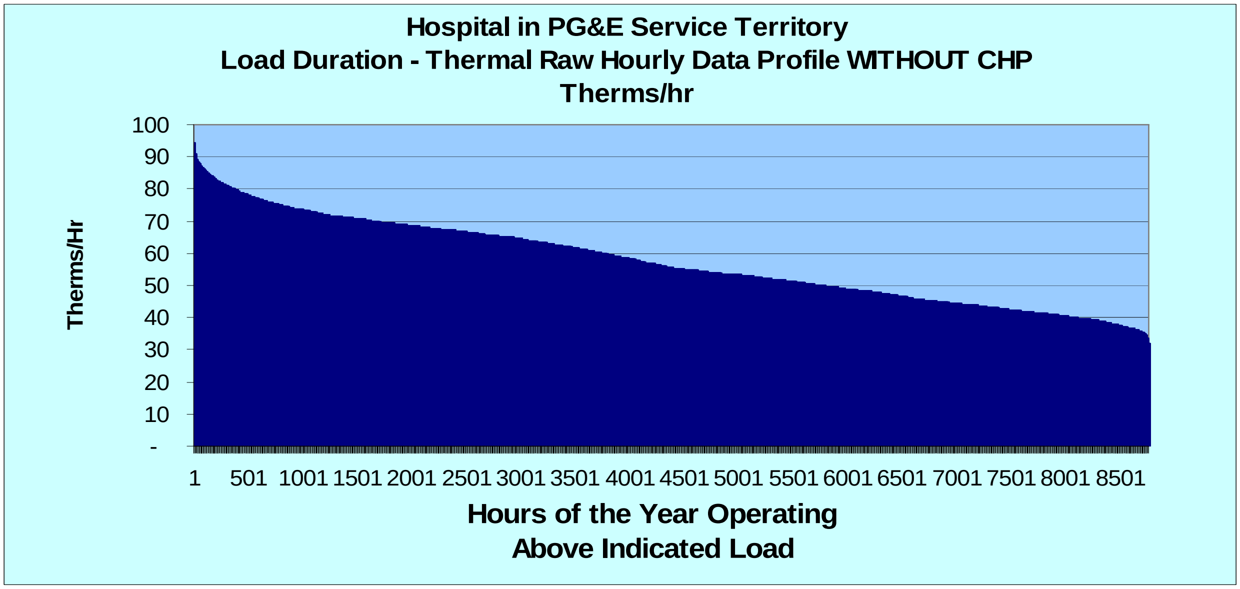


Figure 18 – Proxy Annual Electric Load for College Building in PG&E Service Territory

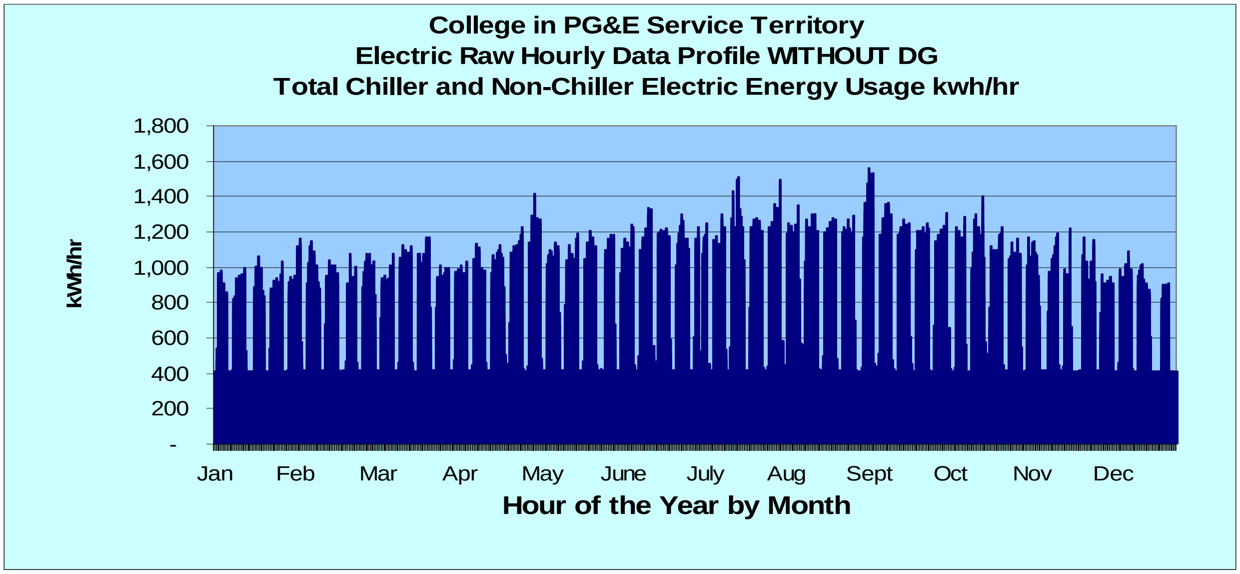


Figure 19 –Proxy Annual Electric Load Duration Curve for College Building in PG&E Service Territory

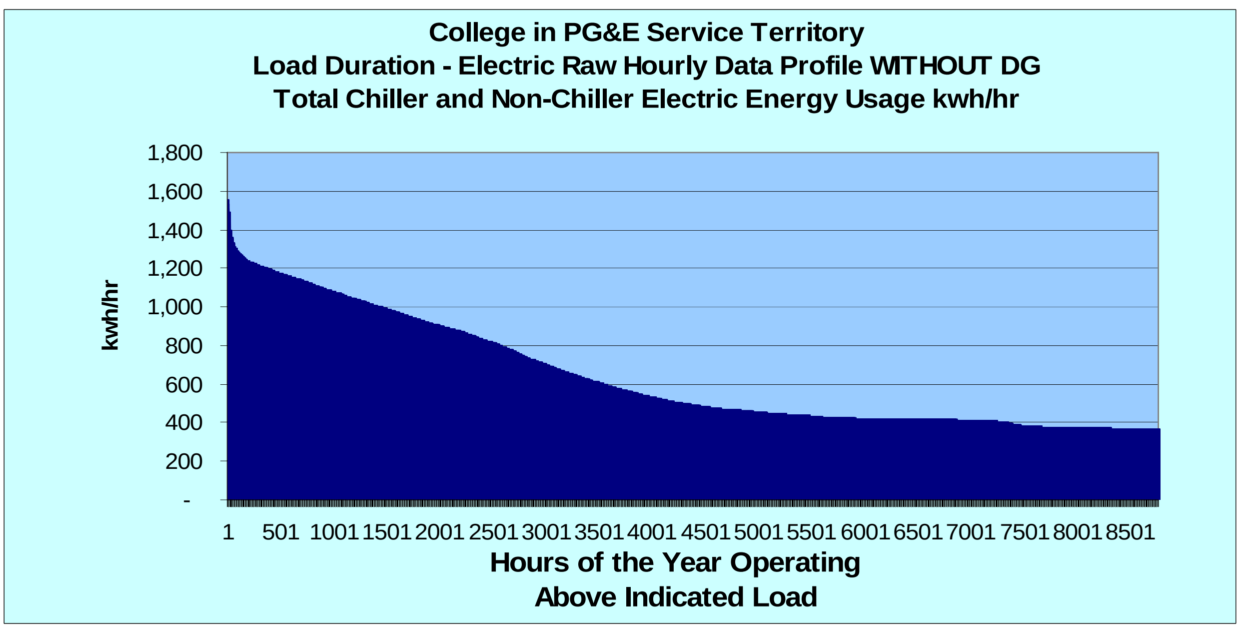


Figure 20 – January Hourly Electric Load Profile for College in PG&E Service Territory

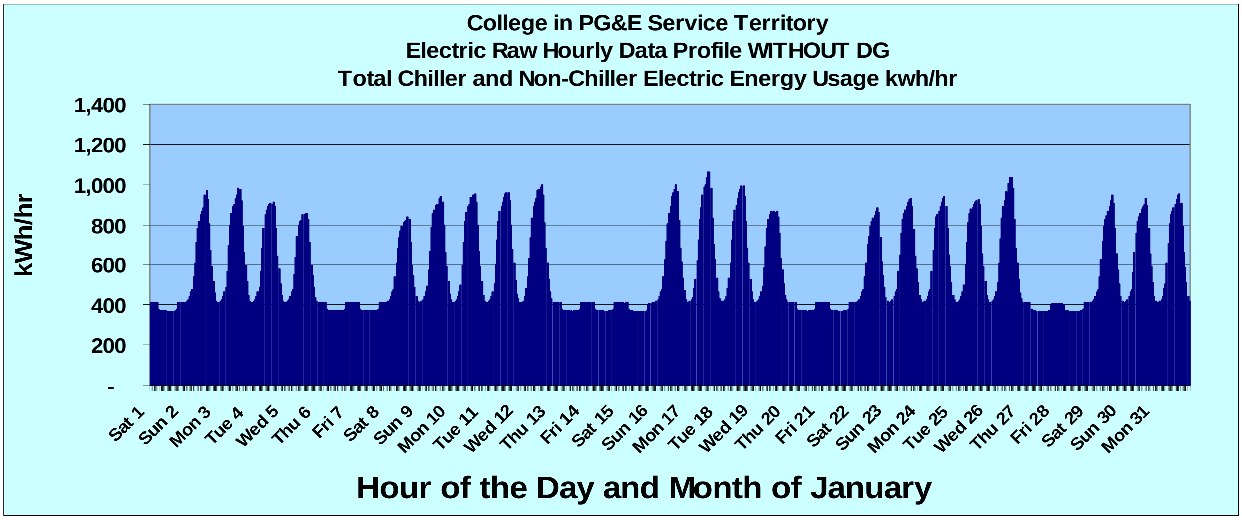


Figure 21 –Proxy July Hourly Electric Load Profile for College in PG&E Service Territory

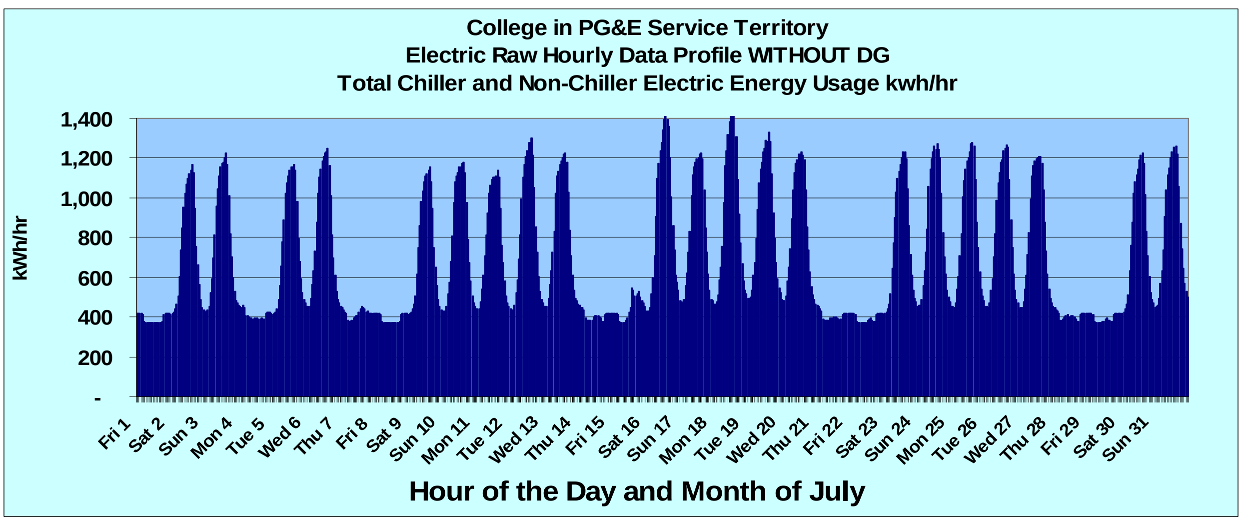


Figure 22 – Proxy Annual thermal Load Profile for College Building in PG&E Service Territory

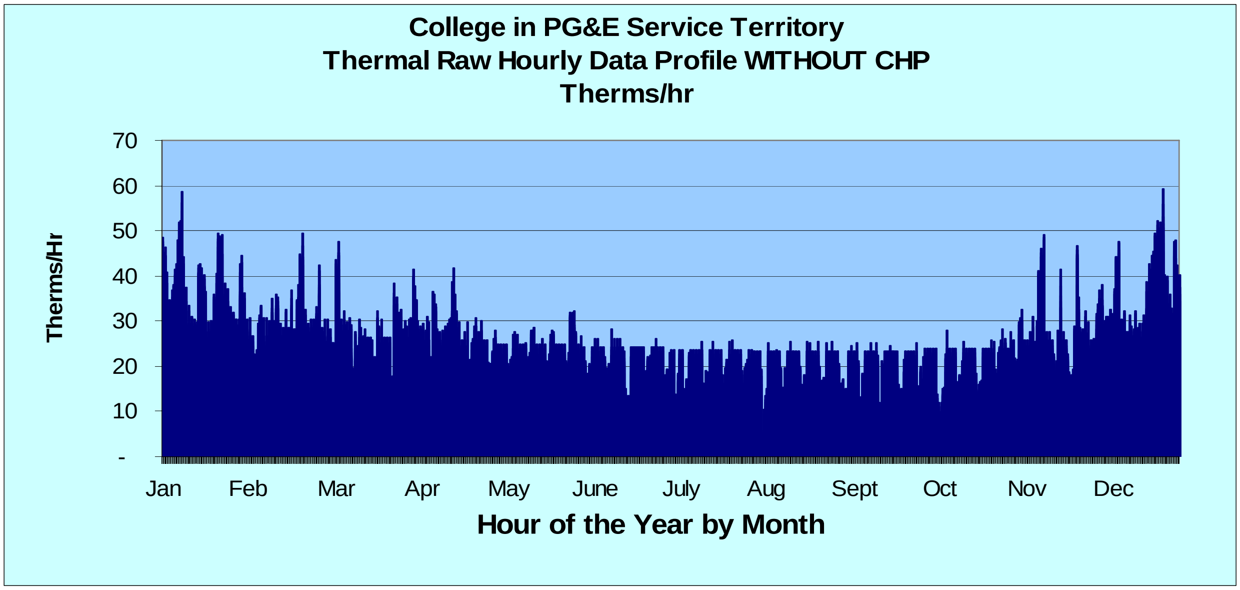


Figure 23 –Proxy Annual thermal Load Duration Curve for College Building in PG&E Service Territory

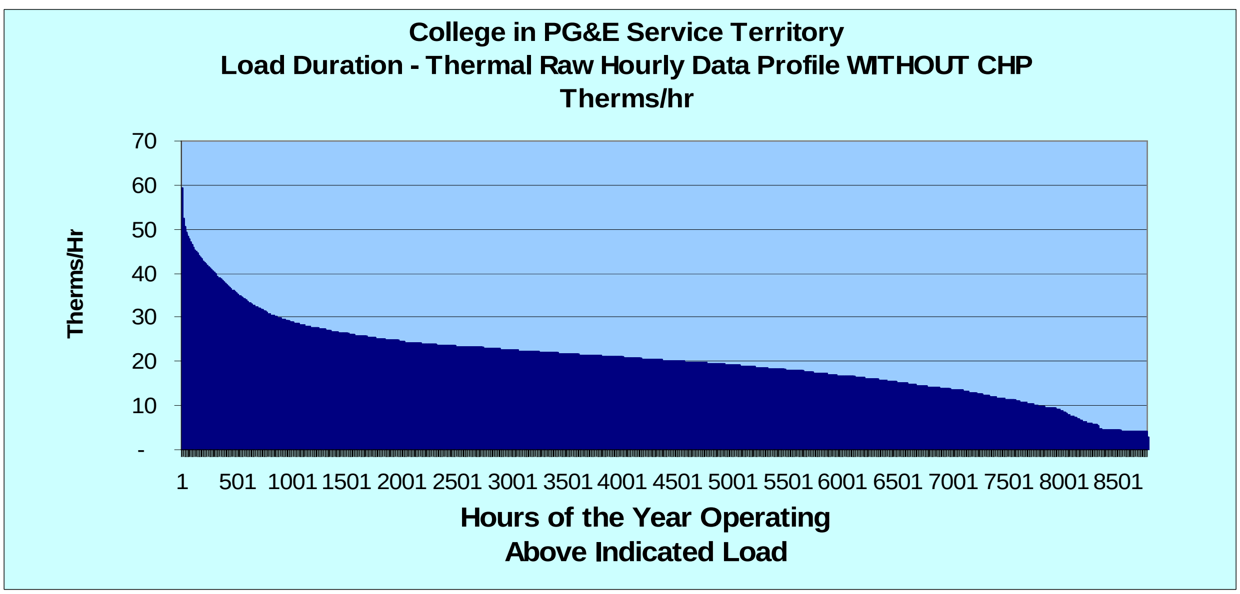


Figure 24 – Proxy Annual Electric Load for Hotel in PG&E Service Territory

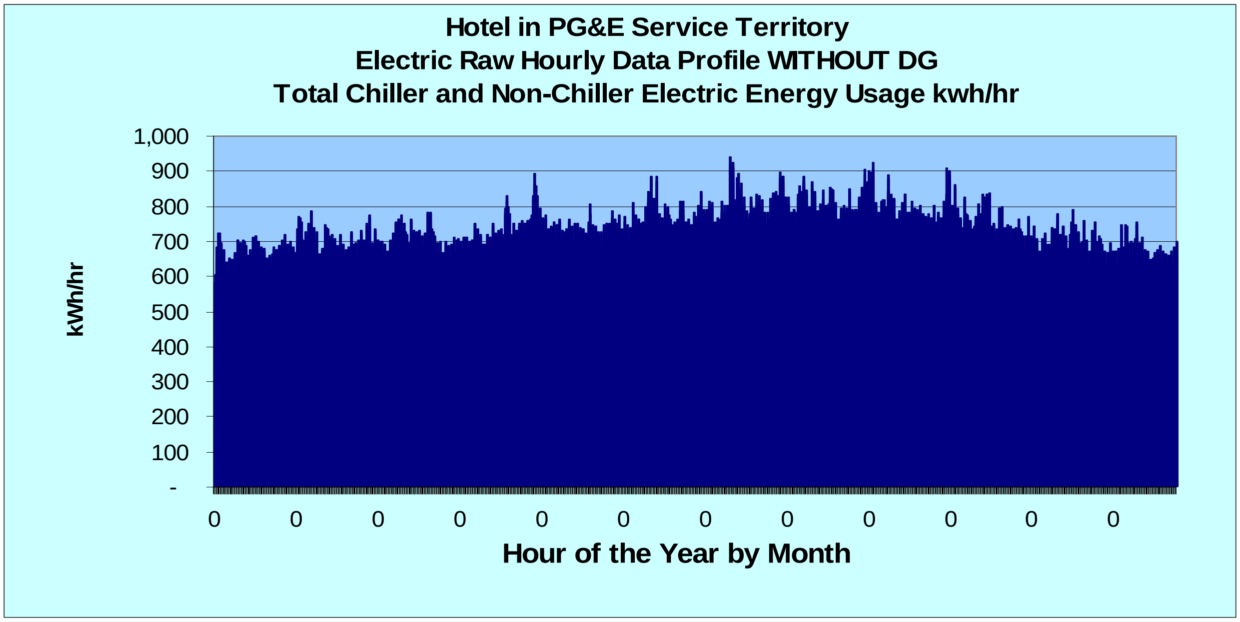


Figure 25 –Proxy Annual Electric Load Duration Curve for Hotel in PG&E Service Territory

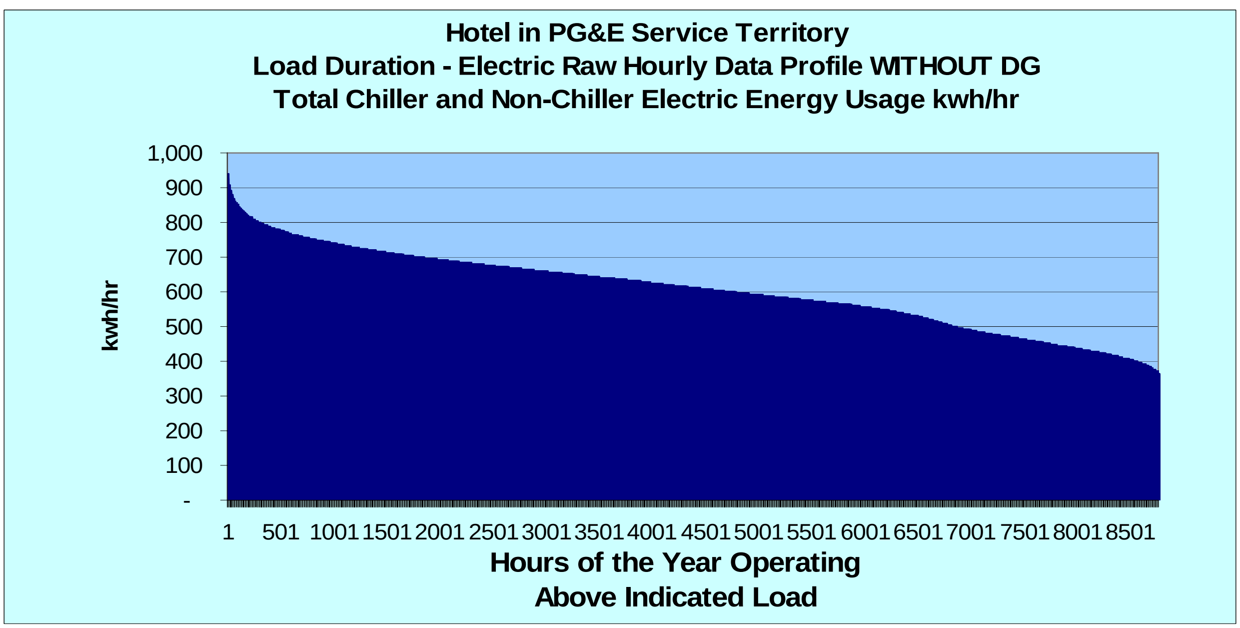


Figure 26 – January Hourly Electric Load Profile for Hotel in PG&E Service Territory

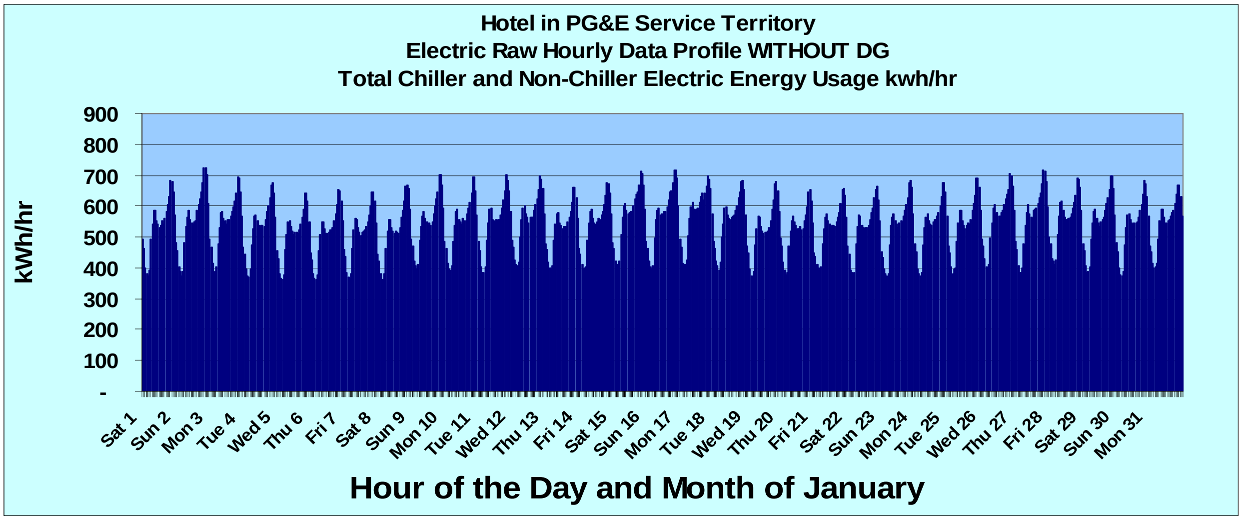


Figure 27 –Proxy July Hourly Electric Load Profile for Hotel in PG&E Service Territory

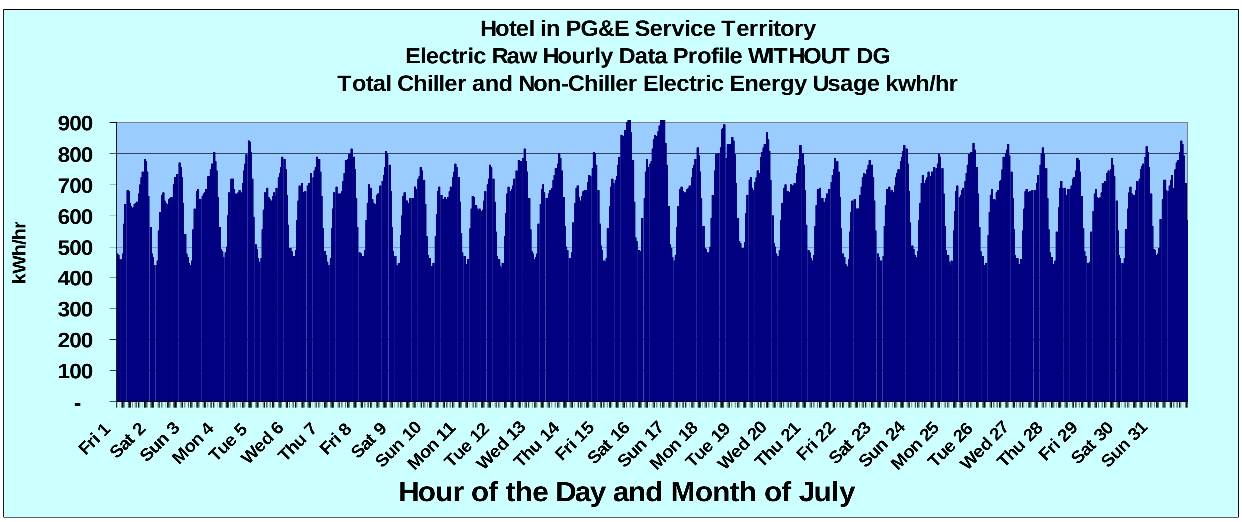


Figure 28 – Proxy Annual thermal Load Profile for Hotel in PG&E Service Territory

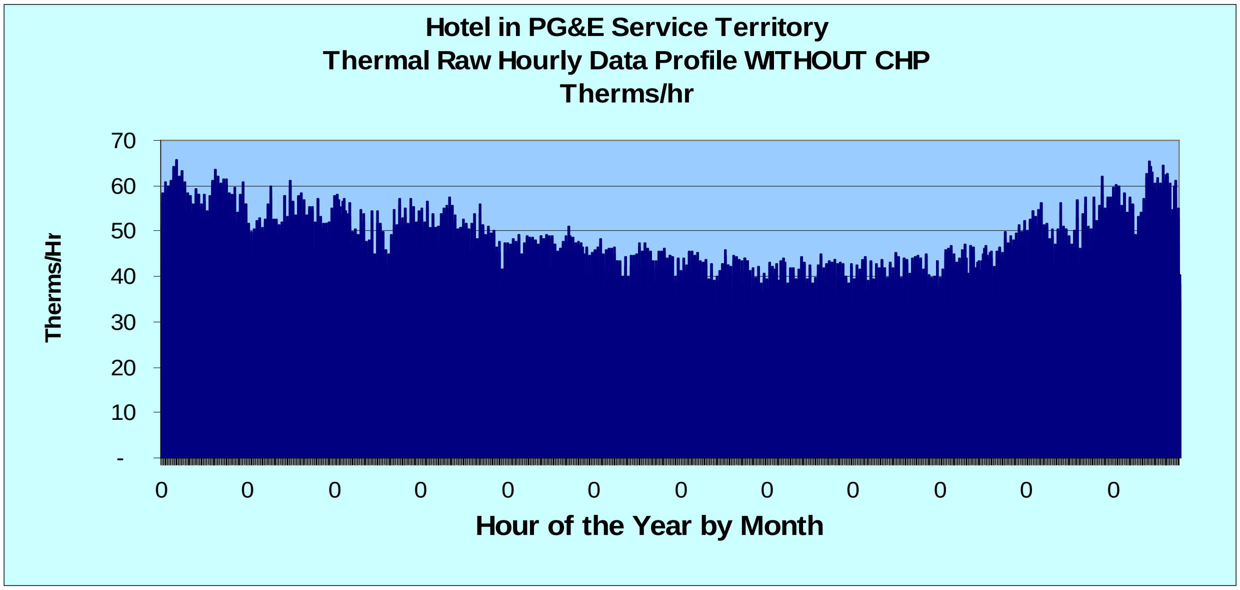
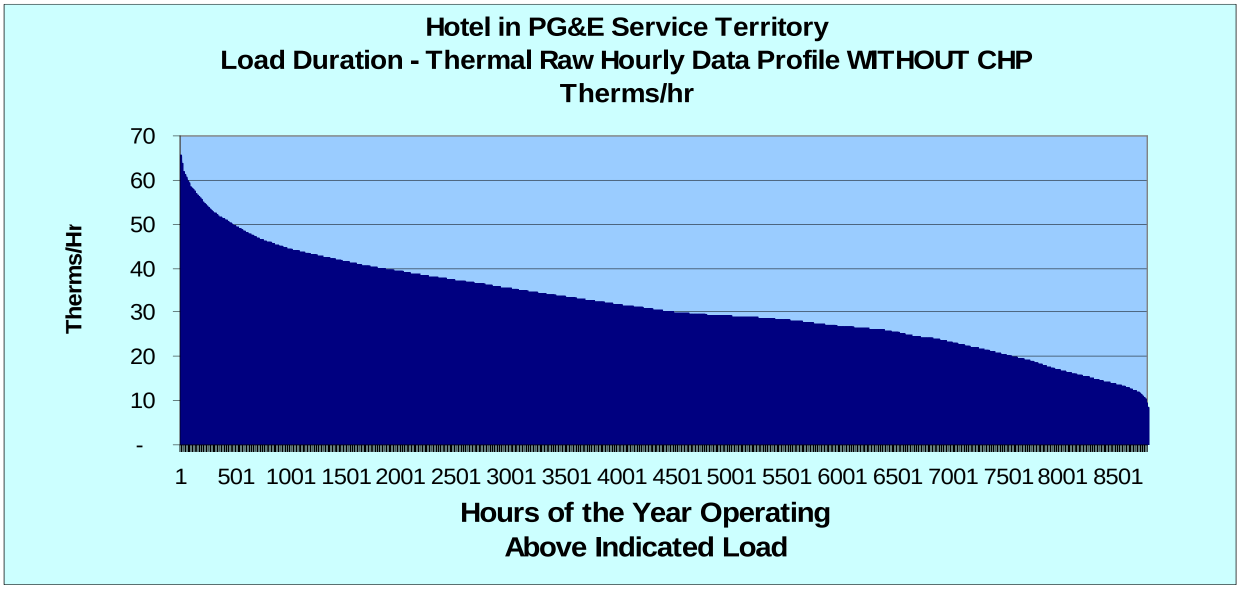


Figure 29 –Proxy Annual thermal Load Duration Curve for Hotel in PG&E Service Territory



SCE Loads are for a facility in the San Bernardino Area

Figure 30 – Proxy Annual Electric Load for Hospital Complex in SCE Service Territory

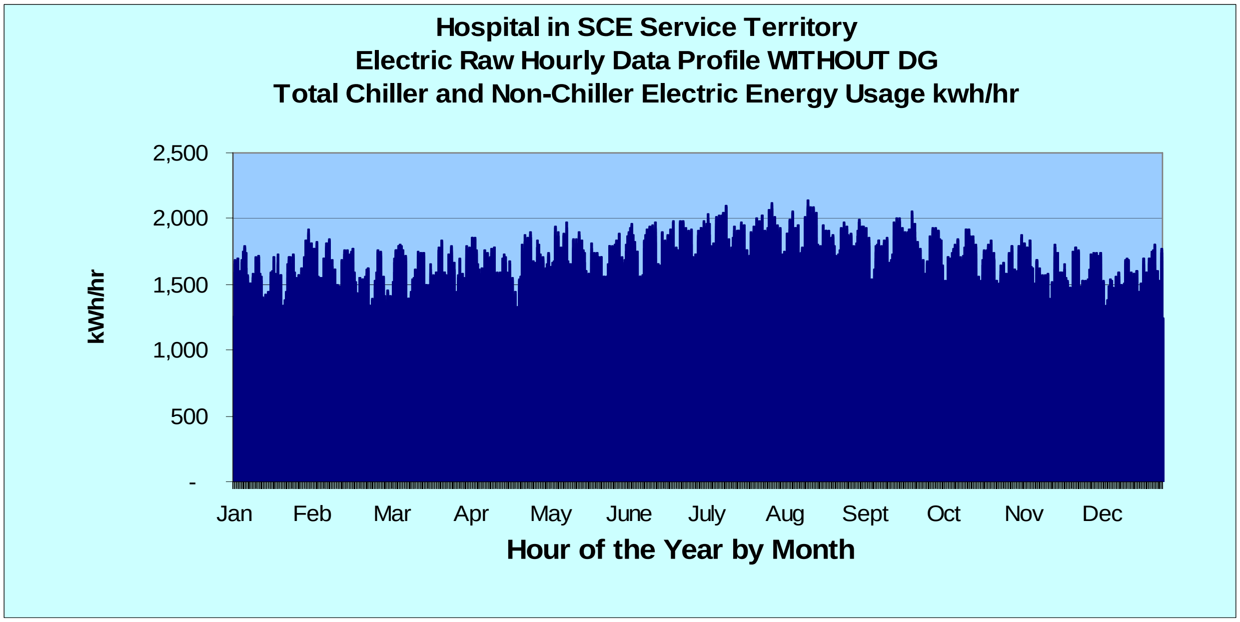


Figure 31 –Proxy Annual Electric Load Duration Curve for Hospital Complex in SCE Service Territory

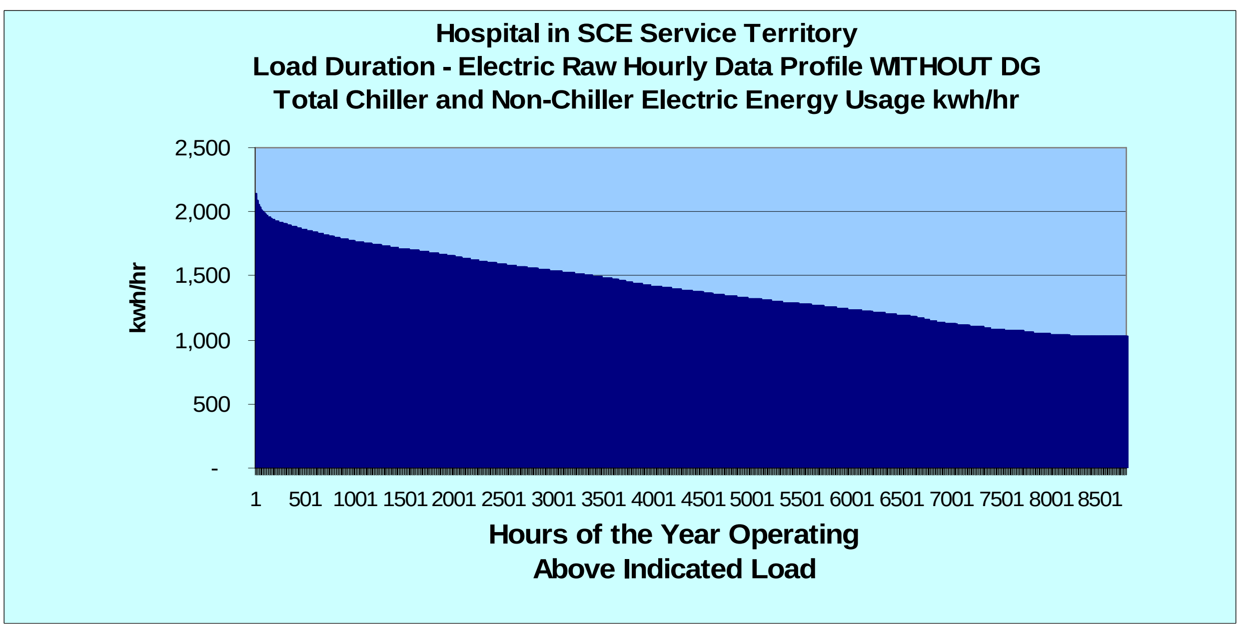


Figure 32 – January Hourly Electric Load Profile for Hospital Complex in SCE Service Territory

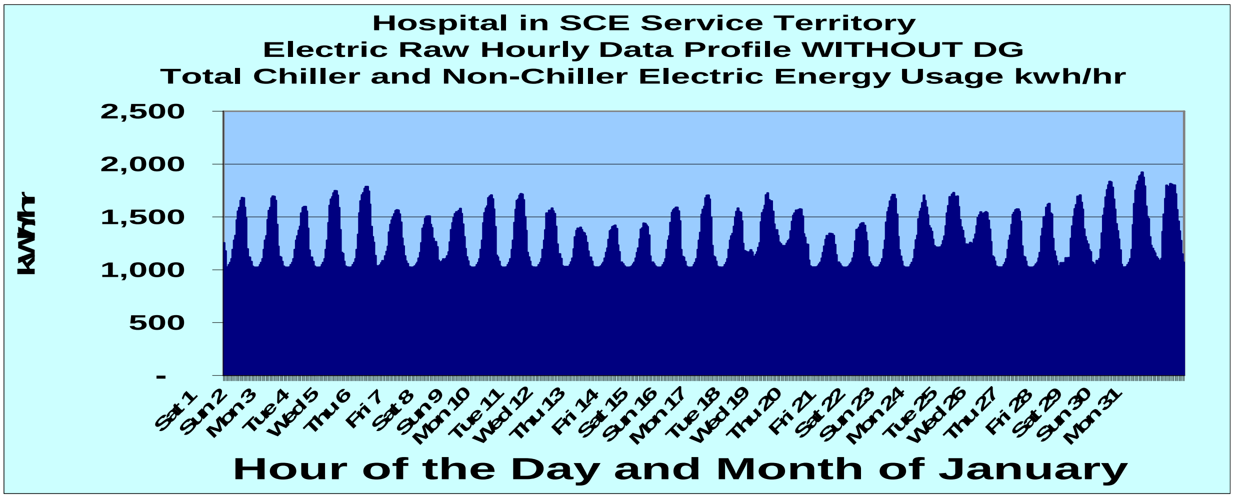


Figure 33 – January Electric Load Duration Curve for Hospital Complex in SCE Service Territory

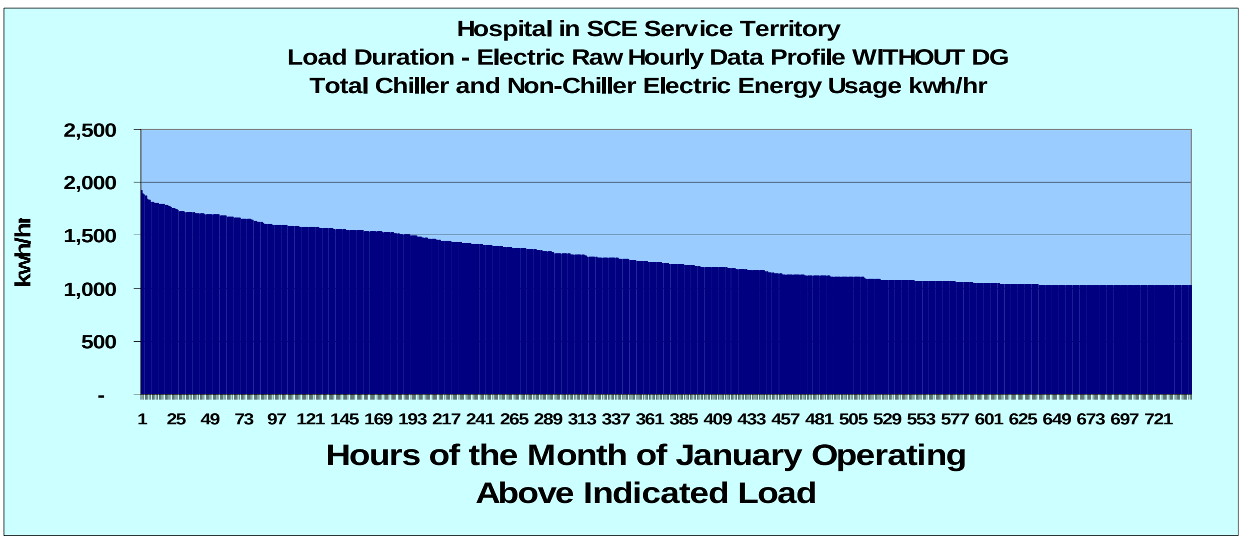


Figure 34 – July Monthly Proxy Annual thermal Load Profile for Hospital Complex in SCE Service Territory

