C C D C
California Clean DG Coalition

July 30, 2013

Mr. Mike Tollstrup
California Air Resources Board
State Environmental Protection Agency
Sacramento, CA 95814

RE: Comments on the California Air Resources Board (CARB) 2013 Update to AB 32 Scoping Plan - Kickoff Workshop Presentation 6/13/13

Dear Mr. Tollstrup:

The California Clean DG Coalition ("CCDC") appreciates the opportunity to provide these comments regarding California Air Resources Board's ("ARB") 2013 Update to the AB 32 Scoping Plan. CCDC is an ad hoc group interested in promoting the ability of distributed generation ("DG") system manufacturers, distributors, marketers, investors, and energy users to deploy DG. Its members represent a variety of clean DG technologies including combined heat and power ("CHP"), renewables, gas turbines, microturbines, reciprocating engines, and storage. CCDC is currently comprised of Capstone Turbine Corporation, Caterpillar, Inc., Cummins Inc., DE Solutions, Inc., GE Energy, Holt of California, NRG Thermal, Penn Power Systems, Peterson Power Systems, Recycled Energy Development, Solar Turbines, Inc., and Tecogen, Inc. The majority of CCDC member projects are purposed for the customer side of the meter.[1]

CHP is recognized in the 2008 Climate Change Scoping Plan as an energy efficiency measure with significant potential for reducing GHG emissions.[2] The United States Department of Energy, the United States Environmental Protection Agency and the California Energy Commission also recognize CHP as an energy efficiency measure. In addition, CHP provides environmental, reliability, economic and jobs benefits. The 2008 Climate Change Scoping Plan targeted CHP for an additional 4,000 MW of capacity and 6.7 MMT CO_{2e} reduction in GHG emissions by 2020. Furthermore, the Governor's Jobs Plan called for 6,500 MW of new capacity by 2030. Yet California CHP deployment has remained sluggish the last several years, far off the target pace. To date not enough has been done to mitigate the long-acknowledged barriers

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[1] All references herein to CHP include CHP that is owned by the customer or by a third party.

[2] *See, e.g.*, Climate Change Scoping Plan (December 2008), p. 44, Table 7.

confronting CHP deployment or to recognize CHP's full benefits. In particular, the continued disparate treatment of various clean on-site generation technologies ensures CHP must keep fighting an uphill battle.

Recommended actions to accelerate the implementation of CHP and achieve the desired targets are noted below:

Cap-and-Trade Economic Impact Needs to Mirror Benefit

CHP displaces less efficient wholesale fossil generation sources from the California grid. CARB currently uses an emissions benchmark of 0.431 MTCO2e/MWh which corresponds to a 42% efficient natural gas generating plant. The GHG emissions reductions from efficient CHP are considerable when compared to this baseline. However, because the grid is not comprised of 100% natural gas power, the economic linkage between the carbon cost adder in natural gas and the carbon cost adder in electricity is distorted.

Eligible renewables, large hydro, and nuclear are included in the electricity carbon adder, which means that the adder is about one half what it would be if it were all natural gas. This results in a negative economic signal instead of a positive economic signal for CHP.

Sending this inadvertent negative market signal to existing and prospective CHP adopters goes against the fundamentals of AB 32. Those who have already made a commitment to efficient

CHP will understandably lose trust in the Cap & Trade mechanism and prospective CHP adopters will question the wisdom of investing in CHP and its uncertain, currently adverse economic treatment under Cap & Trade.

This fundamental flaw with the treatment of CHP in California's Cap & Trade program must be corrected. Many prospective CHP projects are currently delayed because of this situation and, without a speedy remedy, new CHP implementation will be diminished.

In order to create a level economic playing field based on CHP's GHG reducing benefits, the carbon cost for natural gas used for efficient CHP must be adjusted. This can be accomplished through the issuance of allowances for CHP fuel or through payments from either Cap & Trade auction proceeds or the Natural Gas Allowance Revenue Fund. (Please refer to attached CCDC Comments to CARB regarding the May 1, 2013 ARB Workshop on CHP for supporting detail.)

GHG Emission Benchmark for CHP

CARB's current benchmark for CHP is 0.431 $MTCO_2$/MWh which corresponds to a 42% efficient natural gas plant. It is our understanding that CARB is considering applying this benchmark to CHP selling generation wholesale into the grid and that the benchmark used for CHP on the customer side of the meter would be penalized by the RPS % in effect because of the resulting reduction in wholesale power generation that reduces the absolute requirement for renewables. The inadvertent consequence of this literal interpretation of the legislation is energy policy that values wholesale power generation with its attendant requirements for new T&D capacity, T&D losses and firming capacity more than customer solutions whether they are efficiency measures, CHP or renewables. This looming policy flaw should be dealt with administratively by CARB or via legislation.

Departing Load Charges on CHP Generation Should Be Eliminated

CARB appropriately identifies cost issues, including departing load charges ("DLCs"), as an ongoing challenge for CHP.[3] Under current California Public Utilities Commission decisions, DLCs must be paid by consumers who install CHP based on energy that "departs" the utility system. Most other customer measures are exempt from DLCs, even though they also reduce demand on the utility system. For example, efficiency measures, net energy metered renewable DG, net energy metered natural gas fuel cells, fuel switching, and demand response measures are exempt from these charges. Even though customer CHP is widely recognized as an energy efficiency measure, customer CHP has been singularly non-exempted from DLCs. The total amount of DLCs paid for CHP generation varies but can exceed 1.5 cents/kWh for some customer classes. In an assessment performed by ICF International, the elimination of DLCs for CHP would increase market penetration of customer CHP by 26% or 500 MW by 2030 resulting in the following incremental benefits:

- 5.5 trillion Btu/year added primary energy savings by 2030
- $376 million per year in added customer energy cost savings by 2030
- Additional $900 million ($2011) in CHP investment
- Additional 5.5 million MT of CO_2e emissions savings

A copy of the ICF International report is attached.

State policies encouraging clean customer measures should be applied consistently, such that DLCs no longer apply to customers who install CHP.

Revisit Standby Reservation Capacity Charges for CHP

Senate Bill ("SB") X1 28, enacted in 2001, added Article 3.5, "Distributed Energy Resources," to the Public Utilities Code. SB X1 28 expressed the Legislature's preference that DER (including clean CHP) be served – over the long term – under rates, rules, and requirements identical to those of customers that do not use DER, on an interim basis and over the long-term. CCDC interprets SB X1 28 as providing for an interim exemption from the standby reservation capacity charge, pending development of DER tariffs that incorporate a long-term exemption from the standby reservation capacity charge.[4]

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[3] 2013 Update to AB 32 Scoping Plan (June/July 2013), p. 34.

[4] Additionally, Assembly Bill ("AB") 1613, enacted the Waste Heat and Carbon Emissions Reduction Act in 2007 (Public Utilities Code sections 2840 – 2845). Public Utilities Code section 2841(g) provides that the CPUC is to

The interim standby reservation capacity charge has ended, and CCDC is not aware that the DER tariffs have been adopted. Thus, the standby reservation capacity charge remains a challenge for CHP.[5] (Even with an exemption from the standby reservation charge, customers with CHP would pay an energy charge and a customer charge.)

Analysis done for a CCDC member by a rate consultant calculated that standby reservation capacity charges for a 500 kW CHP project comprised of two 250 kW units could range from approximately $7,800 to $15,600 per year. (Reservation capacity charges may be refunded in any month where a customer incurs demand charges as a result of the non-operation of the CHP unit(s).) If an outage of one 250 kW unit occurs during peak and part-peak daytime periods, it is estimated that demand charges could add approximately $6,700 in a summer month, and approximately $2,300 in a winter month (after accounting for a reservation charge credit).[6]

It is time to revisit the standby reservation capacity charge in the context of CHP.

Demand Charges

Demand charges represent a large portion of TOU customer's bills and cannot be avoided with CHP if an outage as small as 15 minutes occurs during one of the peak periods. Unlike the commercial class of customers who have similar peak demand profiles, CHP as a class, does not appreciably contribute to the utility peak load. We recommend that the availability of CHP as a class be factored into a revised demand charge tariff. There are several methods for more fairly developing a CHP demand charge. As an example, a method employed in Illinois uses a daily demand charge for CHP users.

CHP Benefits to the Utility Grid Should be Monetized

Customer-sited CHP, as a class, provides valuable capacity to the California grid. Generation capacity is currently valued in excess of $100/kW/yr. The availability of CHP units varies, but is typically in the 92 – 98% range, for properly maintained and operated units. The California ISO should recognize customer-sited CHP as a class and develop a market-based capacity payment structure. For example, assuming a fleet average availability of 95% and a capacity value of $100/kW/yr, the CHP fleet value would be $95/kW/yr. A CHP unit would have to demonstrate a minimum availability level to remain in the CHP fleet. If availability was more valuable during

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"adopt or maintain standby rates or charges for [CHP] systems that are based only upon assumptions that are supported by factual data, and shall exclude any assumptions that forced outages or other reductions in electricity generation by [CHP] systems will occur simultaneously on multiple systems, or during periods of peak electrical system demand, or both." To CCDC's knowledge, the CPUC has not addressed this section of AB 1613.

[5] The 2007 Integrated Energy Policy Report ("IEPR") recommended that the CPUC and the CEC work cooperatively to eliminate standby reservation charges for DER. (2007 IEPR, Chapter 5, Recommendations, p. 212.)

[6] It is difficult to estimate the net impacts of reservation capacity and demand charges for a project, primarily because the nature and extent of outages are difficult to predict, but these numbers provide a reference point for indicating the impacts of such charges.

specific times of the year (*i.e.*, summer weekdays), planned maintenance could be scheduled around those times to further enhance availability during peak periods.

Likewise, CHP provides localized grid support and should be entitled to appropriate compensation. A location-based payment should be established for self-generation CHP similar to the location bonus developed under AB 1613.

A CHP Fast-track Interconnection Process is Needed

The currently cumbersome, costly and lengthy interconnection process remains a barrier to CHP. An expedited interconnect process is sorely needed for self-generation CHP. In addition to interconnection process and schedule certainty, another priority for CHP is addressing meter requirements and costs, in the context of interconnection, and for purposes of other incentive programs, like SGIP. Metering equipment costs can surpass the value of the SGIP incentive for smaller projects.

Concurrent Consideration of CHP and Energy Efficient HVAC

California's loading order for electricity resources is currently energy efficiency, demand response, renewables and distributed generation. The intent of the loading order is to develop and operate California's electricity system in the best, long-term interest of consumers, ratepayers and taxpayers. Given this goal, all California programs that fund onsite power and energy efficiency, such as Prop 39, should clarify that energy efficiency upgrades to building HVAC systems should be considered at the same time as combined heat and power systems and after building envelope energy efficiency upgrades are finalized.

