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CPUC Self-Generation Incentive Program Sixth Year Impact Evaluation

Final Report

Submitted to:

PG&E
and
The Self-Generation Incentive Program Working Group

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Executive Summary

1.1 Introduction

The Self-Generation Incentive Program (SGIP) was established in response to Assembly Bill (AB) 970[1], which required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation (DG) program activities. The CPUC issued Decision 01-03-073 (D.01-03-073) on March 27, 2001 outlining provisions of a distributed generation program. The first SGIP application was accepted in July 2001. Today, the SGIP represents the single largest DG incentive program in the country.

In its March 2001 decision, the CPUC authorized the SGIP Program Administrators "to outsource to independent consultants or contractors all program evaluation activities…." Impact evaluations were among the evaluation activities outsourced. This report provides the findings of an impact evaluation of the sixth program year of the SGIP covering the 2006 calendar year. The evaluation covers all SGIP projects coming on-line prior to January 1, 2007. The evaluation examines impacts or requirements associated with energy delivery; peak demand; efficiency and waste heat utilization; transmission and distribution; and greenhouse gas emission reductions.[2] Impacts are examined at the program-wide level, and at a technology-specific level, depending on the nature of the reported result.

A number of DG technologies receive rebates under the SGIP. Rebates are provided in accordance with incentive level. Because incentive levels and the groupings of technologies that fall within them have changed over time, this report will summarize results by technology and fuel type instead of incentive level, which was used in the previous impact reports. Table 1-1 summarizes the SGIP technology groups that are used in this report.

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1 Assembly Bill 970 (Ducheny, September 7, 2000)

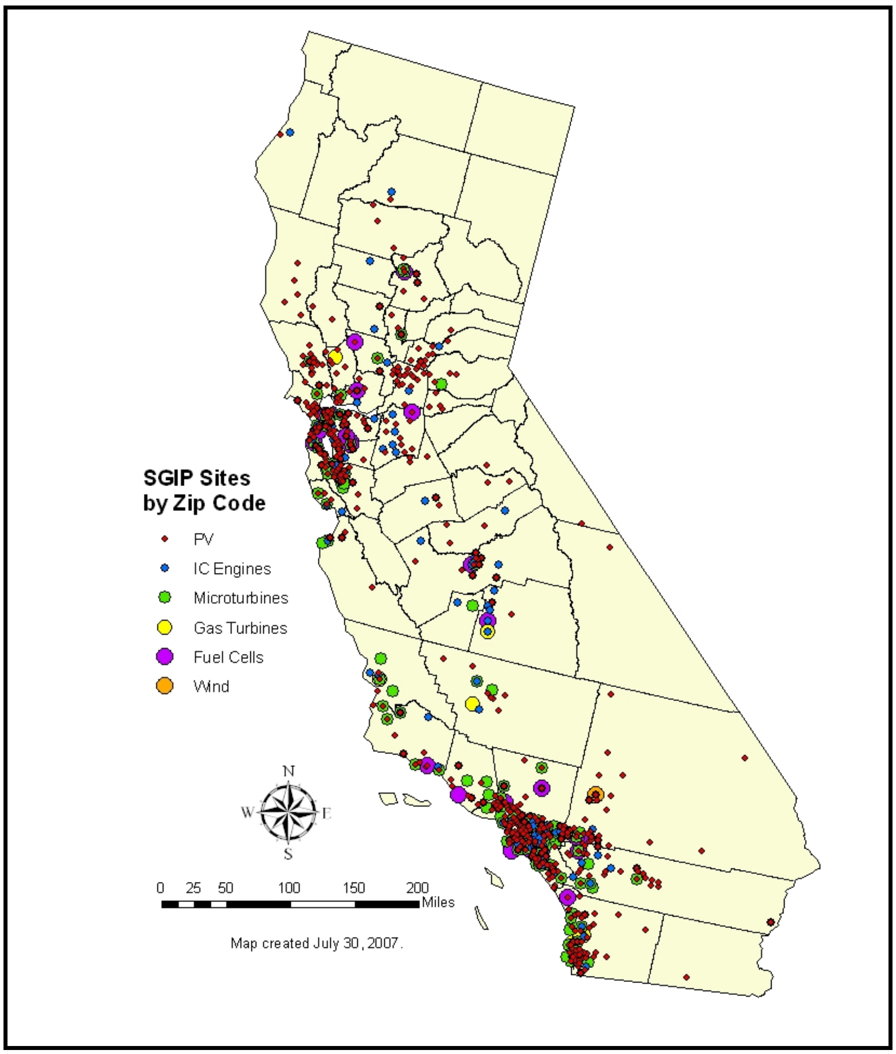
2 The 2005 Impacts Evaluation Report contained an update on compliance of projects using renewable fuels (e.g., biogas) to comply with renewable fuel use requirements set forth by the CPUC. However, based on direction from the Working Group and the Project Manager, renewable fuel use compliance will be reported only in the Renewable Fuel Use Reports filed semiannually with the CPUC.

Table 1-1: SGIP Eligible Technologies

Eligible Generation Technologies	
Photovoltaics (PV)	Wind Turbines (WD)
Nonrenewable-fueled microturbines (MT-N)	Non-renewable fuel cells (FC-N)
Renewable-fueled microturbines (MT-R)	Renewable fuel cells (FC-R)
Nonrenewable-fueled gas turbines (GT-N)	Nonrenewable-fueled internal combustion engines (ICE-N)
Renewable-fueled gas turbines (GT-R)	Renewable-fueled internal combustion engines (ICE-R)

The SGIP stretches over the service territories of the three major investor-owned utilities (IOUs) in California as well as a number of municipal electric utilities. Figure 1-1 shows the distribution of SGIP facilities across California by type of technology.

Figure 1-1: Distribution of SGIP Facilities



1.2 Program-Wide Findings

Program Status

The SGIP has been growing steadily and represents a balanced portfolio of technologies, spread reasonably among Program Administrators (PAs). By the end of 2006, there were 948 projects on-line representing over 233 megawatts (MW) of rebated generating capacity. SGIP projects are distributed among SGIP PAs as shown in Table 1-2.

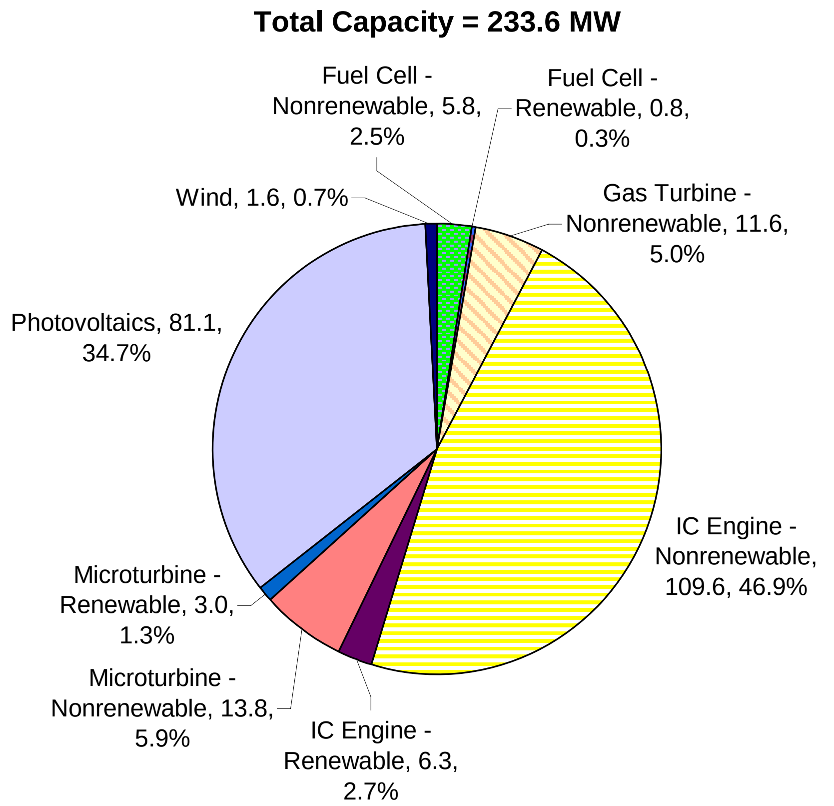
Table 1-2: Distribution of Projects and Rebated Capacity among PAs as of 12/31/06

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	439	105.1	45
SCE	244	46.2	20
SoCalGas	146	55.5	24
CCSE	119	26.8	11
Totals	**948**	**233.6**	**100**

The capacity of Complete[3] projects increased 23 percent (56 MW) from 2005 to 2006. PV systems installed between 2005 and 2006 contributed 28 MW of capacity; or approximately half of the growth of the SGIP during this period. Most of the remaining growth in capacity from 2005 to 2006 came from microturbines and IC engines. Wind and fuel cell systems had little, if any, growth during this same period. Figure 1-2 shows the generating capacity distribution by technology and fuel at the end of 2006.

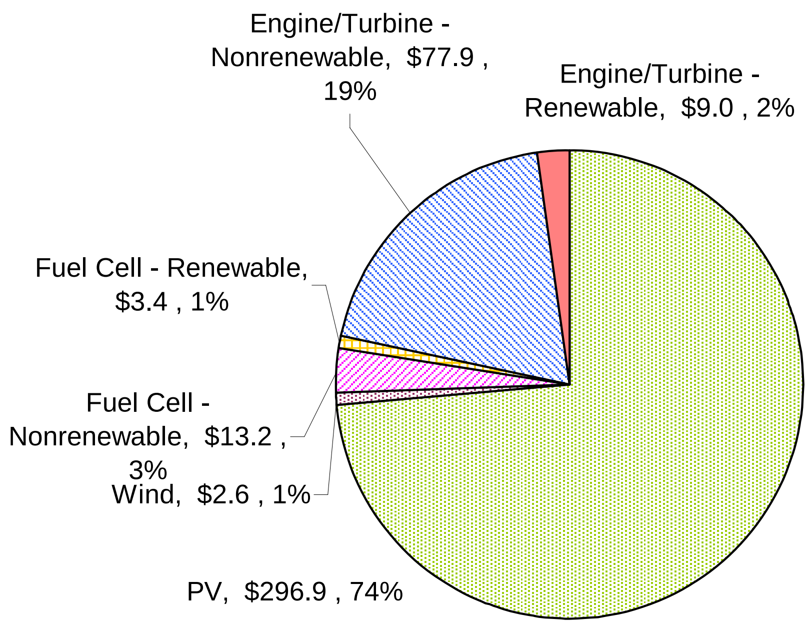
[3] Complete projects are defined as those projects that are on-line and had received an SGIP incentive check

Figure 1-2: SGIP Capacity (MW) by Technology and Fuel Type as of 12/31/06



In accordance with the growth in SGIP capacity, the amount of incentives paid under the SGIP has also advanced steadily. Incentives paid under the SGIP increased substantially between 2005 and 2006 (from $273 million to $403 million). Over 70 percent of incentives have been paid to PV projects. Figure 1-3 shows the distribution of incentives paid by incentive level as of the end of 2006. In addition, SGIP incentives have been matched by private and public funds at a level of approximately 2.5 to 1, with total eligible project costs exceeding $1 billion.

Figure 1-3: Incentive Payments by Technology and Fuel Type as of 12/31/06 ($Millions)



Energy and Demand Impacts

During PY06, SGIP projects delivered over 610,000 MWh of electricity to California's grid. SGIP projects are located at customer sites of the IOUs[4] to help meet on-site demand. Consequently, the 610,000 MWh of electricity provided by SGIP facilities represented electricity that did not have to be generated by central station power plants and delivered by the transmission and distribution system.