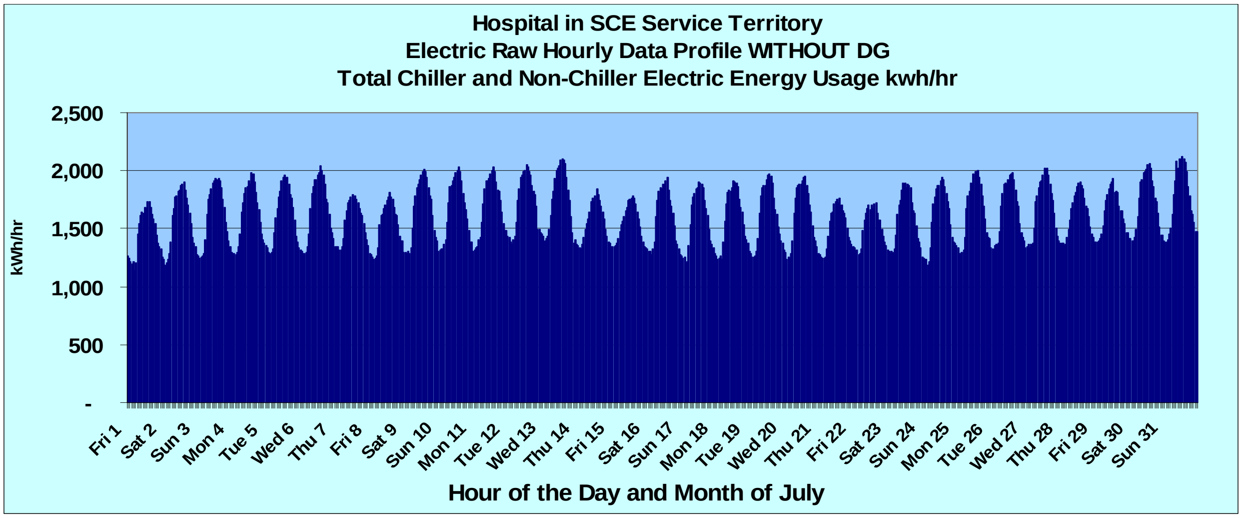

Hospital in SCE Service Territory
Electric Raw Hourly Data Profile WITHOUT DG
Total Chiller and Non-Chiller Electric Energy Usage kwh/hr
kWh/hr
2,500
2,000
1,500
1,000
500
-
Fri 1
Sat 2
Sun 3
Mon 4
Tue 5
Wed 6
Thu 7
Fri 8
Sat 9
Sun 10
Mon 11
Tue 12
Wed 13
Thu 14
Fri 15
Sat 16
Sun 17
Mon 18
Tue 19
Wed 20
Thu 21
Fri 22
Sat 23
Sun 24
Mon 25
Tue 26
Wed 27
Thu 28
Fri 29
Sat 30
Sun 31
Hour of the Day and Month of July

Figure 35 – Proxy Annual thermal Load Profile for Hospital Complex in SCE Service Territory

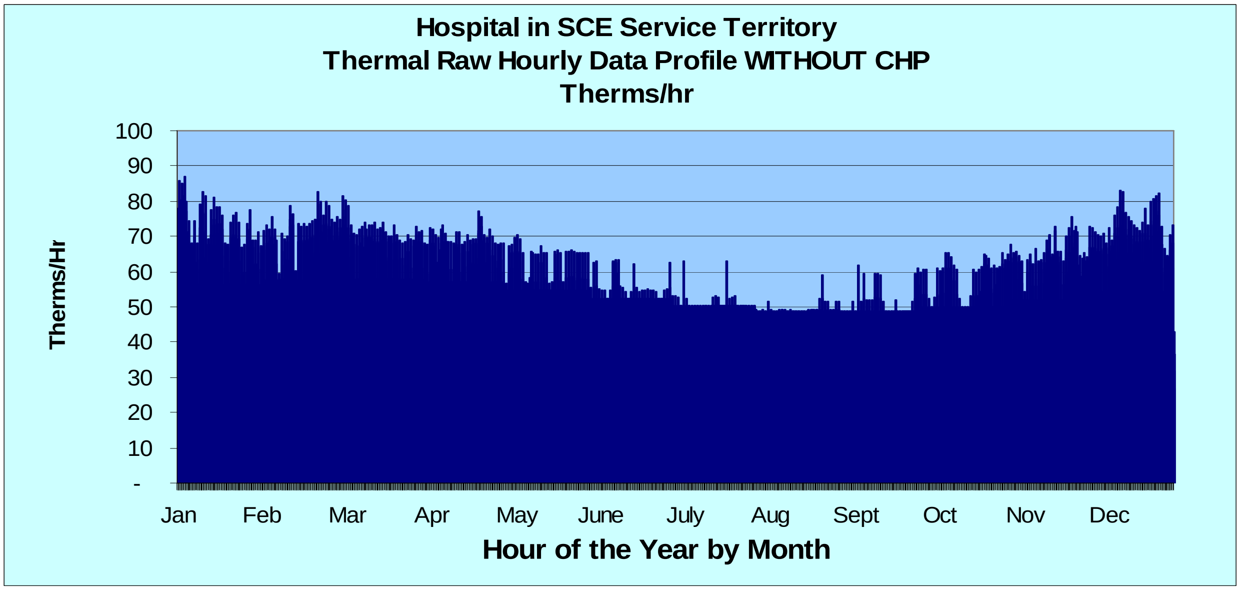


Figure 36 –Proxy Annual thermal Load Duration Curve for Hospital Complex in SCE Service Territory

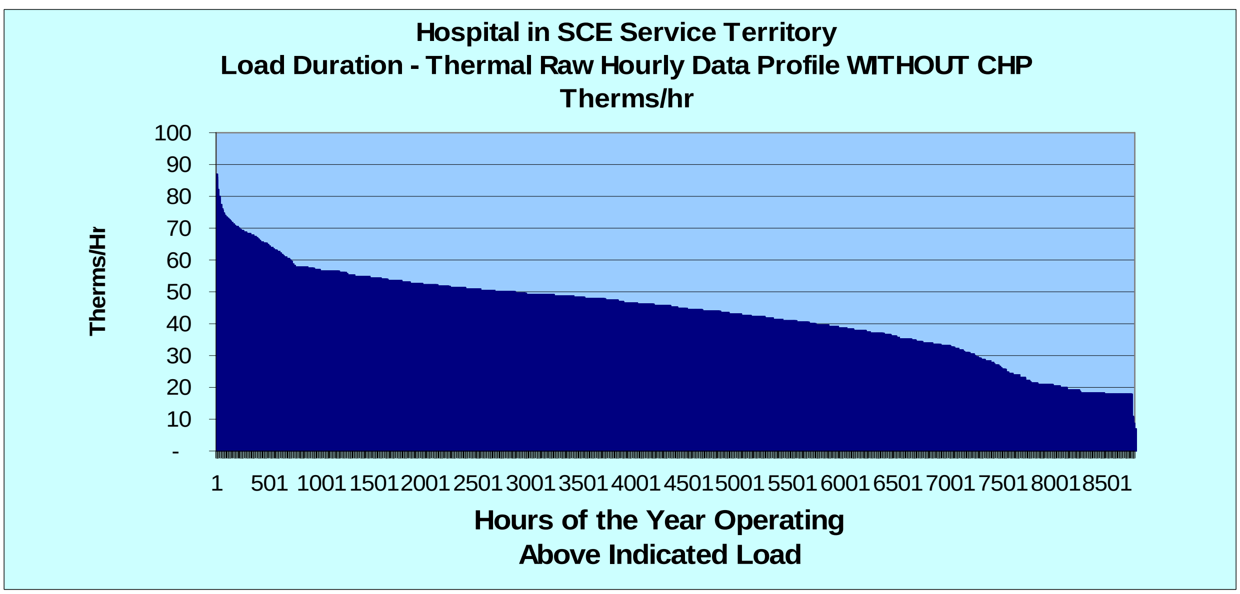


Figure 37 – Proxy Annual Electric Load for College Building in SCE Service Territory

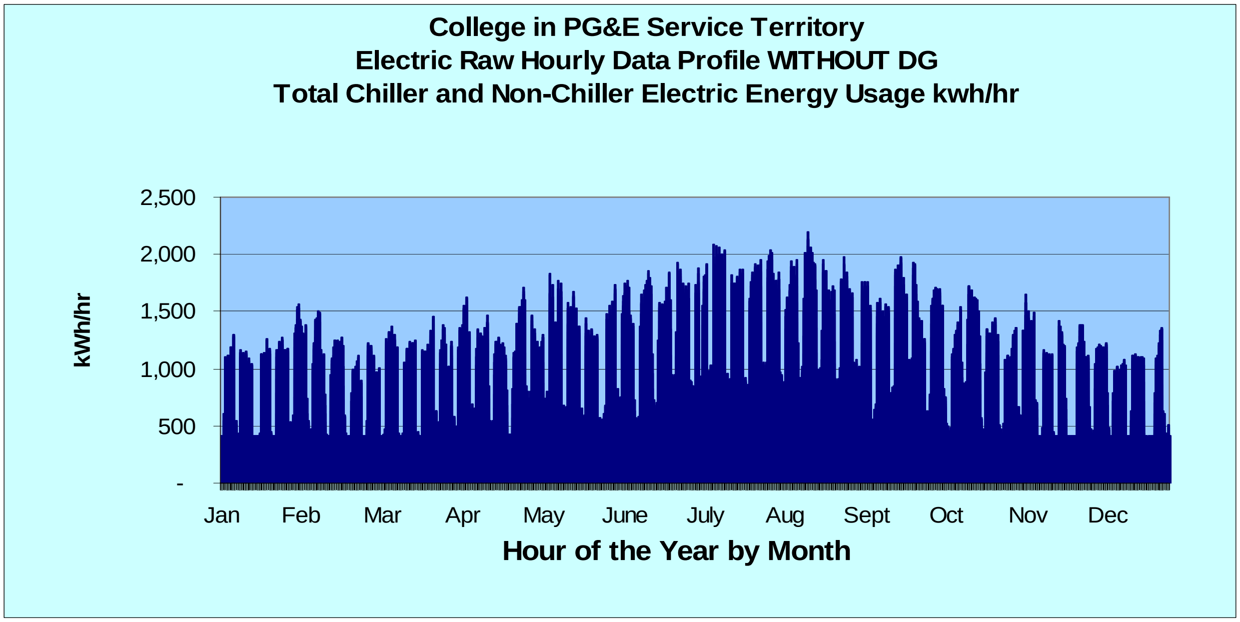


Figure 38 –Proxy Annual Electric Load Duration Curve for College Building in SCE Service Territory

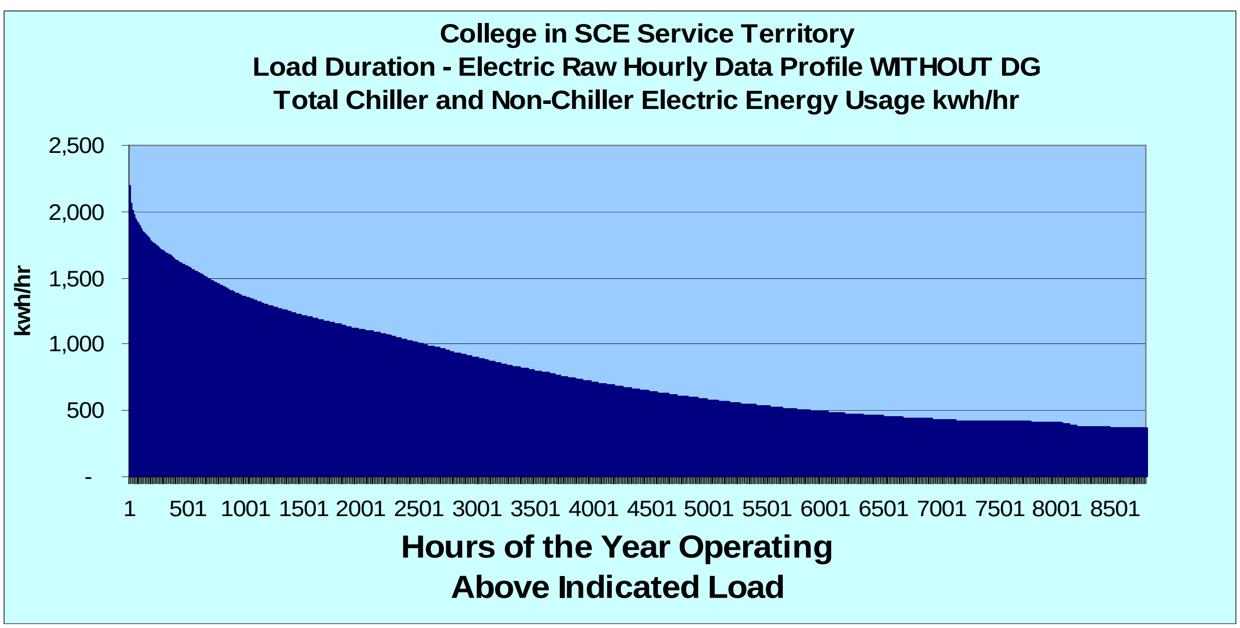


Figure 39 – Proxy Annual thermal Load Profile for College Building in SCE Service Territory

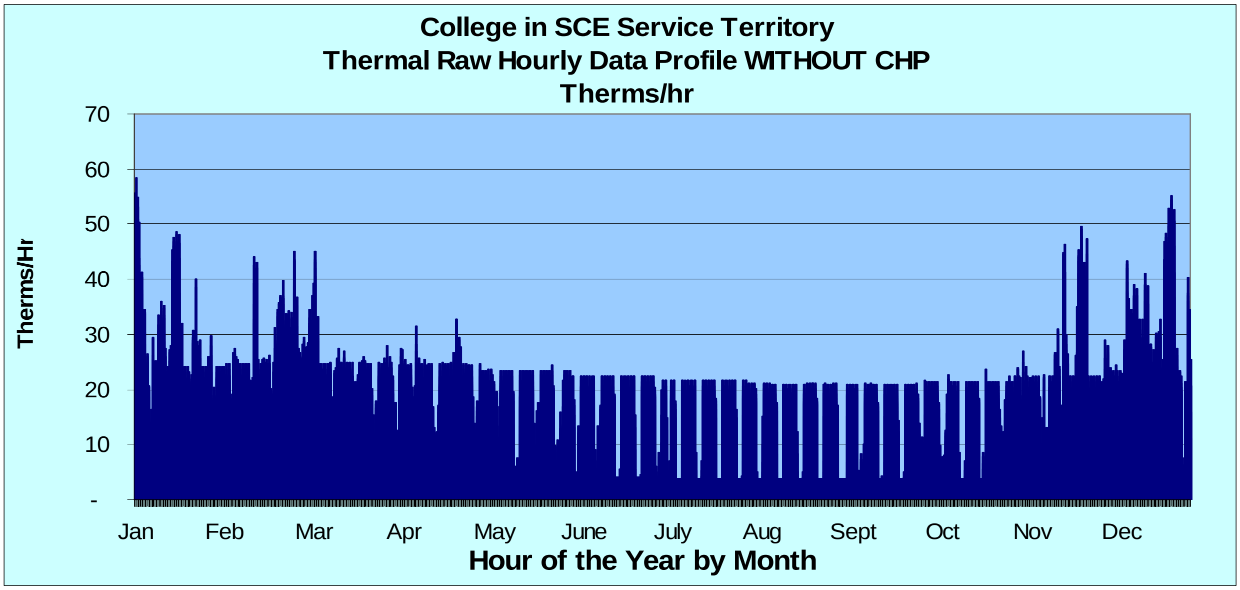


Figure 40 –Proxy Annual thermal Load Duration Curve for College Building in SCE Service Territory

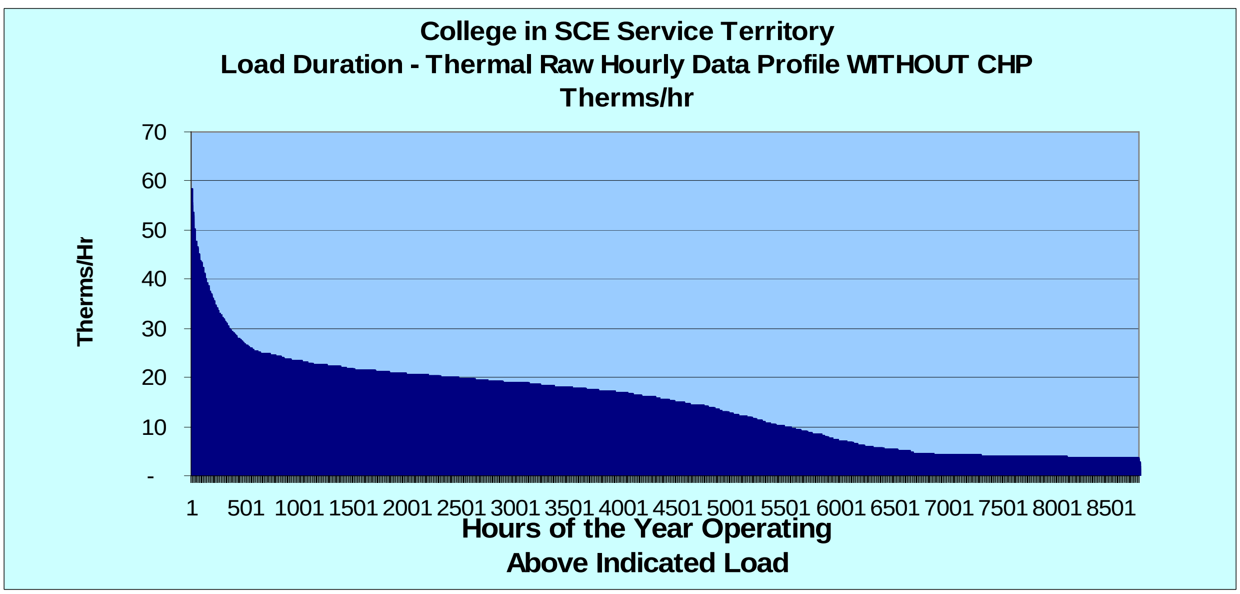


Figure 41 – Proxy Annual Electric Load for Hotel in SCE Service Territory

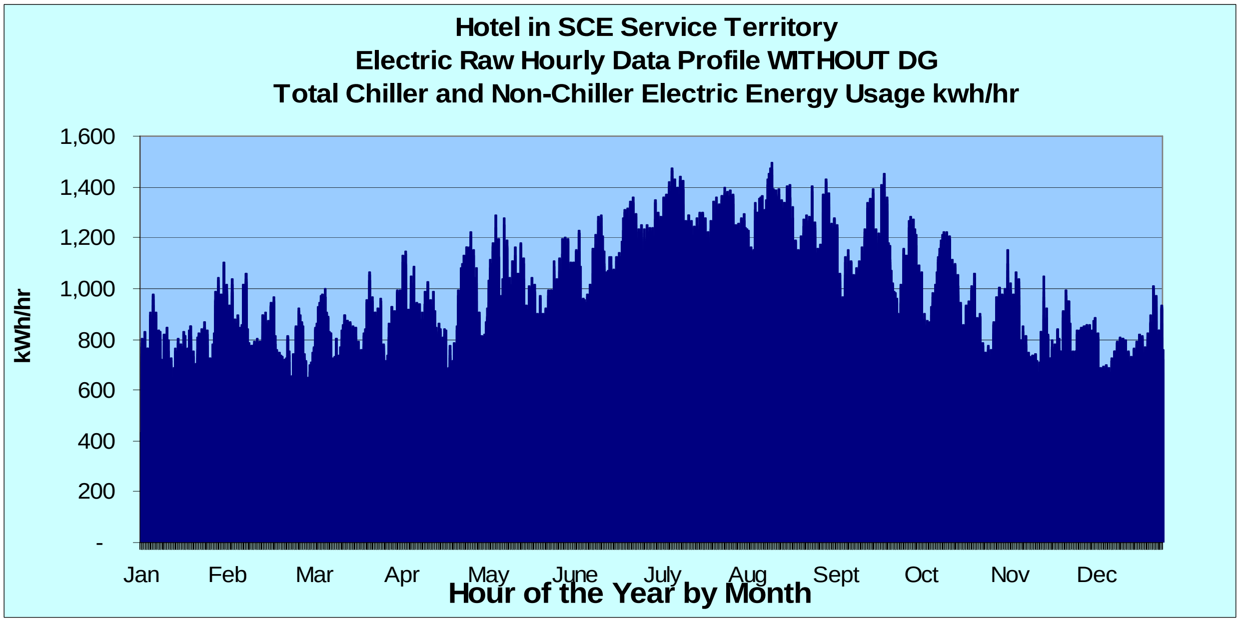


Figure 42 –Proxy Annual Electric Load Duration Curve for Hotel in SCE Service Territory

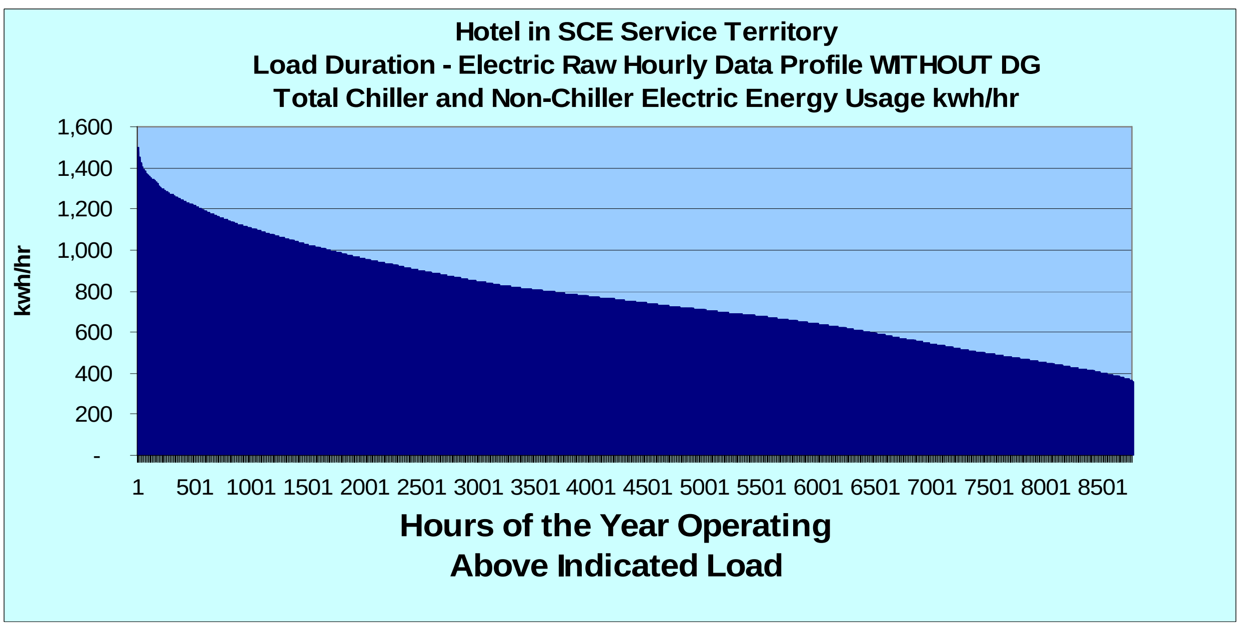


Figure 43 – Proxy Annual thermal Load Profile for Hotel in SCE Service Territory

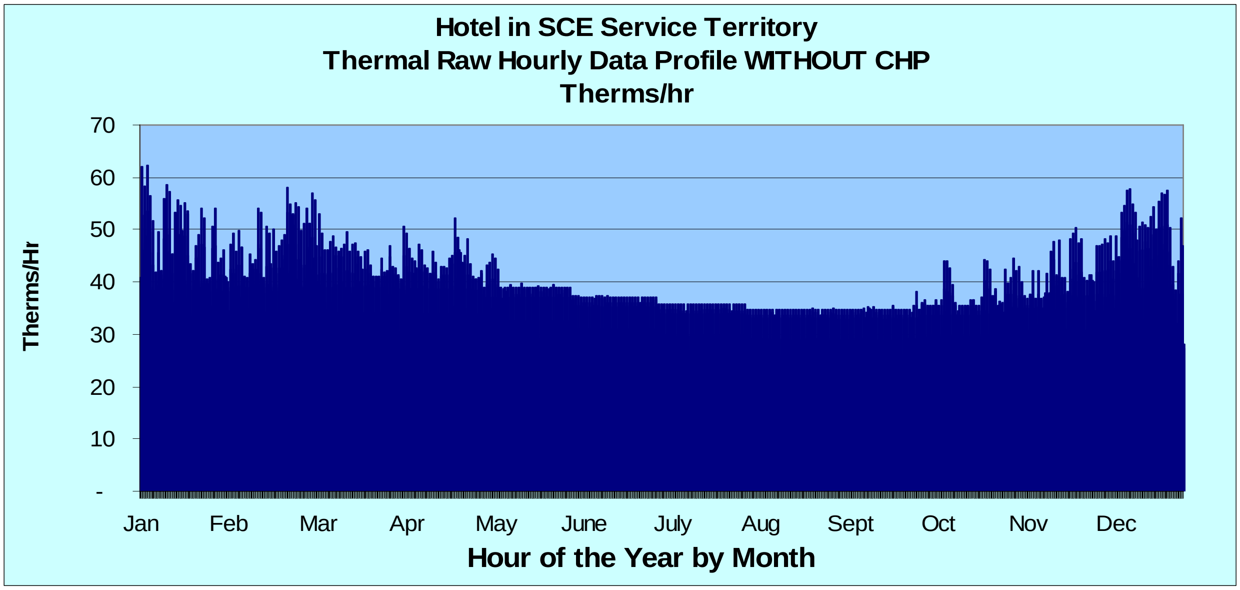
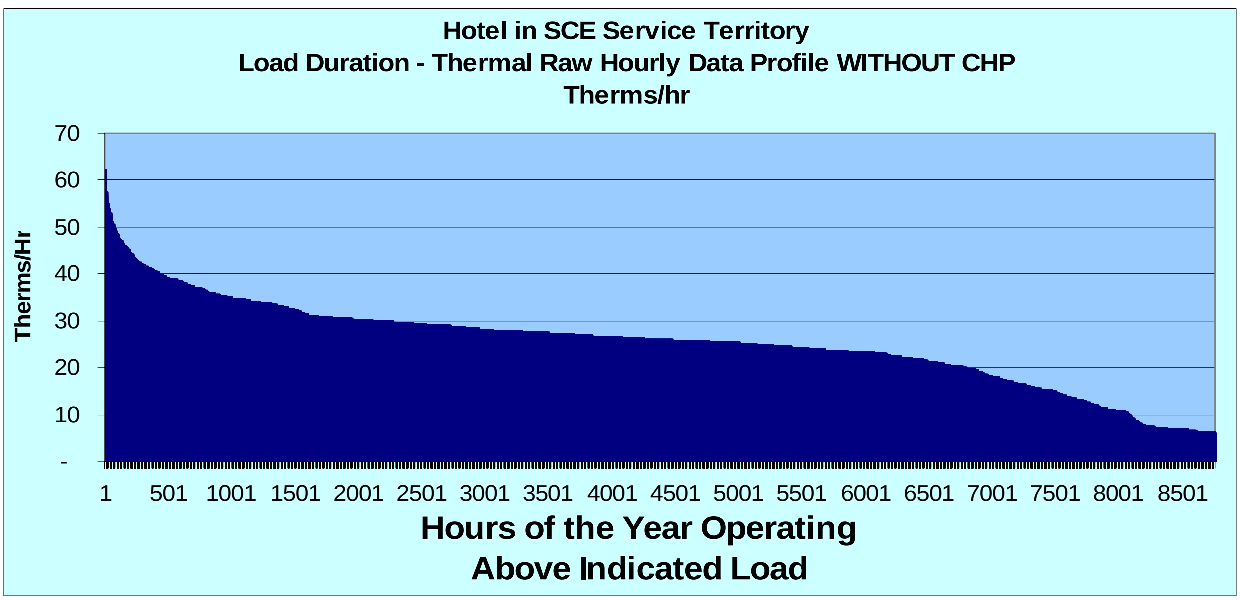


Figure 44 –Proxy Annual thermal Load Duration Curve for Hotel in SCE Service Territory



SDG&E Loads are for a facility in the San Diego Coastal Area.

Figure 45 – Proxy Annual Electric Load for Hospital Complex in SDG&E Service Territory

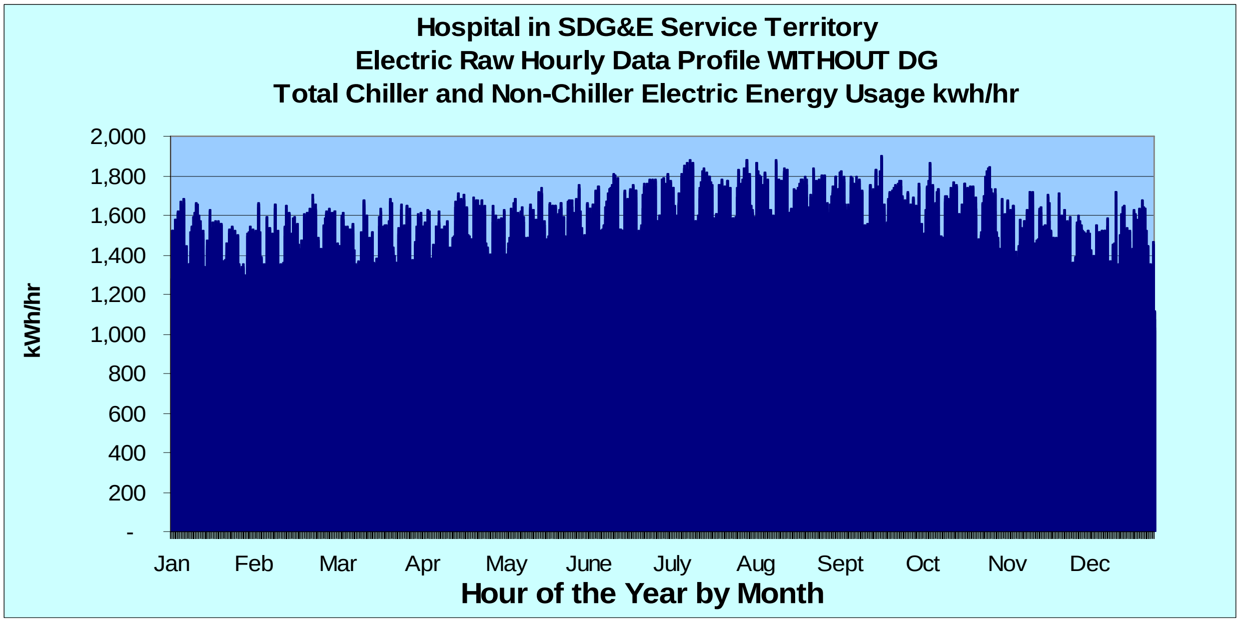


Figure 46 –Proxy Annual Electric Load Duration Curve for Hospital Complex in SDG&E Service Territory

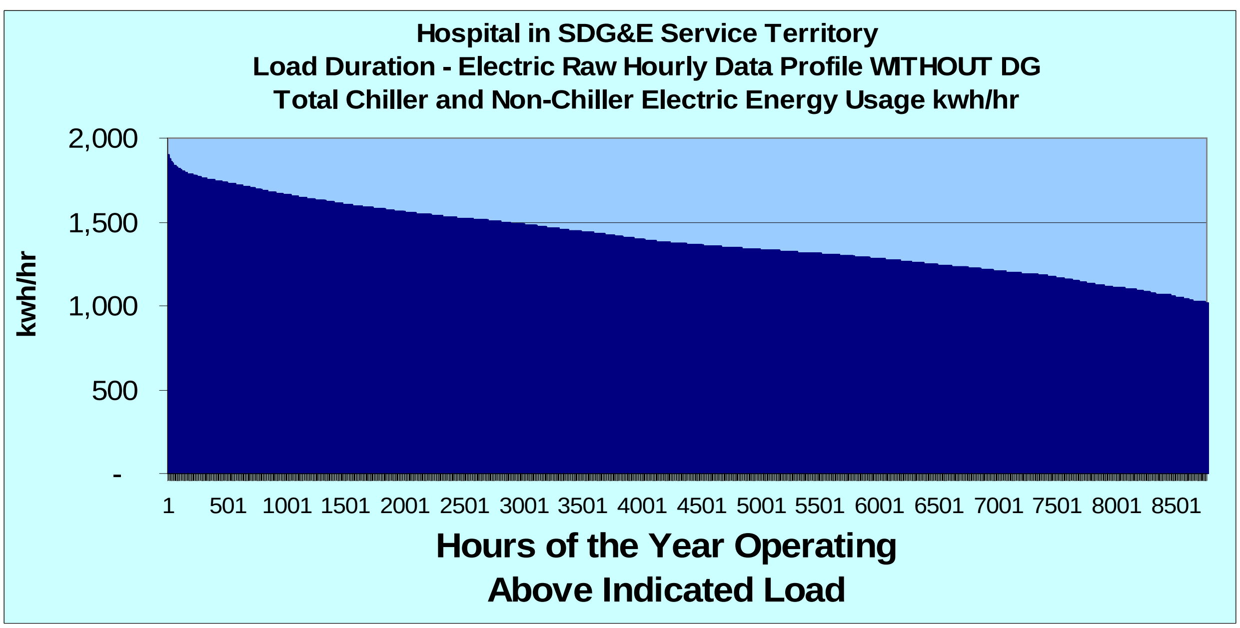


Figure 47 – January Hourly Electric Load Profile for Hospital Complex in SDG&E Service Territory

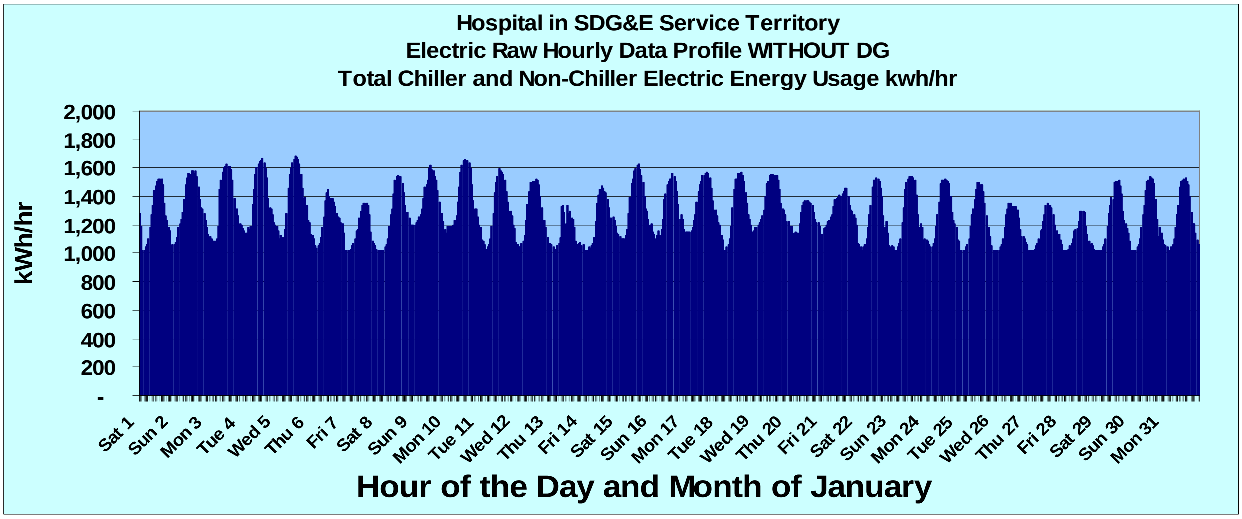


Figure 48 – January Electric Load Duration Curve for Hospital Complex in SDG&E Service Territory

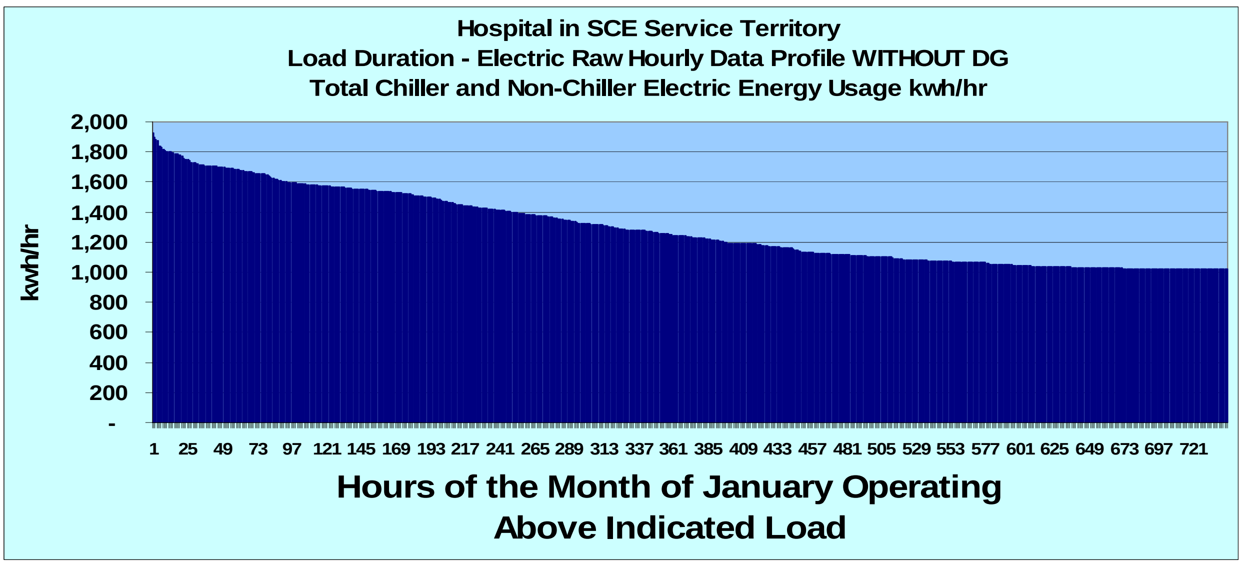


Figure 49 – July Monthly Proxy Annual thermal Load Profile for Hospital Complex in SDG&E Service Territory

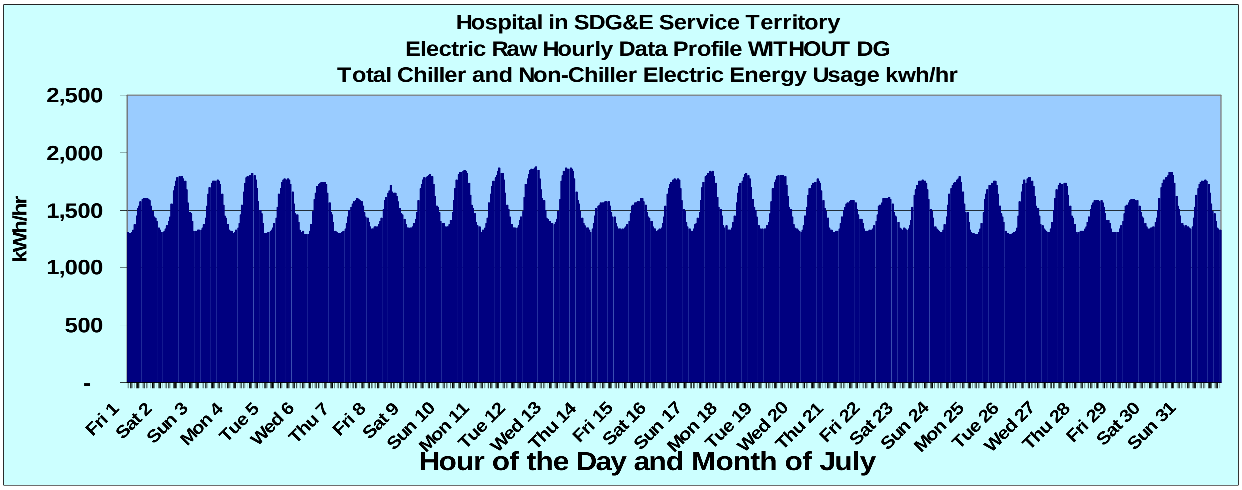

Hospital in SDG&E Service Territory
Electric Raw Hourly Data Profile WITHOUT DG
Total Chiller and Non-Chiller Electric Energy Usage kwh/hr
kWh/hr
2,500
2,000
1,500
1,000
500
-
Fri 1
Sat 2
Sun 3
Mon 4
Tue 5
Wed 6
Thu 7
Fri 8
Sat 9
Sun 10
Mon 11
Tue 12
Wed 13
Thu 14
Fri 15
Sat 16
Sun 17
Mon 18
Tue 19
Wed 20
Thu 21
Fri 22
Sat 23
Sun 24
Mon 25
Tue 26
Wed 27
Thu 28
Fri 29
Sat 30
Sun 31
Hour of the Day and Month of July