Conclusion

Again, CCDC appreciates the opportunity to comment on the 2012 Update to the AB 32 Scoping Plan. As noted above, supporting greater CHP deployment is an important component of California's policy toolkit to reduce GHG emissions. Policymakers at the state and national levels have long recognized the many benefits of CHP, but there is much more to be done to remove the barriers standing in the way of this key energy efficiency measure.

Sincerely,

James P Halloran

James Halloran

Attachments:

1. CCDC comments to ARB regarding May 1 CHP Workshop
2. ICF International Report

CCDC

California Clean DG Coalition

Comments from the California Clean DG Coalition Regarding May 1 ARB Staff Workshop on CHP and Cap & Trade

The California Clean DG Coalition ("CCDC") appreciates the opportunity to provide these comments regarding the California Air Resources Board's ("ARB") Staff Workshop on May 1, 2013 to discuss adjustments to the Cap and Trade Program for Universities and Combined Heat and Power ("CHP"). CCDC is an ad hoc group interested in promoting the ability of distributed generation ("DG") system manufacturers, distributors, marketers and investors, and electric customers, to deploy DG. Its members represent a variety of DG technologies including combined heat and power ("CHP"), renewables, gas turbines, microturbines, reciprocating engines, and storage. CCDC is currently comprised of Capstone Turbine Corporation, Caterpillar, Inc., Cummins Inc., DE Solutions, Inc., GE Energy, Holt of California, NRG Energy, Penn Power Systems, Peterson Power Systems, Recycled Energy Development, SDP Energy, Solar Turbines, Inc., and Tecogen, Inc.

ARB proposes transitional assistance for Universities that have taken early actions and provided leadership to reduce GHG emissions though investments in efficiency and renewable energy. For Universities that are subject to the Cap and Trade Program, most or all of which have an operational CHP system, allowances equal to their three year historical fuel use baseline (excluding electricity exports) would be provided for 2013 and decline in proportion to the cap through 2020. CCDC supports this action and recommends that eligibility be broadened to include other institutional and private entities who have demonstrated similar early action and leadership behavior.

ARB staff also proposes that the Cap and Trade first compliance period threshold for entities with CHP should be based on either steam emissions or electricity emissions exceeding 25,000 $MTCO_2e$, which keeps entities from triggering Cap and Trade only because of efficient CHP. We agree with the proposed methodology. However, CCDC recommends that the offsetting boiler efficiency assumption be changed from 85% to 80% which is a more realistic value for present day facilities serving large steam loads. We also recommend that the words "useful heat" be substituted for "steam," as steam is not always the heat transfer medium in a CHP system.

The "but for" CHP patch applies to an estimated 11 entities and does not go beyond the 1st compliance period. ARB stated that in the 2nd compliance period, all CHP facilities, whether through Cap and Trade or through a carbon adder in the price of natural gas, will be on the same economic playing field and Cap and Trade will improve the incentive for CHP. CCDC disagrees with this statement. ARB recognizes that efficient CHP displaces less efficient wholesale fossil generation sources from the California grid. The ARB emissions benchmark is

0.431 $MTCO_2e/MWh$.[1] However, because the grid is not comprised of 100% natural gas power, the true economic linkage between the carbon cost adder in natural gas and the carbon cost adder in electricity does not exist.

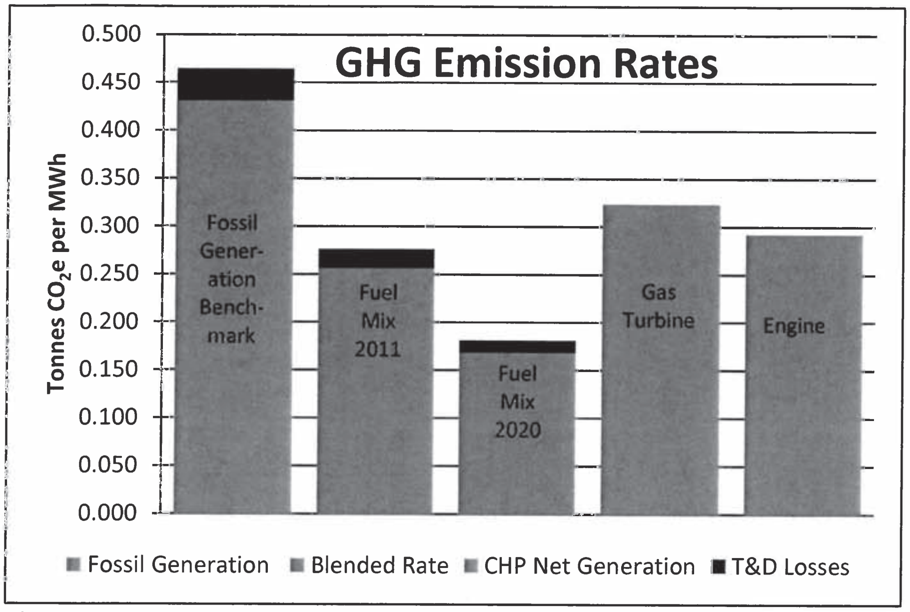
According to the California Energy Commission, fossil power generation comprised 43.8% of the State's energy mix in 2011.[2] And of the 13.7% unspecified fuel sources, we assumed that ½ was natural gas and the other ½ was large hydro. As shown in the figure to the right, this mix corresponds to a blended delivered emission rate of 0.256 $MTCO_2e/MWh$, 41% less than the true benchmark. Based on an estimate of the fuel mix in 2020, the blended emission rate is 61% less than the true benchmark.

CA Fuel Mix	2011 CEC	2020 Estimate	Emission Benchmark $MTCO_2/MWh$	
Natural Gas	35.6%	34.0%	0.431	
Nuclear	15.3%	15.0%		
Eligible Renewables	14.2%	33.0%		
Coal	8.2%	0.0%	0.892	
Large Hydro	13.0%	13.0%		
Unspecified	13.7%	10.0%		
1/2 Natural Gas	6.9%	5.0%	0.431	
1/2 Large Hydro	6.9%	5.0%		
Total	100.0%	100.0%		Electric Price to CO2 Benefit Ratio
Fossil Total	50.7%	39.0%		
Natural Gas Total	42.5%	39.0%		
CA Fuel Mix 2011			0.256	59%
CA Fuel Mix 2020			0.168	39%

The chart below compares the emission impact of these various emission weighting approaches against two typical CHP systems. As shown, CHP's GHG emission benefit goes from a positive when compared against the ARB electricity benchmark to a negative when compared against the whole fuel mix comprising California's wholesale electric grid.

[1] This corresponds with a 42% efficient natural gas plant.

[2] http://energyalmanac.ca.gov/electricity/total_system_power.html; unspecified power are generally out of state short term power purchases from plants that do not have a contract with a California utility. Northwest spot purchases are served by surplus hydro and gas-fired power plants. The Southwest spot market purchases are primarily combined cycle power.



The table below compares the economic value of CHP to the State at allowance costs of $10 and $40 per tonne against the economic cost to CHP users when allowance costs for fossil generation are blended in to the electricity price along with non-fossil sources. As shown, the difference between the cost and the value exceeds 1.0 cent/kWh in 2020 if allowance costs hit $40/tonne.

	Value $/kWh		2011 Cost $/kWh		2020 Cost $/kWh		Cost-Value 2020	
CO2 Cost $/tonne	Turbine	Engine	Turbine	Engine	Turbine	Engine	Turbine $/kWh	Engine $/kWh
10	$0.0014	$0.0017	$0.0005	$0.0002	$0.0014	$0.0011	$0.0028	$0.0028
40	$0.0056	$0.0069	$0.0019	$0.0006	$0.0057	$0.0044	$0.0113	$0.0113

Forcing CHP to absorb an economic penalty because of Cap and Trade sends the wrong market signal to existing CHP adopters who expected a positive benefit from AB 32 and to prospective CHP adopters who will question the "green" in CHP and face uncertain economic consequences as the future price for allowances are unknown. CCDC views this as an inadvertent yet fundamental flaw in the treatment of CHP in California's Cap and Trade Program. Many prospective CHP projects are now stalled in the development pipeline due to this dilemma. If this problem is not corrected, we are concerned that ARB's reliance on CHP as a GHG reduction measure, including estimates for future CHP, will be seriously compromised. In addition, CHP provides additional environmental, efficiency, reliability, economic and jobs benefits that will be lost if CHP adopters risk penalties for their investment. These benefits are reason enough to ensure CHP investment is encouraged.

The State needs to true-up the effective carbon price adder paid for on-site CHP natural gas to mirror CHP's CO_2 benefit relative to CARB's electric benchmark. Possible solutions to this important issue could include the following:

- Payments to CHP owners from Cap and Trade Auction proceeds or the Natural Gas Allowance Revenue Fund
- Issuance of Allowances for CHP fuel

CCDC urges CARB and, as appropriate the CPUC, to fix this inequity as soon as possible so that CHP can live up to its GHG mitigation potential.

Sincerely,

James Halloran
Chairman CCDC

The Effect of Departing Load Charges on the Costs and Benefits of Combined Heat and Power

Final Report

Prepared for:

California Clean DG Coalition

May 2013

Prepared by:

ICF International

Ken Darrow

Anne Hampson

Preface

This report was prepared for the California Clean DG Coalition (CCDC). The CCDC is an *ad hoc* group interested in promoting the ability of distributed generation (DG) system manufacturers, distributors, marketers and investors, and electric customers to deploy DG. Its members represent a variety of DG technologies including combined heat and power (CHP), renewables, gas turbines, microturbines, reciprocating, engines, and storage. CCDC is currently comprised of the following organizations:

- Capstone Turbine Corporation
- Caterpillar Inc.
- Cummins, Inc.
- DE Solutions
- GE Energy
- Holt of California
- NRG Energy
- Penn Power Systems
- Peterson Power Systems
- Recycled Energy Development
- Stowell Distributed Power
- Solar Turbines, Inc.
- Tecogen, Inc.

Contents

Executive Summary

Combined heat and power (CHP) has been identified as an efficient, clean, and beneficial means of meeting electricity demand in California by the governor's office, the legislature, the Public Utilities Commission, the Air Resources Board, and the Energy Commission. CHP is defined as energy efficiency by the Department of Energy, the Environmental Protection Agency, the California Air Resources Board, and the California Energy Commission. As such, CHP is part of the preferred loading order for new power supplies in the state that also includes energy efficiency, demand response, and renewable energy. Of these preferred sources, only customers who invest in CHP are required to pay departing load charges (DLCs) on their avoided electricity purchases. Reducing electricity consumption by investing in energy efficiency technologies or distributed power generation eligible for net metering does not carry with it the responsibility to pay DLCs.