Thermal cogeneration systems (fuel cells, engines, and turbines) provided over 80 percent of the electricity delivered by SGIP facilities during 2006. PV projects supplied the next largest amount at approximately 17 percent of the total.

For purposes of this report, capacity factor is used as a measure of electricity deliverability. It represents the proportion of the rebated generating capacity which can be delivered by a project over a specific time period. For example, an 80 percent June average capacity factor for fuel cells would indicate that every 100 kW of rebated fuel cell capacity would, on average, provide 80 kW of generating capacity during June. Figure 1-4 shows monthly

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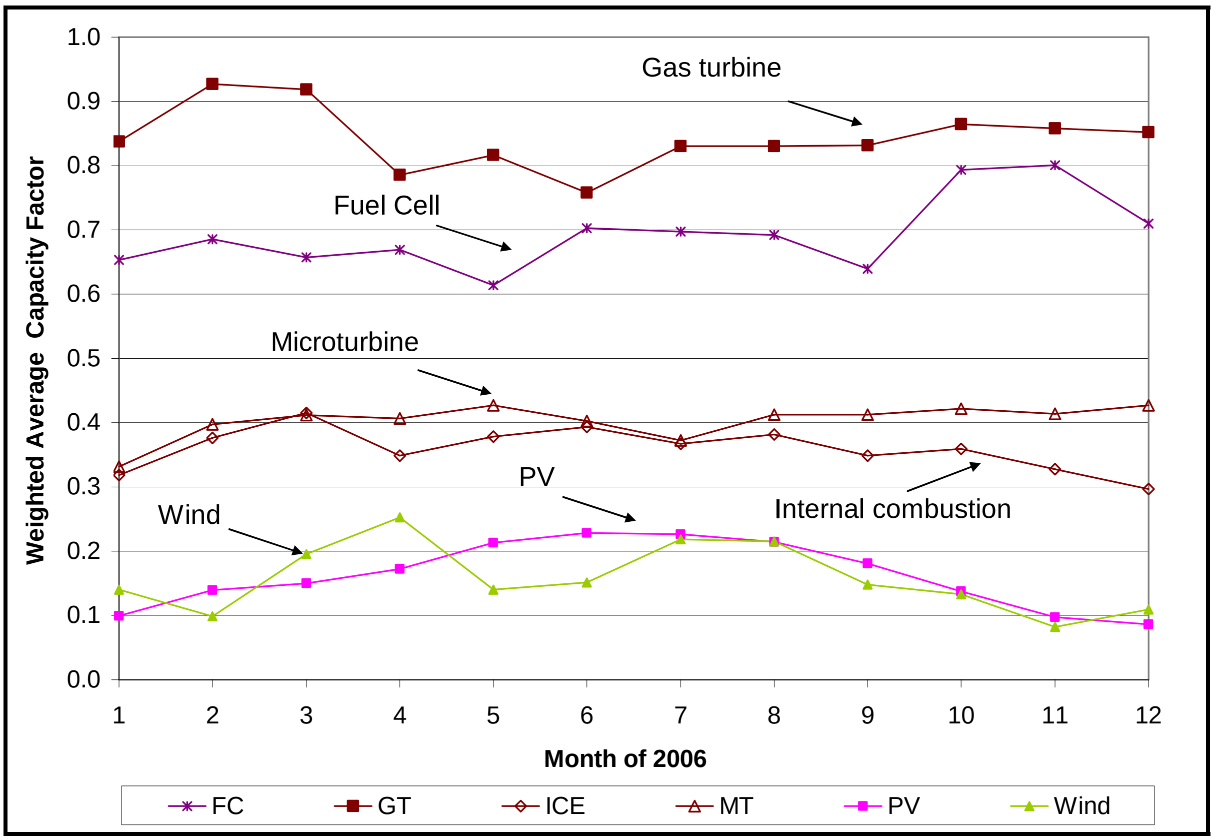
[4] Although rebated through the SGIP, approximately 9 percent of SGIP facilities are located at customer sites of municipal electric utilities.

weighted average capacity factors of SGIP technologies throughout 2006 based on measured performance of SGIP technologies. Overall, natural gas turbines demonstrated the highest capacity factor, generally ranging from slightly below 0.8 to slightly above 0.9. Fuel cell capacity factors are lower than for gas turbines, but this is primarily an artifact of the lowering of capacity factor by fuel cells using biogas fuels.[5] As was observed in the 2005 Impact Evaluation Report, microturbines and IC engines exhibited capacity factors ranging from 0.3 to 0.45; significantly lower than capacity factors for fuel cells and gas turbines. Due to the intermittent nature of their renewable resource supplies, wind and PV projects had monthly capacity factors ranging from slightly less than 0.10 to over 0.20.

Figure 1-4: Weighted Average Capacity Factor by Technology and Month (2006)



[5] Fuel cell capacity factor increases to approximately 0.8 when examining only natural gas powered fuel cells. Impacts of biogas use in fuel cells is discussed more thoroughly in section 5.

Peak Demand Impacts

The ability of SGIP projects to supply on-site electricity during peak demand is critical. Delivery during peak hours reduces grid impacts by alleviating the need to dispatch older and more expensive peaking generators as well as by decreasing transmission line congestion. In addition, by offsetting more expensive peak electricity, SGIP projects provide potential cost savings to the host site. Peak demand impacts for PY06 were estimated by looking at SGIP contributions coincident with the California Independent System Operator (CAISO) 2006 system peak load. The system reached a peak of 50,198 MW on July 24, 2006, from 3:00 to 4:00 P.M. Total SGIP project capacity coincident with the peak was estimated at over 103 MW, representing an aggregate SGIP capacity factor of roughly 0.47 at CAISO system peak. Slightly less than half of this impact came from internal combustion engines. PV systems accounted for 37 percent. Figure 1-5 depicts the impact of SGIP projects on the 2006 system peak.

Figure 1-5: SGIP Project Impacts on 2006 System Peak Technology

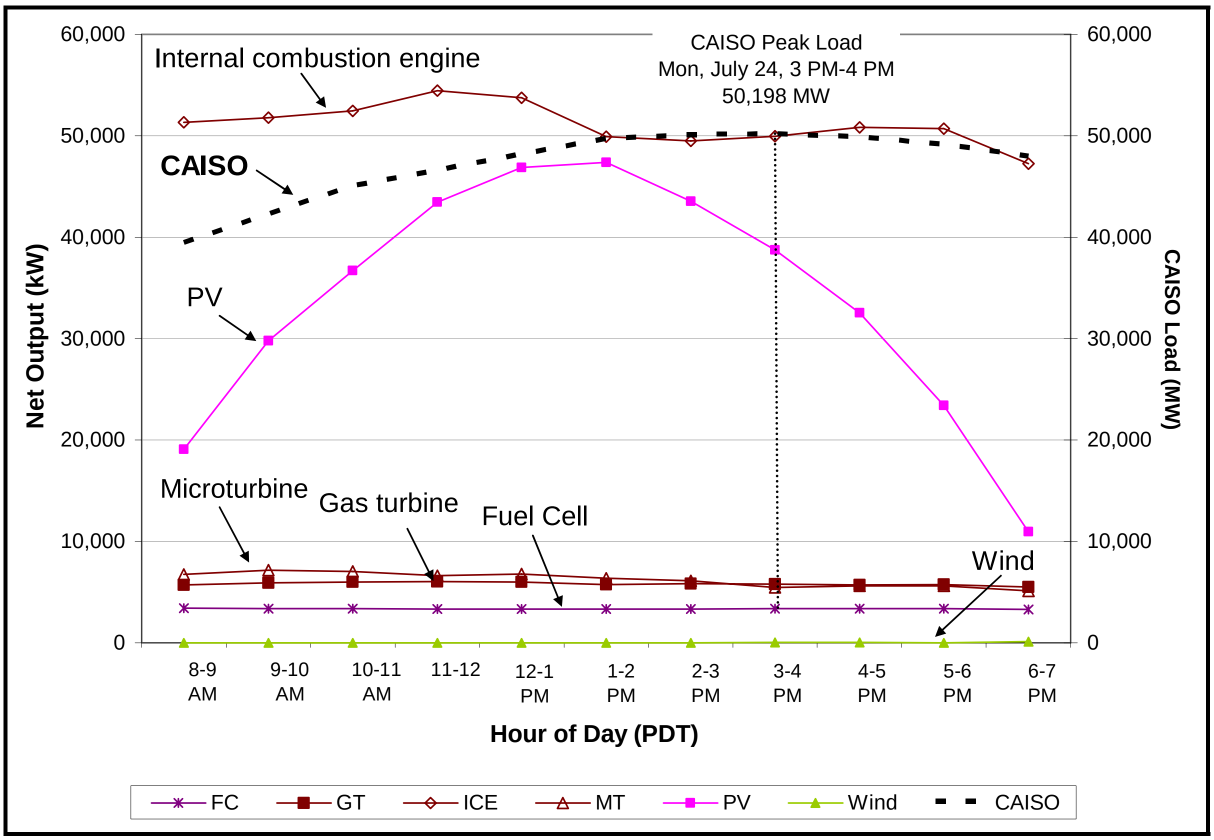


Table 1-3 provides a breakdown of SGIP impact on coincidence peak by technology type. The Impact column refers to the generating kW capacity at the peak hour. The Operational column refers to the total kW capacity potentially available at that time.[6] The Hourly Capacity Factor is the weighted average ratio of impact to operational capacity. The relatively low hourly capacity factor of 0.51 for PV is a result of the late afternoon timing of the CAISO system peak.