Figure 50 – Proxy Annual thermal Load Profile for Hospital Complex in SDG&E Service Territory

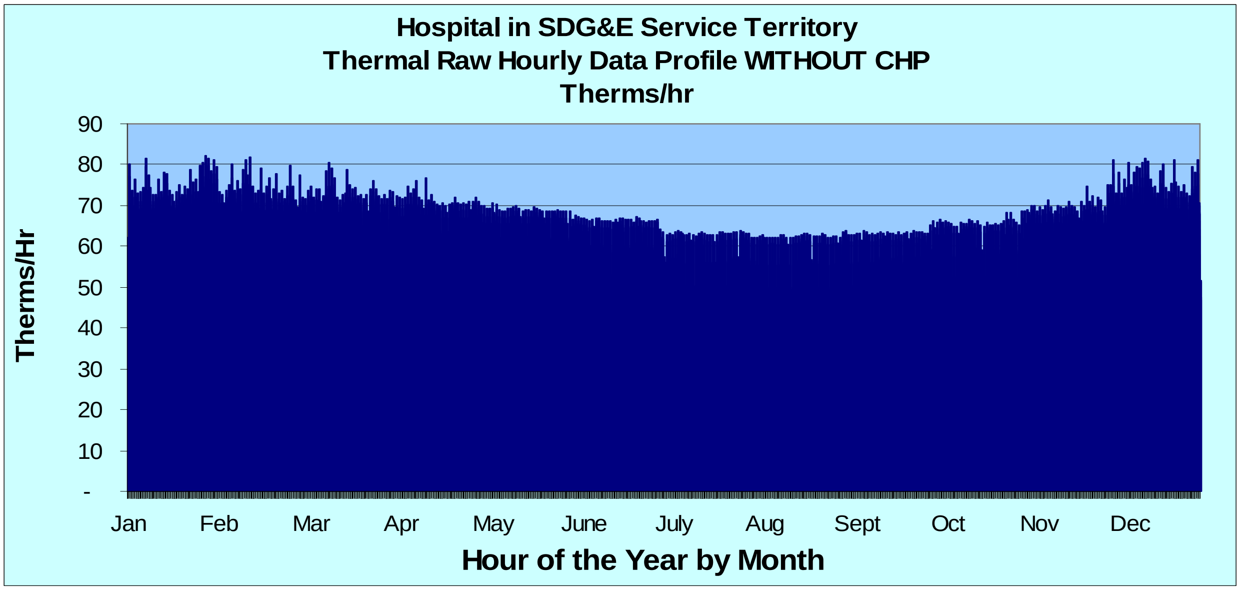


Figure 51 –Proxy Annual thermal Load Duration Curve for Hospital Complex in SDG&E Service Territory

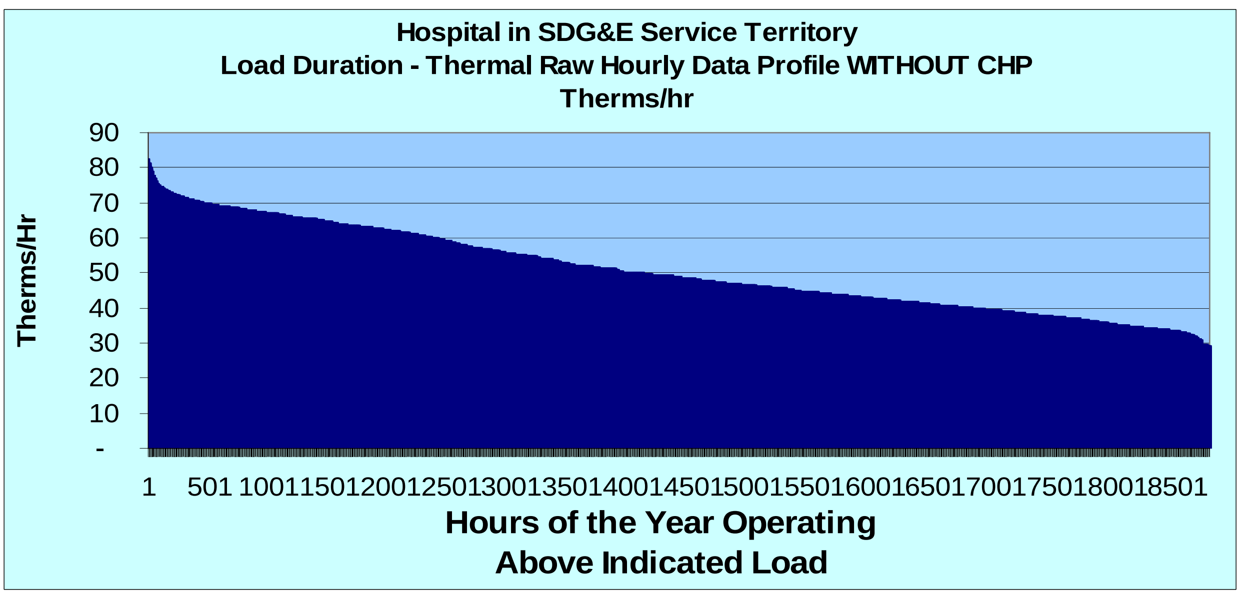


Figure 52 – Proxy Annual Electric Load for College Building in SDG&E Service Territory

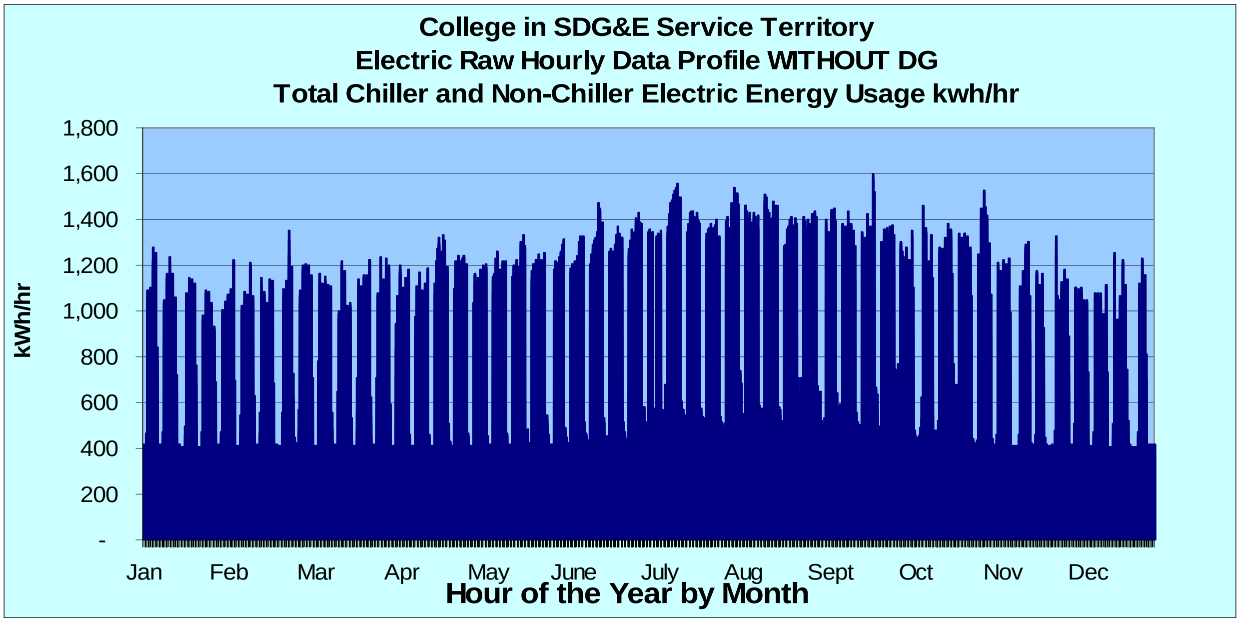


Figure 53 –Proxy Annual Electric Load Duration Curve for College Building in SDG&E Service Territory

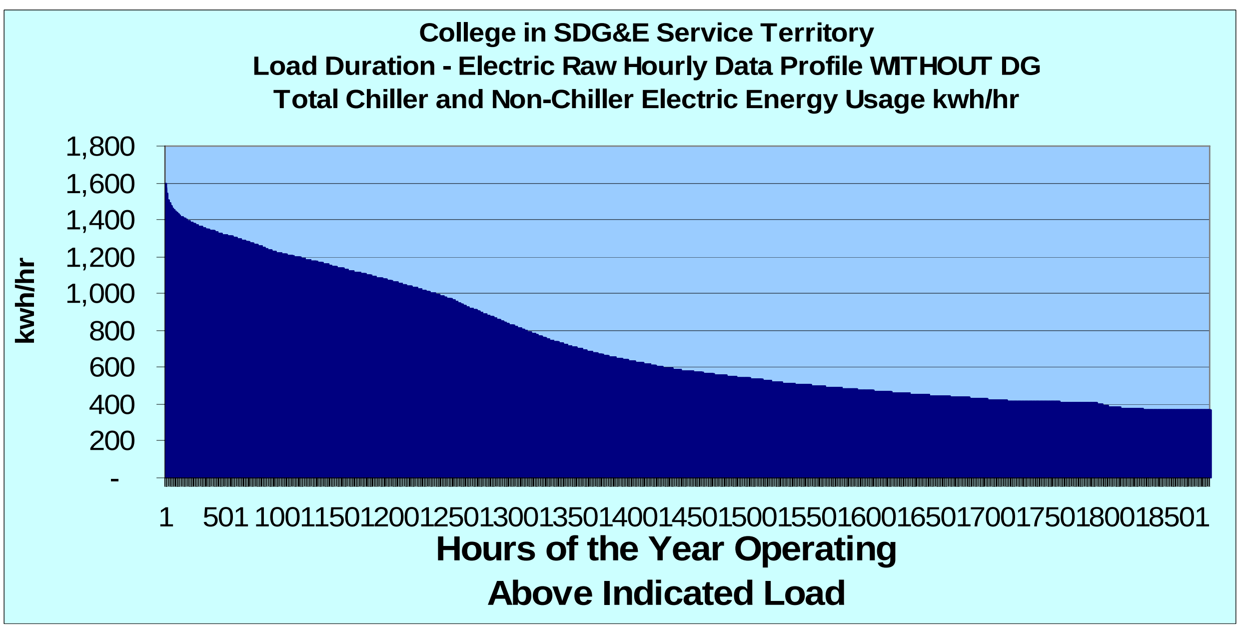


Figure 54 – Proxy Annual thermal Load Profile for College Building in SDG&E Service Territory

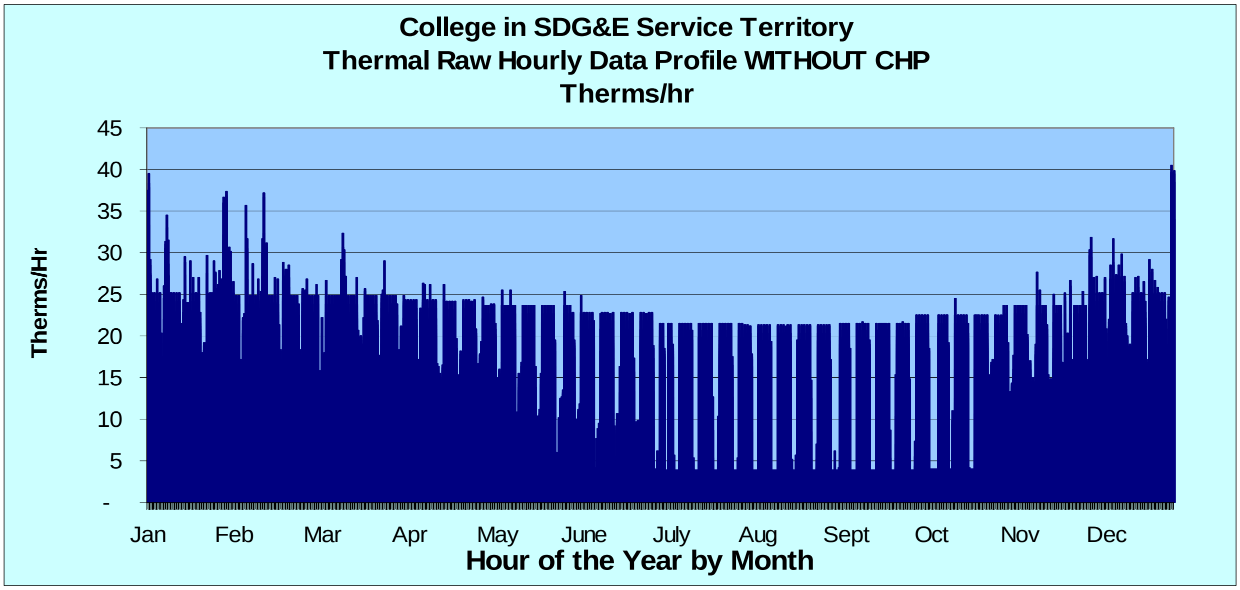


Figure 55 –Proxy Annual thermal Load Duration Curve for College Building in SDG&E Service Territory

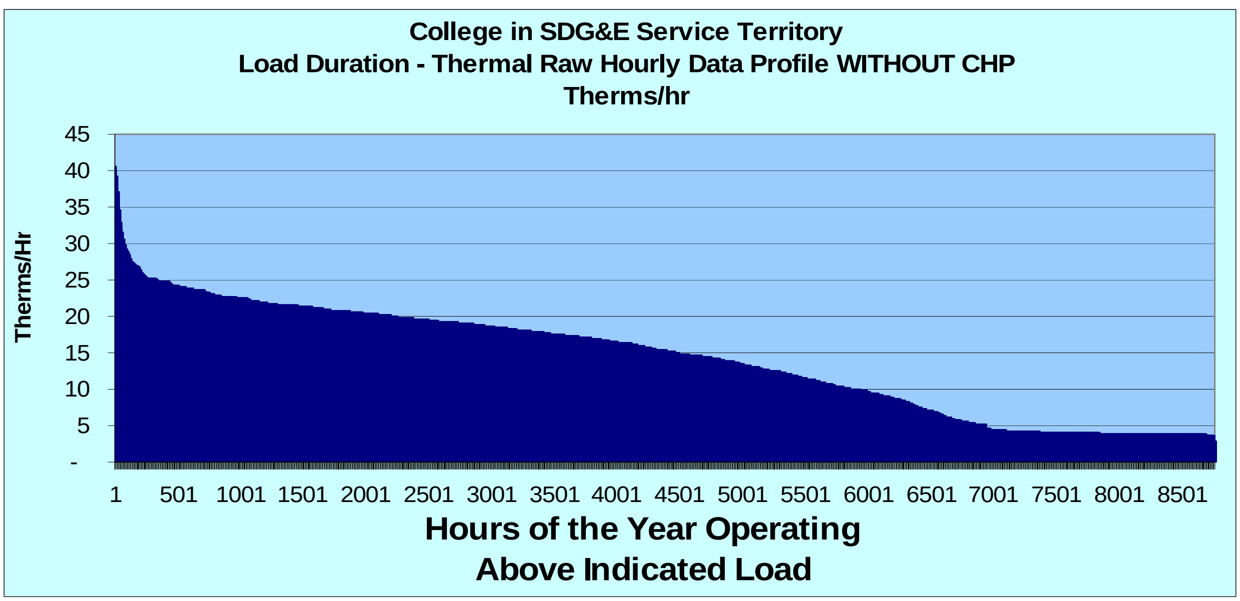


Figure 56 – Proxy Annual Electric Load for Hotel in SDG&E Service Territory

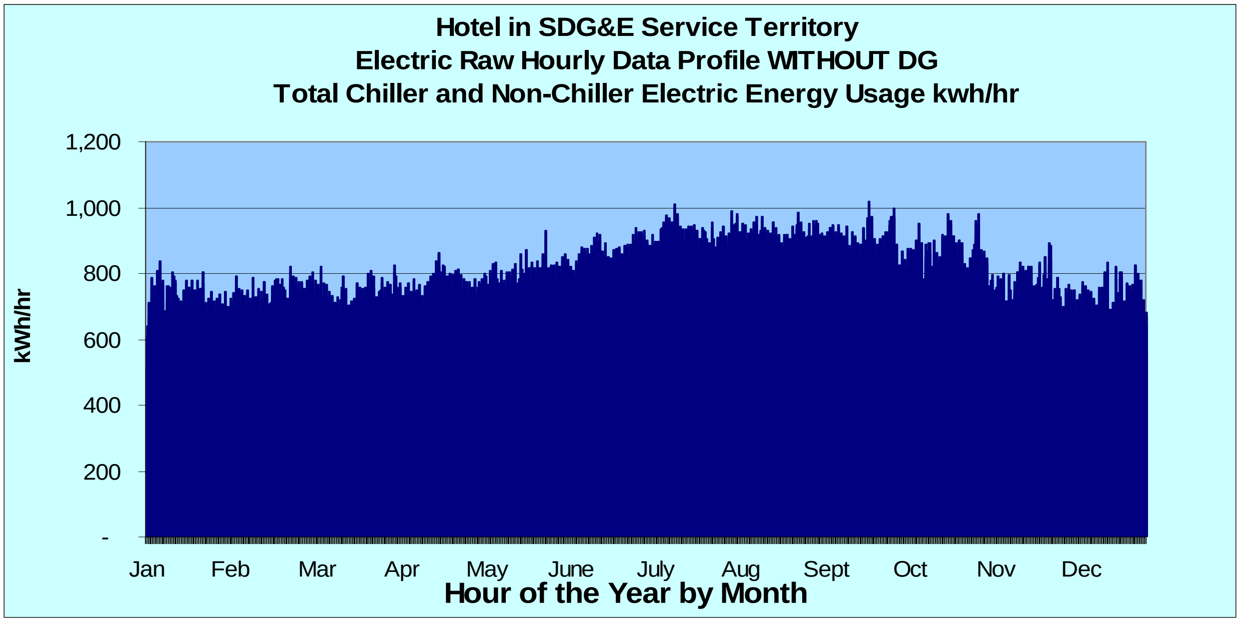


Figure 57 –Proxy Annual Electric Load Duration Curve for Hotel in SDG&E Service Territory

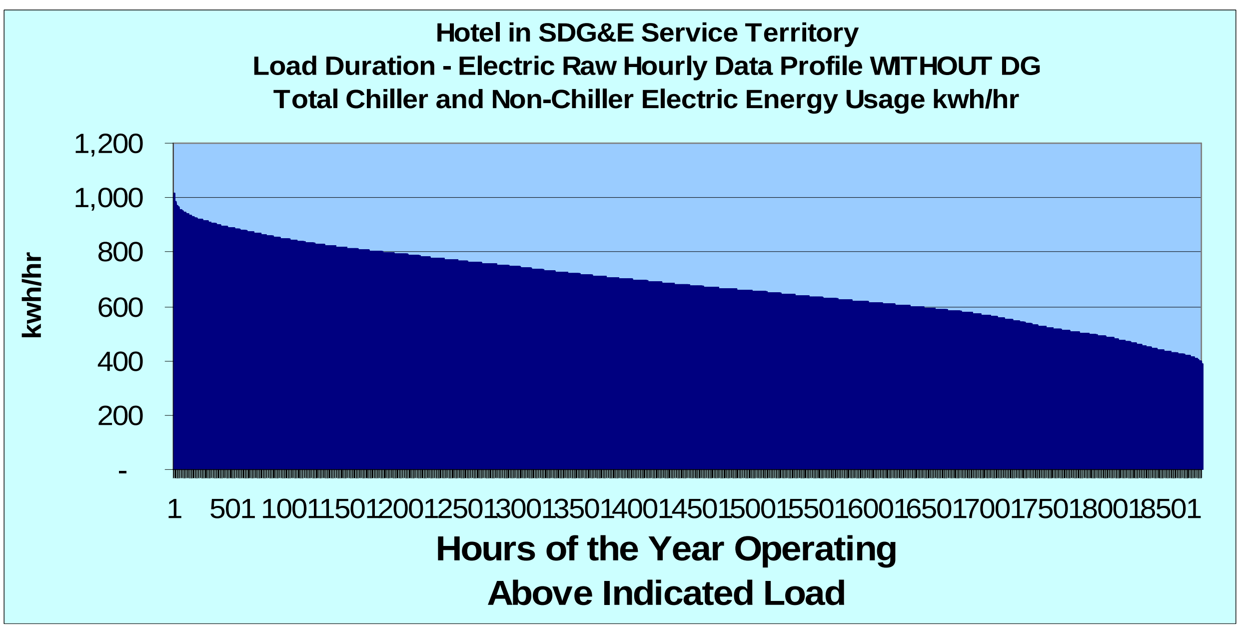


Figure 58 – Proxy Annual thermal Load Profile for Hotel in SDG&E Service Territory

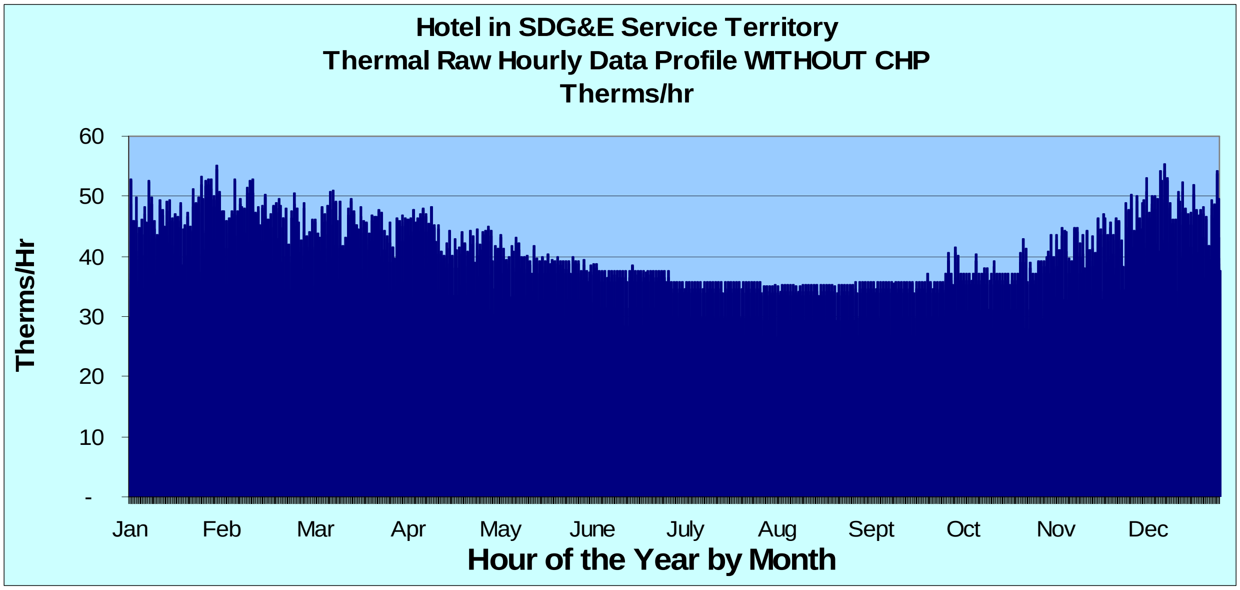


Figure 59 –Proxy Annual thermal Load Duration Curve for Hotel in SDG&E Service Territory

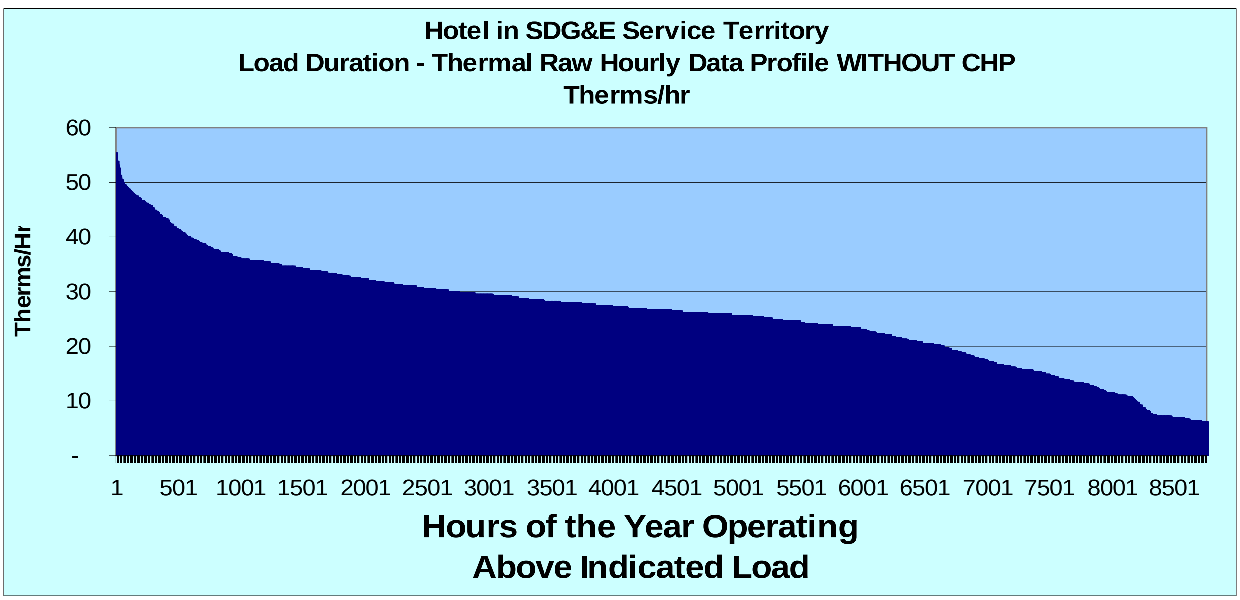


Figure 60 – Specifications for Cummins 334GFBA 2G Engine

QSK 19G - 1800 rpm - 11 :1, 203 deg.F HT Outlet - 2 g/bhph NOx - Engine Driven Pumps Fitted

GENERAL DATA - BASED ON HV FRAME 5 4 POLE ALTERNATOR			
Bore	6.26 in	Genset Weight With Fluids	8798 lbs
Stroke	6.26 in	Genset Overall Length	11.48 ft
Cylinders configuration	In Line 6	Genset Overall Height	5.91 ft
Cylinder displacement	192.7 cu.in	Genset Overall Width	4.27 ft
Rated speed	1800 rpm	Engine HT Water Volume	13 U.S.gal
Mean effective pressure	180 psi	Engine LT Water Volume	11 U.S.gal
		Engine Lub Oil Volume	33 U.S.gal

Genset Designation
334GFBA

TECHNICAL DATA - AT CONDITIONS REFERENCED BELOW						
Frequency / Engine RPM		60Hz / 1800	2 of 2	Version Date		21st October 2004
	See Note	Units	100%	90%	75%	50%
General Data						
Effective mechanical output with engine driven pumps	1	kW	350	315	263	175
Effective mechanical output with engine driven pumps	1	bhp	469	422	353	235
Generator electrical output	2	kWe	336	303	253	168
Energy input (LHV)	2,3	mmBTU/h	3.32	3.02	2.56	1.83
Electrical efficiency		%	34.6%	34.2%	33.6%	31.3%
Mechanical efficiency		%	36.0%	35.6%	35.0%	32.5%
Heat Rate	4	BTU/kWhe	9868	9980	10144	10909
Total heat rejected to LT. Circuit	4	mmBTU/h	0.24	0.20	0.16	0.04
Total heat rejected to H.T Circuit	4	mmBTU/h	0.79	0.72	0.61	0.52
Unburnt	4	mmBTU/h	0.05	0.04	0.03	0.03
Heat radiated to ambient + unaccounted	4	mmBTU/h	0.09	0.08	0.05	0.03
Available Exhaust Heat To 221 deg.F	4	mmBTU/h	0.92	0.81	0.64	0.32
Fluid Flows						
Intake air flow	4	lb/h	4525	N/A	N/A	N/A
Intake air flow	4	scfm	990	N/A	N/A	N/A
Exhaust gas flow rate	4	lb/h	4683	4207	3255	1588
Exhaust gas flow rate	4	scfm	1008	906	701	342
LT. Circuit water flow rate	4	USgpm	26	26	26	26
HT Circuit water flow rate	4	USgpm	141	141	141	141
Maximum pressure drop in HT external cooling circuit		psi	14.5	14.5	14.5	14.5
Maximum pressure drop in LT external cooling circuit		psi	14.5	14.5	14.5	14.5
Maximum exhaust system back pressure		inchWG	20	20	20	20
Temperatures						
Maximum LT. engine water inlet temperature	6	°F	104	104	104	104
Maximum LT. engine water outlet temperature	5	°F	122	122	122	122
Maximum HT engine water inlet temperature	6	°F	180	180	180	180
HT engine water outlet temperature	5	°F	203	203	203	203
Exhaust gas temperature after turbine	7	°F	986	977	995	999
Exhaust Emissions						
NOx emissions (dry)	4	ppm	345	345	345	345
NOx Emission Rate at exhaust condition	4	g/bhp hr	2.32	2.32	2.17	1.61
CH4 emissions (dry) (affected by gas composition)	4	ppm	1799	1810	1839	2011
CH4 Emission Rate (affected by gas composition)	4	g/bhp hr	4.11	4.01	3.81	3.00
CO emissions (dry)	4	ppm	647	655	678	723
CO Emission Rate at exhaust condition	4	g/bhp hr	2.6	2.6	2.5	1.9
O2 emissions (dry)	4	%	9.3	9.3	9.2	9
Miscellaneous						
Gas supply pressure range		psi	3.0 - 85	3.0 - 85	3.0 - 85	3.0 - 85
Minimum Methane Index For This Configuration			75	75	75	75
Minimum static head on LT & HT water cooling circuits		psi	7.3	7.3	7.3	7.3
HT Circuit maximum pressure @ engine		psi	65.3	65.3	65.3	65.3
LT. Circuit maximum pressure @ engine		psi	65.3	65.3	65.3	65.3
Lubricating oil consumption	8	g/kWe.h	< 0.5	< 0.5	< 0.5	< 0.5
Starting air bottle recommended pressure		psi	435 to 580	435 to 580	435 to 580	435 to 580
Electric starter voltage		V	24	24	24	24
Minimum battery capacity @ 104 deg.F		Ah	4 x 180 =720	4 x 180 =720	4 x 180 =720	4 x 180 =720

Engine data subject to change without prior notice and are not contract values.

1) Service conditions according to ISO 8528/1 and reference conditions according to ISO 3046/1:
COP : Continuous output without time limitation between the stated maintenance intervals - no overload allowed, parallel operation with the grid.
Reference conditions : altitude 3280 feet, suction air temperature 95°F, LT. cooling water inlet temperature 104°F, methane index as stated above.
Derating :
If service conditions differ from the reference conditions, the engine is derated according to ISO 3046/1 (Third edition, Tab. 1 - Ref. D).
In first approach, the rules below can be used:
- For each additional degree of suction air temperature above 95°F (max. : 122°F) : 0.2 % of the mechanical output.
- For each additional 328 feet of altitude above 3280 feet, (max. : 8200 feet) : 1.0 % of the mechanical output.
- Gas specific consumption increase : 1/5 of derating (for example: a 10% derating will increase the specific consumption by 2%).
- For a LT. cooling water inlet temperature above 104°F, or a methane index below that stated above, or off the grid installation, consult CPG

2) Low voltage alternator terminals at power factor = 1.0 according to IEC 34.1.
3) According to ISO 3046/I with a tolerance of +5% - Natural gas LHV 900 BTU/scf.
4) Tolerance ±5%.
5) Outlet : maximum temperature allowed. Inlet : for information, with 30% of glycol and with outlet T° at max allowed.
6) Inlet : maximum temperature allowed. Outlet : for information, with 30% of glycol and with max allowed inlet T°.
7) With air intake at 95°F. Tolerance ± 20°F.
8) At full load (l/h for information, with lubricating oil Specific Gravity = 0.83).

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Manston
Ramsgate, Kent CT12 5BF
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Appendix B – Task 4

Supplemental Report
Impacts of the Changes of Market Conditions, Transmission Credits and Renewable Energy Credits on the Economic Viability of California Based CHP

I. Overview for Task 4 Report

Introduction

This supplemental report entitled Changes of Market Conditions, Transmission Credits and Renewable Energy Credits on the Economic Viability of California Based CHP, was prepared under a contract with the California Energy Commission under the Public Interest Energy Research (PIER) Program under California Energy Commission Contract No. 500-04-015. This report was prepared under Task 4 of the subject contract and serves as a supplemental update to the report prepared under Task 3 of the same contract. The objective of this update is to address changes in market conditions that occurred over the period 5/1/2005 – 2/1/2006, particularly the volatility of natural gas prices during that period and changes in electric rates of the three CA utilities over that same period. In addition, an assessment is provided to examine certain "externalities" that could be paid to CHP owners to further incentivize investments in CHP.

Background

That Task 3 Report referred to above was based on electric and gas prices prevalent during the spring of 2005. That report presented the following findings:

- There are significant inconsistencies between the rate approaches and methods of cost recovery used by the three California utilities. The rate structures are each also quite complex. This provides inconsistent and difficult to interpret pricing signals to the CHP market place.
- While rates are not structured in a consistent manner, there seems to be a trend in CA electric rates towards shifting cost recovery from energy rates to demand and standby rates, even in a market of increasing fuel prices. This is a substantive disincentive to CHP projects for which fuel is their most significant cost factor and which under current rate structures can usually only capture demand savings if the CHP facility operates flawlessly over an entire billing period. CHP projects do not appear to be credited based on the value of the marginal electric energy on the grid that they are truly displacing though such an approach would likely add complexity not reduce it.
- CHP owners appear to have a common perception that the rate-making process is heavily influenced by the utilities in the utilities' self-interest and a sense of frustration that the CHP community does not have the means and resources to provide input to the process.
- Rapidly rising gas prices are a serious concern for CHP owners who must rely on energy rates as the tariff component to recover CHP facility fuel costs. CHP owners expressed a sense of concern that it appears that recovery of increases experienced by the utilities in their fuel costs may sometimes be reflected though demand charge or other cost mechanisms in the tariffs.
- Utilities are making serious efforts to be available to customers to assist them in understanding and applying rates
- From a utility's perspective, revenue recovery often times does not fairly reflect the true costs of service. Savings to CHP owners can ultimately lead to higher electric rates for other rate payers

- Ratemaking policy is often times dictated by other complex factors that are unrelated to impacts on CHP ownership and operation

It was observed in that study based on May 2005 market conditions that SDG&E's ALTOU rate and PG&E's E20 rates could provide attractive economics for CHP under the right conditions while SCE's TOU-8/standby tariff was clearly not attractive for CHP applications. Supporting findings of the study included:

- Very low off-peak power rates are disincentives to CHP. The benefits of the high efficiency of CHP are difficult to capture if off-peak energy rates are very low. Because off-peak rate periods typically comprise 50 – 60% of the hours of the year, CHP is most viable if savings can be produced during off-peak periods. SCE's tariffs tend to have the lowest off-peak rates.

- Owners of CHP facilities can sometimes substantively improve their economics by operating facilities in a manner that accounts for time-related load and energy price changes. Components of tariffs like non-coincident demand charges and higher off-peak standby rates penalize CHP owners for this type of optimized operation.

- Demand charge structures that emphasize on-peak operations incentivize CHP owners to try to achieve high on-peak reliability. Conversely, high "non-coincident" demand charges and ratchets disincentivize emphasis on on-peak power production.

- Standby charges are a substantive disincentive to CHP. Exemptions allowed from standby charges by the California utilities sometimes impose even more severe penalties on CHP through other mechanisms in the tariffs.

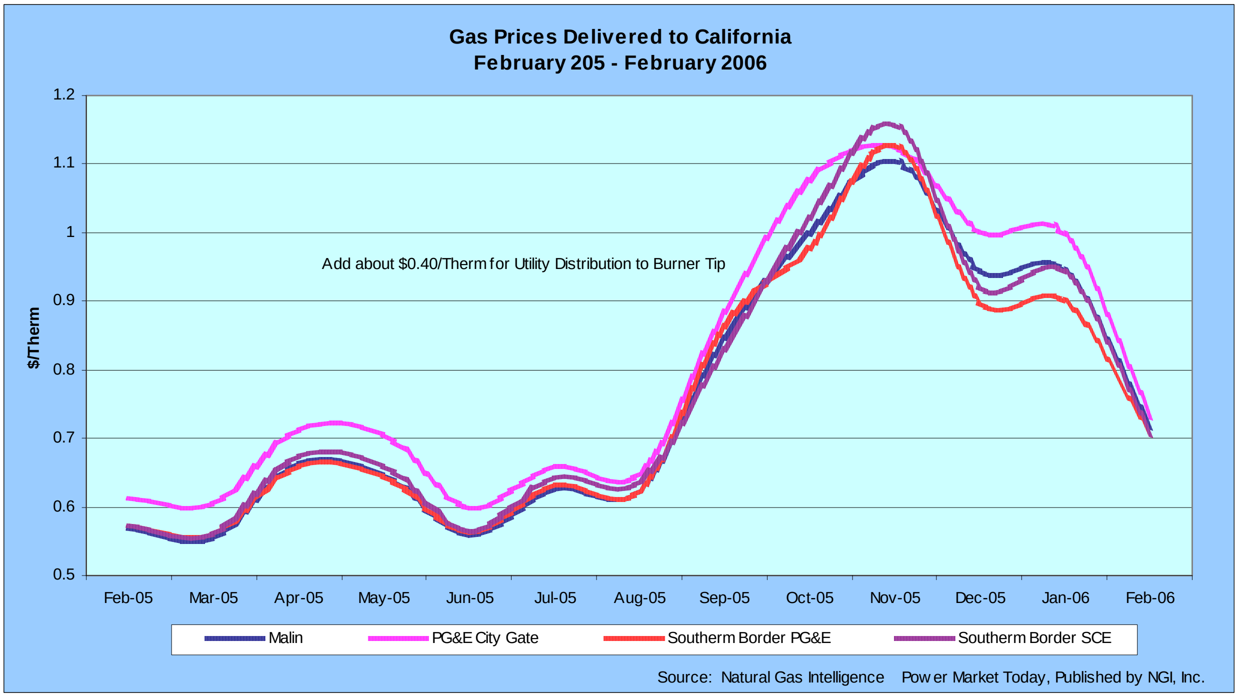
- Exempting only projects sized less than 1000 kW from the DWR bond component of departing load charges creates an arbitrary breakpoint in the incentives/disincentives to CHP ownership

- The SGIP program is critical to CHP economics in the current scenario. It does not, however, provide incentives to align owners to effectively operate their facilities in a manner that supports the needs of the grid and the interest of the public once they are installed.

Results and Key Findings of this Task 4 Supplemental Report

Analysis performed during Task 4 was largely motivated by dramatic changes in the market conditions prevalent in May of 2005 and January / February of 2006. Figure 61 provides an illustration of the volatility of gas prices over the subject evaluation period, during which dramatic swings in natural gas prices occurred with gas rates at the CA border ranging from a low of about $0.57 - $0.65/Therm in the Spring of 2005 to a high of over $1.10/Therm in late fall of 2005, and then settling back down to the range of $0.70/Therm by the Spring of 2006. (Note that about $0.04/Therm is typically added to these prices for local distribution to the burner tip). This unprecedented volatility was the consequence of high gas demand, volatile world energy prices and supply disruptions resulting from a series of hurricanes in the Gulf of Mexico during the summer and fall of 2005. A relatively warm winter across the country resulted in some declines in gas prices which by February of 2006 were about 20% above February 2005 prices.