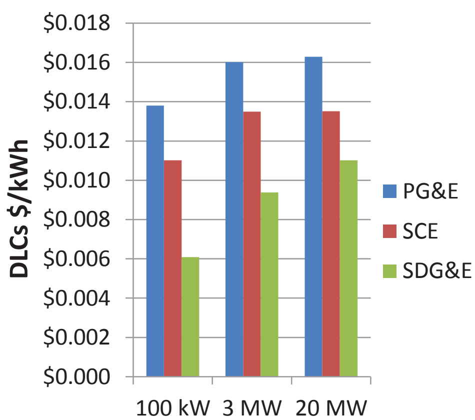


Figure ES-1. Departing Load Costs by Customer Size and by Utility

There are three DLCs that must be paid on the output of CHP that replaces customer retail electricity purchases; these are the Public Purpose Programs Charge, the Division of Water Resources Bond Charge, and Nuclear Decommissioning. These DLC costs are shown in Figure ES-1 for a range of customer sizes that could economically support investment in CHP. DLCs range from a high of 1.4-1.6 cents/kWh for PG&E to a low of 0.6-1.1 cents/kWh for SDG&E. For SCE, they range from 1.1 to 1.35 cents/kWh. For the largest customer class analyzed, the DLCs make up almost 23% of the total average rate for SCE and PG&E – 15% for SDG&E.

Currently, the three investor owned utilities must collect from all ratepayers and many departing customers, $3.4 billion per year in the surcharges that make up the CHP DLCs. The contribution of CHP to the three surcharges that make up the DLCs was estimated based on the non-exempt CHP operating capacity in the state. While there is over 8,500 MW of CHP capacity in California, the DLCs apply only to capacity that was installed after December 20, 1995, and then only for generation that was used to replace retail electric consumption or sales to a final user. Sales for resale do not pay the DLCs. The DWR Bond Charge only applies to customers that came online after February 2001. The total estimated costs collected from CHP are $50.8 million. This amount represents only 1.5% of the $3.4 billion collected for these surcharges from all customers. The average rate impact of redistributing this amount to remaining customers would be 0.026 cents/kWh, or about 13 cents/month for the typical residential customer using 500 kWh/month. As discussed below, this *de minimis* impact is offset or exceeded by the benefits of CHP.

If the DLCs did not apply to all sizes of customers with CHP, economic savings for new CHP projects would increase by 6-36% depending on size and utility. This improvement in economics would greatly increase the future deployment of CHP in support of market goals set by the Governor's office and by the Air Resources Board. Based on the ICF CHP market study funded by the California Energy Commission,[1] elimination of DLCs for CHP would increase the 20-year market penetration of CHP in California by nearly 500 MW (**Figure ES-2**) – 89% of this increase would be in DG sized systems of less than 20 MW. This added CHP market penetration would have the following key benefits for the state:

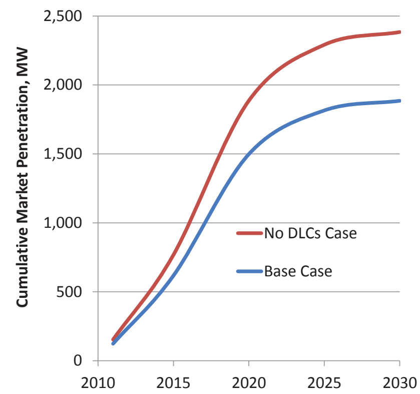


Figure ES-2. CHP Market Penetration Increase from Removing DLCs

- 5.5 trillion Btu/year added primary energy savings by 2030 due to the efficiency benefits of CHP
- Additional $900 million ($2011) in CHP investment providing stimulus to the California economy
- $376 million per year in added customer energy cost savings by 2030 providing funds for productivity enhancing investments, higher income for California businesses and resulting more jobs and greater economic growth.
- Additional 5.5 million MT of cumulative CO2 emissions savings over the 20-year forecast period bringing CHP closer to the ARB GHG emission reduction targets

These benefits to the state as a whole outweigh the modest ratepayer impact due to removing DLCs from CHP.

Other recognized but unquantified benefits from CHP[2] potentially include:

- Decreased congestion and increased system reliability
- Greater resource adequacy
- Improved stability and power quality including VAR support
- T&D and capacity investment deferrals and reduced electricity supply costs resulting from decreased demand
- Increased economic productivity and investment for host sites resulting in higher employment and economic growth.
- Market transformation impacts.

In order to achieve these expanded benefits for California, DLCs should be removed from CHP customer rates. Customers who do nothing to reduce their energy consumption already pick up the share of surcharges that would have been paid by customers investing in energy efficiency and renewable energy. Therefore, CHP should be treated the same way. The added costs are small compared to the overall benefits to California.

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[1] Hedman, Bruce, Ken Darrow, Eric Wong, and Anne Hampson, ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment*. California Energy Commission. CEC-200-2012-002rev2.

[2] D-09-08-026, *Decision for Adopting Cost-Benefit Methodology for Distributed Generation*, CPUC, August 20, 2009.

Introduction

Combined heat and power (CHP) increases energy efficiency by meeting both the thermal and electric needs of a facility through a single process greatly reducing the energy losses that occur when power is generated in central station electric plants. This inherent efficiency advantage has made CHP an important component of California's energy policy for over 25 years. In recent years, policy support for CHP includes:

- In 2008, the California Air Resources Board (ARB) explicitly identified CHP as an energy efficiency measure to be deployed in support of the reduction of greenhouse gas (GHG) emissions and set a target of 4,000 MW of additional market penetration by 2020 to reduce GHG by 6.7 million MT/year. The ARB noted that CHP still faced significant barriers that needed to be addressed through a combination of incentives and mandates. In 2010, Governor Brown included a target for new CHP market penetration of 6,500 MW over the next 20 years as part of his *Clean Energy Jobs Plan*.
- After a long negotiation among the California Public Utilities Commission (CPUC), the major investor owned electric utilities, and CHP producers, the *Qualifying Facility / Combined Heat and Power Settlement Agreement* was approved by the CPUC at the end of 2011. The IOUs have completed their first round solicitation toward negotiating 3,000 MW of power purchase agreements with existing and new CHP facilities.
- AB 1613 (Blakeslee), the *Waste Heat and Carbon Emissions Reduction Act* required investor owned electric utilities to establish Feed-in tariffs for CHP generated power.
- The Self Generation Incentive Program, originally put in place to provide peak load power support (AB 970 Ducheny, 2000) was modified by SB 412 (Kehoe, 2009) to make GHG emissions reduction a primary goal and to reinstate the eligibility of a range of CHP technologies.

With progress toward these goals still lacking, the California Energy Commission held an IEPR workshop to identify market barriers affecting CHP[3] Based on stakeholder input, several key market barriers were identified:

- Disincentives to CHP under the state's developing Cap-and-Trade program rules
- Nonbypassable and departing load charges (DLCs) that CHP operators must pay on power that they generate which replaces utility purchased power.
- Standby and demand charges that place an additional economic burden on CHP.
- Barriers to small CHP systems including interconnection rules and metering requirements and exclusion from net energy metering.

This paper presents an analysis of one of the key barriers to CHP deployment identified by the Energy Commission during a 2012 IEPR workshop proceeding, namely the negative economic impact of DLCs on CHP project development and the lost benefits to the state of California due to the resulting reduced market penetration.

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[3] *The 2012 Integrated Energy Policy Report Update*, California Energy Commission, 2012, CEC-100-2012-001-CMF.

Departing Load Charges in the California Electric Market

Cost responsibility surcharges (CRS) applicable to "Departing Load" (DL) served by customer generation has a long history. Some of the surcharges emanate from the funding of public purpose programs and the State's Electric Industry Restructuring Law.[4] The electricity crises of 2000 and 2001 created the Department of Water Resources (DWR) Bond Charge to cover the cost incurred by the DWR for the acquisition of power resources on behalf of the IOUs. These charges collectively add costs to CHP project economics and can negatively influence decisions by customers to pursue CHP.

California suffered significant problems with its initial transition to a deregulated electric utility industry. The resulting power crisis resulted in lawmakers passing numerous energy bills in addition to rulings issued by the CPUC. As with many states' electric restructuring laws, California created a competition transition charge (CTC) for utilities to recover their stranded costs as part of the initial legislation. Currently, these costs relate to what are commonly called "tail" competition charges pursuant to legislation enacted in Assembly Bill 1890 (AB 1890, Brulte).. The goal at the time was that these fees would allow for complete cost recovery by March 2002. Nonetheless, the three major electric investor owned utilities (IOUs) still charge "tail" CTCs for departing load. Departing load is defined as that portion of an IOU's customer's electric load for which the customer, on or after December 20, 1995 discontinues or reduces its purchase of electricity supply and delivery services from that utility.

As the power crisis broadened in 2000-2001, the Department of Water Resources had to procure $10 billion in electricity on behalf of the IOUs in order to avoid a complete breakdown of the power grid. Bonds issued by DWR to cover this cost are still being repaid. Other charges were added to recover historical procurement costs for specific utilities such as PG&E's Energy Recovery Bonds and SCE's procurement related obligation account. Those charges have been recovered along with certain ongoing DWR power charges.

In order to ensure the continuation of certain public policy programs, supported through regulated IOU payments, the CPUC included the Public Purpose Programs Charge (previously the Public Goods Charge) so that departing load would continue to contribute to these programs. The current programs supported by the PPPC are rate support for low income families (CARE); energy efficiency, demand response, and renewable energy programs; and research and development (EPIC).

Finally, utilities are authorized to collect for a fund to cover the costs of decommissioning nuclear plants at the end of their useful lives.

Table 1 summarizes the DLCs in the rates and shows the existing general and special exemptions for CHP. The charges apply to CHP for on-site use and sales to final customers. Most CHP installed after December 20, 1995 pays the PPPC and nuclear decommissioning (ND) charges. CHP installed after February 1, 2001 must also pay the DWR-BC. Exemptions from these three charges include certain distributed generation customers, such as fuel cells and renewable systems eligible for Net Energy Metering (NEM) and biogas systems. The first megawatt of clean DG and SGIP eligible systems 5 MW or less is exempt from the DWR-BC. The other departing load charges shown in the table are

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[4] AB 1890, 1996.

generally exempt for CHP meeting ARB emissions standards. As shown in the table, CHP is also exempt from the CTC, PCIA, ECRA, and CAM NBC.