Table 1-3: Breakout of SGIP Project Impact on 2006 Coincident Peak

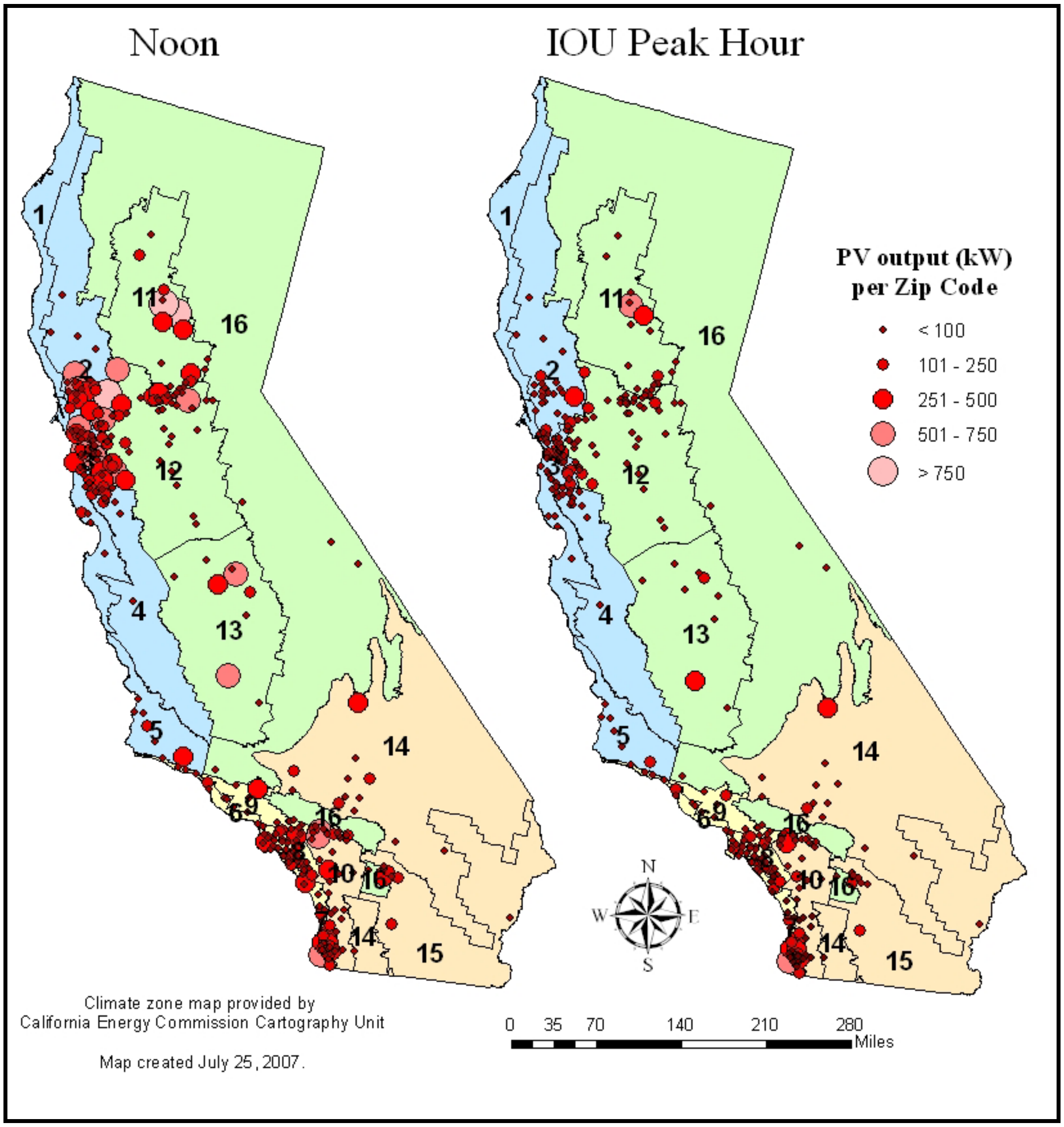
Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	8	4,800	3,372	0.703 [a]
GT	3	7,093	5,789	0.816 †
ICE	185	116,184	49,942	0.430 [a]
MT	98	16,182	5,465	0.338 [a]
PV	609	75,808	38,744	0.511 [a]
WD	2	1,649	53	0.032
TOTAL	**905**	**221,715**	**103,365**	

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

As indicated earlier, nearly half of the growth in capacity in the SGIP in PY06 came from PV systems. The capacity factor for PV is strongly influenced by the amount of solar resource available at the time. PV output increases over the course of the morning, generally peaks around noon and then decreases as the sun sets. As a result, the contribution of PV to the utility peak demand is affected by the timing of the peak. Figure 1-6 illustrates the impact of timing of peak demand on PV's ability to provide capacity. Larger circles represent a higher capacity of PV. The figure on the left shows PV capacity at noon. The figure on the right shows PV capacity at the time of peak demand during 2006 for each of the IOUs. As shown, PG&E's PV capacity at its 6 pm peak is significantly less than its PV capacity at noon. Conversely, there is little difference in PV capacity for SDG&E, which had its 2006 system peak at 2.00 P.M.

[6] This differs from the total installed capacity of 223.6 MW because at the time of system peak not all systems had been brought online.

Figure 1-6: Impact of Peak Demand Time of Day on PV Capacity*



* Note: PG&E's peak was at 6.00 P.M. on July 25, 2006. SCE's peak was at 4.00 P.M. on July 25, 2006. SDG&E's peak occurred at 2.00 P.M. on July 22, 2006.

Transmission and Distribution Impacts

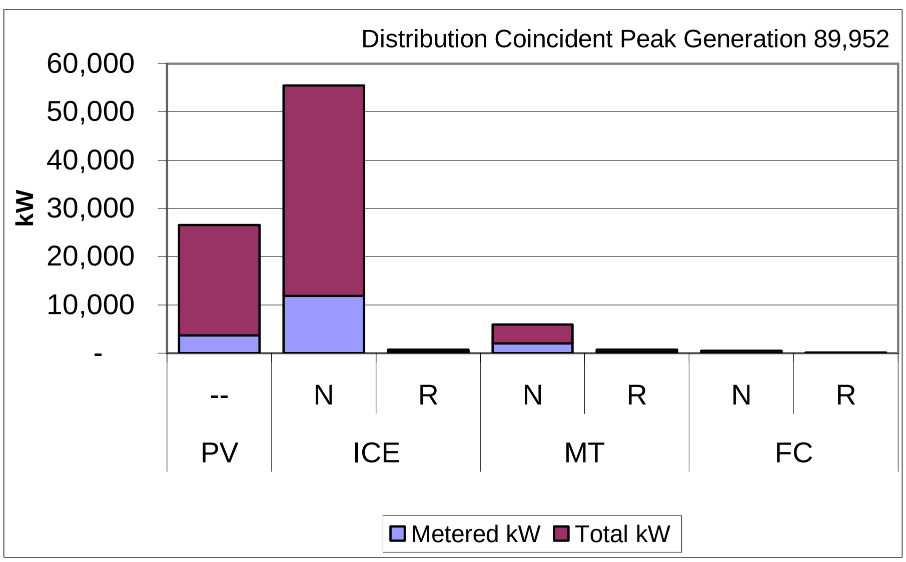
Peak hour capacity factors indicate the ability of a generation technology to provide electricity to the grid during times of peak demand, when that electricity is most needed. However, peak capacity factor cannot provide information on the ability of the generated electricity to actually enter the grid or defer generation from being delivered to a customer site. The ability of electricity to move along the transmission and distribution system depends largely on line loadings. If a distribution or transmission line is heavily loaded, there will be problems in moving additional electricity along the line. One of the anticipated benefits of DG technologies is their potential to reduce transmission and distribution line loadings by providing electricity directly at the demand source. This capability can be especially beneficial during times of peak demand when heavy electricity flow along the T&D system causes line congestion which can result in line overloading and outages.

Distribution System Impacts

Distribution system impacts were assessed by comparing SGIP facility hourly generation profiles against hourly distribution line loadings. Line loadings were limited to those distribution lines serving utility customers hosting SGIP DG facilities. In addition, line loadings used in the analysis represented the peak loading for the individual feeders occurring at the day and hour of the peak loading of that feeder. It is important to recognize that peak loading on feeder lines will often occur on different days and hours from the individual IOU system peaks and the CAISO system peak.

Using only SGIP facility metered data that corresponded with distribution line loading data, the estimated distribution peak load reduction associated with SGIP technologies in 2006 in the three utility service territories was 46.1 MW for PG&E; 37.1 MW for SCE; 6.8 MW for SDG&E; representing a statewide total of 90.0 MW. Figure 1-7 provides a summary of the measured and estimated impact of SGIP technologies on the distribution system in 2006.

Figure 1-7: Distribution System Peak Reduction by SGIP Technology (2006)



Metered kW	3,636	11,914	360	2,024	203	0	0
Total kW	26,516	55,515	744	5,975	688	467	67
Metered #	78	55	3	28	4	1	1
Total #	569	165	9	81	16	9	2

The greatest distribution line reductions in 2006 were found to be associated with natural gas fueled IC engines; providing nearly 55 MW of peak distribution reduction. PV systems were found to provide the next largest distribution line reduction at nearly 26 MW; followed distantly by natural gas-fired microturbines at approximately 6 MW. Interestingly, fuel cells showed a negligible amount of distribution line peak reduction. Of the five fuel cells included in the study, only one was operational during the feeder peak, providing generation equivalent to just nine percent of installed fuel cell capacity that was metered.

Distribution system planners investigating approaches to reduce distribution line peak loading from increased penetration of DG facilities will need a way to estimate the amount of peak reduction available from each DG technology. A "look-up" table that reports measured distribution coincident peak load reduction across the different SGIP technologies, utilities, feeder types and climate zones was developed for this purpose. Table 1-4 provides estimated peak coincident load reduction factors that can be used for distribution system planning. For example, afternoon peaking feeder lines (i.e., those feeder lines peaking before 4 pm) in the coastal zone of PG&E can expect to see a reduction factor of 0.56 for PV entering the distribution system. This means that, based on observed performance, every rebated kW of PV installed and operating in PG&E's coastal zone will effectively act to reduce the distribution line loading by 0.56 kW of peak loading. Similarly, when viewed statewide, PV technologies can be expected to provide 0.35 kW of peak reduction for every kW of rebated PV.

Table 1-4: Distribution Coincident Peak Reduction Factors

		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon Evening	56% 30%	85%					
SCE Coast	Afternoon Evening	46% 6%	65% 48%		44% 52%			
SDG&E Coast	Afternoon Evening	42% 1%	33%		40%			
Inland	Afternoon Evening	63% 26%	29%					
Total by Technology/Fuel		35%	50%	12%	50%	23%	16%	0%
Total by Technology		35%	48%		44%		9%	

Notes: Climate Zones

PG&E Coast (CEC Title 24 Climate Zones 2, 3, 4, 5)

SCE Coast (CEC Title 24 Climate Zones 6, 7, 8, 9, 10 in SCE service territory)

SDG&E Coast (CEC Title 24 Climate Zones 7, 8, 10 in SDG&E service territory)

Inland (CEC Title 24 Climate Zones 11, 12, 13, 14, 15 for all utilities)

Distribution Peak Hour

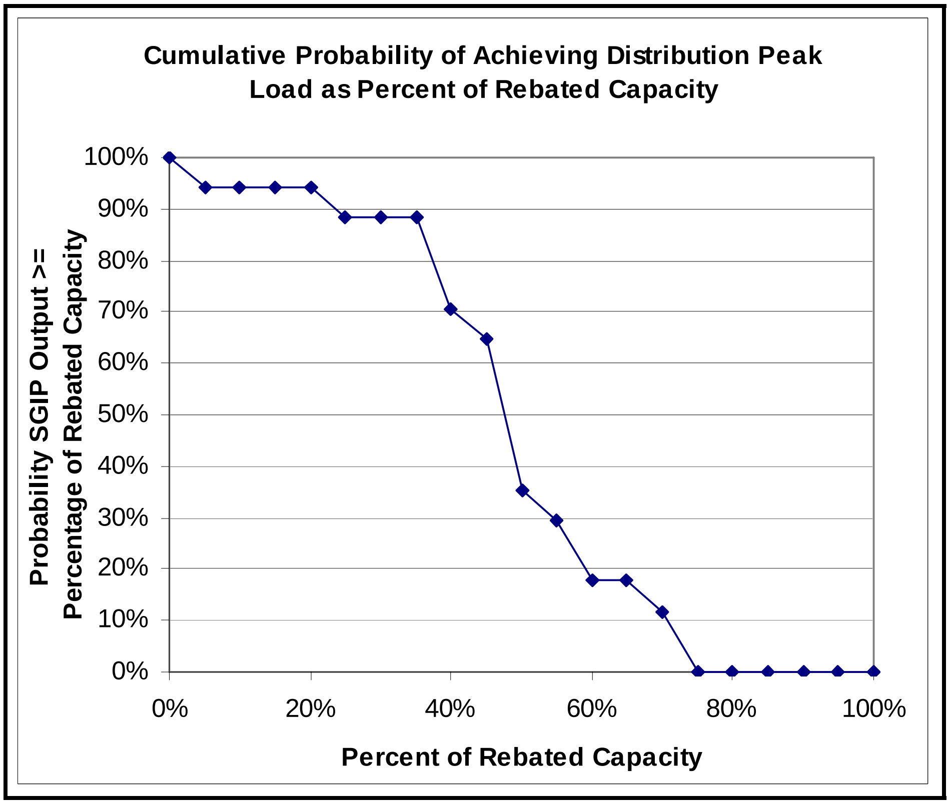
Afternoon (Peak occurs on Hour Ending (HE) 16 or earlier)

Evening (Peak occurs after HE 16)

In order to be a useful source of distribution capacity value, there must also be measurement of the reliability that SGIP installations will be operating during the peak. Otherwise, distribution planners will tend not rely on the load reduction achieved through SGIP in their capacity planning. Therefore, the project team has developed an uncertainty analysis based on the variation of metered SGIP units. Since the percentages above are averages of the generation provided by each technology for each climate zone and feeder group, care should be used when projecting the expected output of an individual generator.