Figure 61 - Average Gas Price at Northern California and Southern California Border, $/Therm



Over this same period, the three California Investor Owned Utilities have also had new rates approved. General observations relative to the changes in rate structures of the utilities include:

- A trend of shifting cost recovery from energy to demand rates, especially in PG&E's and SDG&E's service territories, continued even in the face of increasing gas prices. To many CHP industry stakeholders this appears to be counter intuitive to their expectation that increasing gas prices would result not result in decreases in electric energy rates.

- The combination of higher gas prices, lower energy rates and higher demand charges, has substantively degraded the economics of CHP ownership. This is most notably true in PG&E's and SDG&E's service territories. While some of that differential has been recovered but with the current net average increase in gas prices of about 20% and net average decrease in the energy component of the tariffs of about 5-10% (while demand charges increased

- In SCE's service territory, demand charges remained constant and energy rates increased slightly. While the economics of CHP have degraded less in SCE's service territory than is the case for other utilities, the previously unattractive economics in SCE's territory have still degraded.

The "spark spread" is an industry terminology for the equilibration of the energy rate component of the electric tariff and the cost of gas prices to produce that same electric energy using CHP. During the evaluation period, gas prices increased dramatically while the energy rate component in the electric tariffs tended to decrease. Since demand charges are not reflected in energy consumption, while they are an important cost component on the customer's electric bill, they are not a factor in the spark spread calculation or the incremental operating incentives for CHP.

The low or inverted spark spread meant that the energy cost component of the electric tariff trended lower than the corresponding cost of gas for a CHP owner to produce power. While demand savings and the recovery of waste heat from CHP applications can offset narrow spark spreads, the substantive decline in retail spark spreads observed over the evaluation period was a strong negative for gas fired CHP.

Under gas and electric pricing scenarios evaluated in this Task 4 report, investments in CHP in both PG&E's and SDG&E's service territories appeared to be marginal to uneconomic except in circumstances where virtually all of the waste heat from the CHP facility can be used for thermal offsets. For many CHP applications, this is not practical on a 7 x 24 basis. Use of waste heat in absorption chillers was much less attractive under January / February 2006 rates because of lower energy and higher demand rates. It is always worth noting that special circumstances at a particular site or facility might overcome these obstacles.

To complement analysis of volatile gas prices described above, analysis was also performed of the potential enhancements to CHP economics that might be realized as a result of other generating credits (i.e. externalities) that CHP facilities often provide and yet are not compensated for. These can include transmission offsets, net reductions in greenhouse gas emissions and benefits available under the Federal Energy Policy Act of 2005 for facilities that utilize renewable based fuels and/or micro turbines.

In a report titled Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs issued by the California Energy Commission on October 25, 2004 estimates were provided relative to the potential weight averaged value of avoided transmission and distribution costs and CO_2 offset credits that might be justified in a market trading system.

- A representative value of $40.00/kw year for transmission and distribution offsets.
- A representative value of $8.00/ ton for CO_2 emissions reduction credits.
- For renewable energy based projects, a Production Tax Credits of 0.95 ¢/kwh hour escalating at 1.5% for five years.
- For projects using micro turbines an Investment Tax Credit of 10% of the micro turbine price with a limit of $200/kw.

Due to the significant uncertainty and sometimes site specificity in the market values pf greenhouse gas emissions credits and transmission and distribution offsets, sensitivities were performed on the indicated rates.

In general, these upside benefits have be potential to add on the order of 2% - 7% to the after tax return on investment realized in these applications. While these amounts do not appear to be sufficient to incentivize projects faced with gas prices on the order of $1.00/Therm or higher and electric rates prevalent at the start of 2006, with moderation in gas prices and better equilibration in the energy component of electric rates with the real impacts of higher gas prices on electric rates, these incremental benefits could mean the difference between a marginal and a profitable investment for the CHP plant owner.

II. Comparisons of Gas Price Assumptions and Utility Tariffs for Task 4 Spring 2005 versus Winter 2006

This section discusses the comparison of the gas prices and electric tariffs evaluated in this Task 3 (Spring 2005) and Task 4 (Winter 2006) reports. For the purposes of simplifying the comparisons, gas rates were based on average burner tip prices and electric rates were based on the secondary interconnection rates for each respective utility and tariff. The results shown appear to be illustrative for all of the applicable primary and secondary rate schedules. To complement Task 5 of the analysis, changes in NEMBIO rates are also illustrated.

A. Comparison of Gas Price Assumptions

Table 27 provides a comparison of the relative gas price assumptions used in the Task 3 and this supplemental Task 4 report. As those in the energy market recognize, predicting forward gas prices at any point in time is a very imperfect art. In general, prices for gas tend to be higher in the winter time as heating demands rise and lower in the summer, but are ultimately influenced by a wide range of daily factors including supply disruptions caused by severe weather in the Gulf of Mexico and other factors, demands resulting for seasonal weather conditions, world energy prices and competitive market dynamics. The gas prices evaluated in this analysis are representative of the extremes experienced during the evaluation period. A general assumption of a 3% annual average increase in electric and gas rates going forward from the assumptions provided below was used in the study. Figure 61 provided in the Introduction to this report illustrates the true market volatility observed over the subject period.

Table 27 - Comparison of Burner Tip Gas Price Assumptions used in the Task 3 and Task 4 Reports

Month of the Year	$/Therm Delivered	$/Therm Delivered
	Task 3 Report (Spring 2005 Annual Market Assumptions)	Task 4 Report (Winter 2006 Annual Market Assumptions)
January	$ 0.70	$ 1.10
February	$ 0.70	$ 1.10
March	$ 0.68	$ 1.05
April	$ 0.65	$ 1.05
May	$ 0.60	$ 1.00
June	$ 0.60	$ 1.00
July	$ 0.60	$ 1.00
August	$ 0.60	$ 1.00
September	$ 0.60	$ 1.00
October	$ 0.65	$ 1.00
November	$ 0.68	$ 1.05
December	$ 0.70	$ 1.05
Annual Average	**$ 0.65**	**$1.03**

B. PG&E E20 Tariff Overview

The E20S schedules evaluated in Task 3 (as of June 1, 2005) and Task 4 (as of February 1, 2006) are summarized in Table 28 and Table 29 below. Table 3 provides a relative comparison of the bundled rates and

Figure 62 provides the comparative rate information in bar chart style with the relative changes in rates illustrated by arrows on the chart.

Table 28 - PG&E E20S Rates – Effective June, 1 2005, Unbundled

Typical Franchise Fee 4.50% **Customer Charge (Incl. Franchise Fee)** $/Meter Day $ 13.22

Demand Charges, $/kw mo

	Generation	Distribution	Transmission	Reliability Service	Total	Add Franchise Fees	Bundled Total
Summer						4.5%	
Maximum Peak	7.07	5.93			13.00	0.59	13.59
Maximum Part-Peak	1.95	1.66			3.61	0.16	3.77
Maximum Demand (Non-Coincident)	(3.68)	2.14	2.44	2.18	3.08	0.14	3.22
Winter							
Maximum Part-Peak	1.92	1.64			3.56	0.16	3.72
Maximum Demand (Non-Coincident)	(3.68)	2.14	2.44	2.18	3.08	0.14	3.22

Energy Charges, c/kwh

	Generation	Distribution	Transmission	PPP	NDC	CTC	DWR Bond Charge	ECRA	Bundled Rate w/o Franchise Fee	Add Franchise Fees	Bundled Total
Summer										4.5%	
Peak	11.410	1.383	0.016	0.454	0.035	0.434	0.459	0.534	14.725	0.66	15.39
Part Peak	5.532	0.916	0.016	0.454	0.035	0.434	0.459	0.534	8.380	0.38	8.76
Off-Peak	4.952	0.798	0.016	0.454	0.035	0.434	0.459	0.534	7.682	0.35	8.03
Winter											
Part Peak	5.981	1.006	0.016	0.454	0.035	0.434	0.459	0.534	8.919	0.40	9.32
Off-Peak	4.936	0.795	0.016	0.454	0.035	0.434	0.459	0.534	7.663	0.34	8.01

Filed May 27, 2005 - Effective June 1, 2005
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

Table 29 - PG&E E20P Rates – Effective February 1, 2006, Unbundled

Typical Franchise Fee 4.50% **Customer Charge (Incl. Franchise Fee)** $/Meter Day $ 13.22

Demand Charges, $/kw mo

	Generation	Distribution	Transmission	Reliability Service	Total	Add Franchise Fees	Bundled Total
Summer						4.5%	
Maximum Peak	8.05	6.33			14.38	0.65	15.03
Maximum Part-Peak	1.62	1.61			3.23	0.15	3.38
Maximum Demand (Non-Coincident)		3.71	2.44	0.94	7.09	0.32	7.41
Winter						-	-
Maximum Part-Peak		1.87			1.87	0.08	1.95
Maximum Demand (Non-Coincident)		3.71	2.44	0.94	7.09	0.32	7.41

Energy Charges, c/kwh

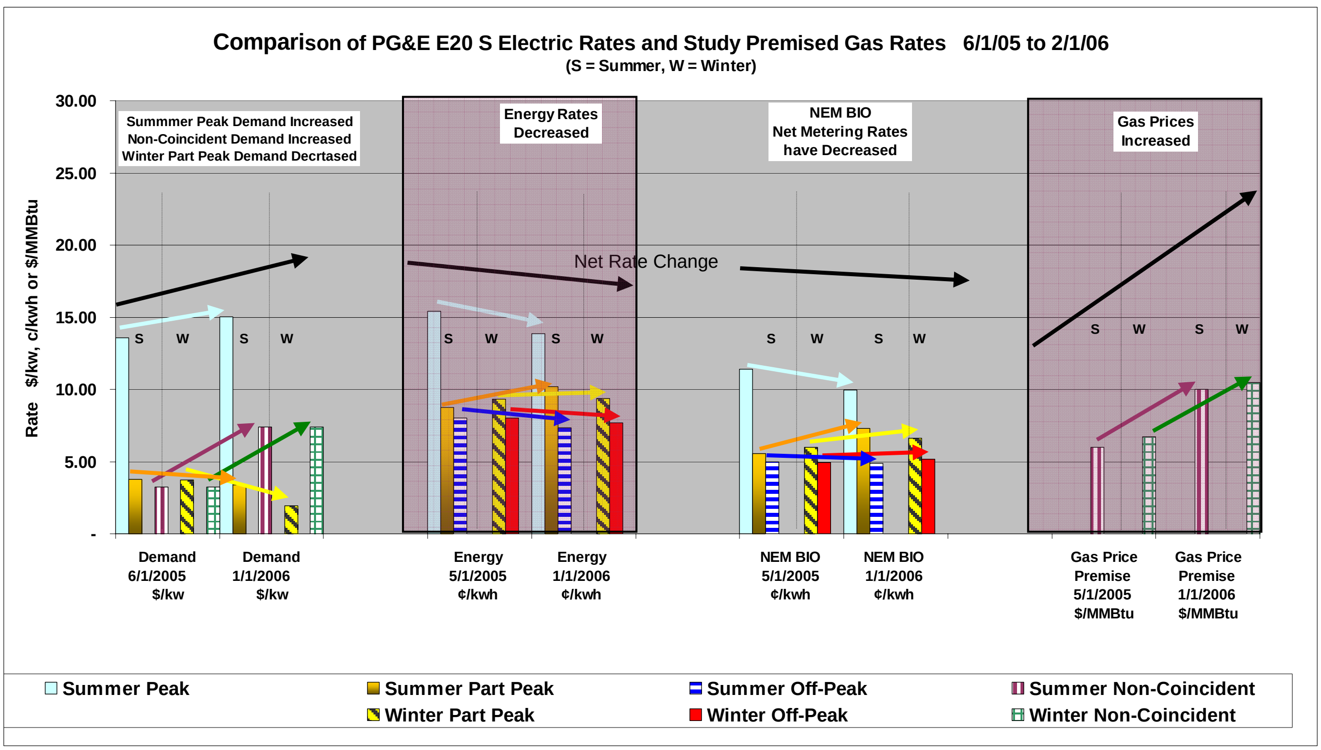
	Generation	Distribution	Transmission	PPP	NDC	CTC	DWR Bond Charge	ECRA	Bundled Rate w/o Franchise Fee	Add Franchise Fees	Bundled Total
Summer										4.5%	
Peak	9.965	1.466	(0.030)	0.549	0.038	0.350	0.485	0.437	13.260	0.60	13.86
Part Peak	7.297	0.612	(0.030)	0.549	0.038	0.350	0.485	0.437	9.738	0.44	10.18
Off-Peak	4.865	0.327	(0.030)	0.549	0.038	0.350	0.485	0.437	7.021	0.32	7.34
Winter											
Part Peak	6.606	0.538	(0.030)	0.549	0.038	0.350	0.485	0.437	8.973	0.40	9.38
Off-Peak	5.146	0.373	(0.030)	0.549	0.038	0.350	0.485	0.437	7.348	0.33	7.68

Effective January 1, 2006
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

Table 30 - Comparison of PG&E E20 S Rates 6/1/05 vs. 2/1/06

	Study PremisesComparison of Bundled Rates (Assuming 4.5% Applicable Franchise Fee)										
	Demand, $/kw			Energy, ¢/kwh			Net Metering Rate, ¢/kwh			Gas Price Premise, $/MMBtu	
Date	Demand 6/1/2005 $/kw	Demand 1/1/2006 $/kw		Energy 5/1/2005 ¢/kwh	Energy 1/1/2006 ¢/kwh		NEM BIO 5/1/2005 ¢/kwh	NEM BIO 1/1/2006 ¢/kwh		Gas Price Premise 5/1/2005 $/MMBtu	Gas Price Premise 1/1/2006 $/MMBtu
Summer											
Summer Peak	13.59	15.03		15.39	13.86		11.41	9.97			
Summer Part Peak	3.77	3.38		8.76	10.18		5.53	7.30			
Summer Off-Peak				8.03	7.34		4.95	4.87			
Summer Non-Coincident	3.22	7.41								6.00	10.00
Winter											
Winter Part Peak	3.72	1.95		9.32	9.38		5.98	6.61			
Winter Off-Peak				8.01	7.68		4.94	5.15			
Winter Non-Coincident	3.22	7.41								6.70	10.50

Figure 62 - Comparison of PG&E E20 S Rates 6/1/05 vs. 2/1/06



Observations concerning PG&E's E20 Tariff include:

- PG&E's energy rates generally declined while demand rates increased. This shift from energy to demand rates is a substantive disincentive to CHP since (see conclusions of Task 3 report).
- The decline in energy rates was accompanied by increases in gas prices paid by CHP owners. The resulting decline and even inversion of the retail "spark spread" was a strong negative for CHP.
- PG&E's previously low non-coincident demand charges more than doubled. This tends to penalized CHP applications because monthly savings in non-coincident demand charges are lost as a result of any single brief (15 minute) outage at any time of day over the month. Increases were on the order of $4.20/kw.
  - Summer peak demand charges increased by about $1.40/kw while summer part-peak demand charges decreased by about $0.40 / kW. Winter part-peak demand charges declined by about $1.80 / kW but this is more than offset by the corresponding increase in non-coincident charges.
- Part peak energy rates increased but off-peak and peak energy rates declined. This represents a decline in the spark spread during over 70% of the annual operating hours.

C. SCE Tariff Overview

The TOU-8 schedules evaluated in Task 3 (as of June 1, 2005) and Task 4 (as of February 1, 2006) are summarized in Table 31and Table 32 below. Table 6 provides a relative comparison of the bundled rates and
Figure 63 provides the comparative rate information in bar chart style with the relative changes in rates illustrated by arrows on the chart.

Table 31 – SCE TOU8 – Effective June, 1 2005, Unbundled

Typical Franchise Fee **4.50%** **Customer Charge (Incl Franchise Fee)** **$/Mo** **$332.27**

Demand Charges, $/kw mo	Generation	Distribution	Total	Bundled Rate with Franchise Fee
Summer				
On-Peak	16.94	9.25	26.19	27.369
Mid-Peak	3.28	0.78	4.06	4.243
Facilities (Non-Coincident)	1.87	6.60	8.47	8.851
Winter				
Facilities (Non-Coincident)	1.87	6.60	8.47	8.851

Energy Charges, c/kwh	Delivery Service						Generation		Bundled Rate prior to Franchise Fees	Bundled Rate with 4.5% Franchise Fee
	Transmission	Distribution	NDC	PPP	DWR Bond Charge	Sub Total	URG 70% Avg.	DWR 30% Avg.		
Summer										
On-Peak	0.063	0.186	0.054	0.500	0.459	1.262	12.400	7.981	12.336	12.891
Mid-Peak	0.063	0.186	0.054	0.500	0.459	1.262	5.280	7.981	7.352	7.683
Off-Peak	0.063	0.186	0.054	0.500	0.459	1.262	1.110	7.981	4.433	4.633
Winter										
Mid-Peak	0.063	0.186	0.054	0.500	0.459	1.262	7.725	7.981	9.064	9.472
Off-Peak	0.063	0.186	0.054	0.500	0.459	1.262	1.341	7.981	4.595	4.802

Filed April 11, 2005 - Retroactive subject to interpretation rulings.
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
DWR Bond Charge = Department of Water Resources Bond Charge
URG - SCE Generation
DWR - Department of Water Resources Generation

Table 32 – SCE TOU8 – Effective February, 1 2006, Unbundled

Typical Franchise Fee **4.50%** **Customer Charge (Incl Franchise Fee)** **$/Mo** **$332.27**

Demand Charges, $/kw mo	Generation	Distribution	Total	Bundled Rate with Franchise Fee
Summer				
On-Peak	16.94	9.25	26.19	27.369
Mid-Peak	3.28	0.78	4.06	4.243
Facilities (Non-Coincident)	1.87	6.60	8.47	8.851
Winter				
Facilities (Non-Coincident)	1.87	6.60	8.47	8.851

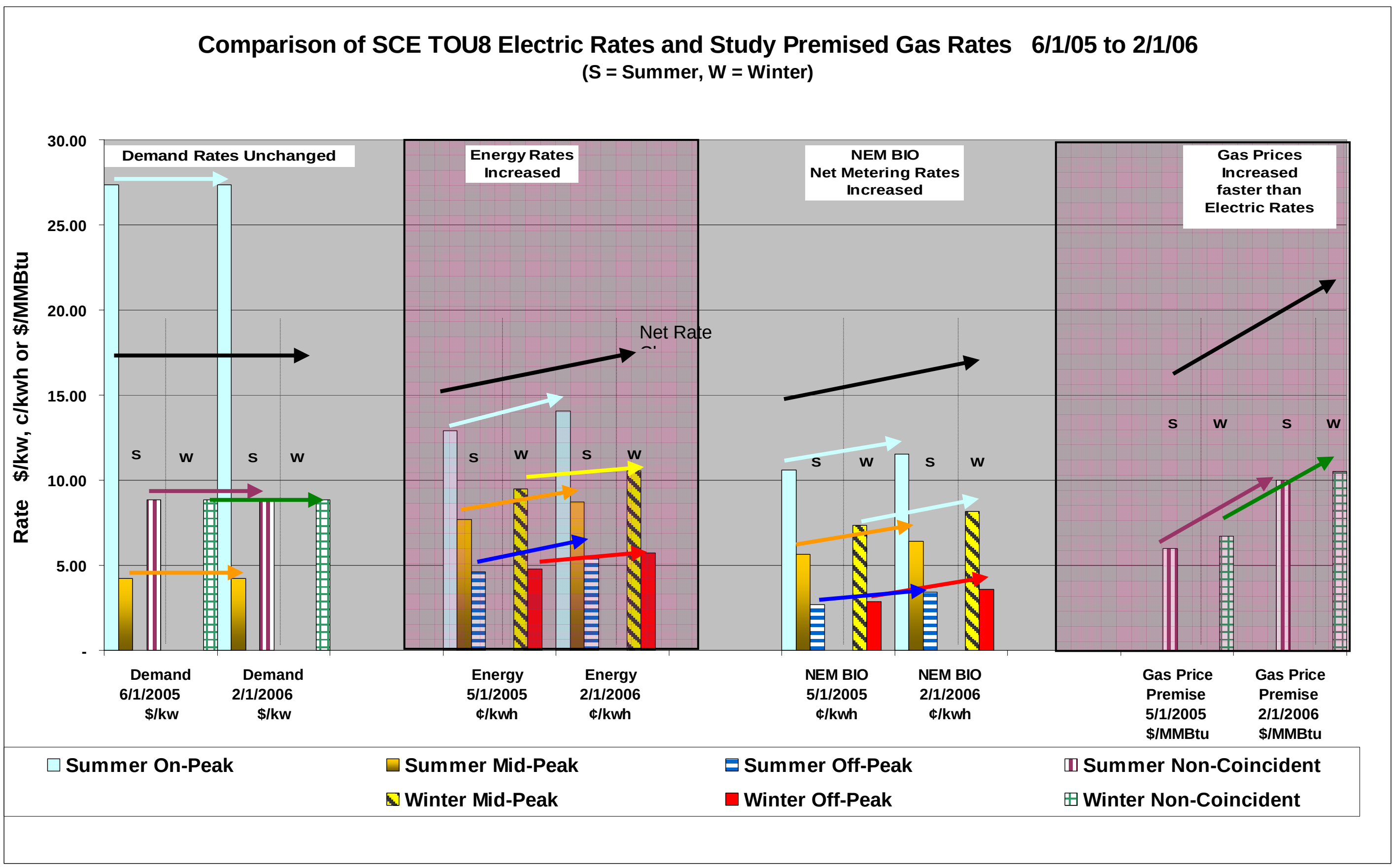
Energy Charges, c/kwh	Delivery Service						Generation		Bundled Rate prior to Franchise Fees	Bundled Rate with 4.5% Franchise Fee
	Transmission	Distribution	NDC	PPP	DWR Bond Charge	Sub Total	URG 70% Avg.	DWR 30% Avg.		
Summer										
On-Peak	0.190	0.186	0.054	0.500	0.485	1.415	12.762	10.369	13.459	14.065
Mid-Peak	0.190	0.186	0.054	0.500	0.485	1.415	5.426	10.369	8.324	8.698
Off-Peak	0.190	0.186	0.054	0.500	0.485	1.415	1.141	10.369	5.324	5.564
Winter										
Mid-Peak	0.190	0.186	0.054	0.500	0.485	1.415	7.938	10.369	10.082	10.536
Off-Peak	0.190	0.186	0.054	0.500	0.485	1.415	1.378	10.369	5.490	5.737

Filed December 16, 2006 - Retroactive subject to interpretation rulings.
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
DWR Bond Charge = Department of Water Resources Bond Charge
URG - SCE Generation
DWR - Department of Water Resources Generation

Table 33 - Comparison of SCE TOU-8 Rates 6/1/05 vs. 2/1/06

	Study PremisesComparison of Bundled Rates (Assuming 4.5% Applicable Franchise Fee)							
	Demand, $/kw		Energy, ¢/kwh		Net Metering Rate, ¢/kwh		Gas Price Premise, $/MMBtu	
Date	Demand 6/1/2005 $/kw	Demand 2/1/2006 $/kw	Energy 5/1/2005 ¢/kwh	Energy 2/1/2006 ¢/kwh	NEM BIO 5/1/2005 ¢/kwh	NEM BIO 2/1/2006 ¢/kwh	Gas Price Premise 5/1/2005 $/MMBtu	Gas Price Premise 2/1/2006 $/MMBtu
Summer								
Summer On-Peak	27.37	27.37	12.89	14.06	10.62	11.56		
Summer Mid-Peak	4.24	4.24	7.68	8.70	5.63	6.42		
Summer Off-Peak			4.63	5.56	2.71	3.42		
Summer Non-Coincident	8.85	8.85					6.00	10.00
Winter								
Winter Mid-Peak			9.47	10.54	7.34	8.18		
Winter Off-Peak			4.80	5.74	2.87	3.59		
Winter Non-Coincident	8.85	8.85					6.70	10.50

Figure 63 - Comparison of SCE TOU-8 Rates 6/1/05 vs. 2/1/06



Observations concerning SCE's TOU8 Tariff include:

- SCE's rates demand rates were unchanged.
- SCE's energy rates increased by about 9% on peak, 11-13% mid peak and 20% on peak. These increases resulted in some offset to the impacts of increases in gas prices resulting in a lesser decline in CHP economics than in the other utility territories, but relative to gas price increase of up to 60% were not sufficient to maintain economic parity for CHP which was already suffering from unattractive economics at previously lower gas prices in SCE's service territory.
- As of February 1, 2006 SCE had not published a new standby rate schedule so analyses provided are based on the same rate schedule that was in effect in May/June of 2005.

D. SDG&E Tariff Overview

The ALTOU and effective EECC schedules evaluated in Task 3 (as of June 1, 2005) and Task 4 (as of February 1, 2006) are summarized in Table 34and Table 35 below. Table 9 provides a relative comparison of the bundled rates and
Figure 64 provides the comparative rate information in bar chart style with the relative changes in rates illustrated by arrows on the chart.

Table 34 – SDG&E ALTOU and EECC Rates – Effective June, 1 2005, Unbundled

Typical Franchise Fee 5.78% **Customer Charge (Incl. Franchise Fee)** $/Meter Mo $ 205.28

Demand Charges, $/kw mo

	Generation	Transmission	Distribution	CTC	Reliability Service	Total	Total w/ Franchise Fee
Summer							
On-Peak			4.09	1.50		5.59	5.91
Maximum Demand (Non-Coincident)		2.65	6.26	0.34	2.33	11.58	12.25
Winter							
On-Peak			3.48	0.35		3.83	4.05
Maximum Demand (Non-Coincident)		2.65	6.26	0.34	2.33	11.58	12.25
Standby Rate under ALTOU							
On-Peak		1.31	2.80	0.25	0.32	4.68	4.95

Energy Charges, c/kwh

	Generation See EECC Schedule	Transmission	Distribution	PPP	NDC	CTC	DWR Bond Charge	Reliability Service	Bundled Rate w/o Franchise Fee	Bundled Rate w/ Franchise Fee
Summer										
Off-Peak	6.987	(0.157)		0.576	0.056	0.578	0.459	0.378	8.877	9.390
Semi-Peak	6.987	(0.157)		0.576	0.056	0.330	0.459	0.378	8.629	9.128
On-Peak	9.389	(0.157)		0.576	0.056	0.563	0.459	0.378	11.264	11.915
Winter									-	
Off-Peak	6.987	(0.157)		0.576	0.056	0.264	0.459	0.378	8.563	9.058
Semi-Peak	6.987	(0.157)		0.576	0.056	0.331	0.459	0.378	8.630	9.129
On-Peak	9.389	(0.157)		0.576	0.056	0.471	0.459	0.378	11.172	11.818

ALTOU Rate Filed January 11, 2005 - Effective February 1, 2005
Standby Rate Filed January 27, 2005 Effective February 1, 2005
EECC - Electric Energy Commidity Cost Rate Effective April 21, 2005
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

Table 35 – SDG&E ALTOU and EECC Rates – Effective February 1, 2006, Unbundled

Typical Franchise Fee 5.78% **Customer Charge (Incl. Franchise Fee)** $/Meter Mo $ 205.28

Demand Charges, $/kw mo

	Generation	Transmission	Distribution	CTC	Reliability Service	Total	Bundled Total w/ Franchise Fee
Summer							
On-Peak			4.18	2.20		6.38	6.75
Maximum Demand (Non-Coincident)		2.79	6.39	-	2.20	11.38	12.04
Winter							
On-Peak			3.56	0.33		3.89	4.11
Maximum Demand (Non-Coincident)		2.79	6.39	-	2.20	11.38	12.04
Standby Rate under ALTOU							
Non-Coincident		1.36	3.45	0.25	0.66	5.72	6.05

Energy Charges, c/kwh

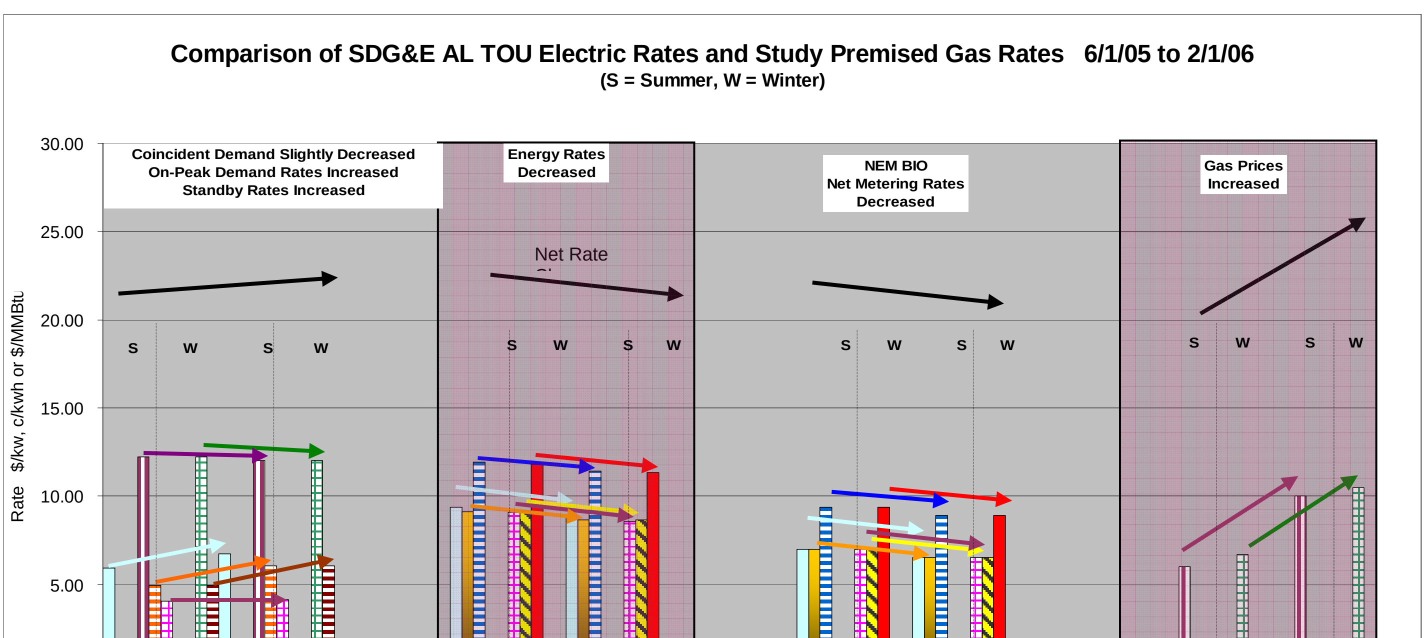
	Generation See EECC Schedule	Transmission	Distribution	PPP	NDC	CTC	DWR Bond Charge	Reliability Service	Bundled Rate w/o Franchise Fee	Bundled Rate w/ Franchise Fee
Summer										
Off-Peak	6.502	(0.157)		0.576	0.056	0.578	0.485	0.378	8.418	8.905
Semi-Peak	6.502	(0.157)		0.576	0.056	0.330	0.485	0.378	8.170	8.642
On-Peak	8.904	(0.157)		0.576	0.056	0.563	0.485	0.378	10.805	11.430
Winter									-	
Off-Peak	6.502	(0.157)		0.576	0.056	0.264	0.485	0.378	8.104	8.572
Semi-Peak	6.502	(0.157)		0.576	0.056	0.331	0.485	0.378	8.171	8.643
On-Peak	8.904	(0.157)		0.576	0.056	0.471	0.485	0.378	10.713	11.332

ALTOU Rate Filed January 12, 2006 - Effective February 1, 2006
Standby Rate Filed January 12, 2006 - Effective February 1, 2006
EECC - Electric Energy Commidity Cost Rate Effective April 21, 2005
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

Table 36 -Comparison of SDG&E ALTOU and EECC Rates 6/1/05 to 2/1/06

	Study PremisesComparison of Bundled Rates (Assuming 4.5% Applicable Franchise Fee)							
	Demand, $/kw		Energy, ¢/kwh		Net Metering Rate, ¢/kwh		Gas Price Premise, $/MMBtu	
Date	Demand 5/1/2005 $/kw	Demand 2/1/2006 $/kw	Energy 5/1/2005 ¢/kwh	Energy 2/1/2006 ¢/kwh	NEM BIO 5/1/2005 ¢/kwh	NEM BIO 2/1/2006 ¢/kwh	Gas Price Premise 5/1/2005 $/MMBtu	Gas Price Premise 2/1/2006 $/MMBtu
Summer								
Summer Off-Peak			9.13	8.64	6.99	6.50		
Summer Semi-Peak			9.39	8.90	6.99	6.50		
Summer On-Peak	5.91	6.75	11.92	11.43	9.39	8.90		
Summer Non-Coincident	12.25	12.04					6.00	10.00
Summer Standby	4.95	6.05						
Winter								
Winter Off-Peak			9.06	8.57	6.99	6.50		
Winter Semi-Peak			9.13	8.64	6.99	6.50		
Winter On-Peak	4.05	4.11	11.82	11.33	9.39	8.90		
Winter Non-Coincident	12.25	12.04					6.70	10.50
Winter Standby	4.95	6.05						

Figure 64 - Comparison of SDG&E ALTOU and EECC Rates 6/1/05 to 2/1/06



Observations concerning SDG&E’s ALTOU and EECC Tariffs include:

- SDG&E’s energy rates generally declined while demand rates generally increased. This shift from energy to demand rates is a substantive disincentive to CHP since (see conclusions of Task 3 report).
    - Non-coincident demand rates decreased slightly but summer on-peak demand rates increased substantially. The combination resulted in an overall increase in demand rates.
- The decline in energy rates was accompanied by increases in gas prices paid by CHP owners. The resulting decline and even inversion of the retail “spark spread” was a strong negative for CHP.
- SDG&E’s standby rates increased by over 20%.

III. Findings from Task 4 - Comparative Economics of CHP Respective Changes of the Utility Tariffs

This section discusses the net relative impacts of the changes in gas and electric rates on the economics of CHP ownership. Offsetting benefits of “externalities” including transmission and distribution system benefits and reductions in greenhouse gas emissions are also evaluated. It should be noted that both of these factors are market specific and in the case of transmission and distribution benefits associated with CHP are highly location specific. Typical or average values were assigned to each of these externalities based on estimates provided in the report Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs issued by the California Energy Commission on October 25, 2004. Economic benefits associated with Production Tax Credits available under the Energy Policy Act of 2005 were also evaluated.

It is important to note that these respective cases are not intended to be illustrative of the economic attractiveness of CHP in any site specific application as there are many factors that will differentiate one site from another. They do provide a valuable indication of the relative economics of CHP across the respective scenarios that were studied. It is also important to note that these cases were intended to illustrate “typical engineering design approaches”. In some instances attention to the optimization of heat recovery and utilization at a site can result in improvements IRR of a CHP project of 5 – 6 percentage points (i.e. from a 10% after tax IRR to a 16% after tax IRR). As gas prices increase, this attention to heat recovery becomes increasingly important.

Figure 65 and Figure 66 illustrate the relative impacts that the alternate scenarios studied in this supplemental report had on the results found in the Task 3 report. For the purposes of simplifying the illustration, the “College” case from the Task 3 report was selected illustrative of a 666 kW CHP facility located on a College Campus. The scenario selected for comparison was “Case M” which represented a subject facility that experienced a loss of 25% of the potential annual demand savings as a result of unplanned outages of the CHP facility (e.g. 75% of the potential demand savings are realized). Impacts on both the after-tax IRR and NPV are provided. In this type of analysis, NPV may be the best metric for comparing results since change in IRR from case to case will be different depending on what the base case IRR is.

The left side of the respective charts shows the net after-tax Internal Rate of Return and Net Present Value based on gas and electric rates prevalent in the spring of 2005 in the Task 3 report. The projects located in PG&E’s and SDG&E’s service territories illustrated relatively attractive economics while due to very low off-peak energy rates, returns for CHP SCE’s service territory were not attractive.

The first set of bars to the right of the Task 3 case show the incremental decrease in IRR that each of the respective cases would observe as a result in the changes in electric and gas rates that were evaluated in Task 4. In all cases, the evaluated increases in burner tip gas prices (from an average of about $0.60 - $0.70/Therm in the spring of 2005 to about $1.00 - $1.10/Therm in the early winter of 2006), and the corresponding changes in electric rates, resulted in substantial degradation in the economics of CHP. Findings in the Task 3 report indicated that (as a rule of thumb) a relative increase of electric energy rates of at least 40% of the increase in gas prices is necessary to maintain parity for CHP economics. This was not the case as energy rates in SDG&E’s and PG&E’s generally declined in the face of steeply rising gas prices.

Increases in demand rates in SDG&E's and PG&E's service territories were also a strong negative factor for CHP applications. As indicated in the Task 3 report, the 15 or 30 minute demand measurement intervals used over the monthly billing cycle mean that a CHP owner can lose some or all of the demand savings for an entire month as the result of only one brief CHP facilities outage in that month. Additional shifts in PG&E's rates to higher non-coincident demand rates further exacerbate this problem for CHP owners in northern California.

The three groups of bars moving farther to the right on the respective charts illustrate the relative after tax economic benefits that the following externality and tax credits that could apply to CHP applications:

- Transmission and Distribution Credits. At the direction of California Energy Commission staff, a range of estimated values of the deferral or reduction of costs for electric transmission upgrades was assumed to be from \$10 - \$100 / kW year, with a most likely benefit on the order of \$40 / kW yr. This was generally based on findings in the report Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs cited above. As illustrated in Figure 65 and Figure 66, at a value of \$10/kw yr, transmission credits would have only a marginal impact on CHP economics where credits in the range of \$40 - \$100 / kW yr could be substantive.

- Greenhouse Gas Reduction Credits. Similar to the approach described above for transmission and distribution credits, credits for reductions in Greenhouse Gas Emissions (CO_2) were evaluated over a range of \$2 - \$20 / Ton of CO_2. The net potential reductions in greenhouse gas emissions were estimated based on the following assumptions:

  - A utility system wide marginal heat rate of 9000 Btu/kwh. This represents the assumed gas fired utility generating capacity that on the average would be offset by CHP facility operations over the course of a calendar year.
  - An average gas to electricity heat rate (HHV) for CHP facilities of 11,500 Btu/kwh.
  - Available waste heat from the CHP facility would be used first for absorption chilling with all remaining waste heat used for thermal applications, offsetting the corresponding emissions of CO2 that would otherwise be produced equivalent utility electric production (at the 9000 Btu/kwh heat rate described above) and by on-site natural gas fired boilers operating at an average thermal efficiency of 80%.

  The net result of these assumptions is a 33% reduction in CO2 emissions per kWh of utility electric generation that is displaced by the CHP facility. Under this set of assumptions Figure 65 and Figure 66 illustrate the incremental benefits that these credits would provide to CHP attractiveness if available. In general a credit benefit of over \$10 / ton appears to be necessary to substantively benefit CHP economics.

- Production Tax Credits (PTCs for Renewable Energy applications) and Investment Tax Credits (ITCs for microturbines). The Energy Policy Act of 2005 provides additional incentives to CHP projects that use renewable energy (biogas, biomass, wind or solar) as the energy source, or that employ microturbines as the prime mover. The PTCs offer a net benefit of about 0.95 ¢/kwh for energy exported from the site for five years. The investment tax credits for microturbines are 10% of the investment cost for the turbines, up to \$200/kw.

The net incremental benefits of the PTCs are illustrated. All cases evaluated in this study are based on internal combustion engines which are not eligible for the ITC.

The NPV of the 10% ITC for microturbines is about twice that of the indicated PTCs, however, comparisons of the economics of microturbines and internal combustion engines are not part of the scope of this evaluation. Such an analysis, in addition to addressing the tax benefits, must also address the relative capital investment costs, operating costs and the quality of thermal applications needed for a specific site.