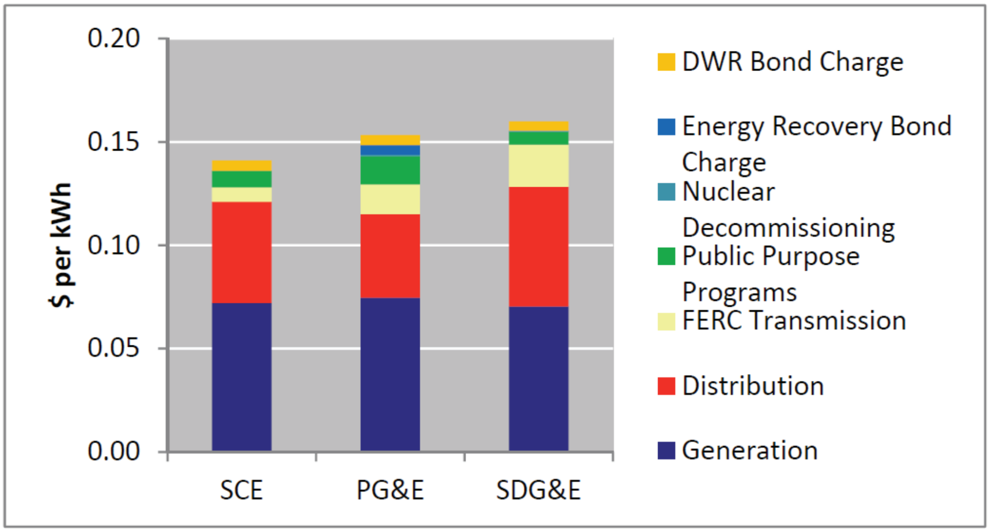
Table 1. Departing Load Charges Applied to CHP

Surcharge	***CHP Applicability***	***Special CHP Exemptions***
Public Purpose Program Charge	Applies to CHP projects put in after 12/20/1995	*biogas CHP and NEM exempt*
Nuclear Decommissioning	Applies to CHP projects put in after 12/20/1995	*biogas CHP and NEM exempt*
DWR Bond Charge	Applies to CHP projects put in after 2/1/2001	*biogas CHP and NEM exempt, first 1 MW of clean DG and SGIP eligible for projects up to 5 MW exempt*
Competition Transition Charge (CTC)	CHP Exempt per Public Utilities Code §372	CHP Exempt
Power Charge Indifference Adjustment (PCIA)	CHP Exempt, URG: D.08-09-012; Res. E-4226; DWR: D.03-04-030	
Energy Cost Recovery Amount (ECRA) -- PG&E only	CHP Exempt, D.04-02-062, D.04-11-015	
New System Generation Charge (CAM NBC) -- SCE Only	CHP Exempt, D.08-09-012; D.06-07-030	

Source: CPUC and Alcantar

The Share of DLCs in Rates

Combined, the annual revenue requirements for the IOUs to supply electricity in California are close to $27 billion. The average rates for 2011, shown in **Figure 1**, range from 14.1 cents/kWh (SCE) to 16.0 cents/kWh (SDG&E) with PG&E in the middle at 15.3 cents/kWh. These average rates are heavily weighted by the costs of serving residential and small commercial customers. This section quantifies the overall electric rates and the DLC costs for larger customers that might use CHP.



Source: CPUC

Figure 1. Average Electric Rates for Investor Owned Utilities by Category, 2011

RATE ANALYSIS FOR CUSTOMERS WITH CHP

Commercial and industrial rates for the three main IOUs were analyzed for hypothetical CHP installations in three sizes:

- 100 kW rich burn reciprocating engine CHP system connected to the utility secondary voltage distribution system, operating in a load following manner 6,000 hours per year and utilizing 80% of its recoverable thermal energy
- 3,000 MW lean burn reciprocating engine system connected to the utility primary voltage distribution system operating at a 95% capacity factor and utilizing 90% of its recoverable thermal energy
- 20,000 MW gas turbine CHP system connected to the utility transmission system operating at a 95% capacity factor and using all of its recoverable thermal energy

Average retail rates for these customers were estimated using the appropriate tariffs as shown in **Table 2**. In the analysis, retail electric costs were calculated for each CHP size and load. Supplementary customer electric load above what is to be replaced by the CHP system was ignored, the assumption being that these costs would “float” on top of the power ordinarily served by the CHP system. The residual costs of power were calculated for the CHP system assumptions above. It was assumed that there would be one forced outage on-peak in both the summer and the winter seasons. It was further assumed that scheduled outages for maintenance would impose additional demand charges, only the energy costs while the system was not operating. Finally, the appropriate DLCs were included in the residual electric costs. The difference between the retail costs without CHP and the residual costs makes up the electric costs that can be avoided by CHP.

Table 2. Applicable Tariffs for Customers with CHP

Customer Size, kW	100	3,000	20,000
General Rate Category			
PG&E	E-19 TOU	E-20	
SCE	GS-TOU3	GS-TOU8	
SDG&E	AL-TOU		
CHP Rate or Rider			
PG&E	Schedule S		
SCE	Schedule S		
SDG&E	Schedule S		
DLC Riders			
PG&E	E-DCG		
SCE	CGDL-CRS, DL-NBC		
SDG&E	E-DEPART, E-DWR-BC		

Source: PG&E, SCE, SDG&E

The average cost breakdown for each of the three CHP systems in the three IOUs are shown in **Figure 2**, **Figure 3**, and **Figure 4**. The values for the figures are shown in **Table 3.** The detailed electric rate analysis is shown in **Appendix A**.

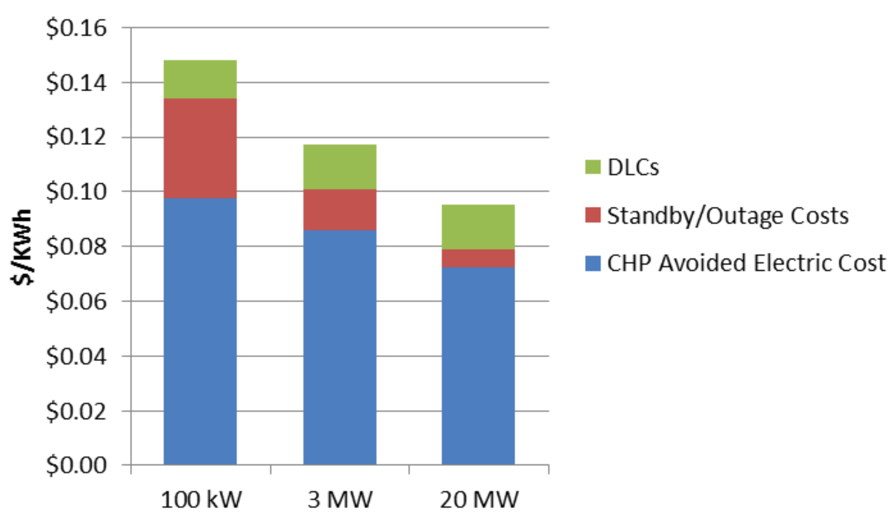


Figure 2. PG&E Retail Rates and CHP Unavoidable Costs

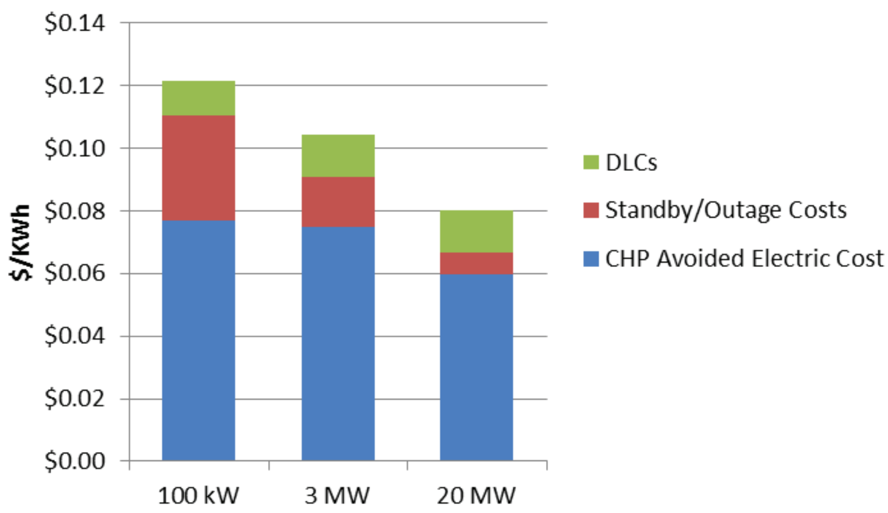


Figure 3. SCE Retail Rates and CHP Unavoidable Costs

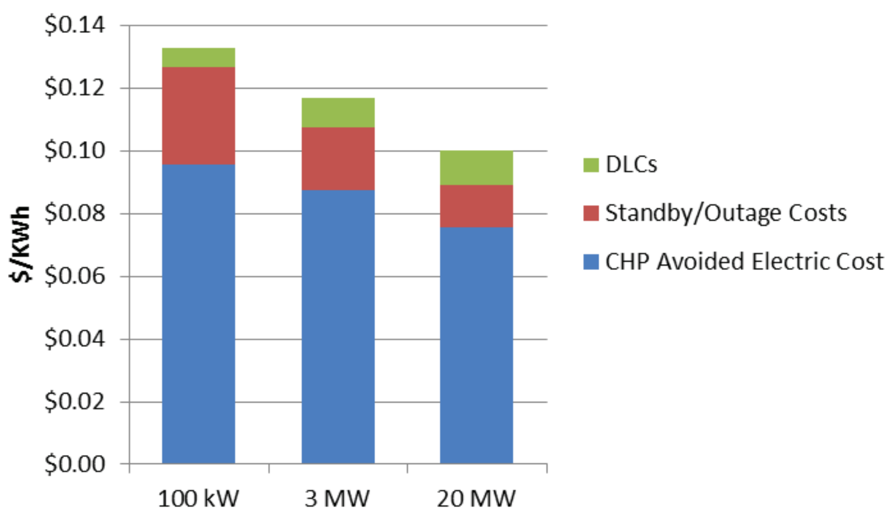


Figure 4. SDG&E Retail Rates and Unavoidable CHP Costs

Table 3. Comparison of Average Retail and CHP Avoided Costs for PG&E, SCE, and SDG&E

Utility	PG&E			SCE			SDG&E		
Tariff Capacity, kW Voltage	E-19 TOU 100 S	E-20 3,000 P	E-20 20,000 T	GSTOU3 100 S	GSTOU8 3,000 P	GSTOU8 20,000 T	AL-TOU 100 S	AL-TOU 3,000 P	AL-TOU 20,000 P Subs
Average Unit Cost, $/kWh	$0.14805	$0.11706	$0.09527	$0.12140	$0.10416	$0.08040	$0.13268	$0.11701	$0.10018
DLCs									
PPPC	$0.01330	$0.01222	$0.01086	$0.01102	$0.01021	$0.00859	$0.00643	$0.00643	$0.00643
DWR-BC		$0.00329	$0.00493		$0.00329	$0.00493		$0.00329	$0.00493
ND	$0.00050	$0.00050	$0.00050	$0.00014	$0.00014	$0.00014	-$0.00034	-$0.00034	-$0.00034
Total DLCs	**$0.01380**	**$0.01601**	**$0.01629**	**$0.01102**	**$0.01350**	**$0.01352**	**$0.00609**	**$0.00938**	**$0.01102**
Other Standby / Outage Costs	$0.03651	$0.01496	$0.00650	$0.03326	$0.01560	$0.00720	$0.03093	$0.02039	$0.01370
Net Avoided Costs, $/kWh	$0.09773	$0.08610	$0.07248	$0.07698	$0.07492	$0.05953	$0.09567	$0.08725	$0.07545

Figure 5 shows a comparison of the DLCs by CHP/customer size and by utility. DLCs are the highest for PG&E, ranging from 1.4-1.6 cents/kWh. For SCE, they range from 1.1 to 1.35 cents/kWh. SDG&E are the lowest, ranging from 0.6 to 1.1 cents/kWh. For the largest customer class analyzed, the DLCs make up almost 23% of the total average rate for SCE and PG&E – 15% for SDG&E.