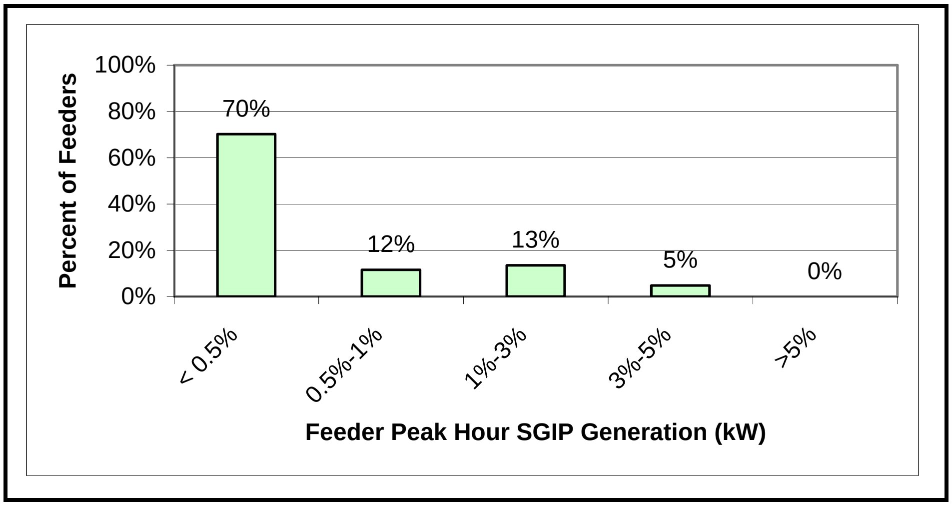
Therefore, for each SGIP technology a reliability curve has been developed based on the measured data that associates a probability of achieving an amount of load reduction. For example, Figure 1-8 below shows the probability profile of a PV installation achieving different distribution peak load reductions on a feeder that peaks on or before HE 16. There is 100 percent probability of having an output of zero or greater, a very low probability of having output equal to the rebated capacity, and a 35 percent probability of having output at least as high 50 percent of the rebated capacity. A spreadsheet tool was developed to compute combined probability distributions for multiple SGIP installations of different types on a single feeder using the measured data.

Figure 1-8: Probability of PV Output at Distribution Peak Hour (SCE Coast, Feeder Peak > HE 16)



Based on the results in Table 1-4, SGIP technologies are seen to provide the potential for significant reduction in peak loading of the distribution system. However, high penetration of DG technologies will be needed to achieve significant overall reduction in peak loading across each IOU service territory. Figure 1-9 provides a summary of the amount of peak reduction actually observed to occur in 2006 due to the impacts of SGIP technologies.

Figure 1-9: Peak Reduction as Percentage of Feeders



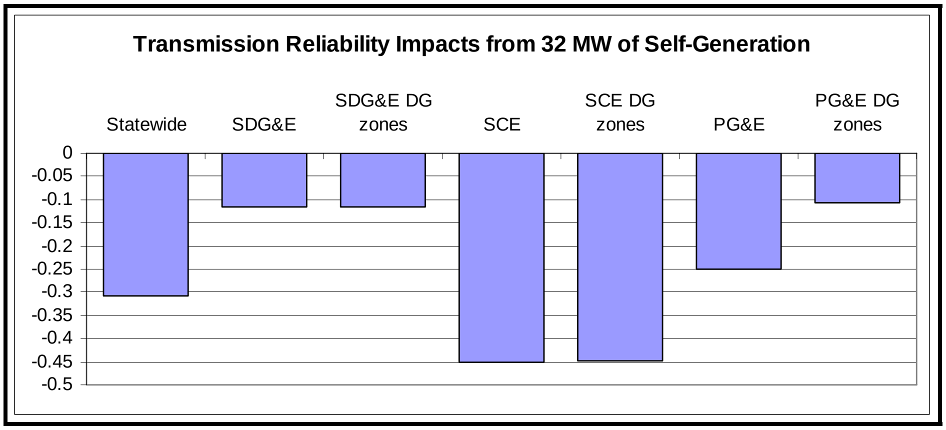
Overall, SGIP facilities had limited impact on reducing distribution system peak program-wide. No feeders or substations saw greater than five percent reduction of their peak loading. Approximately 70 percent of the feeders had peak loading impacts that were limited to less than 0.5 percent of the peak feeder loading. The low overall impact is attributable to the limited penetration of SGIP DG in the overall distribution system.

Transmission System Impacts

As load reduces due to self-generation on the distribution network, there is a corresponding reduction on distribution transformers, sub-transmission lines, transmission substations and ultimately on the high voltage lines. However, very high penetration of DG is generally considered necessary to provide significant benefits to the high voltage transmission lines.

Transmission system impacts were assessed by using measured SGIP generation and then modeling the aggregated capacity (MW) of SGIP DG facilities at each substation. Modeling of the transmission system focused on reliability impacts. In essence, the modeling simulated the impact on system reliability associated with removing SGIP generation out of the electricity system. A Distributed Generation Transmission Benefit Ratio (DGTBR) was calculated by the modeling approach and represents the net reliability impact. A negative DGTBR represents an improvement in system reliability. A positive DGTBR indicates a probable decrease in system reliability. Figure 1-10 is a summary of the reliability impacts associated with SGIP DG facilities during the summer 2006 peak.

Figure 1-10: Transmission Reliability Impacts for 2006 Peak



Overall, the power flow modeling results show that SGIP DG facilities improved system reliability at the transmission level. Statewide, each kW of rebated SGIP DG improved system reliability by 0.3 kW. Within each of the IOUs, SGIP facilities had the impact of improving system reliability from 0.1 to nearly 0.45 kW of increased reliability per kW of rebated SGIP capacity.

Even though the total aggregated capacity of the SGIP DG facilities represented only 32 MW out of the 42,000 MW of demand occurring under the 2006 summer peak conditions, the DG facilities were still found to provide overall DGTBR benefits to the system.

Efficiency and Waste Heat Utilization

Cogeneration facilities represent approximately two-thirds of the on-line generating capacity of the SGIP. Due to their large contribution to SGIP capacity, it is important that SGIP cogeneration facilities harness waste heat and realize high overall system and electricity efficiencies. In accordance with Public Utility Code (PUC) 216.6[7], fuel cells, IC engines, and turbine technologies powered by non-renewable fuels face certain minimum levels of thermal energy utilization and overall system efficiency. PUC 216.6(a) requires that recovered useful waste heat from a cogeneration system exceeds five percent of the combined recovered waste heat plus the electrical energy output of the system. PUC 216.6(b) requires that the sum of the electric generation and half of the heat recovery of the system exceeds 42.5 percent of the energy entering the system as fuel.

End uses served by recovered useful thermal energy in SGIP cogeneration systems include heating, cooling, or both. Available metered thermal data and input fuel collected from on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. The end uses served by recovered

[7] Public Utility Code 216.6 was previously PUC 218.5. The requirements have not changed.

useful thermal energy at projects on-line through the end of 2006 are summarized in Table 1-5.

Table 1-5: End-Uses Served by Level 2/3/3-N Recovered Useful Thermal Energy (Total n and kW as of 12/31/2005)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	182	69,935
Heating & Cooling	58	35,526
Cooling Only	28	20,673
To Be Determined	20	23,171
Total	288	149,305

Available metered thermal data collected from on-line cogeneration projects were used to calculate overall system efficiency incorporating both electricity produced as well as useful heat recovered. The results are summarized in Table 1-6.

Table 1-6: Nonrenewable-Fueled Engine/Turbine Cogeneration System Efficiencies (n=288)

Technology	n	216.6 (a) proportion	216.6 (b) Efficiency	Overall Plant Efficiency
Fuel Cell	11	43%	55%	70%†
IC Engine	181	42%	39%	50%
Microturbine	96	50%	28%†	37%†

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Metered and estimated data collected to date suggest that roughly 17 out of 288 cogeneration projects achieved the 216.6 (b) overall system efficiency target of 42.5 percent.

One possible explanation for the lower than expected efficiency results could be tied to low electricity efficiencies. Results of an analysis of SGIP cogeneration system electrical conversion efficiencies are presented in Table 1-7. In the case of reciprocating internal combustion engines (ICE), actual electrical conversion efficiencies of approximately 29 percent are typical for monitored SGIP cogeneration systems. However, this typical result is below electrical conversion efficiencies normally found in published technical specifications of engine-generator set manufacturers. These nominal nameplate electrical generating efficiencies published by manufacturers generally exceed 30 percent, and sometimes exceed 35 percent.

Table 1-7: Electrical Conversion Efficiency

Summary Statistic	Fuel Cells (FC)	Internal Combustion Engines (ICE)	Microturbines (MT)
n	11	181	96
Min	40%	0%	0%
Max	40%	35%	22%
Median	40%	29%	19%
Mean	40%	28%	18%
Std Dev	0%	4%	3%

Another explanation for cogeneration systems not meeting PUC 216.6(b) is the lack of a significant coincident thermal load. In other words, many facilities do not have a need for the waste heat that the generator provides. This issue was explored in detail previously.[8]