Figure 65 - Incremental Impacts of Changes on CHP Owner's Internal Rate of Return

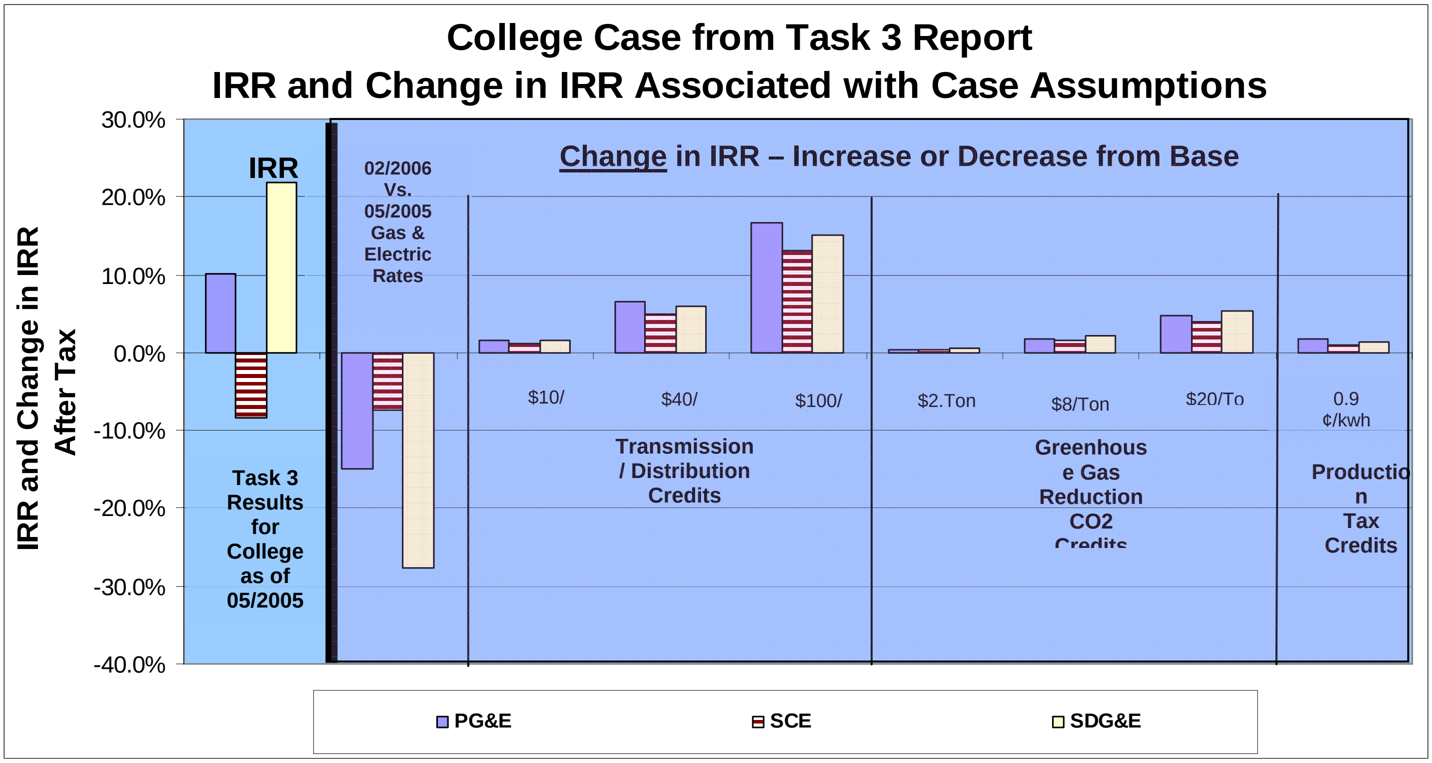
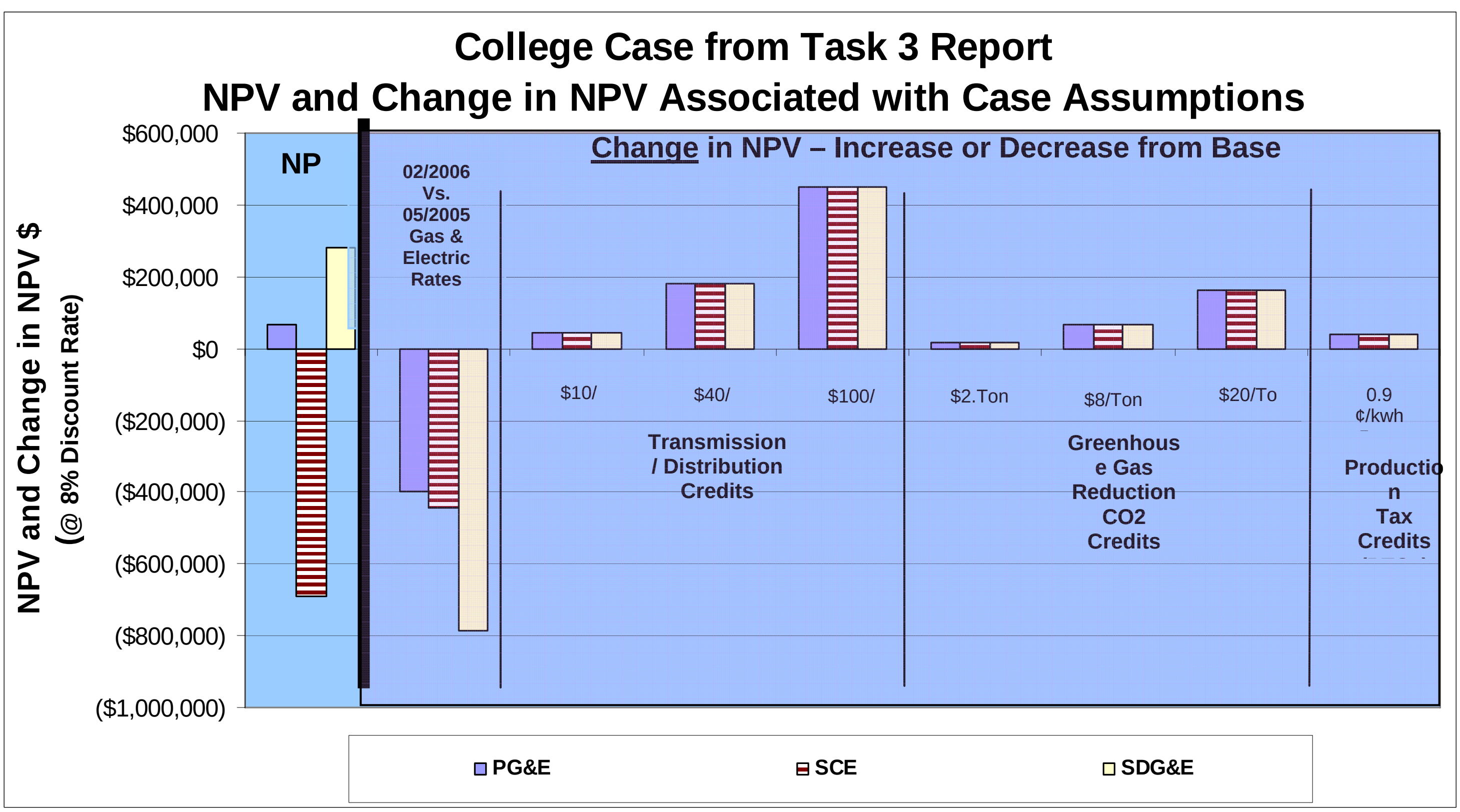


Figure 66 - Incremental Impacts of Changes on CHP Owner's Internal Rate of Return



Appendix C – Task 5

Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based Dairy Digester CHP Projects

I. Executive Summary for Task 5

A. Background

The California Public Utilities Commission and the State of California have expressed an objective of increasing the application of Combined Heat and Power (CHP) projects in California. Dairy farms offer a unique and strategic application for CHP because manure produced by cattle is both an environmental problem and a potential energy source. Using anaerobic digester technologies that are commercially available and well demonstrated, manure can be continuously decomposed to produce a cleaned combustible gas, suitable for use in certain reciprocating engine technologies. These applications at dairy farms offer many strategic benefits including:

- Conversion of manure which would otherwise decay producing fugitive gaseous emissions and an undesirable solid waste to combustible gas and fertilizer
- Reductions in emissions of environmental pollutants and greenhouse gasses
- The generation of power from these combustible gases
- The utilization on-site of waste heat produced during the combustion and power generation process
- Economic benefits to the site host

While policy makers in California have agreed that digester applications offer substantive benefits to the public and to the State, unless otherwise environmentally mandated, the decision to install and operate digester facilities ultimately resides with the private owners of livestock farms that are candidates for digesters. These business owners' objectives are to both improve environmental quality and to save enough money from the energy generated by the facility to justify the associated investment costs and risks.

B. Task 5 - Results and Key Findings

Stakeholders in the digester community expressed frustration with what they view as unfair and insufficient net metering rates paid under the NEM BIO tariff schedules. Their concerns included:

- Most digester projects installed to date have not proven to be cost effective
  - NEM BIO net metering rates are generally insufficient to cover the operating costs of the digester, engine and generator leaving the owner with little or no margin to cover capital investment and fixed costs.
  - The NEM BIO net metering rates are based only on the generation component of the energy rate and exclude all other related costs included in retail rates. Owners find themselves in a position where they are simultaneously purchasing power from the utility at a substantially higher rate than they are selling power back to the utility.

The electric utilities, on the other hand, expressed concerns that revenue recovery from dairy farms implementing digesters often times does not reflect the true costs of service incurred by the utility to serve the dairy. The result is that the utility and rate payer are incurring direct and indirect costs as a result of the installation and operation of these privately owned facilities.

The results yielded by the study indicate that at current NEM BIO rates, a reasonably attractive return on the investment in a digester and associated engine and generator can only be achieved if:

- The bulk of the energy (greater than 75%) generated by the digester is used on-site, behind the meter and minimal energy is net metered, and
- A substantial portion (greater than 50%) of the waste heat from the engine is efficiently utilized on site

These two objectives can be difficult for a dairy farm to achieve because of the dispersed nature of energy uses on the dairy farm. While farms typically use enough electric energy to meet the first criteria, that energy use is generally metered through multiple electric meters dispersed around the farm. Only a small percentage of the total power needs occur at the meter where the digester, engine and generator are interconnected. The majority of the power produced by the digester is treated as export energy at low net metering rates while at the same time energy is being purchased at higher retail rates through other meters on the farm.

Waste thermal energy from the engine is also difficult to utilize in many cases because of the difficulties in moving heat from the location of the digester, engine and generator to where it is needed. It appears, however, that opportunities to use waste heat in current digester projects may not have been fully addressed, detracting from the economics of those projects. Better designs are needed which might include locating the engine and generator nearer to the dairy facilities and piping the gas from the lagoon to that location. This could allow more complete use of the electric and thermal energy from the engine for on-site uses. Also, with more complex digester designs, waste heat from the engine could be used to heat the digester, improving its performance digester performance. These considerations are always site specific.

All of the cases studied showed potentially attractive digester economics at equivalent retail electric rates for the generated power when a sufficient amount of waste thermal energy generated by the engine is captured and utilized. However, the NEM BIO rates for exported power were generally insufficient. Relatively, the NEM BIO rates paid under the respective tariffs studied compared as follows:

- PG&E's NEM BIO rates (under Ag5C) are the least attractive of any of the utilities. The effective net metering rates, even during on-peak periods, are generally at or below the costs of operating the digester, engine and generator, leaving little or no margin to cover fixed and investment costs in the facilities. Projects in PG&E's territory only showed attractive economics when all of the power was used behind the meter and the majority of the waste heat is used on-site.

- SCE's NEM BIO rates (under the TOU-PA) are substantially more attractive during on-peak than they are during off-peak periods. Projects in SCE's territory can be attractive if the majority of the energy produced is used behind the meter and sufficient waste thermal energy from the engine is captured and utilized on site.

- SDG&E's NEM-BIO rates (under the EECC schedule) provide the best incentive of any of the utility rates in California. This is true because the EECC schedule most clearly isolates the fuel cost component in the electric rates and so provides the highest net metering payment. Unfortunately, SDG&E's service territory has by far the fewest potential applications because of the limited number of livestock farms in the SDG&E service territory.

Other findings of Task 5 included:

- Operating costs are a key consideration for digester applications. While the fuel (manure) is essentially free or can even converted to a salable byproduct, maintenance of the digester , engine and generator can be expensive, as high as 4 ¢/kwh or more

- Federal Production Tax Credits (PTC) are important for these projects but unless they involve a third party owner, will apply only to the portion of the energy that is exported. It appears that under the Energy Policy Act 2005 that the PTC rates can be reduced as a result of funding received from sources like the USDA. All analyses in this study included available PTC benefits to the owner.

- Incentives like the SGIP and USDA programs are critical to digester economics. While alone these incentives are not adequate to make these capital intensive projects economic, without these incentives the economics of digesters would be clearly unattractive without very substantial increases in electric rates

Recommendations of the Task 5 study included:

- The PUC should review net metering rates and should allow credits more equivalent to the retail rates that farm owners are simultaneously paying for separately metered farm uses.

- Digester applications should make more efficient use of waste heat from the engine. At current gas prices, thermal uses such as milk pasteurization, processing and other thermal uses should be given highest priority followed by chilling uses such as refrigeration and space conditioning. Some of these might be more easily accomplished if the engine and generator are located near the dairy facilities and the gas is piped from the lagoon to the engine.

- As indicated in the CHP Market Assessment Report, incentives to digester project owners for externalities, including net CO_2, methane or other emissions reductions would provide further incentives for digester to support broader societal benefits.

- Future studies and planning efforts performed by the California Energy Commission and the California Public Utilities Commission should include analysis from the digester owners' perspectives to ensure that the impacts of tariff decisions on project economics are fully understood during the policy making process.

II. Introduction for Task 5

Analysis of the economics of anaerobic digestion at dairy farms involves the tradeoffs between purchasing electricity and gas from the utility or generating power and thermal energy on-site. Digesters involve the continuous production of electric power based on the quantity of manure generated on the farm. Electric and thermal uses on the farm vary over the course of the day and year so at times electric production from the digester will exceed farm needs while at other times all of the energy might be used on-site. If the residual thermal energy from the facility can also used as efficiently for chilling and site thermal uses, the economics can be strongly enhanced. Unfortunately, the dispersed nature of manure lagoons from the site users of energy including milking, milk processing and storage, pumping and irrigation and other uses of power and heat on the dairy farm pose an exceptional challenge to the effective use of electric power behind and single meter and of thermal energy on the farm.

III. Project Approach for Task 5

A. This section overviews the approach used in the study.

B. Stakeholder Interviews

A series of interviews were conducted with representatives of the industry including:

- California Investor Owned Utilities (IOUs)
  - Southern California Edison - Peter F. Moreno – Project Manager
  - Pacific Gas and Electric - Chris Tufon – Senior Tariff Analysis, Harold Hirsch – Tariff Analyst – NEM Tariff, Susan Buller – Senior Regulatory Analyst
  - San Diego Gas and Electric - Bonnie Baily – Supervisor Rate Support, Nancy Winter – Commercial & Industrial Services Mgr., Joe Kloberdanz – Regulatory Affairs Mgr

- Owners, Developers, Engineers and Representatives of digester projects in California
  - Western United Dairymen’s Association , Michael Marsh – CEO of WUD and Chief Executive, Tiffany LaMendola – Director of Economic Analysis
  - Geupard Energy - Rock Swanson - President / CEO
  - Van Ommering Dairy - Rob Van Ommering – General Manager
  - California Power Partners - Tom Moore - President
  - Sustainable Conservation - Ken Krich – Now with University of California
  - RCM Biothane - Eric Larsen – Environmental Scientist, Angie McEliece –State & Federal Incentives

In advance of each interview, a questionnaire was provided to the parties. The respective questionnaires for utility and non-utility interviewees are included in the appendix as are the formal notes from each interview, which were reviewed following the interviews and included edits by the interviewees to ensure that their positions were accurately represented. Other input including data for the study was provided by William Harrison of eGuepard Energy, Larry Castelanelli of Castelanelli Bros. Dairy and Ed Imsand of Meadowbrook Dairy.

Key areas discussed during the interviews included:

- Feedback from the parties regarding what aspects of California tariffs and regulatory policy have the greatest impact on digester economics for dairy applications

- Comments on the structure, benefits and limitations of the California Self Generation Incentive Program and other federal incentive programs

The interviews tended to focus on electric rates and rate making policy relative to the NEM BIO schedules. Not surprisingly, there was a dramatic contrast in the perspectives of the utilities and the digester community relative to the appropriateness and fairness of these rates. This study will not focus on the validity of these alternative positions but rather will concentrate on how rates and other factors influence the economics of digester ownership.

C. Key Points and Observations from Interviews with Suppliers, Owners and Advocates in the Digester Community

Provided below is a summary of the findings reached from discussions with stakeholders in the supply, ownership and operation of digester applications.

- The environmental benefits associated with digester applications are recognized and appreciated. If a reasonable economic scenario can be achieved these projects offer significant potential for odor and greenhouse gas reductions.

- Dairies are low margin facilities and often do not generate sufficient cash flow to support capital intensive investments. Market dynamics, especially variations in feed costs and milk prices, are substantive influences on the cycles and appetite for capital investments of this type of technology.

- Digester projects are capital intensive costing in the range of $5,500/kw (before incentives) to install. To date, the economics of projects installed have been poor.

- There was a consistent and strong concern from all parties we interviewed about the rates paid for exported power under the NEM-BIO schedule, resulting in unattractive economics for these investments.
    - The rates are based only on the generation component of the energy rate and exclude all other tariff components.
    - Owners of these facilities find themselves in a position where they are simultaneously purchasing power from the utility and buying power, at dramatically different rates.
    - Oftentimes NEM-BIO rates are not even sufficient to cover the operating costs of the digester, engine and generator leaving the owner with little or now margin to cover capital investment and fixed costs associated with the digester, engine and generator.
    - Incentive programs are critical because with the current programs the economics of digesters appear to be marginal.

- The tariff structures of the three California IOUs are viewed as overly complex. Most participants expressed that in spite of efforts to understand the tariffs that they still do not have a clear understanding about how the tariffs work or how alternative strategies available to them result in benefits or added risk. Frustration with the utilities was repeatedly expressed.

- Owners and investors feel that they do not have (and can not financially afford to have) an adequate voice in the rate making process. In general, they feel that the utilities have control of the process.
- The rate making process is often contradictory with programs such as the Self-Generation Incentive Program. Customers perceive that the PUC is simultaneously encouraging digesters through the SGIP program and discouraging them through NEM BIO net metering rates.

- Many of the digester projects installed to date are exporting a large percentage of the power they produce and are making minimal use of available waste thermal energy from the engine. The economics of these projects could be substantially enhanced by:
  - Greater benefits under net metering provisions by making net metering rates more equivalent to retail energy rates
  - An option for direct negotiation of power purchase agreements with the utilities with reasonable mandatory provisions for the utility to buy the power similar to those employed under PURPA
  - Greater use behind the meter of the generated power

- Waste heat from the engine has been largely unutilized in existing projects

- Production Incentives including production tax credits (PTCs) are an incentive to digester owners but often apply only to excess energy sales and not to energy used at the site. PTC's can be reduced if other sources of incentive funding are utilized such as funding from the USDA. Further, dairy owners may not have a sufficient tax liability to be able to take full advantage of the tax benefits available to them.

- Technically and operationally, most participants expressed that digester technologies have worked reliably and that the associated technologies are now commercially proven. Substantial emission benefits can result from what?

- Digester and power plant expertise is not standard "know-how" for dairy farmers who generally are focused on maintenance and milking of cattle and sale of milk and milk products. In essence, a digester project is a combination of a chemical facility (the digester) and a small power plant (the engine and generator), carrying with it the issues associated with ownership and operation of these types of equipment.

D. Key Points and Observations coming from the interviews with the California Investor Owned Utilities during Task 5

Discussions with the utilities focused largely on the interpretation and application of the tariffs, especially net metering rates. Provided below is a summary of points made that does not relate to tariff rates. A more detailed overview of the respective tariffs and their components is provided in Section 6.1.A.vi on Page xvii of this report.

- PG&E and SCE see numerous projects underway in their respective service territories. There are a limited number of livestock and dairy facilities in SDG&E's territory.

- Load aggregation is a key provision of the NEM-BIO tariffs.

- The three California IOUs are each making visible efforts to try to be available and responsive to customers questions and inquiries about their tariffs. Each of the utilities had assigned staff dedicated to answering questions and to providing insight to customers with questions.

- Utility personnel reaffirmed that rates do not often accurately reflect or allocate the true costs of service. From their perspective local transmission and distribution facilities are not often adequately sized for the export of power from dairy farms. This can add costs to the utility that is often born by rate payers.

E. Description of Digester Technologies

Figure 67 provides a schematic of a typical dairy based biogas application. Most confined livestock operations handle bio-waste as liquids, slurries, semi-solids, or solids that are stored in lagoons, concrete basins, tanks, and other containment structures. These structures are typically designed to comply with local and state environmental regulations and are a necessary cost of production. Anaerobic digesters biologically convert manure, resulting in biogas and a liquefied, low-odor effluent. Anaerobic digestion of bio-waste significantly reduces Biochemical Oxygen Demand (BOD) and pathogen levels, removes most noxious odors, and converts most of the organic nitrogen to inorganic N (e.g., ammonium).

A typical biogas system consists of the following components:

- Bio-waste Collection
- Anaerobic Digester
- Effluent Storage
- Gas Handling
- Gas Use

Each of these components is discussed briefly.

F. Bio-waste Collection

Livestock facilities use bio-waste management systems to collect and store bio-waste because of sanitary, environmental, and farm operational considerations. Bio-waste is collected and stored as liquids, slurries, semi-solids, or solids. In this study the waste products were assumed to be in liquid or slurry form.

- **Liquid Bio-waste.** Bio-waste handled as a liquid can be diluted to a solid content of less than 3 percent. This liquid is typically "flushed" from where it is deposited, often using fresh or recycled water. The stream can be pumped to treatment and storage tanks, ponds, lagoons or other suitable structures before digestion. Liquid bio-waste systems may be adapted for biogas production and energy recovery in "warm" climates.

- **Slurry Bio-waste.** Bio-waste handled as slurry has been diluted to a solids content of about 3 to 10 percent. Slurry bio-waste is usually collected by a mechanical "scraper" system. This slurry can be pumped, and is often treated or stored in tanks, ponds or lagoons. Slurries managed in this manner may be used for biogas recovery and energy production, depending on climate and dilution factors.

G. Digester Types

The digester utilizes naturally occurring anaerobic bacteria to decompose and treat the bio-waste to produce biogas. Digesters are covered with an airtight impermeable cover to trap the biogas for on-farm energy use. The choice of which digester to use is driven by the existing (or planned) bio-waste handling system at the facility. One of three basic options is typically employed:

- **Covered Lagoon.** Covered lagoons are used to treat and produce biogas from liquid bio-waste with less than 2 percent solids. Generally, large lagoon volumes are required, preferably with depths greater than 12 feet. The typical volume of the required lagoon can be roughly estimated by multiplying the daily bio-waste flush volume by 40 to 60 days. Covered lagoons for energy recovery are compatible with flush bio-waste systems in warm climates.

- **Complete Mix Digester.** Complete mix digesters are engineered tanks, above or below ground that treat slurry bio-waste with a solids concentration in the range of 3 to 10 percent. These structures require less land than lagoons and are heated. Complete mix digesters are compatible with combinations of scraped and flushed bio-waste.

- **Plug Flow Digester:** Plug flow digesters are engineered, heated, rectangular tanks that treat scraped *dairy* bio-waste with a range of 11 to 13 percent total solids.

H. Effluent Storage

The products of the anaerobic digestion are a stabilized organic solution that has value as fertilizer and other potential uses. Waste storage facilities are required to store treated effluent because the nutrients in the effluent cannot be applied to land and crops year round. The size of the storage facility and storage period must be adequate to meet farm requirements during the non-growing season. Facilities with longer storage periods allow flexibility in managing the waste to accommodate weather changes, equipment availability and breakdown, and overall operation management.

I. Gas Handling

A gas handling system removes biogas from the digester and transports it to the end-use, such as an engine or boiler. Gas handling includes: piping; gas pump or blower; gas meter; pressure regulator; and condensate drain(s). Biogas produced in the digester is trapped under an airtight cover placed over the digester. The biogas is removed by pulling a slight vacuum on the collection pipe (e.g., by connecting a gas pump/blower to the end of the pipe, which draws the collected gas from under the cover. A gas meter is used to monitor the gas flow rate. Sometimes a gas scrubber is needed to clean or "scrub" the biogas of corrosive compounds contained in the biogas (e.g., hydrogen sulfide). Since the gas storage space is limited (i.e. the volume under the cover), a pressure regulator is used to release excess gas pressure from the cover. Warm biogas cools as it travels through the piping and water vapor in the gas condenses. A condensate drain(s) removes the condensate as it is produced.

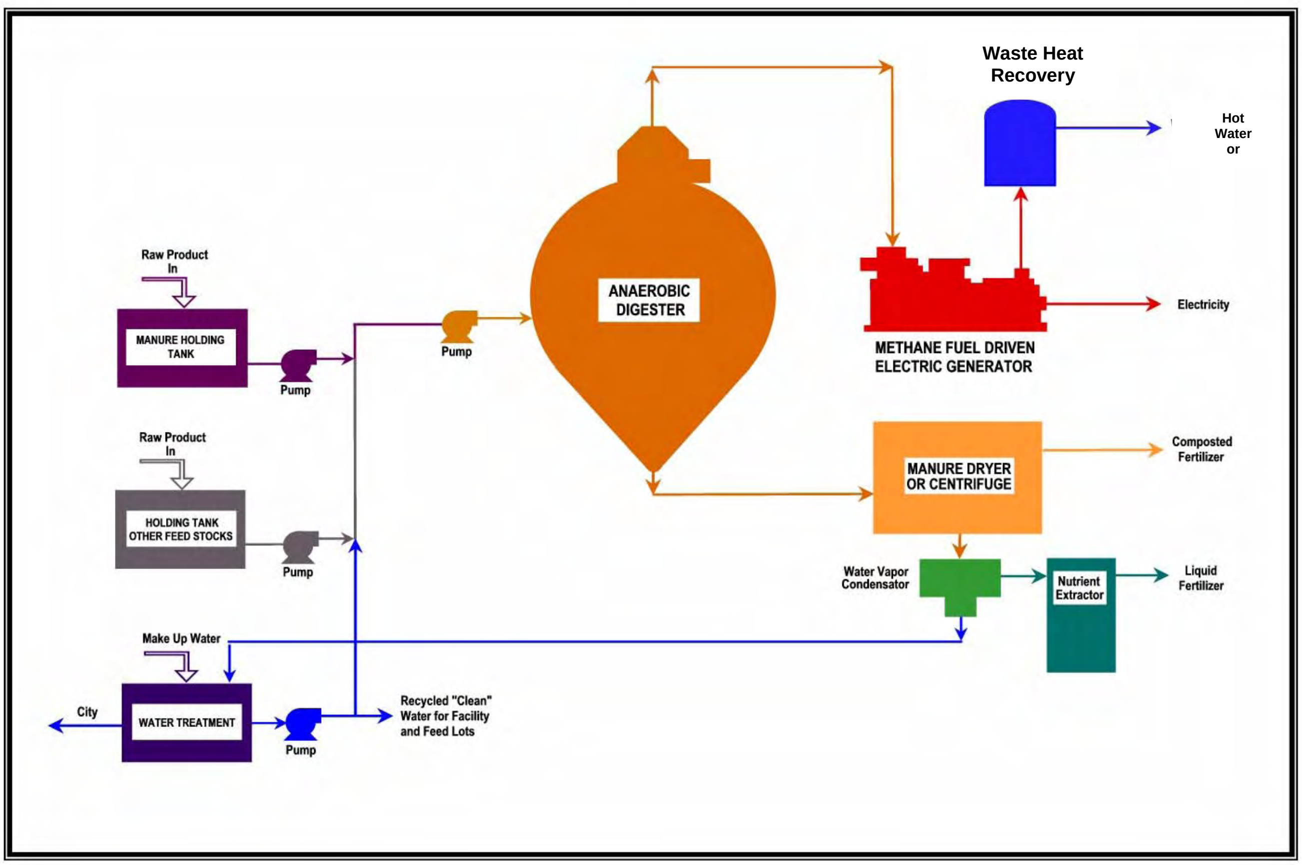
J. **Gas Use**

Recovered biogas can be utilized in a variety of ways. The recovered gas is 60-80 percent methane, with a heating value of approximately 600 - 800 Btu/ft3. The most common technology for generating electricity is an internal combustion engine with a generator. The predicted gas flow rate and the operating plan are used to size the electricity generation equipment.

K. **Chilling/Refrigeration**

Dairy farms use considerable amounts of energy for refrigeration. Approximately 15 to 30% of a dairy's electricity load is used to cool milk. Gas fired or absorption chillers are commercially available and can be used for this purpose.

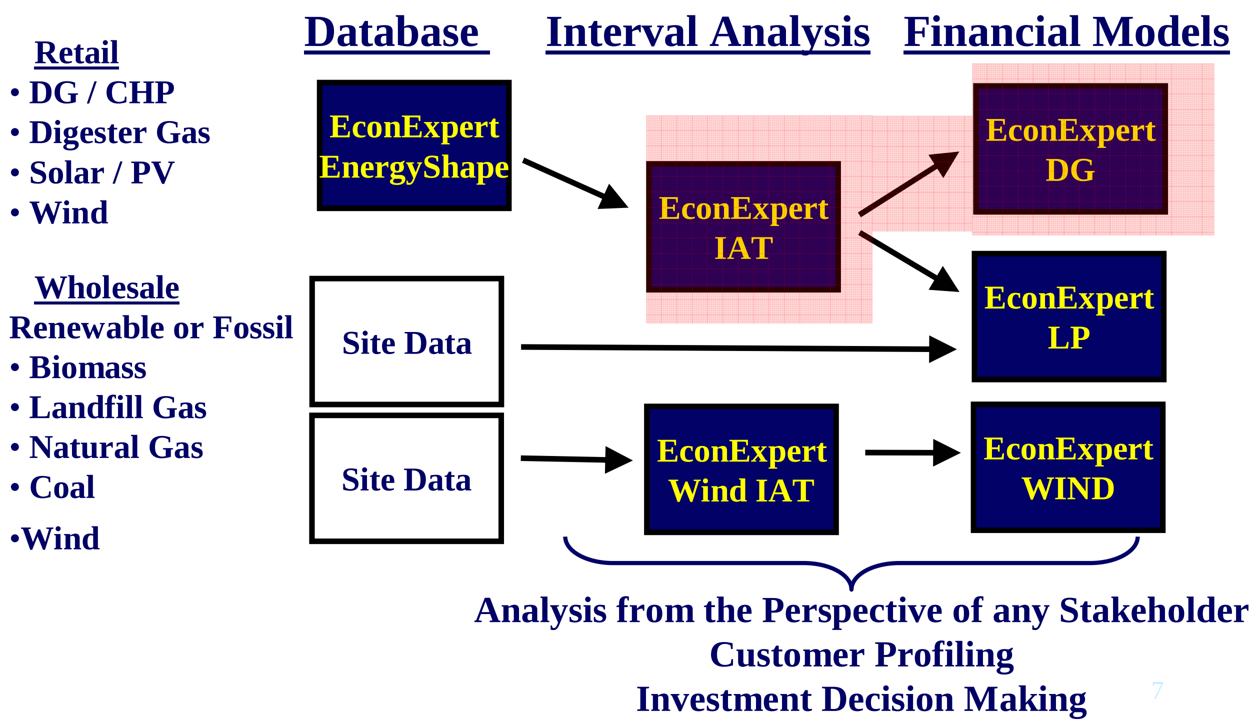
Figure 67 - Schematic of Digester and CHP Power Block



L. Discussion of the Modeling Approach

The analyses provided in this study were performed using the EconExpert™ modeling suite developed by Competitive Energy Insight, Inc. Figure 4 provides a schematic overview of the available components of the EconExpert software suite which include interoperable database, interval analysis and financial modeling modules that were used in this study. The shaded components including EconExpert-IAT and EconExpert-DG were used in this analysis.

Figure 68 - Schematic Diagram of the Software Models Used in the Analysis



The primary steps performed during modeling portion of the study are described below.

M. Develop Proxy thermal and Electric Dairy Load Profiles

The first step in the study was to develop hourly electric, chilling and thermal profiles for a dairy. This was accomplished by blending profiles and billing information provided by three different dairies to arrive at a proxy profile. The dairy owners requested that their specific data remain confidential. The proxy differs from any of the individual profiles or billing data.

Figure 11- Figure 83 in the Appendix provides graphical views of the respective profiles that were used in the analysis.

N. Interval Analysis Modeling

Following the development of the load profiles, the results were entered into the EconExpert-Interval Analysis Tool for hourly operations and savings analysis. Using the standard templates provided in the model, the respective PG&E, SCE and SDG&E tariffs described above were modeled. Details associated with these tariffs are also provided in section 1.A.vi on page 8.

Table 37 – Tariffs Modeled in the EconExpert-IAT Model

Dairy Type	Engine Rated Capacity and Number of Engines	PG&E	SCE	SDG&E
Typical 500 head of cattle	Single 150 kw engine	AG-5C	TOU-PA B	PAT 1B and EECC

The digester facility was assumed to operate at 100% load when available, meeting site needs behind the meter and exporting any excess power at applicable net metering rates. An average availability factor of 95% was assumed.

O. Financial Modeling

Results from the interval analysis were imported into the EconExpert-DG financial model which was used to perform life of project after-tax discounted cash flow analysis for the project. Discounted cash flow is the investment mechanism that large institutional investors including industrials, utilities and banks apply to make investment decisions. All analyses were performed from the perspective of the dairy site host as the project owner.

The primary analysis metrics utilized were:

- Discount Rate - The Discount Rate is the interest rate that is used to bring a series of future cash flows to their present value in order to state them in current or in constant dollars. Use of a discount rate removes the time value of money from future cash flows. The discount rate is typically the weighted average cost of capital of an institution. An average value of 8% was used in the study.
- IRR – The Internal Rate of Return of a project is the discount rate at which the present value of the future cash flows of an investment equals the cost of the investment. When the IRR is equal to the discount rate, the Net Present Value is 0.
- NPV – The Net Present Value can be defined as the future stream of benefits and costs converted into equivalent values today. This is done by assigning monetary values to benefits and costs, discounting future benefits and costs using the discount rate, and subtracting the sum total of discounted costs from the sum total of discounted benefits. The NPV is essentially $ equivalent to the net cash value of the investment, expense and savings streams for the project owner, at the start of the project. When the IRR of the project exceeds the discount rate (8%), a positive NPV will result.

In all cases the owners of the facilities were assumed to be for-profit entities, subject to state and federal income taxes and able to take advantage of available tax benefits and incentives including production tax credits and depreciation.

While many in the distributed generation industry still rely on simple payback as their primary metric to gauge a project's economic viability, CEI does not believe that this is a reliable metric for this type of analysis. Some of the factors not addressed by simple payback which are addressed by IRR and NPV include:

- Inflation and differentiation of escalation rates including variations in electric and gas prices
- The cost of capital
- The timing of cash flows
- Key aspects associated with financing and repayment of debt
- Working capital and inventory considerations
- Annual costs that vary over the life of the asset
- Costs that might occur on a multi-annual basis such a major maintenance
- Equipment life and equipment salvage values
- Changes in annual site electric or thermal demand or conditions
- Degradation in the performance of the equipment over the life of the project
- Partial years of operation
- Accelerated depreciation schedules
- Investment and production tax credits
- Income taxes

While the IRR and NPV targets associated with an attractive investment will vary from owner to owner depending on their whether their enterprise is for-profit or not-for-profit, their access to capital, alternative opportunities for investment of that capital and their perception of the risk associated with an investment. For this purposes of this study, the general rules of thumb that we will apply for target hurdle rates are listed in Table 17.

Table 38 – Illustrative Target Hurdle Rates for Typically Attractive Investments in Dairy Digesters

Investor Type	**Target 10 yr IRR After Tax**	**NPV at Discount Rate of**	**Target 10 year NPV After Tax**
For-Profit Enterprise	**10% - 20% or higher**	**8 – 10%**	**~25% or greater of the initial equity investment**
Not-for-Profit Enterprise	**8% - 10% or higher**	**4 – 6%**	**A Positive Value**

The economics of digester development, installation, ownership and operation are highly site specific and will always require site specific analysis. This study is not intended to illustrate the economic viability of digester for any particular site or installation. The most important findings to be derived from this analysis are the relative impacts of the factors studied on digester economics. Results of these discount cash flow analyses were compared to isolate and illustrate the relative impacts of the various regulatory, tariff and policy factors on digester economics.

P. Scenario and Sensitivity Analyses

Following completion of the discounted cash flow analyses, alternative scenarios were evaluated complemented by a series of sensitivity analyses to measure how changes in premises would affect the economics of digester investments. The effects of individual components of the tariffs were isolated including:

- The amount of produced electric energy credited at retail energy rates versus net metering rates
- The amount of waste thermal energy from the engine that is captured and for site chilling and thermal uses
- Reduced disposal costs and/or sales of waste products produced by the facility as fertilizer

- Capital investment costs
- Investment incentives like the SGIP and USDA programs
- Federal Production Tax Credits (PTCs)
- Operating reliability of the digester
- Interest Rates
- Amount of the owner's equity investment

o The Factors that Affect Digester Economics from an Owner's Perspective – Premises Used in this Analysis

The impacts of policy on digester economics were analyzed with the following goals:

- To compare the economics impacts of zero, partial or full use of electric energy behind the meter
- To compare the economic impacts of zero, partial or full use of thermal energy from the digester for chilling and thermal uses at the site
- To evaluate the incremental benefits of selling byproducts from the digester as fertilizer
- To evaluate other benefits including incentive programs and tax benefits

This section describes the primary factors to consider when modeling the economics of a digester investment and identifies the corresponding premises used in this study.

Q. Dairy Electric Usage Profiles

Understanding the electric and thermal energy use profiles at a dairy is essential for appropriate sizing of the digester and for optimizing the return on investment. Continuous changes in site energy consumption, the balance of opportunities for electric and thermal displacement, and the value of the energy displaced on site versus that of exported energy all play into these considerations. In this analysis proxy hourly profiles were assembled over 8760 hours a year based on profiles assembled from hourly metering data and bills provided by various dairies.

Because quantities of manure production and related environmental considerations are a driver to sizing these applications, site needs must be efficiently integrated with digester gas production in order to achieve optimal economics.

R. Characterization of Dairy Load Profiles Used in this Study

Figure 11 - Figure 83 in the Appendix provide the respective proxy profiles that were generated for the dairy farms in each of the three California IOU service territories. Annual and monthly profiles are displayed, complemented by load duration curves which show the distribution of the respective loads as hours of use. Note that for this study a generator size of 150 kw net production was selected matching a digester sized for a dairy with about 500 head of cattle. During periods when the metered load is less than 150 kw the incremental energy is exported at net metering rates. Table 1 below provides a summary the primary characteristics of these profiles:

Table 39 - Summary of Dairy Proxy Load Profile Characteristics

Interconnection	**Secondary**			
Quarter of the Year	**Q1**	**Q1**	**Q3**	**Q4**
Peak Electric Demand, kw	402	426	484	386
Minimum Demand, kw	34	14	34	37
Season Total Electric	301	467	417	360

Use, 1000 kwh				
Season Chiller Electric Use, 1000 kwh (included above)	30	78	104	53
Calculated Amount of Power Exported from a 150 kw Digester Facility, 1000 kwh	57	13	22	34
Seasonal thermal Use, 1000 Therms	16	13	8	12

A typical 150 kw reciprocating engine fired on digester gas will produce about 6 Therms/hr of usable waste heat (or up to ~13,000 Therms/quarter).

It was observed that most current dairies that have implemented digesters may not be making effective use of the waste thermal energy produced by the engine set. This is for a variety of reasons including the geographically dispersed potential uses of waste heat on the farm (for both chilling and direct thermal uses) and the seasonal / time-related variations. CHP experience has shown that the effective use of waste heat produced from the engine is a key factor in achieving attractive economics. This is also true for digester applications. thermal use at the dairy ranging from 0 – 13,000 Therms/quarter were evaluated to quantify how the effective use of waste heat might influence the economics.

Technical and Economic Premises

Table 4 - Table 6 illustrate the technical and economic premises used in the study. An installed cost of $5,500 / kW was assumed ($3,000 / kw for the digester and auxiliaries and $2,500/kw for the engine and generator) corresponding to firing of a single 150 kW engine. The resulting net total installed cost for the facility was assumed to be $825,000, including:

- Project development expenses
- Costs for start-up
- Working capital
- Spare parts
- Financing or other fees

In the cases where chillers were utilized a cost of $800/ton was added for a 10 ton chiller. A typical 150 kw engine might support 10 – 20 tons of chilling depending on how much of the heat from the engine is recovered. This added amount ($8,000) is relatively insignificant compared to the costs for the balance of the project and in most cases represents only a small portion of the chilling load at the farm. Incentive program credits of $150,000 ($1.00/watt) were applied for funding under the SGIP and $150,000 from the USDA – Natural Resources Conservation Program / Environmental Quality Improvement Program (50% of project cost or $150,000, whichever is less).