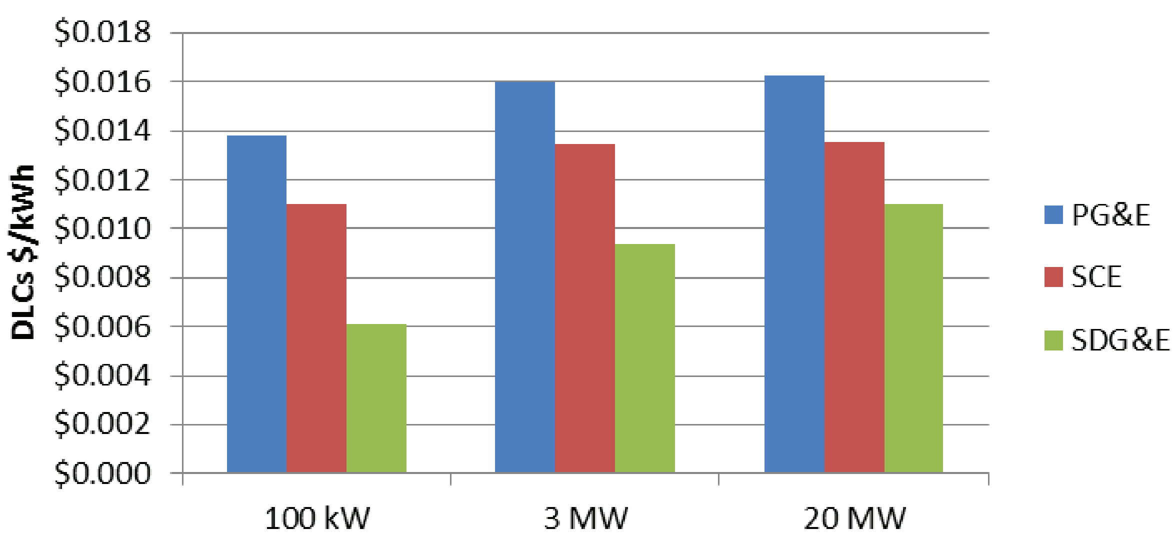


Figure 5. DLCs Applicable to New CHP by Size and Utility

The Contribution of Existing CHP on Total DLCs Collected

This section shows the share of DLCs that are paid by existing CHP systems. The analysis shows that while the surcharges included in the CHP DLCs make up 12-14% of total utility revenue requirements, only 1-2% of this amount is collected from existing CHP The resulting impact of exempting CHP from the DLCs would add a little over a quarter of one mill per kWh to the costs for remaining ratepayers.

Table 4 shows the revenue requirements for the three IOUs for the Public Purpose Programs Charge, the DWR Bond Charge, and Nuclear Decommissioning reported in the CPUC 2012 *Electric and Gas Utility Cost Report*. The charges shown are the revenue requirements including any balancing account adjustments except for the CARE program which is based on the authorized program and administrative costs. Over $3.4 billion is collected from all electric customers for these three surcharges.

Table 4. Total CHP Applicable Surcharges Collected from All Customers, 2012

CHP Applicable Surcharges, million $	PG&E	SCE	SDG&E
Public Purpose Programs			
CARE	$771	$315	$44
Energy Efficiency	$505	$496	$82
RD&D (EPIC)	$72	$59	$13
ND	$49	$127	$9
DWR BC	$393	$390	$96
Total CHP DLCs	$1,789	$1,387	$243
Total Revenue Requirements, 2012	$12,332	$10,986	$3,163

Source: CPUC, Electric and Gas Utility Cost Report, April 2013.

The contribution of CHP to the three surcharges that make up the DLCs was estimated based on the non-exempt CHP operating capacity in the state. **Table 5** shows this breakdown. While there is over 8,500 MW of CHP capacity in California, the DLCs apply only to capacity that was installed after December 20, 1995, and then only for generation that was used to replace retail electric consumption or sales to a final user. Sales for resale do not pay the DLCs. The DWR Bond Charge only applies to customers that came online after February 2001. The total estimated costs collected are $50.8 million. This amount represents only 1.5% of the $3.4 billion collected for these surcharges from all customers. The average rate impact of redistributing this amount to remaining customers would be 0.026 cents/kWh based on the IOU volume forecasts for 2013 shown in the table. At a typical residential monthly consumption of 500 kWh, the impact would be an additional 13 cents/month. As discussed, herein, this amount would be offset or exceeded by the benefits of expanded deployment of CHP.

Table 5. DLCs Collected from Existing CHP

Investor Owned Utility	Pacific Gas & Electric	Southern California Edison	San Diego Gas & Electric	IOU Total
Applicable CHP Capacity, MW	227	380	76	683
PPPC, million $	$16.0	$21.7	$2.7	$40.3
DWR-BC, million $	$2.5	$6.0	$1.2	$9.7
ND, million $	$0.7	$0.3	-$0.1	$0.8
Total CHP DLCs, million $	$19.2	$27.9	$3.7	$50.8
Utility Sales Forecast, GWh	85,663	85,758	20,809	192,230
Ratepayer Impact, $/kWh	$0.00022	$0.00033	$0.00018	$0.00026

Source: ICF CHP Installations Database and ICF Rate Analysis.

The Impact of DLCs on CHP Economics

An economic analysis for the three representative CHP systems was performed to show the economics of CHP both with and without the cost of the DLCs. In addition to the retail and electric rates already analyzed, CHP economics depend on the cost and performance of CHP technology, the site thermal and electric load characteristics, and the customer's gas rates.

Table 6 shows the CHP cost and performance assumptions and site operating conditions assumed for this analysis:

- U.S. average capital cost estimates shown in the table are adjusted for the analysis using a cost multiplier that reflects the higher costs for construction in California. This multiplier is 10% for southern California and 20% for PG&E territory. In the smallest system, exhaust treatment costs are integral to the basic price, but for the two larger systems, an amount is added for selective catalytic reduction (SCR) of the exhaust gases.
- The heat rates for each system determine the gas consumption for the CHP generator. A lower heat rate indicates that electricity is generated more efficiently. However, systems with higher heat rates have more recoverable thermal output. The overall efficiency of the system reflects the sum of the thermal and electric energy produced per unit of fuel input.
- The thermal energy from all systems is assumed to replace natural gas fuel used in an 80% efficient boiler.
- The operating conditions for the systems vary as a function of size. It is assumed that the 100 kW system operates in a load following mode equivalent to 6,000 hours of full load operation.

The larger systems both are assumed to operate continuously with a 95% capacity factor reflecting only maintenance and forced outages.

- Only 80-90% of the available thermal energy from the CHP system is assumed to be utilized for the two smallest systems. The largest system, that might be installed in a large process industrial facility, was assumed to have 100% utilization of the available thermal energy.

Table 6. CHP Cost and Performance Assumptions

Technology	100 kW Rich Burn RE Integral 3 way catalyst	3000 kW Lean Burn RE with SCR	2 x10 MW GT with SCR
Capacity, kW	100	3,000	20,000
U.S. Average Base Capital Cost, $/kW	$3,300	$2,200	$2,000
After-treatment Cost, $/kW	$0	$200	$180
U.S. Average System Cost, $/kW	$3,300	$2,400	$2,180
Heat Rate, Btu/kWh	12,637	9,800	11,765
Thermal Output, Btu/kWh	6,700	4,200	4,674
O&M Costs, $/kWh	$0.0220	$0.0160	$0.0088
Avoided Boiler Efficiency	80%	80%	80%
Annual Operating Values			
Equiv. Full Load Hours	6,000	8,322	8,322
O&M $/kW-year	$132.00	$133.15	$73.23
Fuel Consumption MMBtu/kW/year	75.82	81.56	97.91
Avoided Thermal Load, %	80%	90%	100%
Avoided Boiler Fuel MMBtu/kW/year	40.20	39.32	48.62
Annual Net Energy MMBtu/MW	35,622	42,234	49,287

The analysis also includes the 10% federal investment tax credit for CHP and the SGIP capital and performance based incentives.

The analysis of natural gas rates was based on the tariffs for SDG&E and PG&E within their service territories and on Southern California Gas (SCG) for gas used within SCE territory. In California, CHP is entitled to lower delivery charges under the rate category for electricity generation. **Table 7** shows the average gas rates for each size CHP system for each utility for the avoided boiler and added CHP loads. Included in the costs shown is an assumption of $4.31/MMBtu for the commodity cost of gas. This estimate is based on the May 2013-April 2014 Henry Hub price on the futures market. The table shows that there is a significant benefit for CHP by being eligible for the electric generation rate. It should also be noted that the gas rate for electric generation is exempted from the PPPC – unlike the treatment under electric rates.

Table 7. Average Gas Costs for Boiler Load and CHP Load by Utility

			PG&E		SCG		SDG&E	
			Boiler Load	CHP Load	Boiler Load	CHP Load	Boiler Load	CHP Load
CHP Size, kW	Monthly Boiler Load, therms	Monthly CHP Load, therms	G-NT Tariff, Average Cost, $/MMBtu	G-EG Tariff, Average Cost, $/MMBtu	G-T Tariff, Average Cost, $/MMBtu	G-TF5D Tariff, Average Cost, $/MMBtu	GT-NC Tariff, Average Cost, $/MMBtu	G-EG Tariff, Average Cost, $/MMBtu
100	3,722	6,319	$7.24	$5.48	$6.16	$5.30	$7.41	$5.37
3,000	103,478	203,889	$6.61	$5.21	$5.60	$5.22	$6.51	$5.30
20,000	853,005	1,631,806	$5.84	$5.21	$5.03	$4.88	$6.48	$4.99

Note: Gas Commodity Cost assumed to $4.31/MMBtu in each case based on forward 12 months average Henry Hub futures prices.