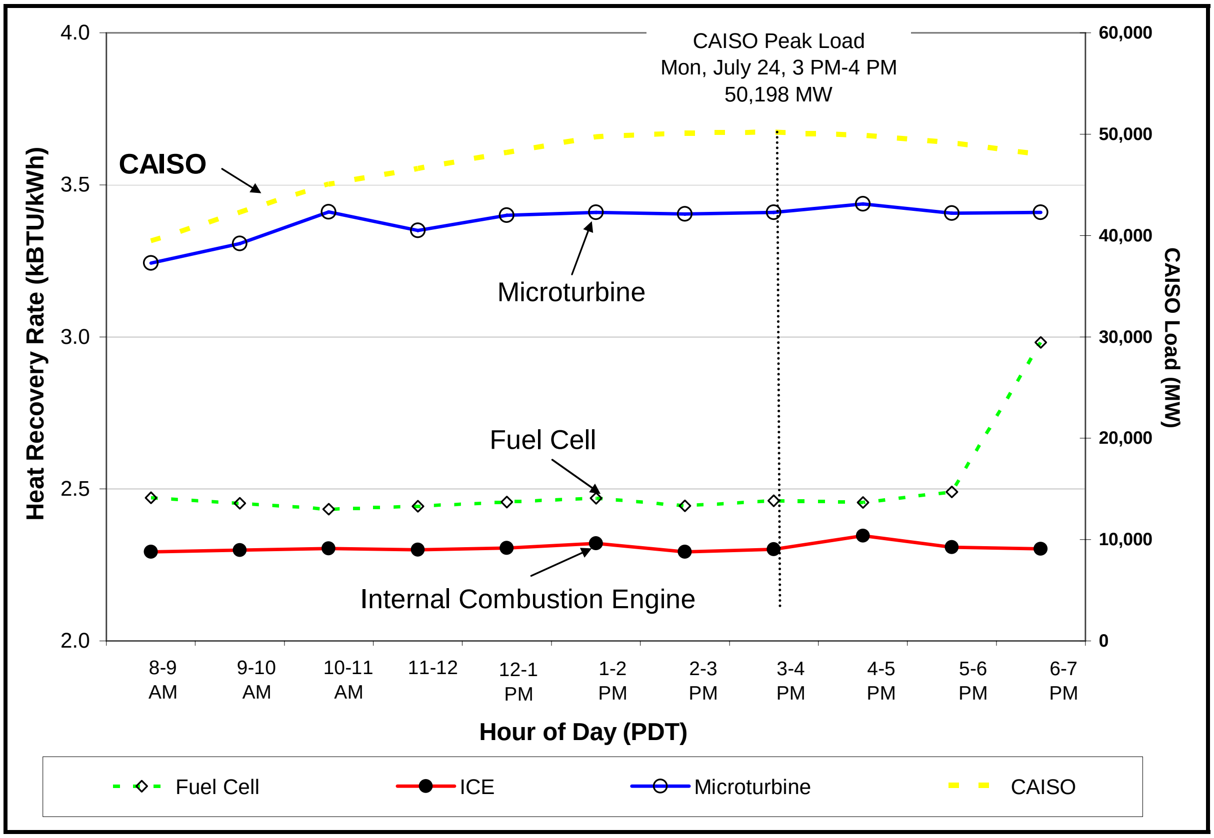
When both the electrical and thermal shortcomings are combined the resulting PUC 216.6(b) efficiencies fall short of the standard. Briefly stated, if a cogeneration system inputs 100 units of fuel and nominally produces 34 units of electricity, then one might expect 15 units lost due to system inefficiencies and 51 units of heat. In order to meet 216.6(b) only 17 units of heat would need to be recovered for useful purposes, which corresponds to a heat recovery rate of 1.7 kBtu/kWh.

In the case of ICEs in the SGIP, that same 100 units of fuel only produces 28 units of electricity, 18 units of loss, and 54 units of heat. If these systems were to meet PUC 216.6(b), they would have to recover 29 of those 54 units of heat. This translates to a heat recovery rate of 3.5 kBtu/kWh, more that twice the nominal heat recovery rate. Monitored ICE cogeneration systems typically do not exceed 2.5 kBtu/kWh.

The contribution of cogeneration systems during peak periods was developed for 2006. As the GHG and T&D portions of the analysis evolve hourly heat recovery results will become increasingly important. Figure 1-11 provides hourly heat recovery rates during the CAISO system peak day. As shown, the variability is relatively low during the day. Subsequent evaluations will attempt to incorporate additional metered points as well as an examination of base loading vs. load following facilities.

[8] Itron for the CPUC, "In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems," February 2007.

Figure 1-11: Heat Recovery Rate During CAISO Peak Day



Greenhouse Gas Emission Reduction Impacts

Greenhouse gas (GHG) emission reductions from SGIP facilities were investigated for the first time in the 2005 Impacts Evaluation Report. The approach used for calculating GHG reductions for PY06 remains essentially the same as used for PY05. However, GHG for PY06 are reported by technology type rather than by incentive level. This approach provides greater refinement of results and an increased understanding of the relationship between GHG reductions and fuel type. In addition, the focus on GHG emission reduction in the SGIP analysis has remained primarily on two gases: carbon dioxide (CO_2) and methane (CH_4) as these are the main contributors of GHG from SGIP facilities.

Table 1-8 is a summary of net reductions in GHG emissions attributable to SGIP facilities during PY06. The results are reported in tons of CO_2 equivalent to allow comparison of contribution from the different SGIP technologies and with other GHG sources outside the SGIP.

Table 1-8: Net Reduction in GHG Emissions from SGIP Technologies (2006)

Technology	Tons of CO_2 eq. Reduced	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWhr)
Photovoltaics	62,253	103,306	0.60
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	6,176	26,170	0.24
Non-renewable MT	-10,306	47,202	-0.22
Non-renewable fueled ICE	72	353,436	0.0002
Non-renewable and waste gas fueled small gas turbines	-7,245	55,287	-0.13
Renewable fueled fuel cells	3,715	2,498	1.49
Renewable fueled MT	46,551	9,281	5.01
Renewable fueled IC Engines	8,463.5	10,233	0.82
TOTAL	**110,945**	**609,515**	**0.18**

PV systems accounted for over half of the GHG emission reductions from SGIP facilities in PY06. Biogas fueled SGIP facilities provided over 58,700 tons per year of CO_2 equivalent reductions; representing slightly over 50 percent of the total GHG reductions[9]. Non-renewable cogeneration facilities combined provided a net reduction of approximately 7,500 tons of CO_2 equivalent reductions; or approximately seven percent of the overall GHG reductions.

There are three major sources of GHG emission reductions from SGIP facilities:

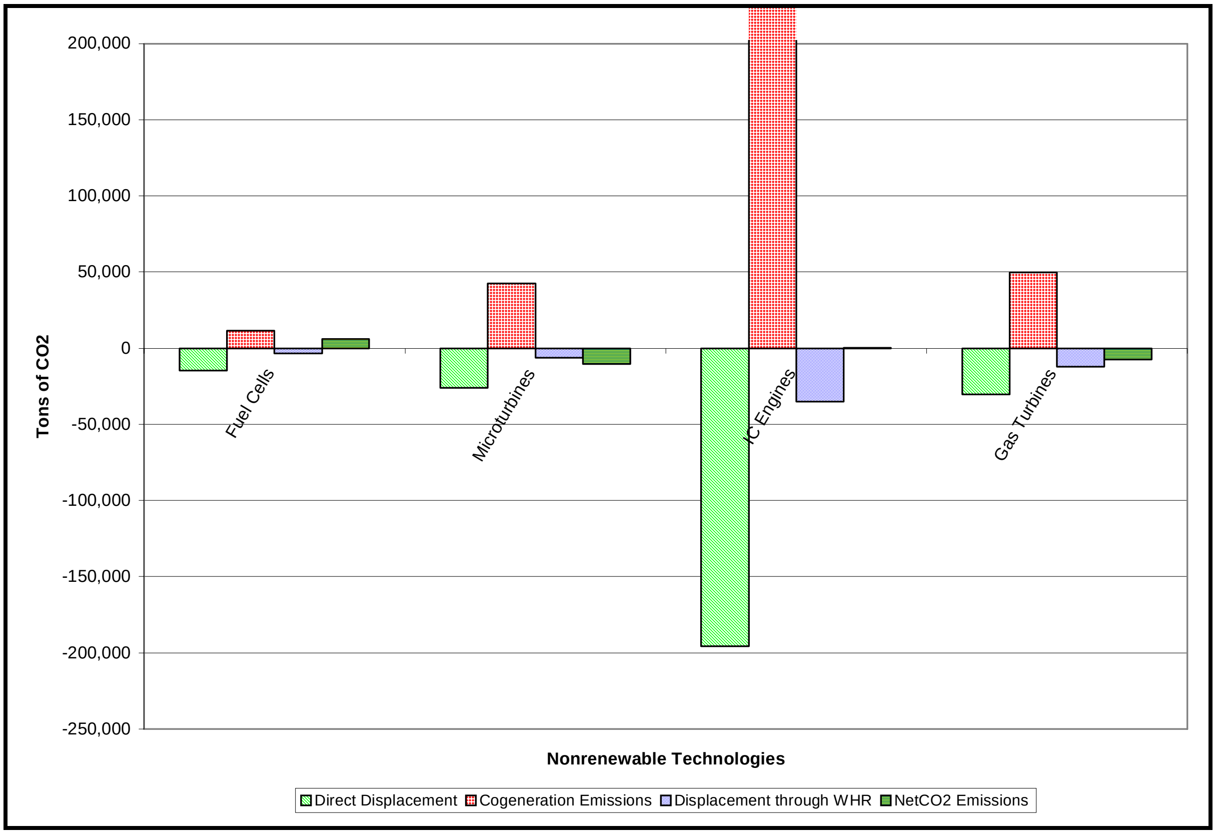
1. Net differences in CO_2 emissions resulting from electricity supplied to utility customers from central station generation facilities versus electricity supplied by the customer's own SGIP generator (i.e., "direct displacement"),
2. Net CO_2 emission reductions due to waste heat recovery systems used at SGIP facilities and which either displaced natural gas otherwise used to produce process heat or displaced electricity normally supplied from central station generation facilities to drive electrical chillers ("displacement through waste heat recovery"), and
3. Methane captured and used by biogas-fired SGIP facilities.

The importance of waste heat recovery on CO_2 reductions for non-renewable cogeneration facilities is illustrated in Figure 1-12. In general, CO_2 emissions from direct displacement of grid provided electricity essentially zero out the CO_2 emissions from the SGIP generators.

[9] Note that percent contributions to GHG emission reductions from specific sources use a total which is based on both positive and negative contributions; and as such the sum of the percentages exceeds 100 percent.

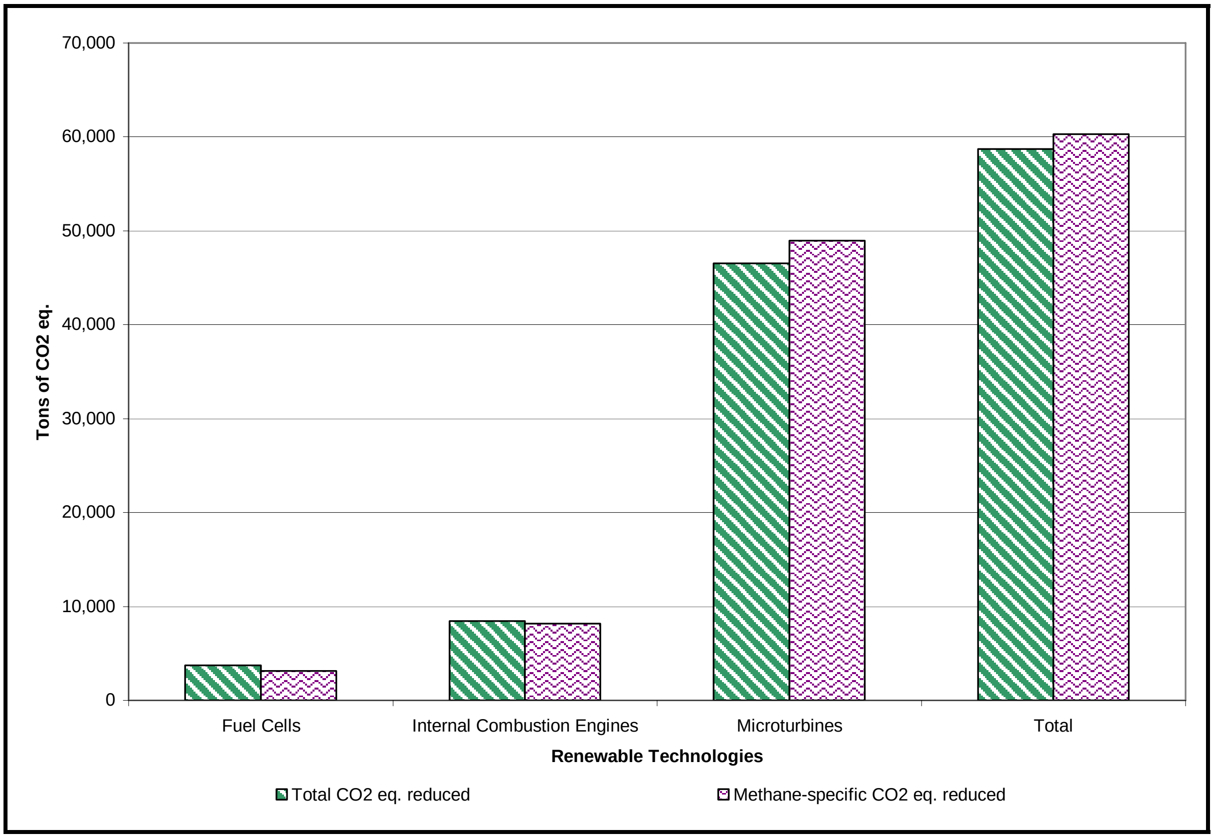
However, CO_2 emission reductions still occur due to waste heat recovery. Consequently, CO_2 emission reductions from waste heat recovery provide a net reduction in CO_2 emissions for non-renewably fueled microturbines, IC engines and gas turbines.