Table 40 – Basic Economic Premises

Factor	Premise
Type of Business	For-Profit Dairy Farm Typically 500 Head of Cattle
General Inflation Rate	2.5% / yr
Inflation Rate for Gas and Electric Prices	2.8% / yr
Discount Rate	8.0%
Construction Term	4 Months
Start-of-Operations	1/1/07
Project Life	10 years
Cost of Equipment and Installation incl. working capital, start-up, spare parts, fees and construction interest	$5,500 / kw (Digester and Auxiliaries $3,000/kw Engine and generator $2,500/kw)
Cost of Absorption Chillers	$800 / Ton
SGIP Rebate	$1.00 / watt = $150,000
USDA – Natural Resources Conservation Program / Environmental Quality	50% up to $150,000
Variable Operating Costs (incl. allowance for major Maintenance)[1]	4.0 ¢ / kwh
Interest Rate on Borrowed Funds	9.0% / yr Fixed
Debt / Equity Ratio	50 % / 50 %
Loan Term	10 years
Federal Income Tax Rate	35%
California State Income Tax Rate	8.84 %
Tax Depreciation	50% 5 Year MACRS 50% 10 Year MACRS
Production Tax Credits	0.95 ¢ / kwh for export sales for 5 years reduced by 18% to account for funding received under the USDA Program

1 – Source eGuepard Inc. from Project Costs Estimates for Dairy Project in the Imperial Valley

Table 41 - Gas Price Premises, Value of Displaced thermal Energy

Month of the Year	Gas Price, $/Therm Delivered

January	1.10
February	1.10
March	1.05
April	1.05
May	1.00
June	1.00
July	1.00
August	1.00
September	1.00
October	1.00
November	1.05
December	1.05
Annual Average	1.03

Table 42 – Basic Technical Premises

Factor	Premise
Efficiency of host's existing boilers	80 %
Engine Specifications / Manufacturer	Caterpillar – 3406 Adapted for Biogas
Base Fuel	Natural Gas
Rated Capacity	150 kw net
Number of Engines	1
Minimum Load / Engine	100% - No Cycling
Useful engine thermal produced at full load	6.5 Therms/hr
Forced + Planned Outage Rate	5.0% Minimum Downtime / Engine
Chiller Capacity	20 Tons

Utility Tariffs Typically Applicable to Dairy Facilities

It is very important to emphasize that it is not in the scope of this analysis to evaluate the basis or justification for the utility electric tariffs. This study is focused exclusively on evaluating how various factors, including electric tariffs, influence the economic viability of digester applications in California based dairy farms from the perspective of a dairy farm owner.

As regulated entities, Investor Owned Utilities in California are required to obtain approval from the California Public Utilities Commission for the rates that they charge to their customers. This process is complex and often times highly political with the conflicting interests of a myriad of parties participating either directly or indirectly in the rate making process. Rates paid to the utilities are intended to cover both historical and annual costs and to reward a rate of return to the utilities on invested capital. Tariffs typically include allowances for:

- The cost of installed generation, transmission and distribution facilities
- Fuel costs
- Operating costs
- Financing costs
- Costs for decommissioning of aged facilities, including nuclear projects
- Overhead costs associated with operating the utility business
- Other special accounts including public purpose funds, competitive transition charges, bond payments, energy purchases (i.e. Department of Water Resources), etc.

The tariffs applied by the California IOU's generally include the following components designed to recover the costs described above and to provide the utility with a profit margin.

- Basic Service Fees - Fixed fees that do not vary with demand or energy use
- Demand Charges which may include coincident and/or non-coincident components
    - Coincident Demand Charges – Fees based on the maximum demand (kW) in one or more specific rate periods
    - Non-Coincident Demand Charges – Fees based on the maximum demand (kW) without consideration of at what time of day or in what rate period that demand occurs
- Energy Charges – Fees tied to the amount of energy use (kWh) in each rate period
- Other cost components and fees such as power quality adjustments and franchise fees, etc.
- SDGE imposes demand ratchet on the user in a given month that are actually based on demand use in prior periods
- Customers under NEM BIO are exempt from the Standby Tariff under PUC 2827

The utility rate components are then each further broken down based on the level of service associated with the interconnection to the site. Service levels for the dairy types evaluated in this study were assumed to be "secondary" (standard utility service).

Table 7 provides a simplified comparison of the respective tariffs evaluated in this report effective on January 1, 2006. The table includes rounding of certain rates (actual rates without rounding were used in the financial modeling). Franchise fees were not included because most dairy applications are rural.

Following Table 7 is a discussion of the key features of each of the tariffs, including insights derived from the interviews with utility personnel. The tariffs are complex and there are exceptions and special conditions that apply under specific circumstances; for the purposes of this study a common set of assumptions was applied across the three proxy sites. The reader is advised to consult their utility with respect to the specific conditions that apply to a site specific application.

Table 43 –Bundled Rates for Dairies with Peak Demand on the order of 500 kw[1, 2]

Utility	**PG&E**	**SCE**	**SDG&E**
Agricultural Tariff Studied Secondary Interconnection	AG-5C	TOU PA B	PA-T-1A, EECC
Applicable to Peak Loads Over	200 kw	500 kw	500 kw or sites under 500 kw who install on-site generation
Basic Service Fees[4]	$1.97 / Meter/Day	$47.95 / Meter / Mo	$48.52/Meter/Mo
Standby Rate	NemBio - Exempt	NemBio - Exempt	NemBio Exempt
Bundled Demand Charges, $/kw[4]			
Metering Interval	30 Min	15 Min	15 Min
Non-Coincident	$0.73 – $4.78	$3.90	
Mid-Peak[3]	$0.73 - $1.24		$6.53
On-Peak[3]	$4.78	$11.35	$6.25
Bundled Energy Charges, ¢/kwh[4]	Winter - Summer	Winter – Summer	
Off-Peak[3]	5.3 – 5.4 ¢	5.0 ¢	7.88 ¢
Mid-Peak[3]	6.3 – 6.6 ¢	8.8 –10.3 ¢	7.98 ¢
On-Peak[3]	8.4 ¢	13.6 ¢	10.39 ¢
NEM Bio Net Metering Rate, ¢/kwh			
Off-Peak[3]	**2.2 – 2.3 ¢**	**3.1 ¢**	**6.5 ¢**
Mid-Peak[3]	**3.1 – 3.2 ¢**	**6.9 – 8.4 ¢**	**6.5 ¢**
On-Peak[3]	**3.6 ¢**	**11.6 ¢**	**8.9 ¢**
Departing Load Charges	NemBio - Exempt	NemBio - Exempt	NemBio - Exempt
Ratchets	N/A	N/A	For the non-coincident demand charge the customer pays the current months peak or 50% of highest peak established during the preceding 11 Months.

8. The rates shown are those effective on 1/1/2006.
9. Bundled rates are rounded for illustrative comparisons. In the modeling analysis, the actual seasonal, time and transmission level specific rates were used without any rounding using the values shown in
10. Ranges shown indicate Winter - Summer Periods. The three utilities all use different nomenclature to designate rate periods. PG&E uses Peak, Part-Peak and Off-Peak, SCE uses On-Peak, Mid-Peak and Off-Peak, and SDG&E uses On-Peak, Semi-Peak and Off-Peak. For the purposes of comparison the general categories of On-Peak, Mid-Peak and Off-Peak are used reflecting the three respective rate periods.
11. All rates exclude franchise fees. Applications are assumed to be rural.

S. PG&E Tariff Overview

The PG&E tariff evaluated in the Task 5 study was the AG-5C which is the most common tariff applied to dairies. AG-5C generally applies for customers who use 70% or more of their power for agricultural purposes and whose demand exceeds 200 kw. After installing a digester, a customer previously subject to the AG-5C tariff may stay on that tariff.

The AG-5C schedule for secondary service is summarized in Tables 8 and 9 below. The AG-5 Primary rate structure is similar with generally higher energy and demand rates which tend to be more favorable to digester where applicable, but are less common for dairies.

Observations concerning PG&E's AG-5-C Tariff include:

- PG&E meters electric demand on a 30 minute interval basis
- PG&E has the lowest NEM BIO net metering rates. The generation component of the energy rates are in the range of 2.2–3.7 ¢/kwh. Operating and maintenance costs of the digester, engine and generator can be as high as 4 ¢/kwh meaning that net metering rates are not sufficient to cover just the operating costs of the facility. To incentivize these investments, fixed, capital investment costs and a return must also be provided.
- Significant non-coincident demand charges apply in the summer and winter periods

Table 44 - PG&E AG-5C Rate Periods

Winter — **November - April**

	Bundled Rates	Weekdays				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Off-Peak	5.43	12:00 AM	8:30 AM	9:30 PM	12:00 AM	11
Part Peak	6.32	8:30 AM	9:30 PM			13
		Weekends/Holidays				Hours/Day
Off-Peak	5.43	12:00 AM	12:00 AM			24

Summer — **May - October**

	Bundled Rates	Weekdays				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Off-Peak	5.27	12:00 AM	8:30 AM	9:30 PM	12:00 AM	11
Part Peak	6.65	8:30 AM	12:00 PM	6:00 PM	9:30 PM	7
Peak	8.36	12:00 PM	6:00 PM			6
		Weekends/Holidays				
Off-Peak	5.27	12:00 AM	12:00 AM			24

The bundled rates above do not include Franchise Fees.

Table 45 - PG&E AG-5 C Rates - Unbundled

Typical Franchise Fee 0.00% **Customer Charge** **$/Meter Day** **$ 1.97**

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Demand Charges, $/kw mo

	Generation	Distribution	Transmission	Reliability Service	Bundled Sub-Total
Summer					
Maximum Peak		4.78			4.78
Maximum Part-Peak		1.24			1.24
Maximum Demand (Non-Coincident)		3.75			3.75
Winter					
Maximum Part-Peak		0.73			0.73
Maximum Demand (Non-Coincident)		1.88			1.88

Energy Charges, c/kwh

	Generation	Distribution	Transmission	Reliability Service	PPP	NDC	CTC	DWR Bond Charge	ECRA	Bundled Rate w/o Franchise Fee
Summer										
Peak	3.661	2.051	0.489	0.193	0.529	0.038	0.472	0.485	0.437	8.355
Part Peak	3.186	0.821	0.489	0.193	0.529	0.038	0.472	0.485	0.437	6.650
Off-Peak	2.212	0.410	0.489	0.193	0.529	0.038	0.472	0.485	0.437	5.265
Winter										
Part Peak	3.056	0.621	0.489	0.193	0.529	0.038	0.472	0.485	0.437	6.320
Off-Peak	2.348	0.441	0.489	0.193	0.529	0.038	0.472	0.485	0.437	5.432

Filed December 30, 2005 - Effective January 1, 2006
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges

W. SCE Tariff Overview

The SCE tariff evaluated in the Task 5 study was the TOU PA which applies for customers with a maximum demand of 500 kW or greater and for all NEM BIO applications. The TOU PA primary rate is summarized in Tables 8 and 9 below. The TOU PA primary and secondary service level rates are similar. Observations concerning SCE's TOU PA Tariff include:

- SCE meters electric demand on a 15 minute interval basis
- SCE breaks out utility generation (URG) from DWR generation purchased on a monthly basis. The factoring of these rates varies monthly but is generally in the range of 70% URG / 30% DWR proportions
- SCE's on-peak NEM BIO net metering rates are generally attractive for digester applications but off-peak rates are not. These low off-peak net metering rates (~3¢/kwh) are a substantive disincentive to digester applications which generally must operate around the clock.
- Demand is billed monthly and there is no ratchet

Table 46 – SCE TOU-PA Rate Periods

Winter **October - May**

	Bundled Rates	Weekdays				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Off-Peak	5.00	12:00 AM	8:00 AM	9:00 PM	12:00 AM	11
Mid-Peak	10.34	8:00 AM	9:00 PM			13
		Weekends/Holidays				Hours/Day
Off-Peak	5.00	12:00 AM	12:00 AM			24

Summer **June - September**

	Bundled Rates	Weekdays				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Off-Peak	5.00	12:00 AM	8:00 AM	11:00 PM	12:00 AM	9
Part Peak	8.86	8:00 AM	12:00 PM	6:00 PM	11:00 PM	9
On-Peak	5.00	12:00 AM	6:00 PM			6
		Weekends/Holidays				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish			Hours/Day
Off-Peak	5.00	12:00 AM	12:00 AM			24

Table 47 – SCE TOU-PA Rates

Typical Franchise Fee **0.00%** **Customer Charge** **$/Meter/Mo** **$47.95**

Demand Charges, $/kw mo	Generation	Transmission and Distribution	Total
Summer			
Peak	**3.86**	**7.49**	**11.35**
Part Peak			**-**
Facilities (Non-Coincident)		**3.90**	**3.90**
Winter			
Facilities (Non-Coincident)		**3.90**	**3.90**

Energy Charges, c/kwh	Delivery Service						Generation		Bundled Rate prior to Franchise Fees
	Transmission	Distribution	NDC	PPP	DWR Bond Charge	Sub Total	URG 70% Avg.	DWR 30% Avg.	
Summer									
Peak	**0.121**	**0.839**	**0.054**	**0.439**	**0.485**	**1.938**	**12.157**	**10.369**	**13.559**
Part Peak	**0.121**	**0.839**	**0.054**	**0.439**	**0.485**	**1.938**	**5.450**	**10.369**	**8.864**
Off-Peak	**0.121**	**0.839**	**0.054**	**0.439**	**0.485**	**1.938**	**(0.063)**	**10.369**	**5.005**
Winter									
Part Peak	**0.121**	**0.839**	**0.054**	**0.439**	**0.485**	**1.938**	**7.554**	**10.369**	**10.337**
Off-Peak	**0.121**	**0.839**	**0.054**	**0.439**	**0.485**	**1.938**	**(0.063)**	**10.369**	**5.005**

Filed December 16, 2005 - Retroactive subject to interpretation rulings.
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
DWR Bond Charge = Department of Water Resources Bond Charge
URG - SCE Generation
DWR - Department of Water Resources Generation

X. **SDG&E Tariff Overview**

The SDG&E tariffs used in this Task 5 study was the PA-T-1 rate and EECC rate which is an experimental rate that currently applies for dairies and like agricultural facilities.

Observations concerning SDG&E's rates include:

- SDG&E's net metering rates are the highest of the three utilities consistent with the relative isolation of fuel costs in the EECC schedule. For the purposes of this study the EECC rate effective 1/1/06 was used for both summer and winter commodity rates. This tends to more frequently equilibrate bundled energy rates with gas prices than do the other utilities.

- SDG&E assesses a demand ratchet. Non-coincident demand charges are computed as the maximum of the current monthly demand and 50% of the highest monthly demand over the previous 11 months

- SDG&E's PAT-1 rates apply only coincident demand charges. This is unlike non-agricultural rates which substantively emphasize non-coincident demand charges.

- SDG&E's bundled energy rates (including PAT-1 and EECC components) exhibit a much smaller range from on-peak to off-peak than do the other utilities' rates. This is because the EECC component comprises most of the energy rate and does not typically vary as significantly from rate period to rate period.

While SDG&E's rates are the most attractive of the California IOUs for these applications, there are very few potential livestock applications in SDG&E's service territory.

Table 48 – SDG&E PAT-1 Rate Periods (Includes EECC Rate but not Franchise Fee)

Winter	**October - April**					
	Bundled Rates	**Weekdays**				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Off-Peak	8.10	12:00 AM	6:00 AM	10:00 AM	12:00 AM	8
Semi-Peak	8.28	6:00 AM	5:00 PM	8:00 PM	10:00 PM	13
On-Peak	10.86	5:00 PM	8:00 PM			3
		Weekends/Holidays				
Off-Peak	8.10	12:00 AM	12:00 AM			24

Summer	**May - September**					
	Bundled Rates	**Weekdays**				
Name of Period	Rate ¢/kwh	Hr Start	Hr Finish	Hr Start	Hr Finish	Hours/Day
Off-Peak	8.10	12:00 AM	6:00 AM	10:00 AM	12:00 AM	8
Semi-Peak	8.28	6:00 AM	11:00 AM	6:00 PM	10:00 PM	9
On-Peak	10.86	11:00 AM	6:00 PM			7
		Weekends/Holidays				
Off-Peak	10.86	12:00 AM	12:00 AM			24

Table 49 – SDG&E PAT-1-B & EECC Rates – Unbundled

Typical Franchise Fee	0.00%	**Customer Charge**	$/Meter Mo	$ 48.52

Demand Charges, $/kw mo

	Generation	**Distribution**	**Transmission**	**CTC**	**Reliability Service**	**Total**
Summer						
On-Peak		5.27		0.91		6.18
Maximum Demand (Non-Coincident)						-
Winter						
On-Peak		5.27		0.91		6.18
Maximum Demand (Non-Coincident)						-

Energy Charges, c/kwh

	Generation See EECC Schedule	Distribution	Transmission	PPP	NDC	CTC	DWR Bond Charge	Reliability Service	Bundled Rate w/o Franchise Fee
Summer									
Off-Peak	6.502		(0.139)	0.560	0.046	0.286	0.459	0.387	8.101
Semi-Peak	6.502		(0.139)	0.560	0.046	0.463	0.459	0.387	8.278
On-Peak	8.904		(0.139)	0.560	0.046	0.640	0.459	0.387	10.857
Winter									-
Off-Peak	6.502		(0.139)	0.560	0.046	0.264	0.459	0.387	8.079
Semi-Peak	6.502		(0.139)	0.560	0.046	0.331	0.459	0.387	8.146
On-Peak	8.904		(0.139)	0.560	0.046	0.471	0.459	0.387	10.688

PA-T-1 Rate Filed December 29, 2005 - Effective January 1, 2006
EECC - Electric Energy Commidity Cost Rate Effective Janary 1, 2006
PPP = Public Purpose Programs
NDC = Nuclear Decommissioning Charges
CTC = Competitive Transition Charges
DWR Bond Charge = Department of Water Resources Bond Charge
ECRA = Energy Cost Recovery Account

IV. Project Outcomes

This Task 5 study had two primary goals:

- To provide an objective analysis of the impacts of policy in California - including rate making policy, utility tariffs, the NEM BIO net metering schedules for the 3 utilities, the Self Generation Incentive Program (SGIP) and funding programs available under the USDA, and available tax benefits - on the economic viability of digester in California from a dairy owner's perspective
- To perform sensitivity analyses to evaluate how other factors including capital costs, alternative net metering rates, the use of energy on site, production tax credits and other factors can impact the economic viability of digester and can influence of impacts of policies on the economic viability of digester

The comparisons performed were based on proxy dairy load profiles assembled from actual metering and billing data received from various dairies.

Descriptions of Scenarios

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Table 18 provides a matrix of the scenarios and cases that were modeled in this study. For each of the 3 utility service territories, 7 cases were modeled. The base assumptions are summarized in Section 1.A.iii,

Table 4- Table 6. The seven cases respectively represent incremental improvements to the respective economics of digester implementation as described below:

Table 50 - Case Study Matrix – Applied for Each Tariff Studied

Case	Derived from Case	% of Energy Exported Under NEM-BIO	% of Energy Produced Used Behind the Meter	% of thermal Recovered and Applied to Chilling	% of thermal Recovered and Applied to Site thermal Uses	% of thermal Energy Discarded	Value of Waste Product from Digester
Least Optimistic 1		100%				100%	
2	1	**50%**	**50%**			100%	
3	1		**100%**			100%	
4	3		100%	**50%**		**50%**	
5	3		100%		**50%**	50%	
6	3		100%		**100%**		
Most Optimistic 7	6		100%		100%		**$3.00**

Shaded items the value of that parameter was 0 in the identified case.
Bold Items represent Values that were changed relative to the "Derived from Case"

B. **Case *1* – Least Optimistic - All Energy Net Metered, No thermal Recovery and No Value for Waste Produced from the Digester**

The first case analyzed for each utility represents the most conservative case where:

- All of power is generated is exported at net metering rates
- None of the available waste heat from the engine is captured and utilized on-site
- No value is realized for the by-product waste produced

In essence this is reflective of a digester project located remotely from the virtually all thermal and electric uses at the site. While most projects typically use some of the power behind the meter and may use some of the waste heat on site, it is not unusual for these projects to export the propensity of the energy produced.

C. **Case *2* – Derived from Case 1 - 50% of the Electric Energy Used Behind the Meter, 50% Net Metered, No thermal Recovery and No Value for Waste Produced from the Digester**

This case is the same as Case 1 except that 50% of the power generated by the engine is assumed to be credited at retail ("behind-the-meter" rates).

There was a consistent and strong concern from all parties we interviewed about the rates paid for exported power under the NEM-BIO schedule. The rates are based only on the generation component of the energy rate and exclude all other related credits. As a result, owners of these facilities find themselves in a position where they are simultaneously purchasing power from the utility and selling power to the utility at dramatically different rates. This case illustrates some of the relative benefits of valuing the energy produced at retail rates rather than at net metering rates. It also provides guidance on the relative incentives that higher net metering rates would provide to owners of these projects

D. **Case *3* – Derived from Case 1 – 100% of the Electric Energy Used Behind the Meter, No thermal Recovery and No Value for Waste Produced from the Digester**

This case is the same as Case 1 except that 100% of the power generated by the engine is assumed to be credited at retail ("behind-the-meter" rates) and no energy is net metered.

E. **Case *4* – Derived from Case 3 - 100% of the Electric Energy Used Behind the Meter, 50% of the thermal Energy Recovered for Chilling Uses, No Value for Waste Produced from the Digester**

This case is the same as Case 3 plus benefits for recovering half of the available waste heat from the engine and using it to drive absorption chillers to further reduce electric energy use behind-the-meter. Adding chillers also adds about $800/ton to the cost of the project. In this case a 10 ton chiller is applied, with marginal added capital of about $8000.00.

F. **Case *5* – Derived from Case 3 - 100% of the Electric Energy Used Behind the Meter, 50% of the thermal Energy Recovered for Site thermal Uses, No Value for Waste Produced from the Digester**

This case is the same as Case 3 plus benefits for recovering half of the available waste heat from the engine and using it for thermal uses at the site, displacing natural gas use. An average annual natural gas price of about $1.03/Therm was assumed with an 80% thermal efficiency for converting the gas to thermal uses like steam or hot water.

As natural gas prices have increased disproportionately relative to electric rates, the relative value of applying thermal energy for direct thermal offsets (though the production of hot water or steam) has increased. It can be anticipated that over time the differentials between electric and gas rates will tend to equilibrate, though since gas accounts for only about 50% of the generation in California and generation accounts for only a portion of the rates, the increases will not be proportionate. This means that the enhanced benefits of capturing energy for thermal offsets rather than chilling is likely to continue.

G. **Case *6* – Derived from Case 3 - 100% of the Electric Energy Used Behind the Meter, 100% of the thermal Energy Recovered for Site thermal Uses, No Value for Waste Produced from the Digester**

This case is the same as Case 3 plus benefits for recovering all of the available waste heat from the engine and using it for thermal uses at the site, displacing natural gas use. As in Case 5, an average annual natural gas price of about $1.03/Therm was assumed with an 80% thermal efficiency for converting the gas to thermal uses like steam or hot water.

H. **Case *7*– Derived from Case 6 - 100% of the Electric Energy Used Behind the Meter, 100% of the thermal Energy Recovered for Site thermal Uses, $3.00/ton Credit for Waste Produced from the Digester for Fertilizer Uses**

This case is the same as Case 7 plus benefits for selling the byproduct solids from the digester. This case shows the incremental value of selling the solid byproducts from the digester for fertilizer uses. A price of $3.00/ton is assumed.

Summary of Task 5 Results

At gas prices prevalent at the time of the study (about $1.00/Therm delivered) the largest potential contributing factor to enhancing the economics of digester applications appears to be full capture and utilization of the thermal energy produced by the engine. This option is limited in practice by the quantities and profiles of thermal uses at the dairy farm, but include applications such as pasteurization of the milk, sanitization and cleaning of facilities and other process applications. Chilled water uses are of lower value at current electric and gas rates. By product sales offer a lesser but important benefit which depends on local market conditions.

Table 16 shows comparative net metering rates. The most prominent influencing factor that the PUC can provide would be to implement net metering rates that are more comparable to retail rates for the aggregated load behind all of the agricultural facilities meters. **Figure 69** provides a summary of the calculated IRRs for each case and Figure 70 provides a summary of the corresponding NPVs. It should be noted that for the first few cases studied in each group the rates of return were less than a minus 10% and so could not be precisely calculated.

Table 51 provides a summary of the incremental changes in NPV for the "derived from" case. This summary provides an important indication of the relative net benefit provided by each of the successive revenue enhancements that were evaluated. Key findings of the analysis follow:

- PG&E's NEM BIO rates are the least attractive and are probably lower than just the cost of operating the digester , engine and generator. Projects in PG&E's territory only appear to show attractive economics only when all of the power can be used behind the meter and the majority of the waste heat can be used on-site. Energy credits at retail rates and recovery of the majority of the waste heat from the engine are necessary to provide sufficient economics to justify the investment on an economic basis. This is true even with SGIP and USDA grant funding.

- SCE's NEM BIO rates are more attractive than PG&E's, especially during on-peak periods. Projects in SCE's service territory could achieve attractive economics the majority of energy is used inside the fence or were credited for energy production at retail rates even if only a small portion of the waste heat can be captured and utilized

- SDG&E's NEM-BIO rates (derived from the EECC schedule) provide the best incentives of any of the studied rates. This is true because the EECC schedule most clearly isolates the fuel cost component in the electric rates and provides the highest net metering payment. Projects in SDG&E's service territory could achieve attractive economics if the majority of energy is used inside the fence or were credited for energy production at retail rates even if only a portion of the waste heat can be captured and utilized. Unfortunately, SDG&E's service territory has by far the fewest potential applications because of the limited number of livestock farms.

At gas prices prevalent at the time of the study (about $1.00/Therm delivered) the largest potential contributing factor to enhancing the economics of digester applications appears to be full capture and utilization of the thermal energy produced by the engine. This option is limited in practice by the quantities and profiles of thermal uses at the dairy farm, but include applications such as pasteurization of the milk, sanitization and cleaning of facilities and other process applications. Chilled water uses are of lower value at current electric and gas rates. By product sales offer a lesser but important benefit which depends on local market conditions.

Table 52 shows comparative net metering rates. The most prominent influencing factor that the PUC can provide would be to implement net metering rates that are more comparable to retail rates for the aggregated load behind all of the agricultural facilities meters.

Figure 69 - Calculated Project IRRs for Each Case

(For-Profit Entity – Owner Assumed to be Taxable)

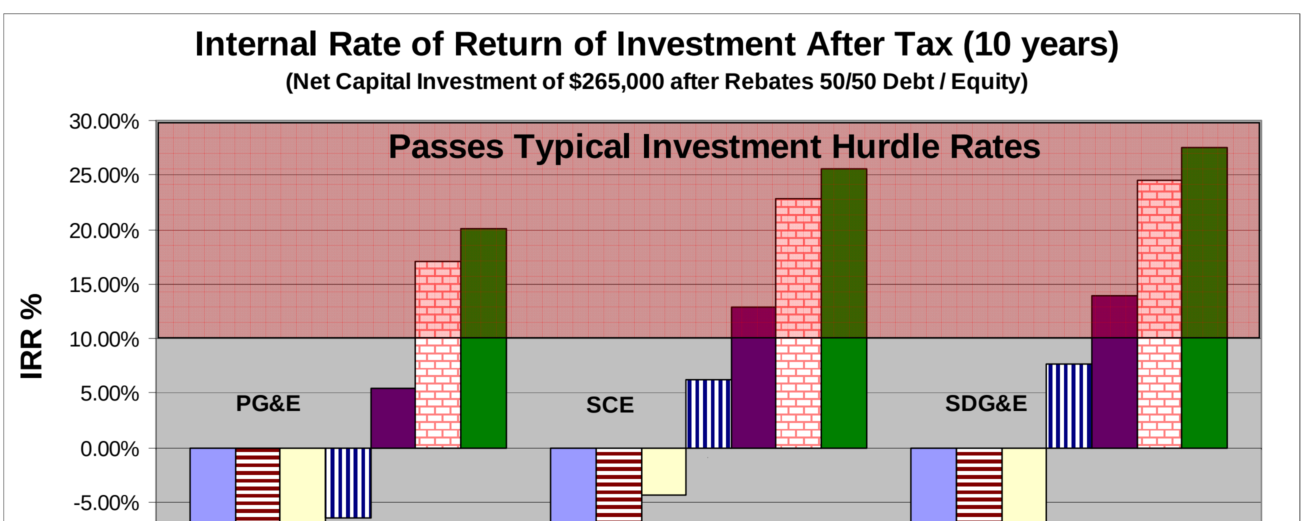


Figure 70 - Calculated NPVs for Each Case

(For-Profit Entity – Owner Assumed to be Taxable)

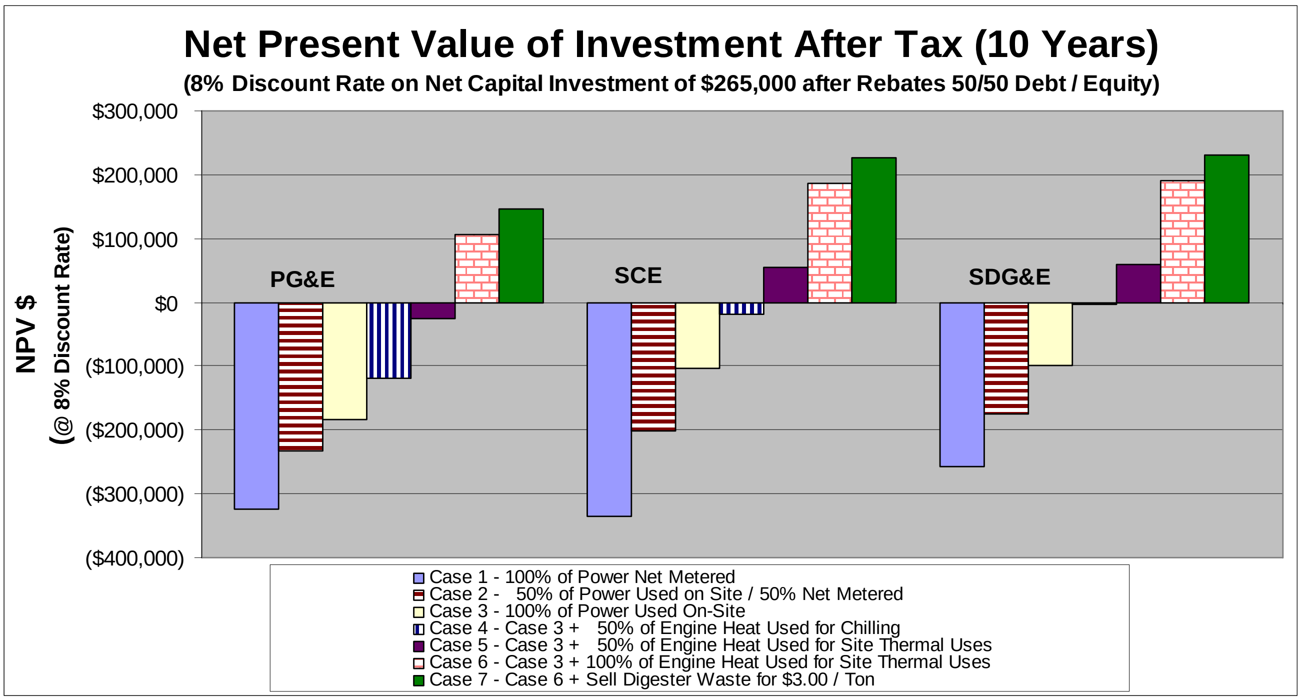


Table 51 – Incremental Value of Each Case versus the Case it was Derived From

1000 $ NPV

Case	**Description**	**Case it was Derived From**	**PG&E**	**SCE**	**SDG&E**
	Tariff		AG-5C	TOU PAB	PA-T-1A and EECC
1	100% of Power Net Metered	N/A	$-	$-	$-
2	50% of Power Used On-Site 50% of Power Net Metered /	1	$91	$133	$84
3	100% of Power Used On-Site	1	$140	$231	$159
4	Case 3 + 50% of Engine Heat Used for Chilling	3	$65	$85	$95
5	Case 3 + 50% of Engine Heat Used for Site thermal	3	$159	$159	$159
6	Case 3 + 100% of Engine Heat Used for Site thermal	3	$290	$290	$290
7	Case 6 + Sell Digester Waste for $3.00/Ton	6	$41	$41	$41

Table 52 - Summary of Net Metering Rates as of 1/1/06

NEM Bio Net Metering Rate, ¢/kwh[1]	**PG&E**	**SCE**	**SDG&E**
Off-Peak	2.2 – 2.3 ¢	3.1 ¢	6.5 ¢
Mid-Peak	3.1 – 3.2 ¢	6.9 – 8.4 ¢	6.5 ¢
On-Peak	3.6 ¢	11.6 ¢	8.9 ¢

1 - Ranges shown indicate Winter - Summer Periods. The three utilities all use different nomenclature to designate rate periods. PG&E uses Peak, Part-Peak and Off-Peak, SCE uses On-Peak, Mid-Peak and Off-Peak, and SDG&E uses On-Peak, Semi-Peak and Off-Peak. For the purposes of comparison the general categories of On-Peak, Mid-Peak and Off-Peak are used reflecting the three respective rate periods.

Other Sensitivity Analyses

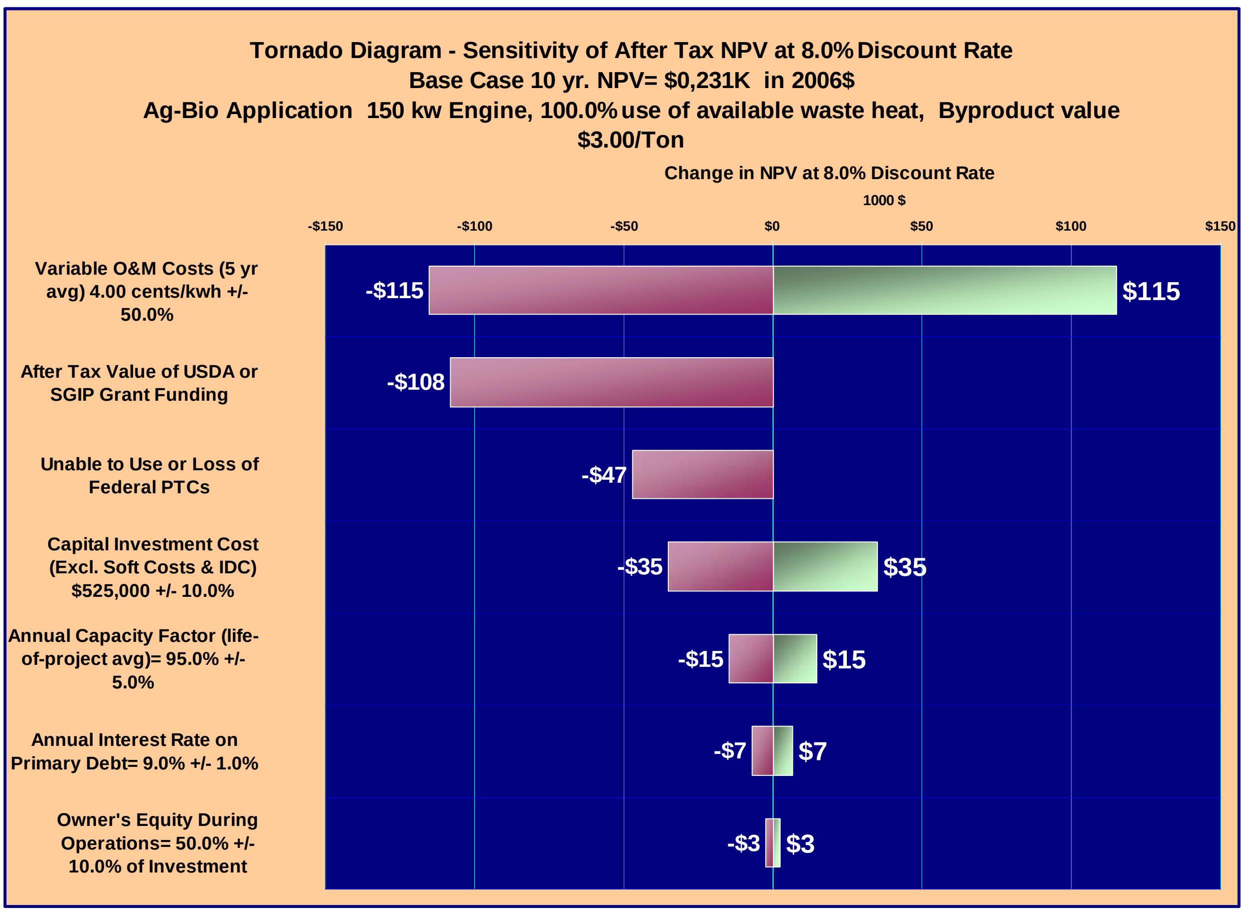
The following additional sensitivity analyses were performed to illustrate how other factors, policy and non-policy related, can impact digester economics. These sensitivities were run against a single dairy type and in only one utility service territory, but are illustrative of net incremental impacts on all of the cases studied. The sensitivities included:

- Capital investment costs
- Incentives offered under state and federal incentive programs
- Operating costs
- Federal production tax credits
- Reliability of the digester , engine and generator
- Interest rates
- Owners equity investment

Since none of these factors are tariff related, the net relative impact on the economics in any of the utility service territories would be the same. Operating costs (assumed to be 4¢/kwh ± 2¢/kwh) and loss of either funding grant ($150,000 from the SGIP program and $150,000 from the USDA program) were the two most significant of the other parameters studied.

Tornado Diagrams are used to identify which economic parameters would have most consequential impacts on the analysis if they were to change. The tornado diagram below illustrates the relative upside and downside impacts on the digester project NPV as a result of the identified changes in each respective parameter.

Figure 71 – Tornado Diagram – Sensitivities of Digester Economics to Other Parameters



V. Conclusions and Recommendations from Task 5

Conclusions of the Task 5 study are:

- Digester technologies appear to be commercially viable, proven to offer substantial opportunities for environmental benefits to dairy and other livestock applications

- Digester projects installed to date at dairy farms have not been cost effective
  - NEM BIO net metering rates are generally insufficient to cover the operating costs of the digester , engine and generator leaving the owner with little or no margin to cover capital investment and fixed costs.
  - The NEM BIO net metering rates are based only on the generation component of the energy rate and exclude all other related components of retail tariffs. Digester owners often find themselves in a position where they are simultaneously purchasing power from the utility at a substantially higher rate than they are generating and selling power back to the utility.
  - Applications installed to date do not appear to take advantage of all potential opportunities to use electricity or waste thermal energy produced by the engine on the dairy farm. These opportunities can offer substantial improvements to project economics.

At current NEM BIO rates, a reasonably attractive return on the investment in a digester and associated engine and generator can usually only be achieved if:

- The bulk of the energy (greater than 75%) generated by the digester is used on-site, behind the meter capturing full retail value and little or no energy is net metered, and

- A substantial portion (greater than 50%) of the waste heat from the engine is fully and efficiently utilized on the farm

These two objectives can be difficult to achieve because of the dispersed and non-continuous nature of energy uses on the dairy farm. While farms overall often use enough electric energy to meet the first criteria, that energy use is disseminated around the farm and usually metered through multiple electric meters. At the meter where the digester, engine and generator are interconnected, usually only a small percentage of the generated power can be used behind the meter. As a result, the majority of the power is treated as export energy and valued at relatively low net metering rates while at the same time energy is being purchased at much higher retail rates through other meters on the farm. thermal energy can also be difficult to harness in many cases because of the difficulties in moving and storing thermal energy across the distances where they are needed on the farm.

Other specific findings of the study include:

- Dairy farms typically operate in a competitive commodity market with relatively low profit margins. Imposing investments like digester plants on them without sufficient incentives could be damaging to the industry in California

- The NEM BIO net metering rates currently offered by PG&E are lower than the cost of operating the digester, engine and generator. Projects in PG&E's territory only appear to show attractive economics when all of the power can be used behind the meter and the majority of the waste heat can be used on-site.