Based on the inputs for CHP cost and performance, site operations characteristics, and energy prices described above, the economic paybacks for each of the three CHP sizes in each of the three IOUs were calculated. These results are shown in **Table 8** (PG&E), **Table 9** (SCE), and **Table 10** (SDG&E). Total savings in first section of each table are calculated with DLCs included in costs. These DLCs are highlighted in the second section of the table. Capital costs include regional markup and are net of Federal ITC and SGIP as applicable. The results show the following improvements in economics resulting from exempting the DLCs:

- PG&E: increase in annual project savings of 8.9% for the 100 kW system, 28.2% for the 3,000 MW system, and over 40% for the 20 MW system
- SCE: the increase in savings for the 100, 3,000, and 20,000 kW systems respectively are 24.%,34.0%, and 52.7%
- SDG&E: increase in annual project savings of from 8.3% (100 kW), 16.5% (3,000 kW), 22.1% (20,000 kW)

The percentage benefit increases as the CHP systems get larger because the DLCs make up a greater percentage of the total rates for larger customers.

Table 8. PG&E CHP Paybacks with and without DLCs

Technology	100 kW Rich Burn RE Integral 3 way catalyst	3000 kW Lean Burn RE with SCR	2 x10 MW GT with SCR
Capacity, kW	100	3,000	20,000
Electricity Savings	$65,153	$2,262,696	$12,697,848
Boiler Fuel Savings	$29,115	$779,352	$5,681,663
SGIP PBI	$4,281	$50,000	
Added CHP Fuel	-$41,515	-$1,273,788	-$10,198,527
O&M Expenses	-$13,200	-$399,456	-$1,464,672
Total Savings	$43,834	$1,418,804	$6,716,312
Total DLCs Paid			
PPPC	$7,980	$305,085	$1,807,538
DWR-BC	$0	$82,055	$820,549
ND	$300	$12,483	$83,220
Total DLCs	$8,280	$399,622	$2,711,308
CHP Capital Cost, $/kW	$3,960	$2,880	$2,616
Federal ITC	-$396	-$288	-$196
SGIP Buydown	-$250	-$83	$0
Net Capital Cost, $/kW	$3,314	$2,509	$2,420
Net Capital Cost, $	$331,000	$7,526,000	$48,396,000
Base Case Payback	**7.83**	**5.32**	**7.21**
No DLC Payback	**6.47**	**4.14**	**5.13**

Table 9. SCE CHP Paybacks with and without DLCs

Technology	100 kW Rich Burn RE Integral 3 way catalyst	3000 kW Lean Burn RE with SCR	2 x10 MW GT with SCR
Capacity, kW	100	3,000	20,000
Electricity Savings	$51,323	$1,968,890	$10,430,368
Boiler Fuel Savings	$24,782	$660,520	$4,892,245
SGIP PBI	$4,281	$50,000	
Added CHP Fuel	-$40,209	-$1,277,356	-$9,547,791
O&M Expenses	-$13,200	-$399,456	-$1,464,672
Total Savings	$26,977	$1,002,597	$4,310,149
Total DLCs Paid			
PPPC	$6,612	$254,903	$1,429,720
DWR-BC	$0	$82,055	$820,549
ND	$84	$3,495	$23,302
Total DLCs	$6,696	$340,453	$2,273,570
CHP Capital Cost, $/kW	$3,630	$2,640	$2,398
Federal ITC	-$363	-$264	-$180
SGIP Buydown	-$250	-$83	$0
Net Capital Cost, $/kW	$3,017	$2,293	$2,218
Net Capital Cost, $	$302,000	$6,878,000	$44,363,000
Base Case Payback	**12.36**	**6.96**	**10.29**
No DLC Payback	**9.55**	**5.13**	**6.74**

Table 10. SDG&E CHP Paybacks with and without DLCs

Technology	100 kW Rich Burn RE Integral 3 way catalyst	3000 kW Lean Burn RE with SCR	2 x10 MW GT with SCR
Capacity, kW	100	3,000	20,000
Electricity Savings	$63,781	$2,292,832	$13,219,272
Boiler Fuel Savings	$29,800	$767,482	$6,297,753
SGIP PBI	$4,281	$50,000	
Added CHP Fuel	-$40,735	-$1,295,639	-$9,769,224
O&M Expenses	-$13,200	-$399,456	-$1,464,672
Total Savings	$43,926	$1,415,220	$8,283,129
Total DLCs Paid			
PPPC	$3,858	$160,531	$1,070,209
DWR-BC		$82,055	$820,549
ND	-$204	-$8,488	-$56,590
Total DLCs	$3,654	$234,098	$1,834,169
CHP Capital Cost, $/kW	$3,630	$2,640	$2,398
Federal ITC	-$363	-$264	-$180
SGIP Buydown	-$250	-$83	$0
Net Capital Cost, $/kW	$3,017	$2,293	$2,218
Net Capital Cost, $	$302,000	$6,878,000	$44,363,000
Base Case Payback	**7.08**	**4.86**	**5.36**
No DLC Payback	**6.48**	**4.17**	**4.38**

Effects of DLCs on CHP Market Penetration

The significant increase in project savings resulting from removal of the DLCs from CHP customer costs would have a large effect on increasing CHP market deployment and associated benefits thereby furthering both the ARB and Governor's market goals. In a previous study undertaken for the Energy Commission, ICF developed a 20-year market forecast for CHP in California.[5] ICF included in that analysis a measure of the effect of removing both DLCs and certain demand charges that are charged on top of the standby reservation charge. This incentive was included in basket of measures for the high market

[5] Hedman, Bruce, Ken Darrow, Eric Wong, and Anne Hampson, ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment*. California Energy Commission. CEC-200-2012-002rev2.

case, so the individual benefit of removing DLCs was not quantified in that report. For this analysis, ICF used the model and data developed for the Energy Commission and looked at the impacts of removing DLCs alone compared to the Commission Base Case. The cumulative statewide market penetration results are shown in **Figure 6**, removing DLCs from CHP bills increases statewide 20-year cumulative market penetration by 26% or 499 MW (1,885 to 2,384 MW). The increase only comes from the IOU behind-the-meter CHP markets as follows:

- 61% increase in SCE markets
- 18% increase in SDG&E markets
- 26% increase in PG&E markets

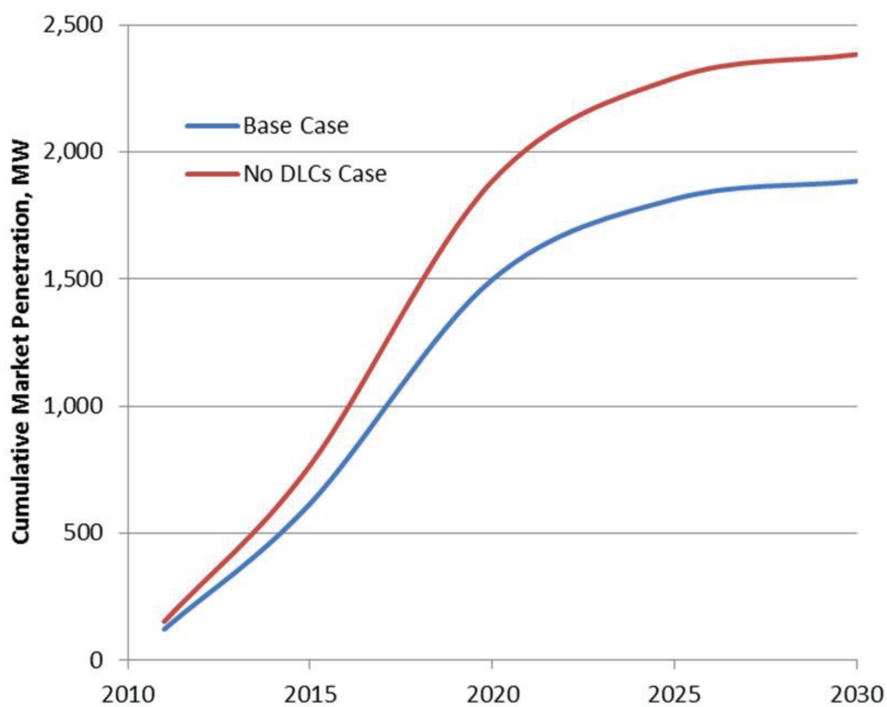


Figure 6. Market Penetration Increase Resulting from Removing DLCs from CHP Rates

As shown in **Figure 7** 89% of the increased market penetration is in the DG systems sized less than 20 MW. The very large CHP system market is dominated by systems exporting the majority of their output to the electric grid. DLCs are charged only on output that displaces a customer's own use or retail sales to a third party.

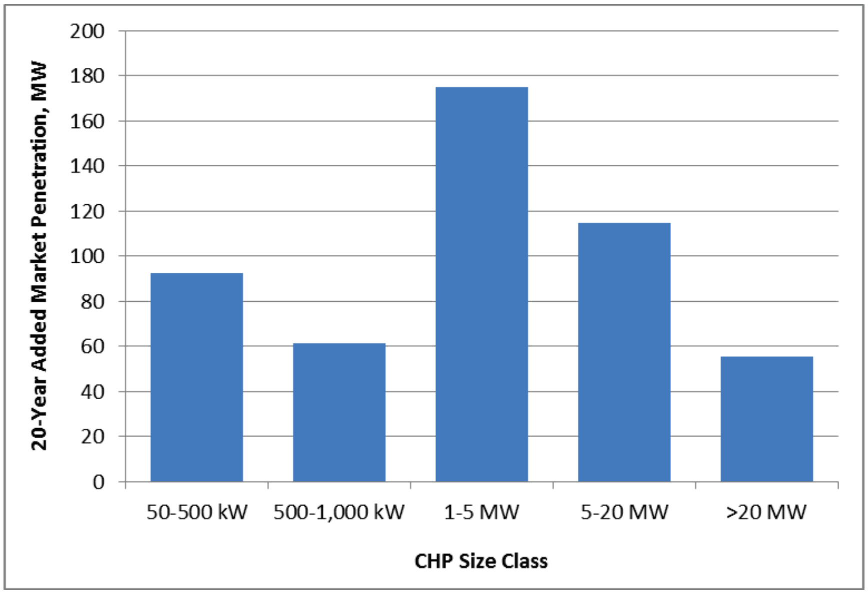


Figure 7. Added CHP Market Penetration by Size due to Exempting DLCs

Benefits of CHP

Increased market penetration for CHP increases benefits for California as a whole. Table 11 summarizes a number of the benefits for CHP showing both the total benefits and the incremental benefits from removing DLCs from CHP customer rates. The incremental benefits include:

- 5.5 trillion Btu/year added primary energy savings by 2030 due to the efficiency benefits of CHP
- Additional $900 million ($2011) in CHP investment providing stimulus to the California economy
- $376 million per year in added customer energy cost savings by 2030 providing funds for productivity enhancing investments, higher income for California businesses and resulting more jobs and greater economic growth.
- Additional 5.5 million MT of cumulative CO2 emissions savings over the 20-year forecast period bringing CHP closer to the ARB GHG emission reduction targets