Figure 1-12: Breakdown of CO2 Sources for Non-Renewable Cogeneration Technologies in the SGIP (2006)



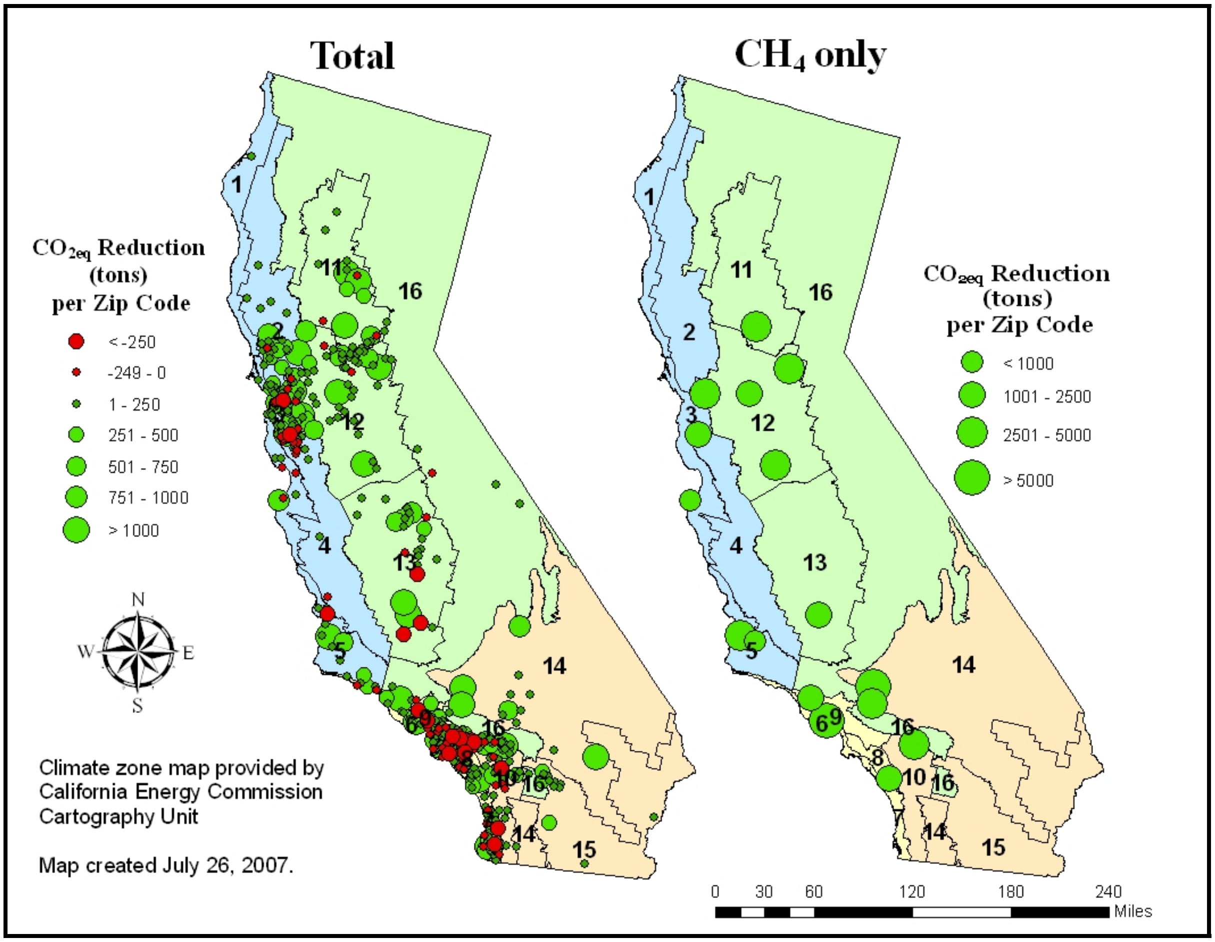
The contribution of captured and harnessed methane in biogas-fueled SGIP facilities is shown in Figure 1-13 along with the total GHG emissions reduced by these technology/fuel contributions. This figure shows that capture and use of methane from biogas sources in 2006 are responsible for most of the GHG reductions from biogas-fueled SGIP facilities.

Figure 1-13: Contribution of Methane to Overall GHG Reductions in Biogas Fueled SGIP Technologies (2006)



Due to the increasing role of GHG emission reductions, it is also important to identify the distribution of GHG reductions within the SGIP. Figure 1-14 shows the distribution of GHG emission reductions due to SGIP facilities throughout California. The figure on the left depicts the total GHG reductions from all sources within the SGIP facilities. The figure on the right shows only the locations of those biogas-fueled SGIP facilities providing methane based GHG reductions.

Figure 1-14: Distribution of GHG Emission Reductions Among SGIP Facilities (2006)

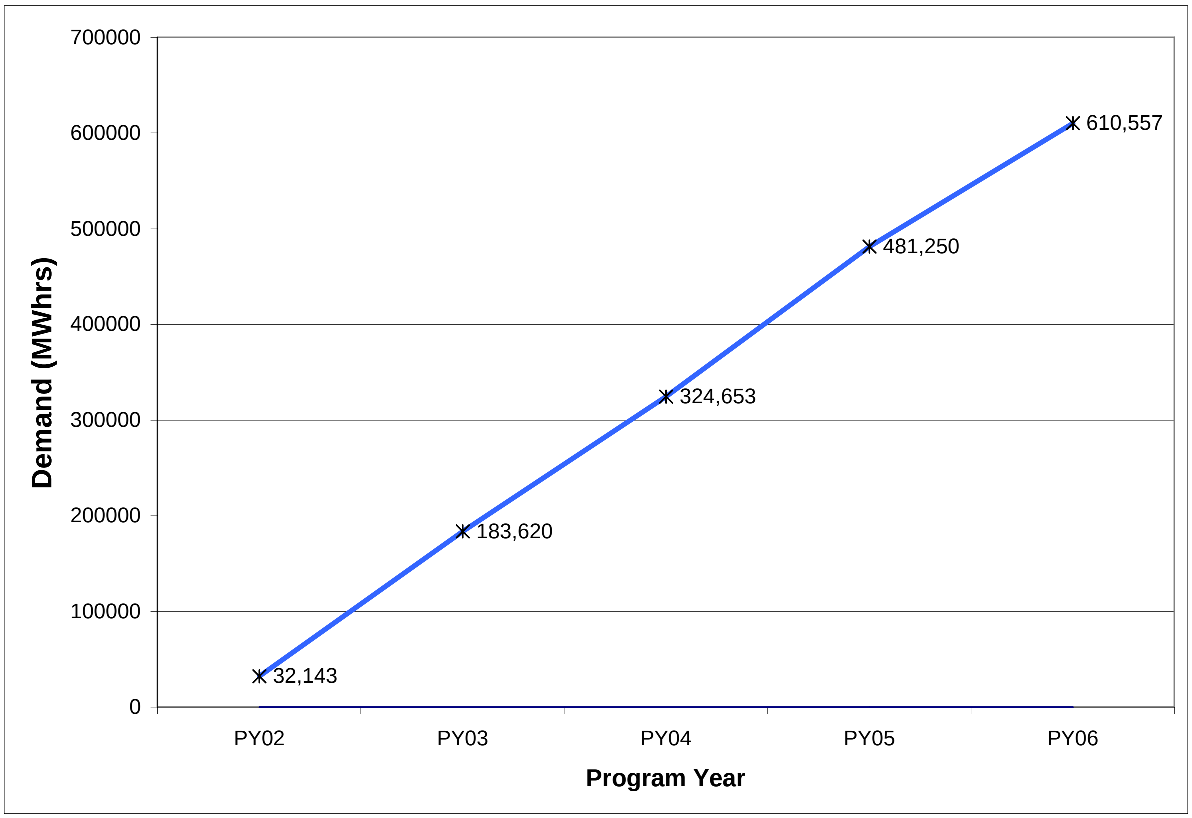


1.3 Trends on Program Impacts

Energy

The ability of the SGIP to deliver energy has steadily increased since inception of the program. Figure 1-15 shows the increase in the amount of electricity delivered by SGIP projects annually from 2002 through the end of 2006. From 2003 on, annual electricity delivered by the SGIP has increased by over 125 percent each year.

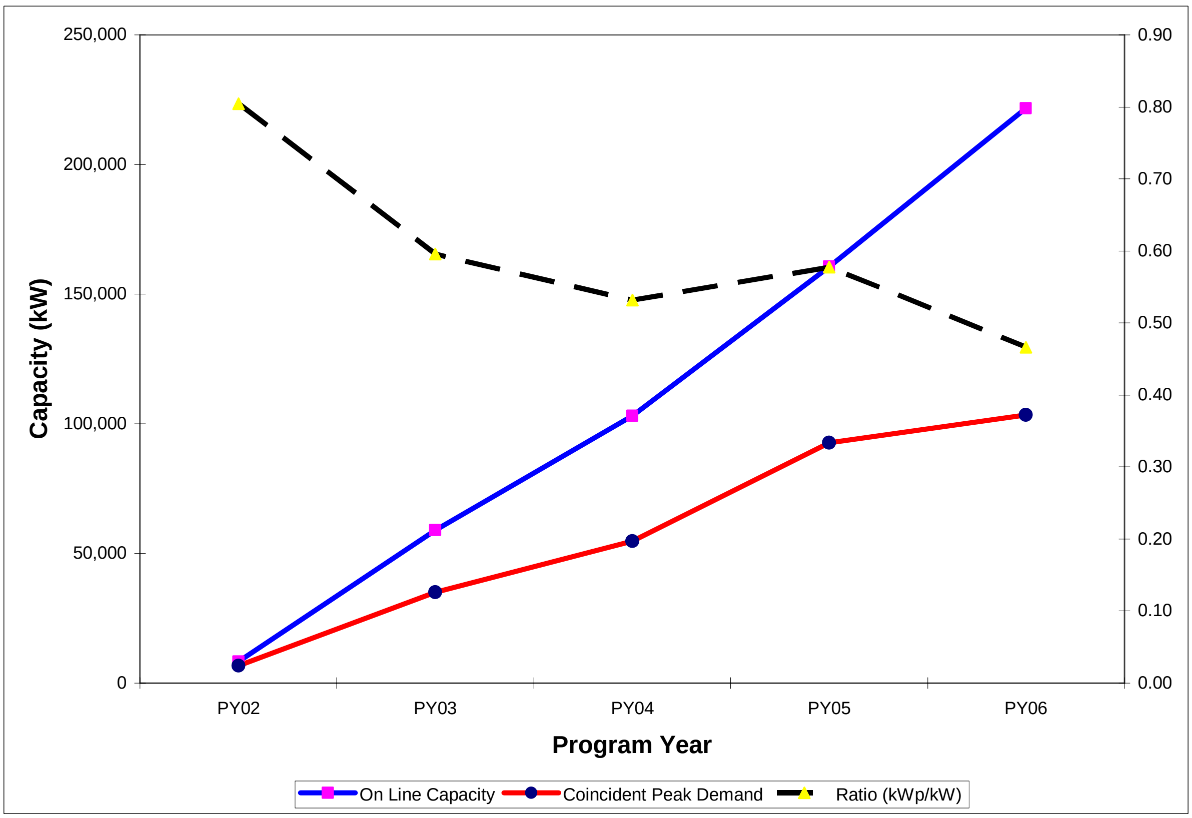
Figure 1-15: Trend in SGIP Energy Delivery from 2002 to 2006