- The relatively high on-peak generation rates under SCE TOU-PA and NEM BIO tariff resulted in economically more attractive digester applications in SCE service territory than PG&E's. Still, attractive returns were subject to use of a majority of the electric power used behind the meter or at equivalent retail-credited net metering rates, and substantive use of waste heat from the engine on the farm.

- SDG&E's NEM-BIO, PAT-1 and EECC schedules provide the best incentive of any of the utility rates in California for digesters. This is true because the EECC schedule most clearly isolates the fuel cost component in the electric rates and provides the highest net metering payment. It appears that digester-like projects in SDG&E's service territory have the best potential to be economically attractive if a substantial portion of the electric energy is used on-site and achieves retail energy rate benefits and a substantial portion of the waste heat is captured and used. Unfortunately, SDG&E's service territory has by far the fewest potential applications because of the limited number of livestock farms in its service territory.

- Operating costs are a key consideration for digester applications. While the fuel (manure) is essentially free or can even be valued as an eliminated or now-salable waste product, maintenance of the system can be expensive, as high as 4 ¢/kwh or more. In addition owners have to cover fixed costs, capital investment costs and earn a rate of return. This dictates that net metering rates have to be on the order of retail electric rates to encourage these types of investments.

- Capture and use of thermal energy is an important economic driver for any CHP application, including digesters. It appears that many projects implemented at dairy farms to date may not have fully taken advantage of these thermal energy opportunities.

- Production tax credits are an important potential benefit for these projects but unless they involve a third party owner, will apply only to the portion of the energy that is exported. It appears under the Energy Policy Act of 2005 that the PTC rates will also be reduced as a result of funding received from sources like the USDA.

- Incentives like the SGIP and USDA programs are critical to digester economics. While alone these incentives are not adequate to make these capital-intensive projects economically feasible, without these incentives the economics of digesters would be poor unless there is a very substantial increase in electric rates.

Recommendations that result from this Task 5 study are:

- The PUC should review net metering rates and should allow credits like those charged for retail energy. The structure of tariffs in the state should also be standardized and simplified.

- Designers and developers of these projects should make more effort to capture and efficiently utilize the waste heat from the engine. It appears that in some of the recently installed projects, some of these opportunities may have been missed, detracting from project returns. Suggested approaches to help better accomplish this include:

- Locate the engine and digester nearer to the dairy facilities. The gas from the digester could be piped to a engine located in close proximity to the milking, storage and pasteurization facilities. This might better allow the power and heat from the facility to be more effectively used on site for applications like pasteurization, refrigeration, space conditioning and sanitization of facilities, and the power to be used for lighting, pumping and other electric uses
- In some cases, the efficiency and production of digester operations can be enhanced by heating the digester. This requires more complex equipment and controls, however, and adds the capital and operating costs of the facilities.
- Ultimately, every case is site specific so suggestions like these may or may not be realistic for a given project.

• As indicated in the digester Market Assessment Report, incentives to digester project owners for externalities, including net reductions in $CO_{2,}$ methane or other greenhouse gas emissions would provide further incentives for digester to support broader societal benefits.

• Future studies and planning efforts performed by the California Energy Commission and the California Public Utilities Commission should include analysis from the digester owners' perspectives to ensure that the impacts of tariff decisions on project economics are understood during the policy making process.

Exhibits to Task 5 - Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based Dairy Digester CHP Projects

II) Task 5 - Questionnaire used for Interviews with Investor Owned Utilities, Consultants, Owners, Engineers and Developers involved in the dairy applications of digesters

<u>Interview Questionnaire Provided in Advance to Utilities</u>

This interview is in support of a study for the California Energy Commission titled:

"Policy Impacts on the Economic Viability from a Project Owner's Perspective of California-based Digester Applications for Dairy Farms".

The goal of the study is to assist the California Energy Commission and the California Public Utilities Commission to better understand how factors such as utility tariffs, incentive programs, income taxes and financing alternatives impact the economic incentives for stakeholders in California to invest in these facilities.

CEI has been selected by the California Energy Commission to perform an economic evaluation of at least three typical digester applications, at least one project located in each of the three California investor owned utility service territories. The "proxy" installations will be based on typical interval (hourly or equivalent) thermal and electric load profile information for these facilities, current or pending tariffs, incentive programs and tax incentives. The analysis will be performed applying CEI's *EconExpert-IAT* and *EconExpert-DG* software tools which are specifically designed to assess the economic and risk factors associated with on-site generation applications from the perspective of the various stakeholders in these transactions, including digester projects.

We have prepared a list of questions regarding your perspectives on the issues affecting the economic viability of digester applications for dairy farms. While the interview will include a list of specific questions, we anticipate an ad hoc type discussion which can be expanded to other factors as we mutually deem appropriate during the discussion. The discussion is anticipated to last about ninety minutes. All information shared may be published by the California Energy Commission and so discussions regarding proprietary information should be avoided. If any such information is inadvertently disclosed during this discussion, please contact us and we will omit it from our reporting to the California Energy Commission. We will also provide you with the opportunity to review the draft report before it is submitted to the California Energy Commission to ensure that your comments are fairly represented and to ensure that no confidential information is inadvertently provided.

Since we have already interviewed you on related subject matter for CHP applications in dairies, this interview can be condensed to focus on differences as they relate to Dairy Digester applications.

6. Please describe your affiliation and role and how that role and your company are involved in Digester Applications in California.

    a. Please describe to us your views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

7. Electric Tariffs: Our goals regarding tariffs and regulatory policy are to classify and to quantify the aspects of tariffs as they relate to incentivizing or disincentivizing Waste to Energy Digester applications for dairy farms. This means we would like to fully understand the mechanisms of the current tariffs as they apply you and how the customer is billed before and after installing a Waste-to-Energy Digester facility.

   We would like to discuss the electric utility tariffs that apply to you in more detail.

   b. For Representatives of California Investor Owned Utilities. We would like to discuss with you the individual agricultural tariffs in your service territory that typically apply dairy farms with peak demand on the order of 500 kW. Classes of information that we would like to discuss will include:
      i. Billing and Rate Periods
      ii. Rate Components
      iii. Rates
         a) Customer Charges
         b) Demand Charges and components of the demand charges – both time related and non-time related.
         c) Energy Charges and components of energy charges– both time related and non-time related.
         d) Standby charges and standby rates
         e) Exit Fees or other fees that continue to apply after a CHP facility is placed in services including:
            1). DWR Bonds
            2). Nuclear Decommissioning
            3). Public Purpose Funds
            4). Other
         f) Adjustments and riders.
         g) Taxes and other adders.
      iv. Limiters
      v. Discounts
      vi. Pertinent Special Conditions that affect the customers bills

8. Incentives Programs in California including the Self Generation Incentive Program and other programs that might apply. The purpose of the SGIP is:

   "to offer financial incentives to customers who install certain types of distributed generation facilities to meet all or a portion of their energy needs. In late 2003, AB 1685 extended the SGIP through 2007."

   a. We would like to discuss with you how the SGIP program is implemented and what are the key provisions relevant to dairy farms with peak demand on the order of 500 kw.

      i. Do you feel you fully understand the current program? If so, how is the program implemented within your service territory or on projects your have or will pursue?
      ii. Are there any other incentive programs in your service territory that would apply for Digester Gas Projects?

9. Federal Incentive and Programs.
    a. We would like to discuss with you how the Federal programs might also provide incentives. The pending Energy Bill will be discussed in the next section.

        i. What Federal programs are you familiar with that might supplement state programs in California?

    b. We would also like to discuss your perspectives on the roles of federal and state tax programs on incentivizing or disincentivizing Waste-to-Energy Digester applications for dairy farms. What provisions of the current Federal and State Tax Code do you feel are most influential on economics and financing of these projects? Please note that the Pending Senate Version of the Energy Bill includes production and/or investment tax credits for Renewable Energy Applications and provisions for a target Renewable Portfolio Standard.

    c. What actions would you like to see included in new federal Energy Legislation to encourage Waste to Energy Digester applications for dairy farms?

    d. Please provide any other feedback that you feel is important for CEI to consider as we prepare this analysis of the impacts of “Policy Impacts on the Economic Viability from a Project Owner’s Perspective of California Based Waste to Energy Digester applications for dairy farms.

Task 5 Interviews with Utilities – Notes taken during the interviews with the three utilities are provided below. These notes were reviewed by the respective utilities after the interviews to ensure accuracy. Their respective edits are included in the notes.

<u>SCE – Peter F Moreno 10/19/05</u>

1. Affiliation and role

- Peter F. Moreno – SCE – Project Manager   Interconnection of DG projects, including net metering Biogas and fuel cell projects. Also works with gas CHP.

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

- SCE has four (4) biogas digester customer-generator plants interconnected.
- Exported generation is credited to aggregate account   Customer can specify to which accounts they want to apply aggregation to.
- Key concern – be sure that customer is aware of agreements / requirements.
- For biogas and fuel cell projects, SCE does not receive initial or supplemental review fees for the project. Net Generation Output Meters (NGOM) are not required for biogas and fuel cell projects.
- The customer is responsible for any Added Facilities cost needed to interconnect the project. Biogas and fuel cell project customers use the main service meter for netting. Customer expenses include Added Facility expenses as mentioned above, but a review expenses of in the beginning is not required.
- History shows that relations and work with their customers have gone well and feels that both the BG-NEM and FC-NEM schedule are relatively easy to administer.

3 NEM-BIO Tariff Overview

- Current BG-NEM is experimental tariff but they expect to extend it to permanent
  Current project size limit is 1,000 kw but expects (unconfirmed) that it will be increased to 5,000 kw
- Special condition 2 – Load Aggregation is a key provision.
  Must be TOU metered and adjacent to same property
  Excess sales credited at energy component of rate (DWR and URG Only)
  Not including Delivery Service or Demand Charges
- Excess production from parent (meter connected to Biogas Facility) credited to energy component of other bills.
- Customer can designate order of child meters against which excess generation credit will be assigned.
- Meters on Pumping Rate are subject to demand ratchet.
- Under PUC 2827 – all NEM BIO projects are exempt from departing load charges.
- Demand is billed monthly and there is no ratchet.

Interview Notes – Utilities
PG&E 9/20/05

1. Affiliation and role
    - Chris Tufon – Senior Tariff Analyst – Admin of standby tariffs – schedule S
    - Harold Hirsch – Tariff Analyst – NEM Net Metering Tariff
    - Susan Buller – Senior Regulatory Analyst – Worked on AB2228 with focus on Dairy and Digester Applications

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

- Air quality issues – imminent issues to deal with degassing from wastes
- Dairies operate on small margins so intense capital investments are difficult
- Interconnection – Aggregation of load vs. multiple meters. Dairy farmers are allowed to aggregate. NEM Bio will allow them to earn a credit to offset the generation charges on their account.
- A big issue for PG&E is adequate distribution facilities relative to capacity to export load.
    - Sometimes the generator may export more than the distribution system can handle.

3. Electric Tariffs:

- NEMBIO Special Condition 2 is relative to load aggregation from AB2228 all IOUs.
- When exporting at the site where the generator is located generator earns a credit to the generation component of the tariff. A credit gets applied to generation component of aggregated accounts. Cost benefits of energy used behind the meter are greater than those for exported power.
- Importance of early communication in the process between system and interconnection engineers are in discussions.
- If customer does not want to build transmit power inside the fence, load aggregation applies only to energy component for exported power.
- Gen to Gen net metering applies to Biogas digesters as opposed to Retail Net Metering as applies to Solar, etc. PG&E position that this is a better reflection of the value.
- Accounting versus actual aggregation of loads.
- Agricultural tariffs require 70% energy of use for agricultural purposes
    - AG-1 Non-Time of Use does not apply
    - NEM BIO tariff is not restricted to agricultural but aggregation is limited to dairy farms on AG Rate
    - Bulk of customers on AG4 and AG-5 <200 kw >200 kw. Would have to specify, AG-5 customers could be required to change to AG4.
        - Rates Elective B or C Greg Bakens 1/19/06
        - New tariff expected on January 1 of 06. Expect totally new approach to rates.
        - AG-ICE Incentive for customers to change diesel engines for electric motors – not applicable.
        - A,B,C,D,E, F components depend on actual connected load. Most likely will be C rate, largest customer (highest demand but lowest energy charges).
        - A,B,C had existing meter
        - D,E,F coming in as new customer and need to add meter.
        - B vs. C Substantive difference in on-peak generation rate, energy rates
    - For agricultural – Not subject to standby currently. Demand seen with or without generator sets demand for the whole year. 1 year ratchet. Under new rate in January

this may change. If ratchet goes away will implement. Demand based on highest for 12 month period.

- Seasonal demand based on greater of the highest maximum demand in the same season. Summer and Winter.

4. Incentives Programs in California

- SGIP program appears to be OK.
- Main issues around interconnection related aggregation of meters, physics vs. economics.
- Check incentive rate for AG.

5. Other Comments:
   - Potential for dairy to participate in renewable portfolio standard. SCE has changed qualification allowing aggregation of sites to get > 1 MW. This was not practical for dairies due to difficulty in getting separate models.
   - 3 issues
     - Total resource
     - Bundled rate payers perspective
     - Dairy Farmers perspective. PG&E has heard that 9¢/kwh is energy breakeven.
   - Problem with waste. Dairy Farmers looking for solution.
   - Export credit is the energy generation portion of the tariff.

Interview Notes – Utilities
SDG&E - 9/22/05

1. Affiliation and role
   - Bonnie Bailey – Supervisor Rate Support
   - Nancy Winter – Commercial and Industrial Services Manager2. Continued.

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.
   - No Comments focus on Tariff and Net Metering.

3. Electric Tariffs
   - ALTOU Tariff – Dairies have more options – Agricultural Rates
   - PAT 1 Time of use Agricultural Rate, Water pumping, sewage pumping etc.
     - Add EECC rate
     - On-Peak and Semi-Peak Demand Charges
     - No non-coincident demand
     - Energy Charges
       i. kwh time periods the same
     - Demand Charges – customer can pick a time window to avoid usage usually 1 – 3 pm
       i. If do that they can entirely avoid the on-peak demand rate
     - PA Flat electric rate – no demand component
   - Customers will use different rates on different meters.
   - Form on web site to access their data. Business / Customer Choice / for Energy service providers / Electric / forms Authorization to receive information or to act on a customer's behalf – Send it to us electronically - Energy Waves
   - California Dairy Production Program – Money for Methane
     - NEM BIO Net Metering
       i. Customer must be on time of use ALTOU or PAT1
       ii. Sometimes combined residential with dairy on meter
       iii. Excess generation on the TOU meter and apply to the other accounts. Calculate a credit.
       iv. Just the EECC component applies to energy credit. DWR bond charges do not apply

4. Incentives Programs in California, Taxes and Financing
   - Not Discussed

Interview Questionnaire – Suppliers / Owners

I am representing Competitive Energy Insight Inc. on a study funded by the California Energy Commission of:

"Policy Impacts on the Economic Viability from a Project Owner's Perspective of California-based Digester applications for Dairy Farms".

The goal of the study is to assist the California Energy Commission and the California Public Utilities Commission to better understand how factors such as utility tariffs, incentive programs, income taxes and financing alternatives impact the economic incentives for stakeholders in California to invest in these facilities.

CEI has been selected by the California Energy Commission to perform an economic evaluation of at least three typical waste to Energy Digester applications, at least one project located in each of the three California investor owned utility service territories. The "proxy" installations will be based on typical interval (hourly or equivalent) thermal and electric load profile information for these facilities, current or pending tariffs, incentive programs and tax incentives. The analysis will be performed applying CEI's *EconExpert-IAT* and *EconExpert-DG* software tools which are specifically designed to assess the economic and risk factors associated with on-site generation applications from the perspective of the various stakeholders in these transactions, including digester projects.

We have prepared a list of questions regarding your perspectives on the issues affecting the economic viability of digester applications for dairy farms. While the interview will include a list of specific questions, we anticipate an ad hoc type discussion which can be expanded to other factors as we mutually deem appropriate during the discussion. The discussion is anticipated to last about ninety minutes. All information shared may be published by the California Energy Commission and so discussions regarding proprietary information should be avoided. If any such information is inadvertently disclosed during this discussion, please contact us and we will omit it from our reporting to the California Energy Commission. We will also provide you with the opportunity to review the draft report before it is submitted to the California Energy Commission to ensure that your comments are fairly represented and to ensure that no confidential information is inadvertently provided.

1. Please describe your affiliation and role and how that role and your company are involved in Digester Applications in California.

    b) Please describe to us your views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

2. Technical considerations

We would like to discuss with you to Digester Process and key factors that drive the economics and economic viability from an owner/operator's perspective. These include factors such as collection of the waste material, processing, cleaning and combustion of the gas to generate power as well as the beneficial uses of power and waste heat on a dairy farm.

3. Regulatory Policy:

   a. Are you familiar with the electric and gas tariff structures that apply to you and in with your utility and do you fully understand how those rate structures affect your costs? If so:

      i. What aspects of electric and gas rate regulatory policy in California do you feel have the greatest impact on the economic competitiveness of Digester Gas applications at the project level? Please describe for us how you feel each of the factors you have identified have consequential positive or negative impacts on digester project economics.

      ii. How would you go about quantifying the factors you have identified at the project level?

4. Electric Tariffs: Our goals regarding tariffs and regulatory policy are to classify and to quantify the aspects of tariffs as they relate to incentivizing or disincentivizing Waste to Energy Digester applications for dairy farms. This means we would like to fully understand the mechanisms of the current tariffs as they apply you and how the you the customer are billed before and after installing a Waste to Energy Digester facility.

   c. We would like to discuss with your perspectives of what are the key issues relating to electric rates and tariffs that impact digester economics. Classes of information that we would like to discuss will include:

      i. Do you feel you have a clear understanding of the various tariff structures that affect your business?

         a) If so, how have you gained this understanding?

         b) If not, what areas do you have uncertainty about? Do you know where to get the needed information and how to interpret it? Do you know who to contact to ask questions?

      ii. Tariff Discussions
         a) Billing and Rate Periods
            1. Tiered and Time of Use
         b) Rates
            1. Demand Charges
            2. Energy Charges
            3. Standby charges
            4. Non-Bypassable / Exit Fees
               a. Nuclear Decommissioning Fees
               b. Public Purpose Programs
               c. DWR Bond Funds
         c) Pertinent Special Conditions that affect the customer's bills.

3. Incentives Programs in California including the Self Generation Incentive Program and other programs that might apply. The purpose of the SGIP is:

   "to offer financial incentives to customers who install certain types of distributed generation facilities to meet all or a portion of their energy needs. In late 2003, AB 1685 extended the SGIP through 2007."

   - We would like to discuss with you how the SGIP program is implemented and what are the key provisions relevant dairy farms with peak demand less on the order of 500 kw.
     i. Do you feel you fully understand the current program? If so, how is the program implemented within your service territory or on projects your have or will pursue?

     ii. What are the key provisions of the program as they relate to renewable energy and specifically dairy projects who are applying for funds?
        1. Installation Rebates - $0.60-0.80 / watt
        2. Other
        3. What do you see as the main strengths and weaknesses of the current program and how could it be improved.

4. Current Federal Incentive Programs.
   - We would like to discuss with you how the Federal programs might also provide incentives to you. The pending Energy Bill will be discussed in the next section.
     i. Do you feel you fully understand the current programs that are available to this sector? If so, please share your understanding with us?

     ii. What are the key provisions of the programs as they relate to cogenerators who are applying for funds?

5. Income Taxes and Financing – Energy Bill
   - We would also like to discuss your perspectives on the roles of federal and state tax programs on incentivizing or disincentivizing Waste to Energy Digester applications for dairy farms. What provisions of the current Federal and State Tax Code do you feel are most influential on economics and financing of these projects? Please note that the Pending Senate Version of the Energy Bill includes production and/or investment tax credits for Renewable Energy Applications and provisions for a target Renewable Portfolio Standard.

   - What actions would you like to see included in new federal Energy Legislation to encourage Waste to Energy Digester applications for dairy farms?

6. Other Comments:
   - For dairy site owners, we would like to discuss your energy usage profiles, including total electric, refrigeration and chilling and thermal uses. This discussion can be on a qualitative or preferably a quantitative basis.
     i. Can you provide representative hourly interval load profile data (or specific electric and gas bills) for us to use as guidance in the study (note: This data will remain confidential and will be used in our study for guidance purposes only. It will not be published.) .

ii. Please provide any other feedback that you feel is important for CEI to consider as we prepare this analysis of the impacts of “Policy Impacts on the Economic Viability from a Project Owner’s Perspective of California Based Waste to Energy Digester applications for dairy farms.

Task 5 Interview Notes – Suppliers / Owners
Western United Dairymen's Association
9/15/05

1. Affiliation and role:

   Tiffany LaMendola - Director of Economic Analysis – Western United Dairymen

   - Dairy Power Production Program Western United Resource Development Corp. is the grant recipient – SB5X grant from California Energy Commission
   - Performs economic analysis of grant projects. Monthly monitoring of projects and 90 day report plus final report at end when all projects rolling. 14 approved digester projects, 5 currently running, 2 projects have dropped out. Of remaining 7 in planning or construction.

   Michael Marsh – CEO of WUD and Chief Executive of WURDC

   - Matching Grants
   - Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.
   - Impediments
     - Regulatory – Bills necessary to facilitate interconnection and net metering.
     - AB2228 which ends at the end of 05
     - AB728 new legislation in front of governor

- Producer's perspective – energy costs are 1 – 2 % of overall cost to dairymen. Feed and labor are much larger costs.
  - Incentives are reduce waste, environmental, permit compliance, opportunities that are unique to use energy etc. Site specific but tend to be specific to interests of a dairy.
  - Dairymen generally feel relationship difficult with utilities.
- 2001 – 2002 price trough in milk prices delayed many projects. 2004 milk prices picked up and projects began to happen.
- Incentive programs very important.
- Adequate market price for the energy would be the best incentive program. Need adequate price for excess power sales. Typical farm can generate 25% or more power than they need on the farm. 6 – 7 ¢/kwh (similar to wind or solar) is low end for digester.
- State water resources control board – John Menke.
- Example Project:
  - 160kw - $5000/kw
  - $800K estimated project cost
  - WD grant $320 K – now expired.
  - USDA $167K
  - PG&E SGIP $61K
  - 5 Projects average cost $1MM at average size (300 kw, 160 kw, 160 kw, 130 kw) $665/cow, $5300/kw. Engine/generator $2500, rest digester, etc.

2. Technical considerations

- Multiple meters so buying and selling at the same time. Barns, irrigation, large acreage, etc. Difficult to connect load to all of the meters. Value is greatest when applied to offset usage at retail rates.
- Generator usually located near lagoon which is not near electric, chiller and thermal uses so have to move gas, electric or hot water to use location.
- Assume 25, 50, 75 or 100% of the power and 25, 50, 75 or 100% of thermal

   - Use power at retail, sell only net meter at generation component.
- SB700 subjected dairies to air quality regulations. Methane digesters viewed as best approach at the time though now understand that there are tradeoffs. Did not consider markets for the energy so economics alone have not been adequate incentive.
- Typically difficult to use thermal at the dairy.

3. Regulatory Policy:

- Excess energy gets very low value. Disincentive for maximizing production to match amount of waste available and how metering is arrange can limit benefits. Important to use the load on site.
- Also depends how the load is connected to the generator – multiple meters. One could be purchasing while the other is selling yet not netted out.
- One example – one dairyman sending all power out to grid and purchasing power for all other meters. Getting different benefit than would otherwise because sold to utility at different rate than purchased energy.
- Important for dairyman to use all power directly on site to get maximum benefit for energy.
- SCE is the most complicated.
- Utilities appear to be having a hard time interpreting the NEM BIO tariffs.
- Generation Charges – usually only one meter does net metering. Important to connect generation to site loads to use as much as possible to offset purchases. In most cases less than 100% of the production can be used on the farm primarily because of multiple meters and connection issues. No incentive or minimum incentive to generate excess power. When exceed usage on the farm (sometimes on an individual meter) the owner gets no benefit for the power. All utilities handling net metering very differently.
   - PG&E – Providing credit only against the generation component of the bills to the extent that the net production offsets generation.
      - Net metering credit only against the generation component.
      - No payment for excess
   - SCE –
   - SDG&E – Seems to be in best readiness for interpreting the NEM BIO
      - One project
      - Commercial and residential accounts aggregated with running total.
   -
- Net metering. Generally the credit is only on the Generation portion of the bill.
      - Difficulties in facilitating interconnections with the utilities – feels like the utilities are in opposition and so cause delays
      - Excess production – Utilities all have different interpretation of net metering
      - Dairies have multiple meters
      - How net metering applies to aggregation of multiple meters and excess production or averaging
      - Charges previously imposed by utility tend sometimes to result in electric bills going up. PUC overruled and now appears to be addressing this.

7. Incentives Programs
   - SGIP program – Not familiar with it.
   - Environmental quality program – USDA – Funds limited and very competitive. Can't count on this funding. Some projects get it usually minor amount.
   - Western Dairymen's not accepting any applications for projects. Funding exhausted. 50% cost share program expired.
   - USDA funding still available

8. Other Comments:
   - Difficulties in "marrying" water and air issues.
   - Utilities apparent reluctance to invest necessary resources to support development of projects.
   - Adequate energy pricing.

   - Federal tax incentives. 0.9 ¢/kwh PTCs. For Dairy expires 2008 or 2009 unless extended.
     - Farmers use income averaging so may not have tax liability.

<u>Interview Notes – Suppliers / Owners</u>
<u>Rock Swanson – Geupard Energy</u>
<u>9/7/05</u>

1. Affiliation and role
    - Rock Swanson - President / CEI of Geupard Energy
        - o Developing on feedlot / manure project with IID. Gasification
        - o Currently working on thermally driven gasification.

    - Amanda Martinez – CFO of Geupard Facilitating financing of project
        - o Bull Moose Energy – Biomass projects in southern California sludge and green waste

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

    - Drivers are primarily Ecological / Environmental with economic complement
        - Disposal of waste. Currently a cost.
        - Avoid fugitive emissions of greenhouse gasses
        - Convert to power and fertilizer.

    - Technical hurdles – Biggest is the collection of the waste and prompt collection of waste.
        - Easier at dairies milking pens and lagoons.

    - Established technologies.
        - Digester – Burn gas in engine.
            - Plug flow is simpler.
            - Ambient temperature – less efficient.
            - Increase temperature – Thermophelic

    - Issues – Financing – Need state tax credits incentives. More important at state level.

3. Technical considerations
    - Tied to PPA – include stream which is economics for owners and utility excess sales.
    - Dairies are small – 6000 – 7000 head of cattle is max. Lakeside 400 head of cattle. Facilities are small.
    - Beef lot have 400,000 head of cattle w/in 15 mi. radius. Can support 30 MW power plant.
    - 3 x 10 MW sites. Will supply steam to mill grain.
    - Will use steam inside the fence.

4. Regulatory Policy:
    - Their projects are all based on sales to Imperial Irrigation District at wholesale rates.
    - No comments on Tariffs

5. Taxes and Financing
    - PTCs are an important benefit but capital tends to drive the economics.
    - CREB bonds – Pay principal only on the loan. Bond holder receives tax credit in lieu of interest payments. Usually have been done as tax exempt bonds. Previously could not use full PTC's 50% max of 0.9 ¢/kwh if had tax exempt bond financing.
    - In the past has been very narrow spread of taxable and tax exempt bonds.

- CREB bonds are a special bond under the energy bill. Taxable bonds allowing full PTC's but owner who pays on bonds only pays the principal payment. Bond holder instead of getting interest payments gets a separate tax credit in the amount of the interest payments. Only $800 MM of these bonds currently appropriated for US. CA does not yet have a state agency to handle the appropriation.
- Site owner still has full access to 0.9¢/kwh PTCs. The two are unrelated.
- Operating leases applicable for PTC
- CA has limited biomass tax incentives. Lagging behind.
  - Would prefer investment tax credit. Other states have are more strongly drawing investors because of combined state and federal incentives.
  - CA energy sales   6¢/kwh avg. Supplemental energy payments funded by California Energy Commission. Limited budget – appropriations not guaranteed beyond budget. Every year have run out of funds and need new appropriations in ensuing years.

6. Other Comments:

- Current Project Braly Beef – Digester

Interview Notes – Suppliers / Owners
Rob Van Ommering – Van Ommering Dairy – Lakeside, CA
9/22/05

1. Affiliation and role

   Rob Van Ommering General Manager – Project Manager
   - 20 years with the Dairy
   - Partner in the Dairy
   - Supervises operation and management of digester, 25% of time required, no full time staff
     assigned to digester.
   - Primary motivation – Grant money and past work with digesters.

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

   - Experience to date: Digester has worked as expected. No major interruptions.
   - Some issues with the generator – electrical side.
   - Engine CAT 3406 IC Engine – 150 kw. Interruptions primarily associated with equipment but unsure what might have been caused by the utility.
   - Design meets all tolerances required by SDG&E for interconnection from SDG&E's spec.
   - Waste collected by vacuuming. Batch collection. 2 -3 times / week then directly to digester.
     - Have not verified devolatilization of manure.
     - Next year will start to collect daily.

3. Technical considerations
   - Will send flow diagram.
   - Gas from digester – condensate traps and H_2S absorber.
   - thermal all used for the digester. Currently 80% of thermal not used.
   - Additional heat available but logistics issue. 800 ft from the milking barn for chilling. Hot water or chilling. Distance issue.
   - Previously spread animal wastes on farmers ground and lost that customer but that didn't come into major play. Disposal was not a major motivator. Previously sold the manure (1/3 got sold, rest donated)
   - 1/3 reduction in waste solids – Present 1/3 of manure through digester but plan to move to 100%

4. Regulatory Policy
   - Sense of familiarity with their tariff
   - Doesn't think they pay standby charges but will send bills so we can review.
   - Net meter energy savings
   - No natural gas interconnection at dairy so used propane.
     - Propane was 1.59/gal. Now as high as 2.50/gal.
     - Propane delivery 600 – 800 gal. 3 – 5 weeks.
     - 50% for hot water in barn. Refrigeration is electric.
   - 8 – 15 year payback. Electric savings only. Electric bill cut in half. 15 yr payback
     - 100% cut would be 8 year payback.

- o 80% of thermal currently not captured.
- o Total $900K 150 kw
  - * Grant $245K – SB5X
  - * Independent $150K grant from USDA – NRCS Environmental quality improvement program. For manure handling only, did not cover electrical.
  - * Qualification of PTCs
    - ▪ October 22 of 2004
    - ▪ August 8 of 2005
    - ▪ Right now not capturing PTCs
    - ▪ How does it apply to new vs. existing facilities and/or expansions.
    - ▪ Minimum size rating 150 kw???

5. Electric Tariffs:

- ▪ Have energy export – net metering.
- ▪ Not aware of any special tariff provisions / implications.
- ▪ Talk with SDGE about net metering.

- ▪ Net bio Tariff – Thinks its ALTOU.   Doesn't believe they currently pay standby charges?
- ▪ Net metering is the energy charge only.
- ▪ Unsure if departing load charges apply (Check with SDG&E)

7. Current Federal Incentive Programs.
   - ▪ USDA grant - Ongoing program. Check Google – Natural Resource Conservation Service – up to $150K or 50% of project cost.
   - ▪ Call 760 – 745 – 2061 Jason Jackson X 102 or Gary Decker x 111 for info on USDA grant.

8. Income Taxes and Financing – Energy Bill (PTCs)

   Annual generation – 130 kw x 24 x 365 = 1.1MM kwh $10,000 (at 0.9 ¢/kwh) - $20,00/ yr (would use if could). 0.9 ¢/kwh potential

9. Other Comments:
   - o 6 meters - Chillers run 70% of the time
     - ▪ Vacuum Pumps run 100% of the time
     - ▪ January 03 – June 04

     - ▪ Propane Heaters – No breakdown

   - ▪ Idea – Google Cow Power in Vermont – Central Vermont Power Services – likes the program they have. Would like to see a program like in Vermont where green projects like this can get premium benefits for this type of energy. This could be set up as a voluntary program for rate payers to incentivize applications like this.

Interview Notes – Suppliers / Owners
Tom Moore California Power Partners
8/25/05

1. Affiliation and role.

   Tom Moore - President California Power Partner
   - Lead marketing and business development
   - Focus in CA markets Waste Water Treatment 3 completed this year and 3 more in construction in CA plus 7 facilities outside of CA
   - Landfill gas – fuel conditioning.

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

- Big issue is collection of the waste
- Digester costs can be prohibitive
- Each biogas type is different (landfill, Diary, Chicken, etc)
- Dairy advantage that cows are in 1 area to be milked.
- Advantage of landfill gas is that there is a common collection point.
- Issues on collection points are not so well established.
  - Environmental remediation.
  - Waste Handing.
  - Power
  - thermal
- Alternative options are landfill, lagoon or spread on field. Need to not just compare economics against alternative cost of thermal and electric but also to alternative cost of disposing of wastes.
- Paybacks 8 years on electric and thermal only.
- Good candidate facilities – Benchmark on retail / tariff.
- Need economies of scale to justify.
- Often times, gas is very low BTU.
  - Manure degasses 40% to 50% in the first 24 hours on its own so have to process the material quickly or lose the value.
  - Methane production is predicated on "dwell time". Need to process the waste quickly.
- Need situations where you can have automated collection of waste.
- Need adequate waste to justify scale.
- Energy is NOT a core business for the dairy farmer. The main incentive may be the remediation / disposal issue of the waste.

2. Regulatory Policy and Tariffs
   - Standby charges are the biggest issue – Utilities frequenting change so that the owner is hanging with risk of change in tariff changing the economics he based his investment on.
   - Transfer of costs from one category to another also burden project (i.e. Energy vs. capacity)
   - Ability to sell excess energy – how value – no dynamic markets for small power blocks. Would allow use of additional heat when on site electric demand changes.
   - Short interval outages 15 minute interval – non-coincident can have substantive impact on savings.
   - Utility caused outages (is system designed to utility standards???)
   - How would you go about quantifying the factors you have identified at the project level?

3. Incentives Programs:
   - Feels that SGIP reductions in funding if also get grants from somewhere else is a problem that limits ability of projects.

4. Other Comments:
   - Big issue is collecting agricultural wastes.
     - Main focus for them is waste water treatment where there are existing digesters.
     - Convert existing gas supply to energy.

   - Estimated Costs
     - Cost of Digester – $1800 – 2000 / kw just for digester
     - Fuel conditioning $1200 / kw
     - Engine and Generator $2500 kw
     - Total $5000 – 6000 / kw
     - Depends on Scale

   - Performance
     - Free fuel but need to transport to digester

   - Gas quality issues
     - Have to treat gas to purify and raise BTU for use in engine
     - Moisture
     - Containments
     - Processed gas 300 – 650 Btu/scf

   - Requires a modifications to engine

   - Technical
     - Digester Continuous vs. Batch

   - Maintenance and operating considerations

<u>Interview Notes – Suppliers / Owners</u>
<u>Ken Krich – University of CA</u>
<u>9/6/05</u>

1. Affiliation and role

Ken Krich - Worked for 4 years for Sustainable Conservation (Environmental Non-Profit) focused on Dairy Methane Digesters as Environmental Initiative

- Dairy digester advocate
- Supported funding, net metering, etc.

- Semi retired business executive.
- Working now with University of California

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

- Recommend that we contact Mark Mosure RCM Digesters – Built half of units in US
- Doug Williams – Cal Poly San Luis Obispo – 3
- Cottonwood Dairy – Joseph Gallo Farms Atwater CA Contact from Tiffany
- Main issues – Technical viability – will they work
  - Dairy applications are bested suited with low tech. Waste water and landfill gas applications are very different. Landfill and Wastewater plants have technical staff to run the unit. Dairy applications are farmers and not technically sophisticated. Better to have robust than complex.
  - Complexities of operation including pH, mechanical, handling, etc.
  - Economics – Expect average cost of power about 8¢/kwh w/ free fuel Levelized 20 yr
  - Capital intensive – $5000/kw installed, over 50% collection and digester. Doesn't include air emissions control. Most dairies in Non-Attainment San Joaquin Valley
  - Data on cost factors – Dairy Power Production Program – Western United Dairyman
    - Financed Dairy of 13 projects and have data on costs and production
  - Other sources of data / costs
    - Biogasworks.com Case study of digesters and cost
    - RCMDisgesters.com.

- New rule says that facilities to qualify for net metering must have BACT. BACT not established yet for digesters.
- Main incentive – eliminate retail purchase of energy. Major win is displacing retail purchase to ensure to reduce consumption. Net metering has minimal value.
- Best to use all of the power on the farm. Cotton wood dairy had cheese plant. Transfer the gas 1 mile to use the gas at the cheese plant. Now can use thermal and electric at the cheese plant.
- His report under grant from USDA – BioMethane – after removing moisture, H_2S and CO_2. Report on Western United Dairyman website. Our applications will not include methane conversion but helpful report.
- If have a covered lagoon digester (no freezing issues) can do some element of load following. Let cover expand and use gas during on-peak.

3. Tariffs

- Utility Interconnection – Rule 21 and that process. Utility requirements. Utility requirements vary between utilities and depending who you talk to at the utility.
- Net metering – Specific ruling for Dairy Digesters AB2228 (separate from wind and solar). Expires Jan 06 will be replaced by AB728 if approved to extend net metering. Very narrow legislation and benefits.
- Owner can aggregate all of their meters (usually 8 – 10 at a site). Allowed to aggregate. Problem, each meter treated separately.
- SDG&E only 10 dairies. Not substantive market opportunity
- PG&E – has most dairies. AG4 and AG-5B. Relatively low prices.
- SCE – also has substantive dairies.
- Have energy export – net metering.
- Not aware of any special tariff provisions / implications.
- Talk with SDGE about net metering.
- Net bio Tariff – Thinks its ALTOU. Doesn't believe they currently pay standby charges?
- Net metering is the energy charge only.
  Call Bonnie Baily re. impacts of peak outage.
  Departing load charges – Applicability for Ag Waste? Ask Bonnie Baily.
- Usually >1 MW = 7000 – 10000 cows. PG&E considering aggregated bid from multiple digesters. Due to size probably need multiple dairies. Hard to compete with wind at the high capital cost.
- This is dispatchable but not valued in RPS at this time.

4. Sources of Funding

- Solar full credit. Runs meter backwards.
- Fuel cells and Biogas only get credit for the energy component. Includes only **Generation** Component. Not just running meter backwards. Less than avoided cost.
- Non-bypassable fees. SGIP same.
- SBIX program up to 50% buy down grant. 2000/kw max. Now expired
- Federal Money - Active
  - Farm bill 2002 title 2 – USDA – Environmental Quality Incentives Program (EQIP). If there are environmental improvements ($450K or 75% for one farm over life of farm). Air or solid waste.
- Title 9 – Energy Section 9006 up to 25% or $500K / By proposal only
- New energy bill biomass material. Amount of bill. This is open loop biomass. Find value of PTC's. 0.9 cent/kwh
- State money for research projects – California, Public Interest Energy Research Program – by application.
- National gas research program. Some other sources of funds by special application.
- Renewable portfolio standard – Utilities only have to pay market reference price 6.05 ¢/kwh. Can't net meter and sell. If don't net meter can get contract to sell.
- SGIP – special provisions / tiers for renewables waste gas – check the value???

5. Other

- Other benefits – odor reduction. Could do just by covering lagoon and flaring gas.
- Odor control has been a main incentive.
- Reduced VOC emissions. Off gassing from the lagoons. Reducing substantive emissions including greenhouse gasses, smog, etc. Dairies 2nd largest emitter after transportation. Will require BACT for dairies with over 700 cows – covered lagoon

capture and combust. Flare produce 15 ppm NOx, Flare 10% of NOx of uncontrolled engine. 90 ppm NOx requirement in San Joaquin. Will need better for net metering.

- With Muni's and coops owner can negotiation with muni like SMUD, IID for better price. Not true with utilities
- New barrier - Permitting – especially air quality. NOx 200 ppm uncontrolled NOx. High H2S content in gas will corrode SCRs and potentially micro turbines. Must reduce H2S (iron sponge – high maintenance) then potentially can add SCR. Valley permits 90 ppm. SCR in this instance not demonstrated. Existing must be retrofitted by 2008 or 2009. San Joaquin Unified Air Quality District rule 4702.