Table 11. Benefits of Increased CHP Market Penetration

CHP Scenario Benefit Measures Comparison	Base Case	No DLC Case	Change	Change %
2030 Avoided Electric Energy Consumption, million kWh delivered	12,306	15,464	3,158	25.7%
2030 Net Added Onsite Gas Consumption, billion Btu/year	76,460	96,944	20,484	26.8%
2030 Primary Energy Savings, Billion Btu/year *	**24,868**	**30,385**	**5,517**	**22.2%**
2030 Avoided Cost of Electric Energy, million 2011$	$1,474.29	$2,055.73	$581	39.4%
2030 Added Cost of Onsite Natural Gas, million 2011$	$735.01	$940.59	$206	28.0%
2030 Total Avoided Site Energy Costs, million 2011$	**$739.28**	**$1,115.14**	**$376**	**50.8%**
Cumulative CHP Capital Investment	**$3,075**	**$3,979**	**$904**	**29.4%**
Cumulative Avoided CO_2 Emissions, thousand MT *	**23,149**	**28,606**	**5,457**	**23.6%**

* ARB Scoping Plan Calculation Method for CHP, 7.8% line losses for avoided generation .437 MT/MWh CO2 savings equivalent of 8.234 MMBtu natural gas/MWh

Other recognized benefits for CHP[6] not quantified in this analysis potentially include:

- Decreased congestion and increased system reliability
- Greater resource adequacy
- Improved stability and power quality including VAR support
- T&D investment deferrals
- Reduced electricity supply costs resulting from decreased demand
- Increased economic productivity and investment for host sites resulting in higher employment and economic growth.
- Market transformation impacts.

These benefits increase the value of CHP deployment.

[6] D-09-08-026*, Decision for Adopting Cost-Benefit Methodology for Distributed Generation*, CPUC, August 20, 2009.

Conclusions

Customers who installed CHP after December 20, 1995 and those customers who install a new CHP system are required to pay DLCs on their generator output that they are using to replace retail electricity purchases. These DLCs consist of the Public Purpose Program Charge, the DWR Bond Charge (for systems announced after February 1, 2001), and the Nuclear Decommissioning charge. DLCs make up to 17% of a large CHP (20,000 kW) customer's retail bill and up to 23% of their avoidable electricity costs. These costs reduce the potential savings from new CHP investments by as much as 36%. These reduced savings result in reduced deployment of new CHP. Eliminating DLCs from CHP customer bills would increase 20-year market penetration by nearly 500 MW – a 26% increase compared to the current market outlook. Nearly 90% of the added CHP would be for systems less than 20 MW. This increase in CHP market penetration supports California policy goals and provides energy, economic, and environmental benefits for the state as a whole that greatly outweigh the very small added costs to remaining customers. CHP is recognized as energy efficiency by DOE, EPA, ARB and the Energy Commission. However, reductions in electricity consumption due to investment in energy efficiency are not subject to DLCs. CHP, as an energy efficiency measure, should receive the same treatment.

Appendix A: Electric and Gas Rate Analysis

Base customer costs are calculated for a constant flat load except for 100 kW customer based on 76% load factor. Customers with load variation would have higher average electric costs but it is the constant load portion of their bill that is addressed by the CHP system. CHP unit cost is calculated on the original base load.

Table 12. PG&E Electric Rates

Tariff	E-19 TOU	E-20	E-20	Schedule S		
Rate Size, kW	500-999	>1000	>1000	>1000		
CHP Size				100	3000	20000
Voltage	Sec.	prim.	Trans.	Sec.	prim.	Trans.
Customer Charge, $/day	$19.7125	$49.2813	$65.7084	$19.7125	$49.2813	$65.7084
Summer May-October						
Demand Charges, $/kW						
Max Peak	$16.13	$15.40	$14.03			
Part-Peak	$3.74	$3.23	$3.04			
Maximum	$11.79	$9.33	$4.05	$3.08	$3.06	$0.95
Energy Charges $/kWh						
Max Peak	$0.14364	$0.13097	$0.09281	$0.45419	$0.45701	$0.09876
Part-Peak	$0.09896	$0.09268	$0.07669	$0.24596	$0.24799	$0.09464
Off-Peak	$0.06970	$0.07028	$0.06319	$0.15872	$0.16059	$0.07900
Winter November-April						
Demand Charges, $/kW						
Part-Peak	0.21	$0.25	$0.00			
Maximum	$11.79	$9.33	$4.05	$3.08	$3.06	$0.95
Energy Charges $/kWh						
Part-Peak	$0.09303	$0.08835	$0.07790	$0.13332	$0.13274	$0.09306
Off-Peak	$0.07305	$0.07360	$0.06671	$0.10857	$0.10988	$0.08065
CHP Departing Load						
PPPC	Included in energy charges			$0.01330	$0.01222	$0.01086
DWRBC				$0.00493	$0.00493	$0.00493
ND				$0.00050	$0.00050	$0.00050
Energy Resources Surcharge Tax	$0.00029	$0.00029	$0.00029	$0.00029	$0.00029	$0.00029
Utility Use Tax	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%

Table 13. PG&E Annual Electric Costs

		Base Customer Electric Costs			CHP Customer Electric Costs		
Tariff	Annual	E-19 TOU	E-20	E-20	E-19 TOU	E-20	E-20
Rate Size, kW	Freq.	500-999	>1000	>1000	500-999	>1000	>1000
CHP Size		100	3000	20000	100	3000	20000
Voltage		sec.	prim.	trans.	sec.	prim.	trans.
Customer Charge, $/day	365	$7,195	$17,988	$23,984	$7,195	$17,988	$23,984
Summer May-October							
Demand Charges, $/kW							
Max Peak	6	$9,678	$277,200	$1,683,600	$0	$0	$0
Part-Peak	6	$2,244	$58,140	$364,800	$0	$0	$0
Maximum	6	$7,074	$167,940	$486,000	$1,848	$55,080	$114,000
Energy Charges $/kWh							
Max Peak	762	$10,945	$299,397	$1,414,424	$3,461	$52,236	$75,255
Part-Peak	889	$5,908	$247,178	$1,363,548	$1,468	$33,069	$84,135
Off-Peak	2729	$12,774	$575,382	$3,448,910	$2,909	$65,738	$215,591
Winter November-April							
Demand Charges, $/kW							
Part-Peak	6	$126	$4,500	$0	$0	$0	$0
Maximum	6	$7,074	$167,940	$486,000	$1,848	$55,080	$114,000
Energy Charges $/kWh							
Part-Peak	1625	$15,117	$430,706	$2,531,750	$2,166	$32,355	$151,223
Off-Peak	2755	$13,516	$608,304	$3,675,721	$2,009	$45,408	$222,191
CHP Departing Load							
PPPC	8760				$7,980.40	$305,085	$1,807,538
DWRBC	8760					$82,055	$820,549
ND	8760				$300	$12,483	$83,220
Energy Resources Surcharge Tax	8760	$171	$7,621	$50,808	$19	$381	$2,540
Utility Users Tax	7.50%	$6,874	$214,101	$1,160,905	$2,339	$56,743	$278,376
Total Bill		$98,697	$3,076,397	$16,690,451	$33,543	$813,701	$3,992,602
Unit Cost		$0.1480	$0.1171	$0.0953	$0.0503	$0.0310	$0.0228

Table 14. SCE Electric Rates

Tariff Voltage	GSTOU3 Sec.	GSTOU8 Prim.	GSTOU8 Trans.	GSTOU 3 Sched. S Sec.	GSTOU 8 Sched. S Prim.	GSTOU 8 Sched. S Trans.
CHP System Capacity, KW				100	3000	20000
Generation Demand						
Peak Summer	13.99	20.94	17.96	11.05	11.81	10.46
Part-Peak Summer	3.32	5.87	4.74	2.87	2.99	1.93
Off Peak	0	0	0			
Part Peak Winter	0	0	0			
Max Winter	0	0	0			
Generation Energy, $/kWh						
Peak Summer	0.10823	0.09275	0.08782	0.10823	0.09275	0.08782
Part Peak Summer	0.07196	0.06863	0.05974	0.07196	0.06863	0.05974
Off Peak Summer	0.04453	0.04016	0.02992	0.04453	0.04016	0.02992
Part Peak Winter	0.04932	0.06271	0.05309	0.04932	0.06271	0.05309
Off Peak Winter	0.03233	0.03558	0.02952	0.03233	0.03558	0.02952
Delivery Demand, $/kW/mo						
Facility Demand Charge	15.22	13.73	6.04	$6.80	$6.20	$1.32
Customer Charge $/mo	512.79	336.45	2579.01	512.79	336.45	2579.01
Delivery Energy, $/kWh						
Peak Summer	0.01962	0.01835	0.01602	0.01962	0.01835	0.01602
Part Peak Summer	0.01962	0.01835	0.01602	0.01962	0.01835	0.01602
Off Peak Summer	0.01962	0.01835	0.01602	0.01962	0.01835	0.01602
Part Peak Winter	0.01962	0.01835	0.01602	0.01962	0.01835	0.01602
Off Peak Winter	0.01962	0.01835	0.01602	0.01962	0.01835	0.01602
Departing Load Charges						
PPPC	**Included in energy charges**			0.01102	0.01021	0.00859
Nuclear Decommissioning				0.00014	0.00014	0.00014
DWR Bond				0.00493	0.00493	0.00493
Energy Resources Surcharge Tax, $/kWh	$0.00029	$0.00029	$0.00029	0.00029	0.00029	0.00029
Utility Users Tax	5%	5%	5%	5%	5%	5%