Coincident Peak Demand

Figure 1-16 shows the change in coincident peak demand that has occurred from PY02 through the end of PY06. The ratio of peak capacity to on-line capacity (kWp/kW) reflects the amount of capacity that was actually observed to be available during the CAISO peak demand. The relatively high kWp/kW ratio observed in PY02 may be due to the low number of systems monitored during that program year. In general, the kWp/kW ratio for the SGIP has stayed between 0.3 to 0.4 for the last two years. This may be reflective of the impact of PV systems, with a kWp/kW ratio that has typically ranged from 0.4 to 0.5.

Figure 1-16: Trend on Coincident Peak Demand from PY02 to PY06

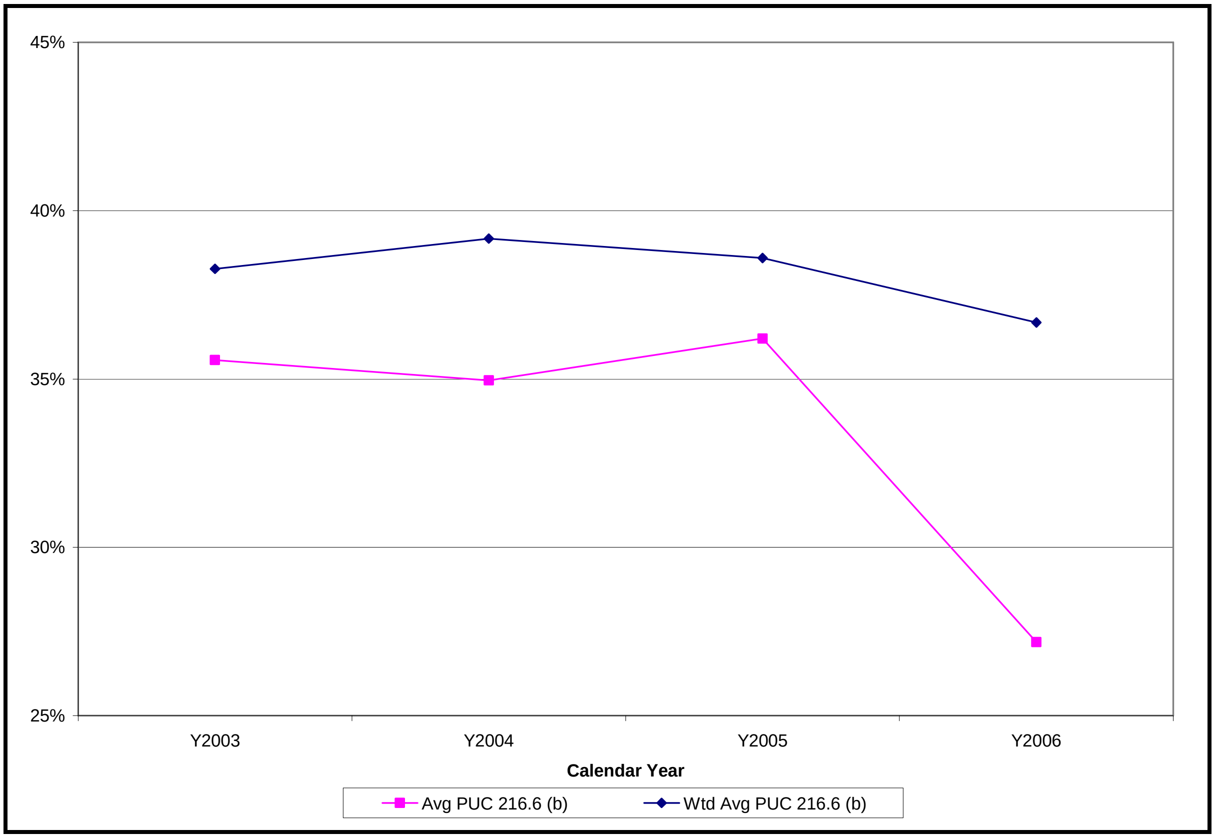


System Efficiency

Cogeneration facilities have been monitored for several years under this evaluation. Although the number of facilities monitored is relatively small, the resulting efficiencies are representative of many other systems. Figure 1-17 provides a trend of PUC 216.6 (b) efficiency from 2003 through 2006. The noticeable dip in efficiency in 2006 may be explained by several possible issues. First, the 2006 analysis includes all completed systems since program inception. Some of these systems are reaching the end of their life and are being decommissioned. Others are operating at part load and are experiencing efficiency issues as a result. Finally, some systems are experiencing heat recovery issues, such as failed heat exchangers, but continue to operate the generating equipment.

The difference between average and weighted average PUC 216.6 (b) efficiencies is a result of larger systems generally operating better than smaller systems. This is due to any number of reasons including dedicated O&M staff, more thoughtful engineering design, a preventive maintenance program, or a more reliable and consistent use for the waste heat.

Figure 1-17: Trend of PUC 216.6 (b) (2003-2006)



1.4 Looking Forward: Opportunities and Challenges

The SGIP represents tremendous opportunities for California and California's utilities. It represents a wealth of experience and knowledge about the deployment and operation of DG facilities in a utility environment. California, like many other states, is poised to move forward into an era of potentially rapid growth in DG. Although DG facilities currently represent less than 2.5 percent of California's peak demand, the California Energy Commission anticipates that by 2020, DG facilities will provide enough electricity to meet nearly 25 percent of California's peak demand.[10] The knowledge gained by the SGIP can be critical in helping California meet this goal.

California is also looking at making significant strides in reducing GHG emissions. In accordance with the Global Warming Solutions Act of 2006 and Executive Order S-3-05 from the Governor, California is to reduce GHG emissions to 1990 levels by 2020. Insights gained from the SGIP on the role of DG facilities will help California not only move forward in meeting the GHG targets but will concurrently help address the role to be played by increased penetration of DG technologies.

Several important challenges face the SGIP as it moves into the future. Under Assembly Bill 2778, approved in September of 2006, eligibility of SGIP technologies may be limited to "ultra-clean and low emission distributed generation" technologies, such as wind and fuel cells. Currently, nearly 65 percent of the SGIP's capacity is based on cogeneration technologies; with the remaining 35 percent based on PV systems. PV technologies have already moved out of the SGIP into the California Solar Initiative Program. The cogeneration portion of the SGIP is dominated by IC engines and microturbines. IC engines and microturbines make up nearly 97 percent of the number of cogeneration facilities and 95 percent of the capacity of cogeneration systems installed under the SGIP. However, both IC engines and microturbines have experienced difficulties in achieving compliance with prescribed NOx requirements and PUC 216.6 energy efficiency requirements. Due to the higher cost of fuel cell technologies and issues facing wind integration, replacement of cogeneration technologies with wind and fuel cell technologies could take time and pose additional problems. For example, the GHG reduction findings and an earlier cost-effectiveness study[11] conducted on the SGIP indicates that it may be beneficial for the program to focus more effort on deploying biogas powered cogeneration facilities. However, a number of technical and cost issues will need to be resolved for fuel cells to use biogas fuels competitively against IC engines and microturbines. For these reasons, there will need

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[10] California Energy Commission, "Distributed Generation and Cogeneration Roadmap for California," CEC-500-2007-021, March 2007

[11] Itron for the CPUC, "CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report," September 8, 2005

to be a greater understanding of the relationships between NOx emissions, GHG reductions and the efficiencies of DG cogeneration technologies that may participate in the SGIP in the future.

As California expands use of DG technologies, they will play a larger role in meeting peak demand. This 2006 Impact Evaluation Report begins to shed light on the interplay between DG technologies, peak loading on distribution feeders, higher voltage transmission lines and overall system peak. However, making a smooth and cost-effective increased deployment of DG technologies into California's grid requires additional understanding of the T&D impacts.

2

Introduction

2.1 Program Background

The Self-Generation Incentive Program (SGIP) was established in response to Assembly Bill (AB) 970[1], which required the California Public Utilities Commission (CPUC) to initiate certain load control and distributed generation program activities. The CPUC issued Decision 01-03-073 (D.01-03-073) on March 27, 2001 outlining provisions of a distributed generation program. The Decision mandated implementation of a self-generation program designed to produce significant public (e.g., environmental and energy distribution system) benefits for all ratepayers, including gas ratepayers across the service territories of California's investor-owned utilities (IOUs). The resulting SGIP offered financial incentives to customers of IOUs who installed certain types of distributed generation (DG) facilities to meet all or a portion of their energy needs. DG technologies eligible under the SGIP included solar photovoltaic systems, fossil- and renewable-fueled reciprocating engines, fuel cells, microturbines, small-scale gas turbines, and wind energy systems.

In October of 2003, AB 1685 extended the SGIP beyond 2004 through 2007. This bill required the CPUC, in consultation with the California Energy Commission (CEC), to administer until January 1, 2008 the SGIP for distributed generation resources in largely the same form that existed on January 1, 2004. However, this decision notwithstanding, a number of program modifications were made in 2004 and 2007. For example, with the funding of the California Solar Initiative (CSI), the SGIP no longer offered incentives to photovoltaic (PV) systems after 2006. Similarly, AB 2778, approved in September of 2006, continues the SGIP through 2012, but limits eligibility to "ultra-clean and low emission distributed generation" technologies, such as wind and fuel cells. It is uncertain what role, if any, other renewable energy technologies, such as biogas-fueled or micro-hydropower systems will play in the SGIP after 2007. Moreover, cogeneration systems were no longer funded beyond 2007 under AB 2778. The future program design details have yet to be worked out, but there is some suggestion that cogeneration may be revisited. Upon enacting AB 2778, Governor Schwarzenegger encouraged parties to revisit the eligibility of the eliminated technologies in the following signing message: "This bill extends the sunset of the Self Generation Incentive Program to promote distributed generation throughout California.

[1] Assembly Bill 970 (Ducheny, September 7, 2000)

However, the legislation eliminated clean combustion technologies like microturbines from the program. I look forward to working with the Legislature to enact legislation that returns the most efficient and cost effective technologies to the program. If clean up legislation is not possible, the California Public Utilities Commission should develop a complimentary program for these technologies."

The SGIP has been operational since July 2001 and represents the single largest DG incentive program in the country. As of December 31, 2006, over $822 million in incentives had been paid out through the SGIP, resulting in the installation of nearly 947 DG projects representing approximately 233 megawatts (MW) of rebated capacity.