Interview Notes – Suppliers / Owners
RCM Biothane
11/09/05

1. Affiliation and role and how that role and your company are involved in Digester Applications in California.
   - Eric Larsen – Environmental Scientist - RCM Biothane – Formerly RCM Digesters
     Responsible for facilitating interconnection process between clients and utility
     Also monitors start-up, troubleshooting, design issues
   - Angie McEliece – (Title) State and Federal Incentive Programs
   - Mark Moser – Principal – (not present in interview) developing digesters 20 years. 40 projects world wide, 6+ projects in CA.

2. Views and experience with the considerations of owning and operating digester to energy projects including specific comments on the digester, engine/generator and other considerations.

- Hog and Dairy farms. Beef lots not conducive since manure is widely distributed and mixed with dirt. Degrades and not typically good for anaerobic digesters. Dairies have flush lanes that capture 50 – 90% of manure allowing maximum fresh manure to digester.
- RCM digesters primarily engaged in design of anaerobic digesters.
  Digester types
  - Plug flow
  - Covered Lagoon
  - Mixed tank – typically hog farm sites / none currently in CA.
- Size of digester based on number of cows – 2.5 kWh / cow / day. Typically prefer 500 or more cows.
- Operational considerations – Learning curve for owner but digester is typically relatively simple. Systems are self contained as long as feed is consistent. Must maintain temperature and amount of water.
- Typically more issues with electric side than with digester.
- Primary issue with using gas in engines is H_2S, corrosiveness. Contract with Martin Machinery to refurbish engines. Lined and reinforced components are more tolerant of HS2.
- Emissions – NOx has not been an issue to date due to small size of applications and so not yet regulated.

3. Technical considerations

- CEI to provide factors we will use in the study. They will review and comment.

4. Regulatory Policy and Tariffs (Net Metering)

- Net metering benefits are minimal to non-existent.
  - Works best only if bulk or all power used on site.
- Would like to see net metering discontinued and instead allow dairies to negotiate and enter PPA's.
- Farmers often can't use energy credits for all power even if spread across all of their meters. Credit to only generation component.
  - Sometimes produce more power than all billing aggregation can take advantage of.
  - One dairy produced 107% of combined use. No credit for 7% excess.
  - Even in generator Dairy, must pay demand and non-generation component of bill because load not connected directly.

5. Incentives Programs

- Federal
  - USDA Renewable Energy Efficiency Grants 25% up to $500K applied to entire project. Wind, solar or anaerobic digesters. RFP issued once / year in past. Next year may have open rolling enrollment. Up to amount of $ available. Audit process to ensure costs are truly part of the project.
  - Energy Policy Act
    - 0.9 ¢/kwh PTC. 5 years if operational by 2004, 10 years if operational by 2005.
    - Must be 150 kw or greater and many dairy's not that size.
    - Still some uncertainty about interpretation relative to QFs. Energy bill and disallowance of PURPA is an issue. Open loop biomass previously qualified and this could eliminate requirement for utilities to purchase power. (Need clarification)

- State level
  - Pennsylvania – Energy Harvest grant. Open. Amount project by project. Has spurred substantial project development for Digesters.
  - Environmental Quality Improvement Program – EQIP – Can be applied to certain equipment so would reduce the USDA grant.
  - Minnesota – Xcel Energy – special program with PPA.
  - CA – SGIP. Rebate / not grant. $1.00/watt $1000/kw. Must get money before interconnect.
  - New York Net Metering proposed 3¢/kwh

- Other
  - Western United Dairymen's program – expired. May be available in the future?

III) Hourly Load Profiles and Load Duration Curves used in the Task 5 Study

This section includes illustrations of the hourly load profiles and load duration curves used in the study. The curves were derived from interval and billing data provided from multiple dairies. The results shown and used in the study represent proxies derived from that data but are not specific to any of the dairies who provided information.

The hourly load profiles (shown annually) illustrate hourly electric use in kwh over the period of a calendar year. Dips in the curves illustrate drops in load associated with weekend or nighttime uses and with seasonal variations. thermal data and chiller load data used in the study was based on averages since period and time-of-use data was not available for these uses.

The load durations curves provide a different view of the data, showing the number of hours in a year that a particular condition occurs. Shaded areas indicate the amount of power produced by the engine set and the relative amount of exported power.

Figure 72 – Proxy Annual Electric Load for Proxy Dairy

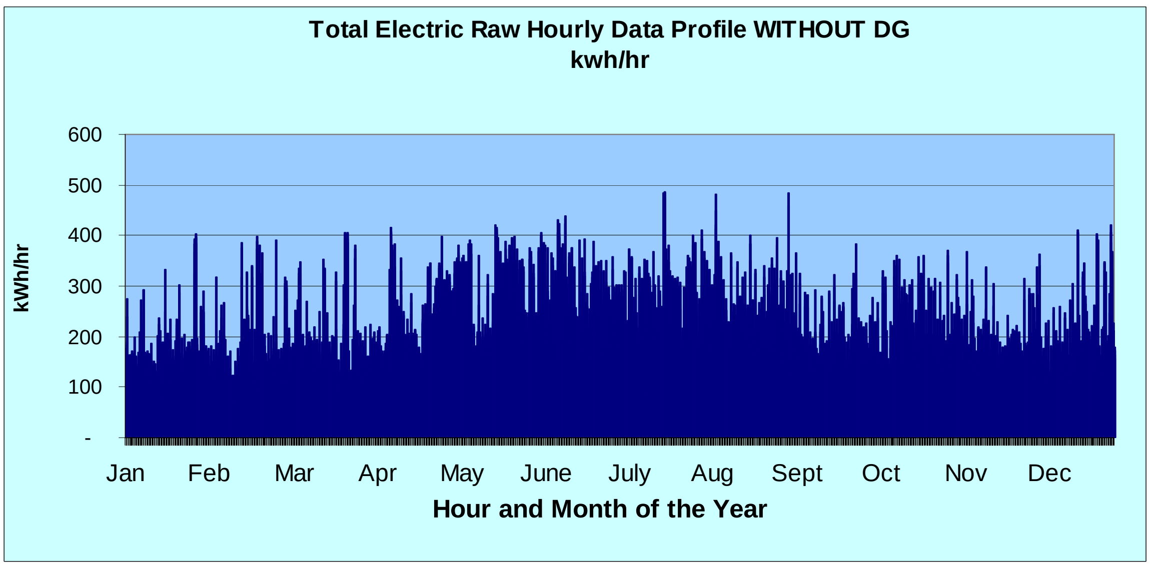


Figure 73 –Annual Electric Load Duration Curve for Proxy Dairy

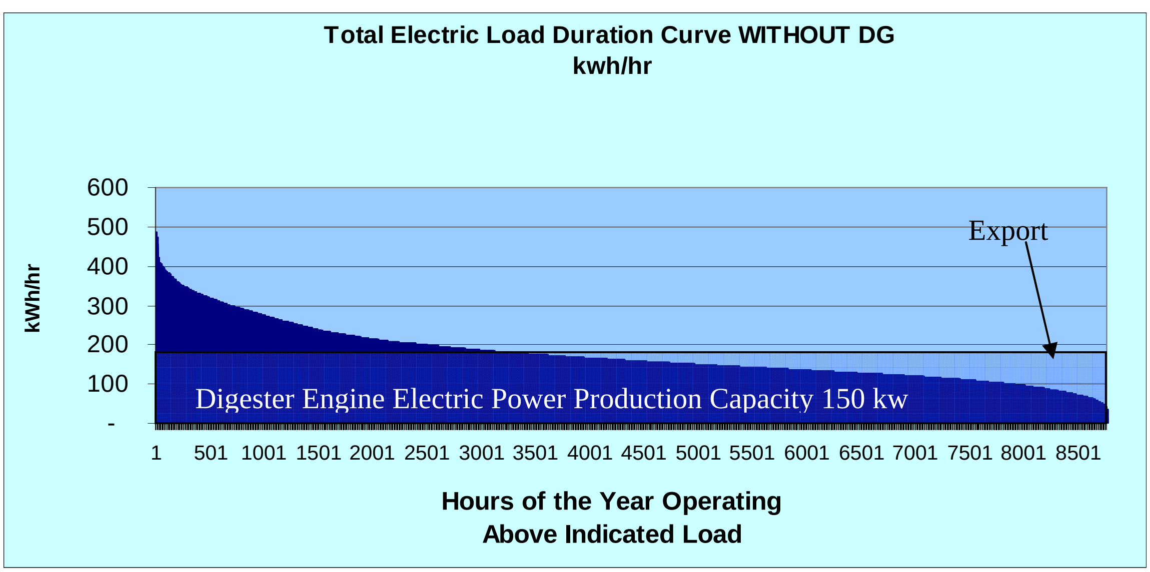


Figure 74 –Hourly Electric Load Profile for Proxy Dairy for the Month of January

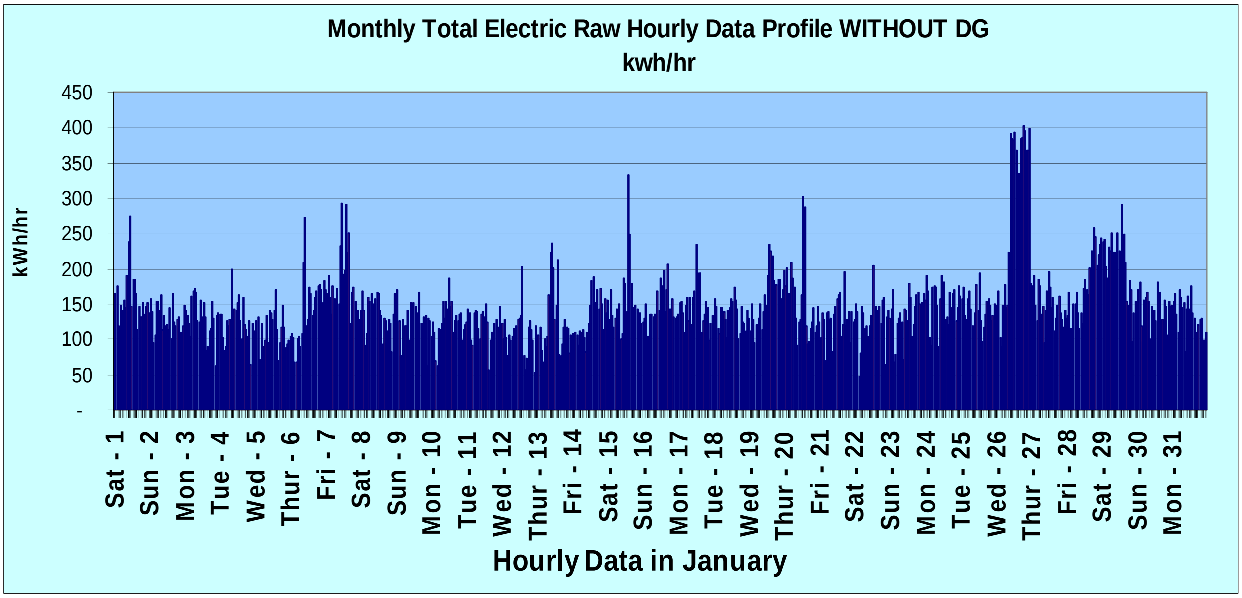


Figure 75 –Electric Load Duration Curve for Proxy Dairy in the Month of January

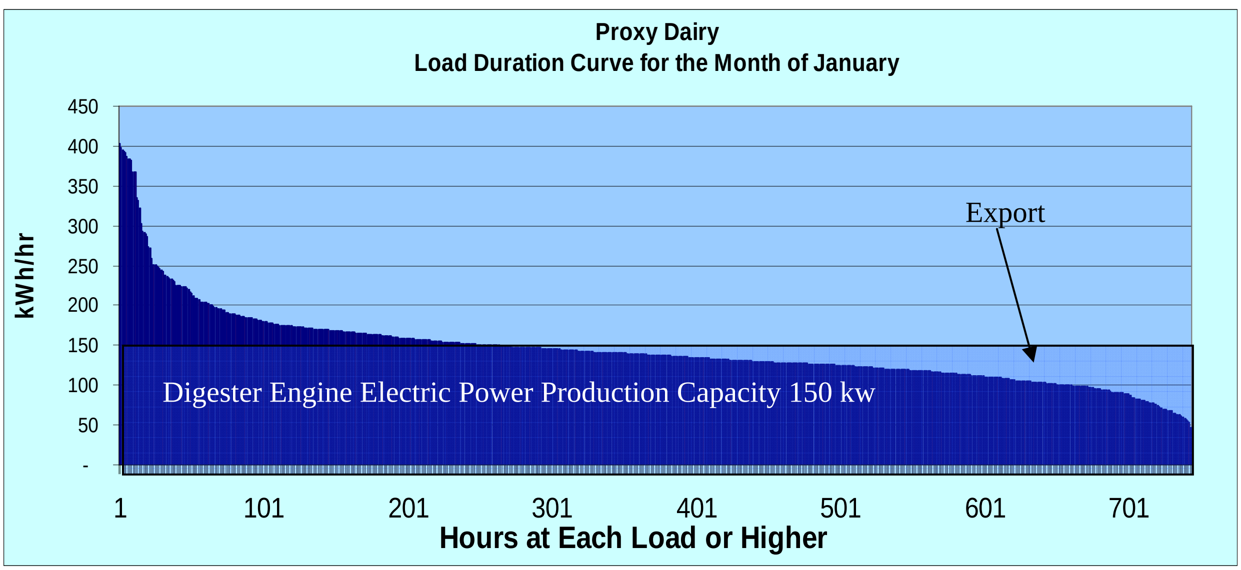


Figure 76 – Hourly Electric Load Profile for Proxy Dairy for the Month of April

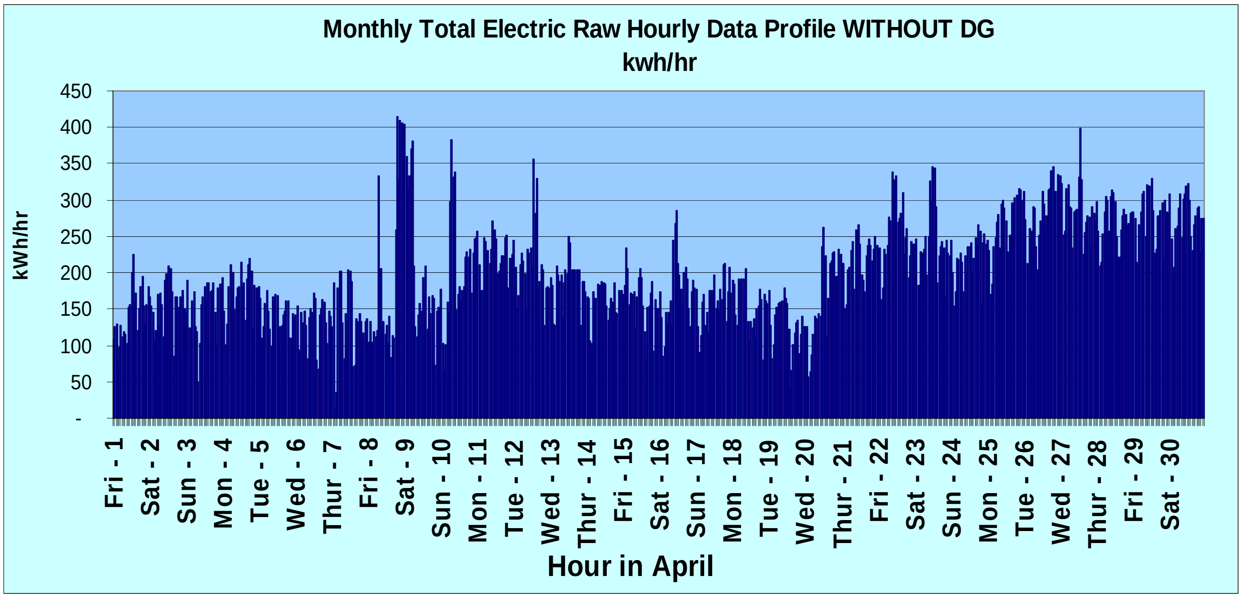


Figure 77 – Electric Load Duration Curve for Proxy Dairy in the Month of April

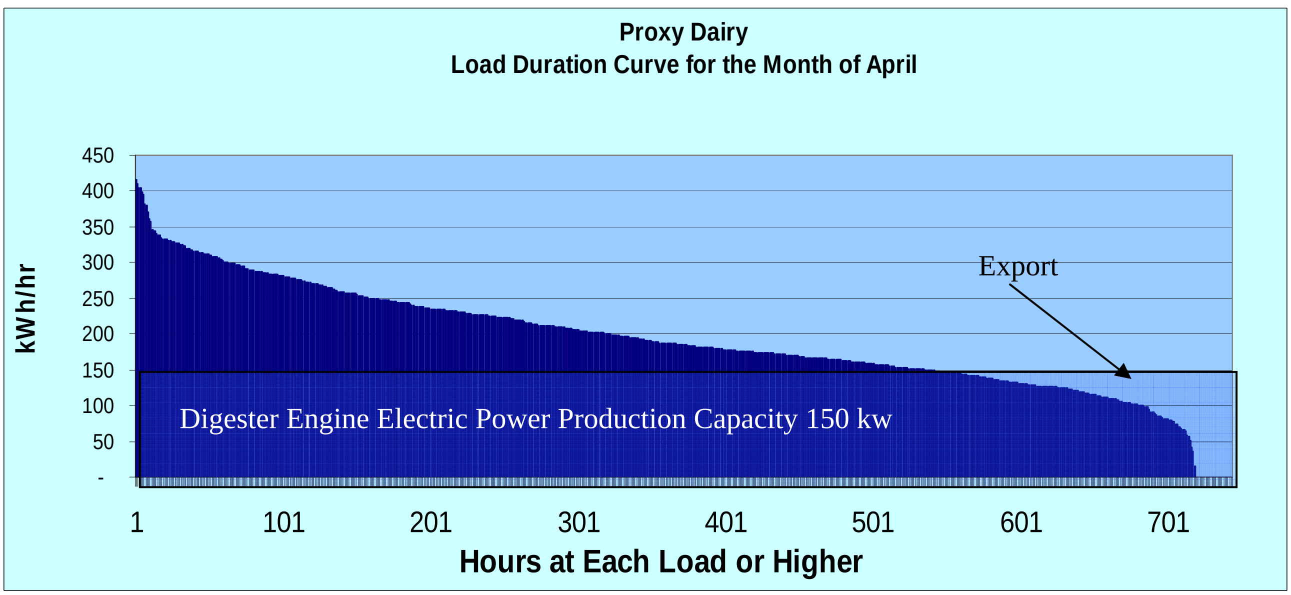


Figure 78 – Hourly Electric Load Profile for Proxy Dairy for the Month of July

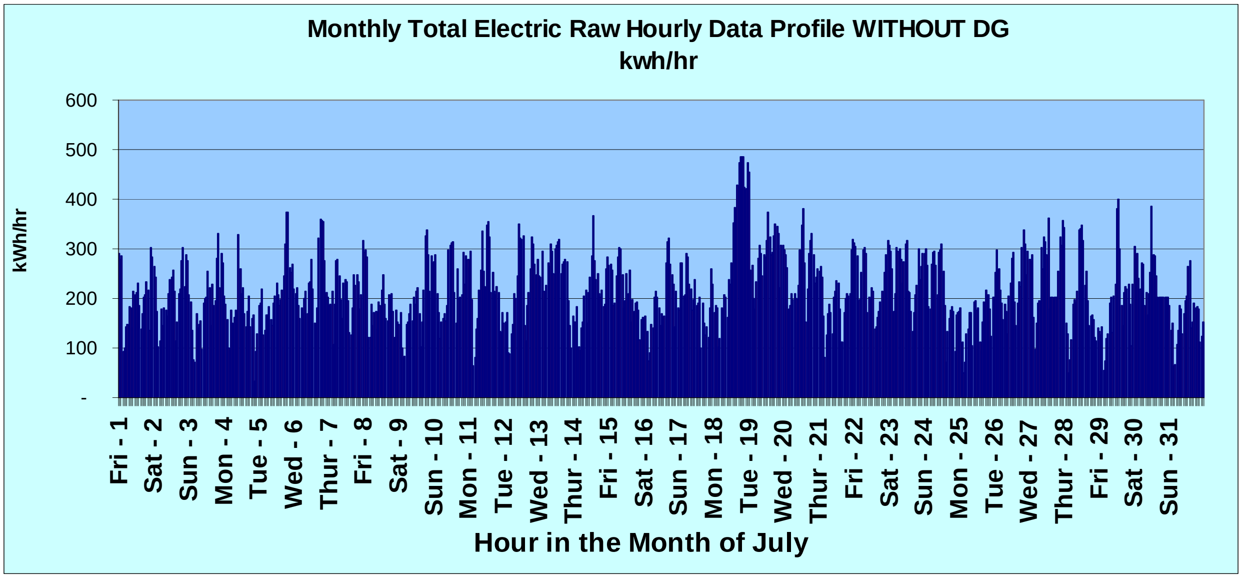


Figure 79 – Electric Load Duration Curve for Proxy Dairy in the Month of July

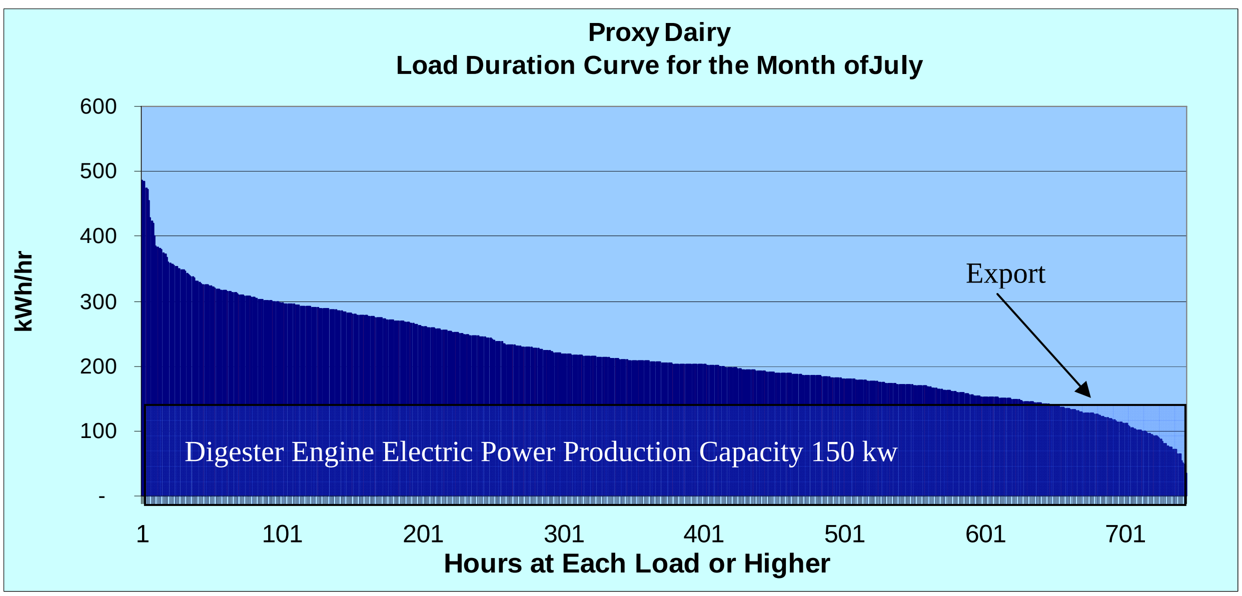


Figure 80 – Hourly Electric Load Profile for Proxy Dairy for the Month of October

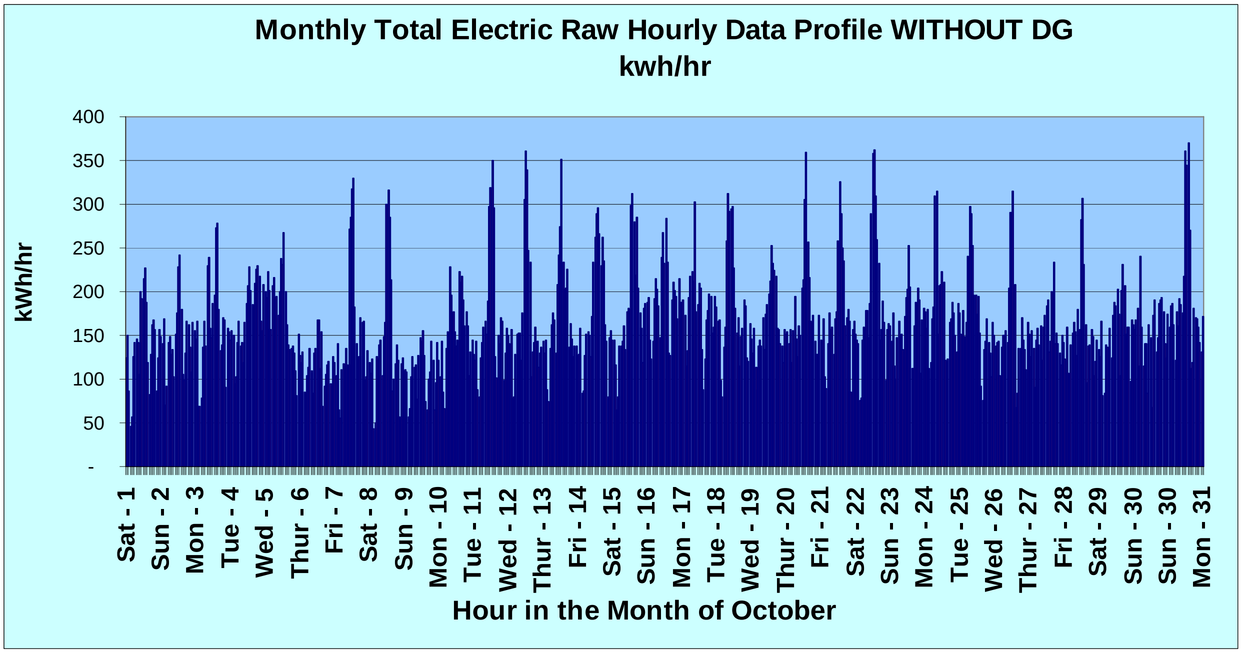


Figure 81 – Electric Load Duration Curve for Proxy Dairy in the Month of October

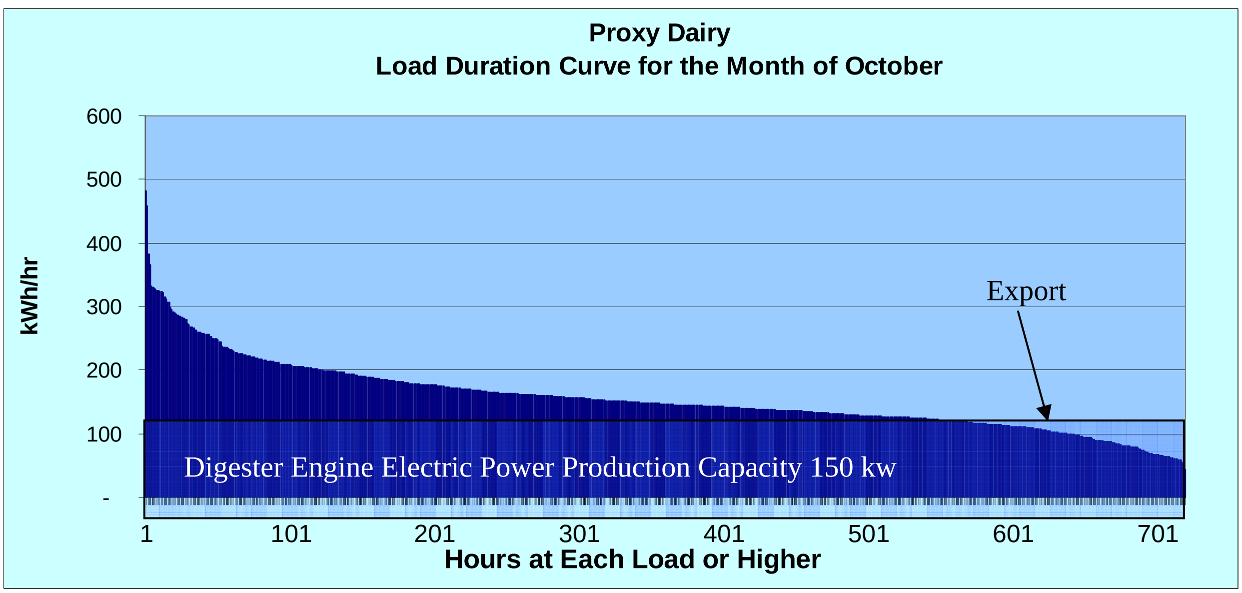


Figure 82 –Hourly Site Electric Profile with DG in Operation

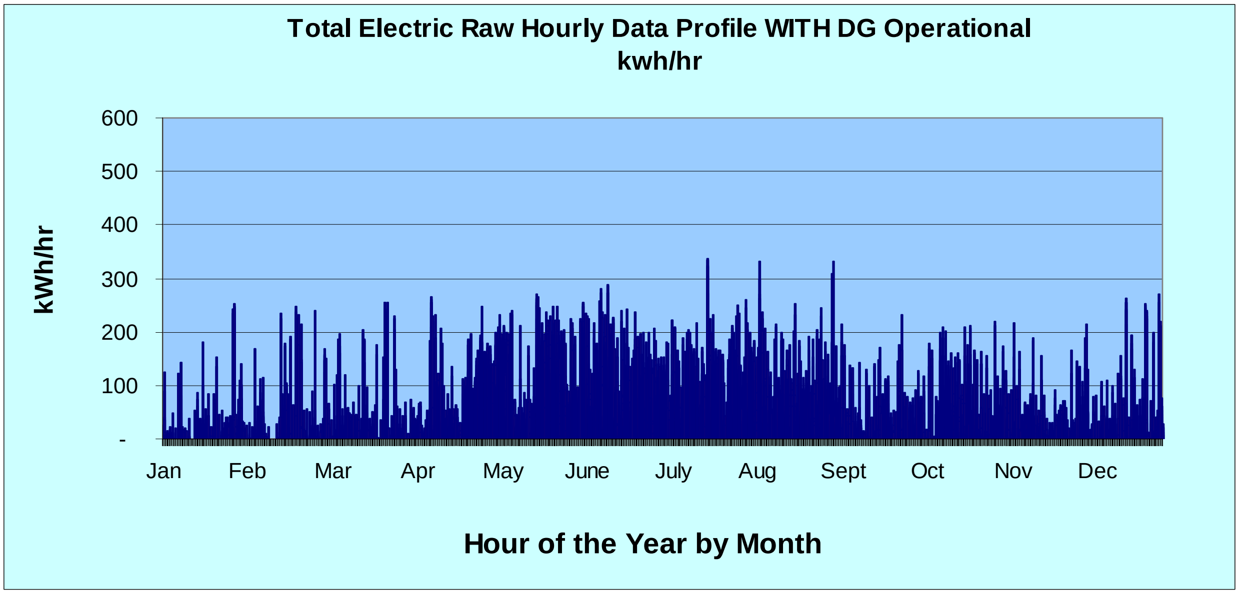
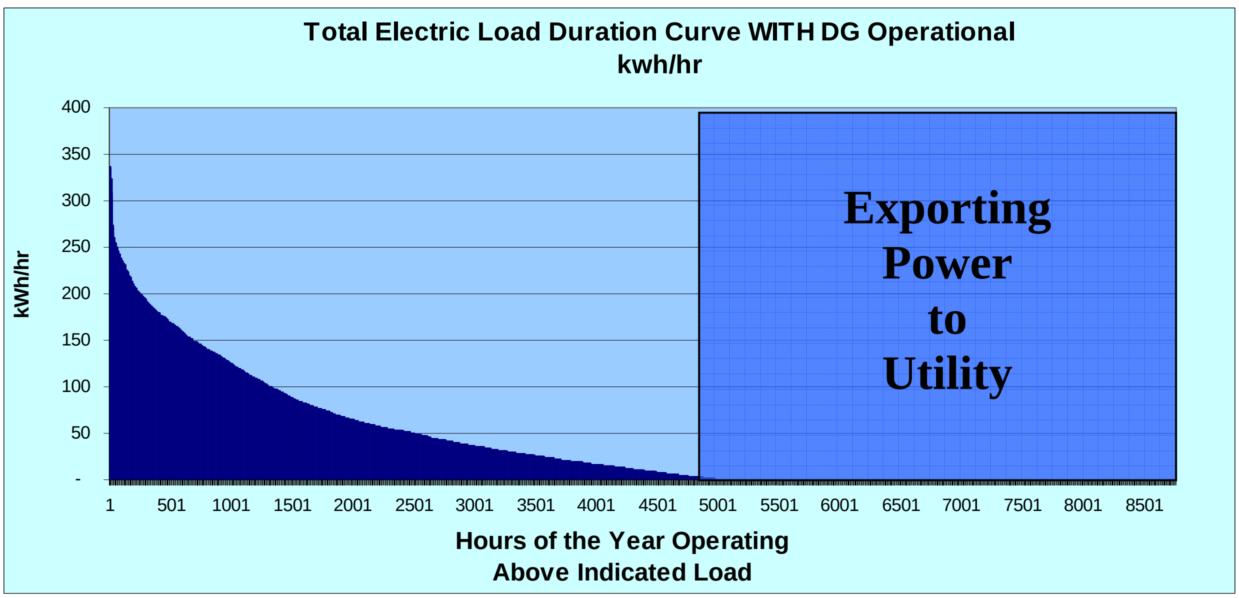


Figure 83 – Annual Load Duration Curve for Electric Purchases with DG in Operation



Appendix D - Overview of Competitive Energy Insight's EconExpert Financial and Economic Analysis Modeling Suite

CEI (established in 1997) has developed and licenses a suite of advanced software products for the analysis of renewable energy, combined heat and power, and central plant applications which we both license to others and use in our consulting practice. All of our tools are Excel-based, making them completely customizable, auditable and adding all of the features of Excel to our advanced features, but they are far more than spreadsheets. Behind each models is powerful Visual Basic programming which provides robust and highly advanced menu driven functionality. These tools have been applied to literally billions of dollars of energy project investments and acquisitions ranging from small Combined Heat and Power applications and Renewable Energy projects to large Coal and Gas Fired Central Power Plants, providing standardization, productivity, cost savings and advanced analysis power.

CEI has developed three powerful financial models for analysis of power project investments. Following the discussion of these models is an overview of our Interval Analysis Tools that allow you to evaluate detailed time-related impacts on project economics.

Our financial analysis suite includes:

- ***EconExpert-DG,*** an economic and financial analysis tool for distributed generation / combined heat and power, inside-the-fence (retail), tariff analysis and energy savings applications. EconExpert-DG is perfectly suited to perform competitive project and market evaluation of projects that represent make/buy analyses with complete flexibility to analyze any utility tariff and any combination of electric and thermal uses.

- ***EconExpert-LP,*** an economic and financial analysis tool for fossil and thermal-based projects that sell wholesale energy to the grid or "over-the-fence" to third parties under all types of market based sales, regulated rates or bilateral contracts. Examples of such projects include thermal-based renewable energy projects (including biomass, land fill gas, etc.), industrial cogeneration applications that sell energy over-the-fence and central power plants.

- ***EconExpert-WIND,*** an economic and financial analysis tool for unregulated or regulated wind farm projects that sell wholesale energy. Architected from *EconExpert-LP* this tool is perfectly suited to perform competitive project and market evaluation of wind projects that can utilize Production Tax Credits, Renewable Energy Credits and often apply complex partnering and financing arrangements. A key feature of this model is the ability to allocate tax credits, equity and debt in any manner and then to "flip" those allocations over the term of the project including utilities for analysis of alternative "Capital Account Structures" and "Partner Exit Strategies".

IMPORTANTLY, all of the financial models described above provide the following benefits:

  - Stakeholder Analysis. Evaluation can be performed from the perspective of every stakeholder in a transaction positioning anyone to fully understand the economic benefits and risk profiles from their own perspective as well as from the perspective of the parties they are negotiating with.

- Energy Policy Act of 2005. All aspects of the Energy Policy Act can be accurately and efficiently addressed in the models including investment tax credits, production tax credits and accelerated depreciation benefits.

- Applicable Over the Full Business Cycle. The models are easily adapted to everything from quick screening to detailed transaction modeling in “bank-quality” format.

- Standardization. The *EconExpert* modeling suite is standardized meaning that all of your financial analysis work can be performed in a consistent, understandable and reproducible platform. You will no longer need to worry about the “Legacy Effect” which can result in changes to one project’s model getting accidentally carried forward into other analyses. With *EconExpert*, all of your customized analysis is driven though the straight forward input sheets in the model and starting with a fresh model can be easily initiated.

- Wizard and Menu Driven. The *EconExpert* models are equipped with menus and wizards that assist the user in setting up analyses and providing clear reports.

- Automated Sensitivities. Included in each model is a suite of automated sensitivity analyses ranging from investment, operations and financing analyses, to asset valuation, forward electric and gas prices, fuel hedging, and contract mechanism risk analyses, allowing the user to gain a thorough understanding of a project's risk profile and to properly structure win-win agreements to manage those risks. Automated case comparison can be used to provide a clear understanding of how multiple changes in costs, performance or deal structure will specifically impact project economics.

- Presentation Quality Graphics. These support the simple communication of results to your peers, your management, your partners and your customers.

- And more. *EconExpert* will grow with you to meet your needs. It is easy to get started with the models using the automated wizards and menus that support data input and analysis, yet the power of the tool is scalable and customizable to meet all of your analysis needs.

Complementing our financial models, CEI also provides a suite of interval analysis tools to evaluate time-related performance and pricing considerations.

- The ***EconExpert-IAT*** **Interval Analysis Tool** for DG/CHP projects simulates the automated dispatch (“optimized make vs. buy”) of DG/CHP facilities as a function of interval electric and thermal demand data, ambient weather conditions, facility operating characteristics and pricing signals imposed from the applicable electric time-related or tiered rates and tariffs. This tool can also incorporate the *EconExpert*-EnergyShape Database (described below) of proxy building thermal and electric profile data that allows the simulation of time-of-use energy and thermal profiles for virtually any building type or configuration when specific metering data is not available. Using *EconExpert*-IAT, the user can gain a thorough understanding of the complex interactions of site needs, tariffs and equipment performance to optimize equipment sizing and to support detailed time-related analysis. Results from the IAT model are nicely summarized in monthly reports and graphics, and can be automatically exported to *EconExpert-DG* or *EconExpert-LP* for seamless time-of-use based financial analysis.

- The ***EconExpert-WIND* Interval Analysis Tool** (in development), will evaluate the energy production and revenue profiles of wind facilities as a function of interval wind data and variable or market-based pricing, including capabilities for evaluating energy storage options. Architected from the *EconExpert-IAT Interval Analysis Tool* for DG/CHP, results from the *EconExpert-WIND IAT* model can be automatically exported to the *EconExpert-WIND* financial model for seamless discount cash flow analysis.

- The ***EconExpert-EnergyShape***[1] database will generate simulated hourly electric and thermal load profiles for use in *EconExpert-IAT* when metering data is not available. *EconExpert-EnergyShape* includes a wide array of commercial building types in various climatic regions. Profiles generated by the model for the various building types are automatically conformed to the site's monthly thermal and electric bills. The results can then be imported into *EconExpert-IAT* for the "make vs. buy" analysis of the optimum sizing and operations of a facility against time-of-use tariffs.

1. CEI has licensed the EnergyShape database from Primen, a division of EPRI Solutions, Inc., with limited rights to sub-license the EnergyShape database for use in combination with the *EconExpert-IAT* model and other *EconExpert* software tools developed by CEI.

Appendix E - Glossary and Definitions of Key Terminology

- DWR – Department of Water Resources
- LADWP – Los Angeles Department of Water and Power
- SCE – Southern California Edison
- SGIP – Self Generation Incentive Program
- PG&E – Pacific Gas and Electric
- SDG&E – San Diego Gas and Electric
- CHP – Combined Heat and Power
- DG – Distributed Generation
- PUC – Public Utilities Commission
- CPUC – California Public Utilities Commission
- EECC - Electric Energy Commodity Cost under SDG&E tariffs
- IOU – Investor Owned Utility
- IC – Internal Combustion Engine
- HVAC – Heating Ventilation and Air Conditioning
- IRR – Internal Rate of Return
- NPV – Net Present Value
- PPA – Power Purchase Agreement