Table 15. SCE Annual Electric Costs

		Base Customer Electric Costs			CHP Customer Electric Costs		
Tariff Voltage	Annual Freq.	GSTOU3 Sec.	GSTOU8 Prim.	GSTOU8 Trans.	GSTOU3 Sched. S Sec.	GSTOU8 Sched. S Prim.	GSTOU8 Sched. S Trans.
CHP System Capacity, KW		100	3000	20000	100	3000	20000
Generation Demand							
Peak Summer	4	$5,596	$251,280	$1,436,800	$737	$23,620	$139,467
Part-Peak Summer	4	$1,328	$70,440	$379,200	$191	$5,980	$25,733
Off Peak	4	$0	$0	$0	$0	$0	$0
Part Peak Winter	8	$0	$0	$0	$0	$0	$0
Max Winter	8	$0	$0	$0	$0	$0	$0
Generation Energy, $/kWh							
Peak Summer	508	$5,498	$141,351	$892,251	$550	$7,068	$44,613
Part Peak Summer	762	$3,434	$156,888	$910,438	$343	$7,844	$45,522
Off Peak Summer	1650	$5,395	$198,792	$987,360	$540	$9,940	$49,368
Part Peak Winter	2175	$10,727	$409,183	$2,309,415	$1,073	$20,459	$115,471
Off Peak Winter	3665	$7,420	$391,202	$2,163,816	$742	$19,560	$108,191
Delivery Demand, $/kW/mo							
Facility Demand Charge	12	$18,264	$494,280	$1,449,600	$9,844	$268,380	$505,600
Customer Charge $/mo		$6,153	$4,037	$30,948	$6,153	$4,037	$30,948
Delivery Energy, $/kWh							
Peak Summer	508	$997	$27,965	$162,763	$100	$1,398	$8,138
Part Peak Summer	762	$936	$41,948	$244,145	$94	$2,097	$12,207
Off Peak Summer	1650	$2,377	$90,833	$528,660	$238	$4,542	$26,433
Part Peak Winter	2175	$4,267	$119,734	$696,870	$427	$5,987	$34,844
Off Peak Winter	3665	$4,503	$201,758	$1,174,266	$450	$10,088	$58,713
Departing Load Charges							
PPPC	8760				$6,612	$254,903	$1,429,720
Nuclear Decommissioning	8760				$84	$3,495	$23,302
DWR Bond	8760					$82,055	$820,549
Energy Resources Surcharge Tax, $/kWh	8760	$193	$7,621	$50,808	$25	$381	$2,540
Utility Users Tax	5%	$3,845	$129,985	$668,327	$1,409	$36,573	$173,941
Total Bill		$80,935	$2,737,297	$14,085,667	$29,612	$768,407	$3,655,299
Unit Cost		$0.1214	$0.1042	$0.0804	$0.0444	$0.0292	$0.0209

Table 16. SDG&E Electric Rates

Tariff	AL-TOU	AL-TOU	AL-TOU
Rate Size, kW	<500	>500	>26 MW
Voltage	Sec	Primary	Primary Subs
CHP Size	100	3000	20000
Basic Service Fee	$58.22	$232.87	$26,185.08
Demand Charges $/kW			
NonCoincident	$16.76	$16.34	$8.96
Summer On-Peak	$8.08	$8.32	$2.68
Winter On-Peak	$4.78	$4.82	$0.56
Standby Contract Demand, Sched S	$9.42	$9.12	$4.49
Delivery Energy Charge $/kWh			
Summer On-Peak	-$0.00032	-$0.00158	-$0.00303
Summer Semi-Peak	-$0.00263	-$0.00332	-$0.00423
Summer Off-Peak	-$0.00329	-$0.00389	-$0.00452
Winter On-Peak	-$0.00122	-$0.00227	-$0.00351
Winter Semi-Peak	-$0.00263	-$0.00332	-$0.00423
Winter Off-Peak	-$0.00329	-$0.00389	-$0.00452
EECC Commodity Rates $/kWh			
Summer On-Peak	$0.09961	$0.09808	$0.09808
Summer Semi-Peak	$0.08071	$0.07943	$0.07943
Summer Off-Peak	$0.05958	$0.05847	$0.05847
Winter On-Peak	$0.09597	$0.09453	$0.09453
Winter Semi-Peak	$0.08823	$0.08682	$0.08682
Winter Off-Peak	$0.06575	$0.06451	$0.06451
EECC Commodity Rates, $/kW			
Summer On-Peak	$5.92	$5.84	$5.84
Winter On-Peak	$0.19	$0.19	$0.19
Departing Load Charges			
Public Purpose Programs	$0.00643	$0.00643	$0.00643
DWR Bond Charge, $/kWh	$0.00493	$0.00493	$0.00493
Nuclear Decommissioning	-$0.00034	-$0.00034	-$0.00034
Energy Resources Surcharge Tax	$0.00029	$0.00029	$0.00029
UUT and Franchise Fee	6.11%	6.11%	6.11%

Table 17. SDG&E Annual Electric Costs

		Base Customer Electric Costs			CHP Customer Electric Costs		
Tariff Rate Size, kW Voltage CHP Size	Annual Freq.	AL-TOU <500 100	AL-TOU >500 3000	AL-TOU >26 MW 20000	AL-TOU <500 100	AL-TOU >500 3000	AL-TOU >26 MW 20000
Basic Service Fee	12	$699	$2,794	$314,221	$699	$2,794	$314,221
Demand Charges $/kW							
NonCoincident	12	$20,112	$588,240	$2,150,400			
Summer On-Peak	5	$4,040	$124,800	$268,000	$808	$24,960	$53,600
Winter On-Peak	7	$3,346	$101,220	$78,400	$956	$28,920	$22,400
Standby Contract Demand, Sched S	12				$11,304	$328,320	$1,077,600
Delivery Energy Charge $/kWh							
Summer On-Peak	744	-$24	-$3,527	-$45,086	-$2	-$176	-$2,254
Summer Semi-Peak	957	-$160	-$9,532	-$80,962	-$16	-$477	-$4,048
Summer Off-Peak	1949	-$482	-$22,745	-$176,190	-$48	-$1,137	-$8,809
Winter On-Peak	434	-$53	-$2,956	-$30,467	-$5	-$148	-$1,523
Winter Semi-Peak	1881	-$315	-$18,735	-$159,133	-$32	-$937	-$7,957
Winter Off-Peak	2795	-$729	-$32,618	-$252,668	-$73	-$1,631	-$12,633
EECC Commodity Rates $/kWh							
Summer On-Peak	744	$7,411	$218,915	$1,459,430	$741	$10,946	$72,972
Summer Semi-Peak	957	$4,924	$228,044	$1,520,290	$492	$11,402	$76,015
Summer Off-Peak	1949	$8,720	$341,874	$2,279,161	$872	$17,094	$113,958
Winter On-Peak	434	$4,165	$123,078	$820,520	$417	$6,154	$41,026
Winter Semi-Peak	1881	$10,579	$489,925	$3,266,168	$1,058	$24,496	$163,308
Winter Off-Peak	2795	$14,573	$540,916	$3,606,109	$1,457	$27,046	$180,305
EECC Commodity Rates, $/kW							
Summer On-Peak	5	$2,960	$87,600	$584,000	$592	$17,520	$116,800
Winter On-Peak	7	$133	$3,990	$26,600	$38	$1,140	$7,600
Departing Load Charges							
Public Purpose Programs	8760				$3,858	$160,531	$1,070,209
DWR Bond Charge, $/kWh	8760	$3,287	$129,560	$863,736	$329	$88,533	$863,736
Nuclear Decommissioning	8760				-$204	-$8,488	-$56,590
Energy Resources Surcharge Tax	8760	$193	$7,621	$50,808	$19	$381	$2,540
UUT and Franchise Fee		$5,083	$176,631	$1,007,694	$1,420	$45,022	$249,284
Total Costs		$88,460	$3,075,097	$17,551,032	$24,680	$782,266	$4,331,760
Unit Cost		$0.1327	$0.1170	$0.1002	$0.0370	$0.0298	$0.0247

Table 18. PG&E Gas Rates

	G-NT		G-EG
Average Monthly Usage	$/day		$/day
0-5,000 therms	$1.93578		$1.93578
5,001-10,000	$5.76658		$5.76658
10,001-50,000	$10.73293		$10.73293
50,001-200000	$14.08570		$14.08570
200,001-1,000,000 therms	$20.43715		$20.43715
1,000,001 and above	$173.35956		$173.35956
Transportation Charge, $/therm	Summer	Winter	
0-20,833 therms	$0.18050	$0.22885	
20,834-49,999 therms	$0.13043	$0.16125	
50-166,666 therms	$0.12020	$0.14744	
166,667-249,999 therms	$0.11220	$0.13664	
>250,000 therms	$0.05098	$0.05098	
All Volumes Transportation EG/CHP			$0.04445
All Use G-PPPS	$0.03568	$0.03568	$0.00000
G-SUR		1.3031%	Exempt
Utility Users Tax		7.50%	7.50%

Forward 12 month Henry Hub, $/therm	$0.431

Table 19. SCG Gas Rates

Gas Transportation for Distribution Customers, G-TF

Customer Charge, $/month	$350

Transportation Charge	$/therm
0-20,833 therms	$0.14511
20,834-83,333 therms	$0.08805
83,334-166,667 therms	$0.05087
>166,667	$0.03010

G-PPPS	0.03092	
G-SRF	0.00068	
G-MSUR	2%	Average on gas transportation and gas commodity, varies by location
UUT Average	5%	

Gas Transportation for EG/CHP GT-F5D

Customer Charge, $/month		$50	those who use less than 3 million therms/year
Volumetric Charge, $/therm		$0.05600	those who use less than 3 million therms/year
		$0.02401	over 3 million therms/year no customer charge

Forward 12 month Henry Hub, $/therm	$0.431

Table 20. SDG&E Gas Rates

GT-NC

Customer Charge, $/month	$350.00
Volumetric Charge, $/therm	$0.13032
minimum monthly use, therms	20,800

Gas Transportation for CHP and EPG, G-EG

Customer Charge, $/month	$50.00	
Volumetric Charge, $/therm	$0.05751	those who use less than 3 million therms/year
	$0.02880	over 3 million therms/year no customer charge

Surcharges $/therm

G-PUC	$0.00068	
G-PPPS	$0.03840	EG and CHP exempt
GP-SUR	$0.01002	Average of San Diego and outside San Diego
Franchise Fee Differential	1.03%	in San Diego
UUT	5%	

Forward 12 month Henry Hub, $/therm	$0.431

Table 21. PG&E Average Gas Rates

CHP Size, kW	Monthly Boiler Load, therms	Monthly CHP Load, therms	Annual Base Gas Cost	Avg. Rate	Annual CHP Gas Cost	Avg. Rate
100	3,722	6,319	$32,350	$7.24	$41,515	$5.48
3000	103,478	203,889	$820,371	$6.61	$1,273,788	$5.21
20000	853,005	1,631,806	$5,980,698	$5.84	$10,198,527	$5.21

Table 22. SCG Average Gas Rates

CHP Size, kW	Monthly Boiler Load, therms	Monthly CHP Load, therms	Annual Base Gas Cost	Avg. Rate	Annual CHP Gas Cost	Avg. Rate
100	3,722	6,319	$27,536	$6.16	$40,209	$5.30
3000	103,478	203,889	$695,284	$5.60	$1,277,356	$5.22
20000	853,005	1,631,806	$5,149,731	$5.03	$9,547,791	$4.88

Table 23. SDG&E Average Gas Rates

CHP Size, kW	Monthly Boiler Load	Monthly CHP Load	Annual Base Gas Costs	Boiler Avg.	Annual CHP Gas Costs	CHP Average
100	3,722	6,319	$33,111	$7.41	$40,735.13	$5.37
3000	103,478	203,889	$807,876	$6.51	$1,295,639	$5.30
20000	853,005	1,631,806	$6,629,214	$6.48	$9,769,224	$4.99