2.2 Impact Evaluation Requirements

D.01-03-073, authorizing the SGIP, states: "Program administrators shall outsource to independent consultants or contractors all program evaluation activities…" Impact evaluations were among the evaluation activities outsourced to independent consultants. The Decision also directed the assigned Administrative Law Judge, in consultation with the CPUC Energy Division and the Program Administrators (PAs), to establish a schedule for filing the required evaluation reports. Table 2-1 lists the SGIP impact evaluation reports filed with the CPUC prior to 2006.

Table 2-1: SGIP Impact Evaluation Reports Prepared to Date

Calendar Year Covered	Date of Report
2001[2]	June 28, 2002
2002[3]	April 17, 2003
2003[4]	October 29, 2004
2004[5]	April 15, 2005
2005[6]	March 1, 2007

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2 California Self-Generation Incentive Program: First Year Impact Evaluation Report. Submitted to Southern California Edison. Prepared by Regional Economic Research (RER), June 28, 2002.

3 California Self-Generation Incentive Program: Second Year Impact Evaluation Report. Submitted to Southern California Edison. Prepared by Itron, Inc., April 17, 2003.

4 CPUC Self-Generation Incentive Program: Third Year Impact Assessment Report. Submitted to The Self-Generation Incentive Program Working Group. Prepared by Itron, Inc., October 29, 2004.

5 California Self-Generation Incentive Program: Fourth Year Impact Evaluation Report. Submitted to Southern California Edison. Prepared by Itron, Inc., April 15, 2005.

6 California Self-Generation Incentive Program: Fifth Year Impact Evaluation Report. Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., March 1, 2007.

On March 8, 2006, the PAs filed a motion with the CPUC proposing a schedule of measurement and evaluation (M&E) activities for 2006 and 2007. In a May 18, 2006 ruling the CPUC provided guidance to the PAs on the schedule of filings for impact evaluation reports through 2008. Table 2-2 identifies the schedule for filing of the 2006 through 2008 impact evaluation reports.

Table 2-2: Post-2006 SGIP Impact Evaluation Reports

Calendar Year Covered	Date of Report Filing to the CPUC
2006	August 31, 2007
2007	June 16, 2008
2008	June 15, 2009

This report provides the findings of an impact evaluation of the sixth program year of the SGIP covering the 2006 calendar year.

2.3 Scope of the Report

The 2006 Impact Evaluation Report represents the sixth impact evaluation report conducted under the SGIP. At the most fundamental level, the overall purpose of all annual SGIP impact evaluation analyses is identical: to produce information that helps the many SGIP stakeholders make informed decisions about the SGIP's design and implementation. As the SGIP has evolved over time, the focus and depth of the impact evaluation reports have changed appropriately. Like prior impact evaluation reports, the 2006 report examines the effects of SGIP technologies on electricity production and demand reduction at different times, on system reliability and operation, and on compliance with renewable fuel use and thermal energy efficiency requirements. In addition, the 2006 report also examines greenhouse gas emission reductions associated with each SGIP technology category and impacts on transmission and distribution (T&D) system operation and reliability.

Table 2-3 summarizes the impact evaluation objectives contained in the 2006 report.

Table 2-3: Impact Evaluation Objectives in 2006 Report

Impact Evaluation Objectives Addressed in 2006 Impact Evaluation Report
Electricity energy production and demand reduction ■ Annual production and production at peak periods during summer (both at Cal ISO system and at individual IOU-specific summer peaks) ■ Peak demand impacts (both at Cal ISO system and at individual IOU-specific summer peaks) ■ Combined across technologies and by individual technology category
Compliance of fuel cell, internal combustion engine, microturbine, and gas turbine technologies will be assessed against PUC 216.6[7] requirements ■ PUC 216.6 (a): useful recovered waste heat requirements ■ PUC 216.6 (b): system efficiency requirements
Transmission and distribution impacts ■ Distribution system impacts at the PA and program-wide level ■ Transmission system impacts at the PA and program-wide level
Provide greenhouse gas emission reductions by SGIP technology ■ Net against CO_2 emissions generated otherwise from grid generation ■ Methane captured by renewable fuel use projects
Trending of performance by SGIP technology from 2002 - 2006

[7] Public Utilities Code 216.6 was previously Public Utilities Code 218.5. The requirements have not changed.

2.4 Report Organization

This report is organized into eight sections, as described below.

- **Section 1** provides an executive summary of the key objectives and findings of this sixth year impact evaluation of the SGIP through the end of 2006.
- **Section 2** is this introduction.
- **Section 3** presents a summary of the program status of the SGIP through the end of 2006.
- **Section 4** describes the sources of data used in this report for the different technologies.
- **Section 5** discusses the 2006 impacts associated with SGIP projects at the program level. The section provides a summary discussion as well as specific information on impacts associated with energy delivery; peak demand reduction; transmission and distribution impacts; efficiency and waste heat utilization requirements; and greenhouse gas emission reductions.
- **Appendix A** gives more detailed information on costs, annual energy produced, peak demand, and capacity factors by technology and fuel type.
- **Appendix B** discusses the transmission and distribution methodology, describes the data used, and presents more detailed results.
- **Appendix C** describes the methodology used for developing estimates of SGIP greenhouse gas emission impacts.
- **Appendix D** describes the data collection and processing methodology, including the uncertainty analysis of the program level impacts. The attachment to this appendix contains the performance distributions used in the uncertainty analysis.
- **Appendix E** gives an overview of the metering systems employed under the SGIP for metering electric generation, fuel consumption, and heat recovery.

3

Program Status

3.1 Introduction

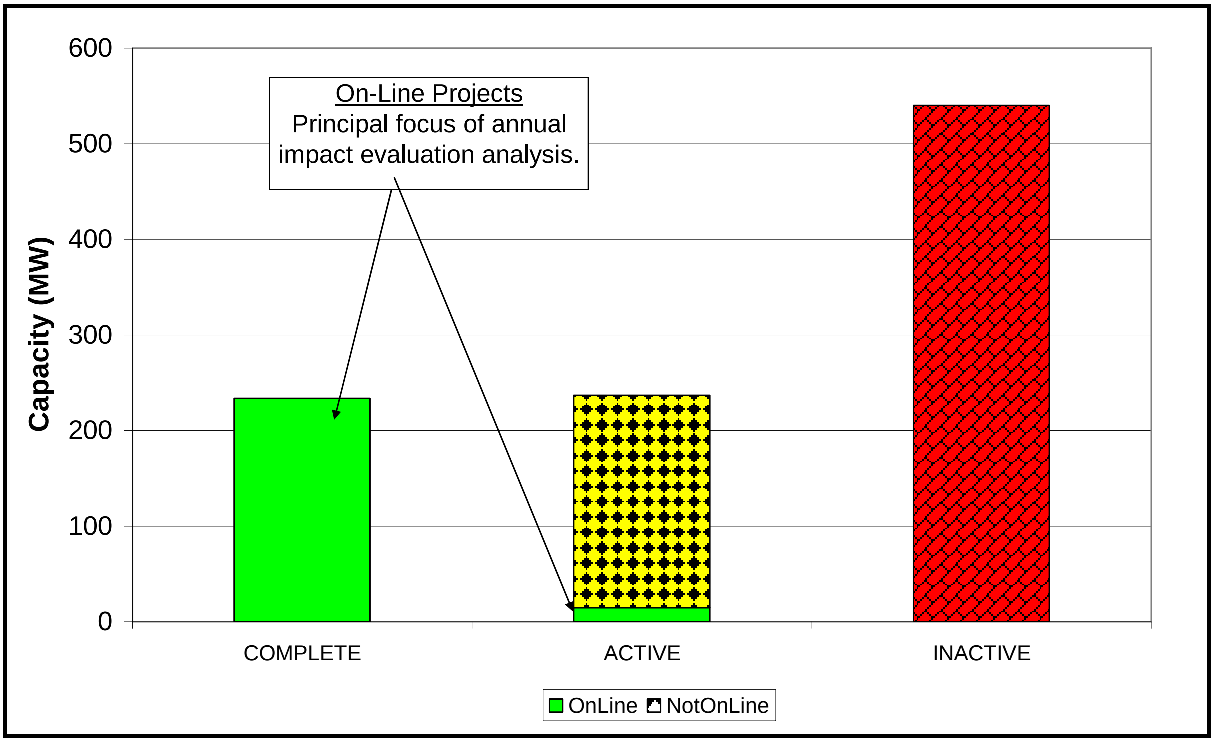
This section provides information on the status of the Self-Generation Incentive Program (SGIP) relative to all applications extending from Program Year 2001 (PY01) through the end of PY06 based on PA tracking data available through December 31, 2006. Information in this section includes the status of projects in the SGIP, the associated amount of system capacity, incentives paid or reserved, and project costs.

3.2 Overview

Figure 3-1 summarizes the status of SGIP projects at a very high level. It shows the status of projects by their stage of progress within the SGIP implementation process and their "on-line" status. "On-line" projects are defined as those that have entered normal operations (i.e., projects are through the shakedown or testing phase and are expected to be providing energy on a relatively consistent basis).[1]

[1] The reference to having entered 'normal operations' is not an indication that a system is actually running during any given hour of the year. For example, some systems that have entered normal operations do not run on weekends.

Figure 3-1: Summary of PY01-PY06 SGIP Project Status as of 12/31/2006



Key stages in the SGIP implementation process include:

- ***Complete Projects:*** The generation system has been installed and verified through on-site inspections and an incentive check has been issued. Projects meeting these requirements are considered "on-line" for impact evaluation purposes.
- ***Active Projects:*** These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a wait list.[2] As time goes on the active projects will migrate either to the Complete or to the Inactive category. Some, but not most, of these projects had entered normal operations as of the end of 2006, but were not considered Complete, as an incentive check had not yet been issued.
- ***Inactive Projects:*** Projects that have been withdrawn by the applicants or rejected by the PAs, and are no longer progressing in the SGIP implementation process.

[2] When SGIP funding has been exhausted, eligible projects are placed on a wait list within the relevant incentive level has been exhausted for that Program Year. Previously, projects that remained on a wait list at the end of the Program Year were required to re-apply for funding for the subsequent funding cycle. This requirement was eliminated in December 2004 by D.04-12-045. Over time, projects that are withdrawn or rejected are replaced by projects from the wait list.

Table 3-1 provides a breakdown by incentive level of the Complete and Active projects depicted graphically in Figure 3-1 on the previous page. The number of projects is represented by an "n." The capacity (MW) refers to the total rebated capacity for those "n" projects.

Table 3-1: Quantity and Capacity of Complete and Active Projects

Technology & Fuel	Complete		Active (All)		Total		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
PV	638	81.1	605	154.2	1243	235.3	189
Wind	2	1.6	4	2.8	6	4.5	744
Fuel Cell - Nonrenewable	10	5.8	6	3.1	16	8.8	550
Fuel Cell - Renewable	2	0.8	10	8.0	12	8.7	725
Engine/Turbine - Nonrenewable	270	135.0	94	62.3	364	197.4	542
Engine/Turbine - Renewable	26	9.3	14	6.5	40	15.8	395
All	**948**	**233.6**	**733**	**236.9**	**1681**	**470.4**	**280**

There were nearly 1700 Complete and Active projects, representing over 470 MW of capacity in the SGIP by December 31, 2006. The principal focus of the 2006 impact evaluation is the subset of projects "on-line" by December 31, 2006. These projects, being connected to the grid and operational, are the ones that had an impact during PY06.

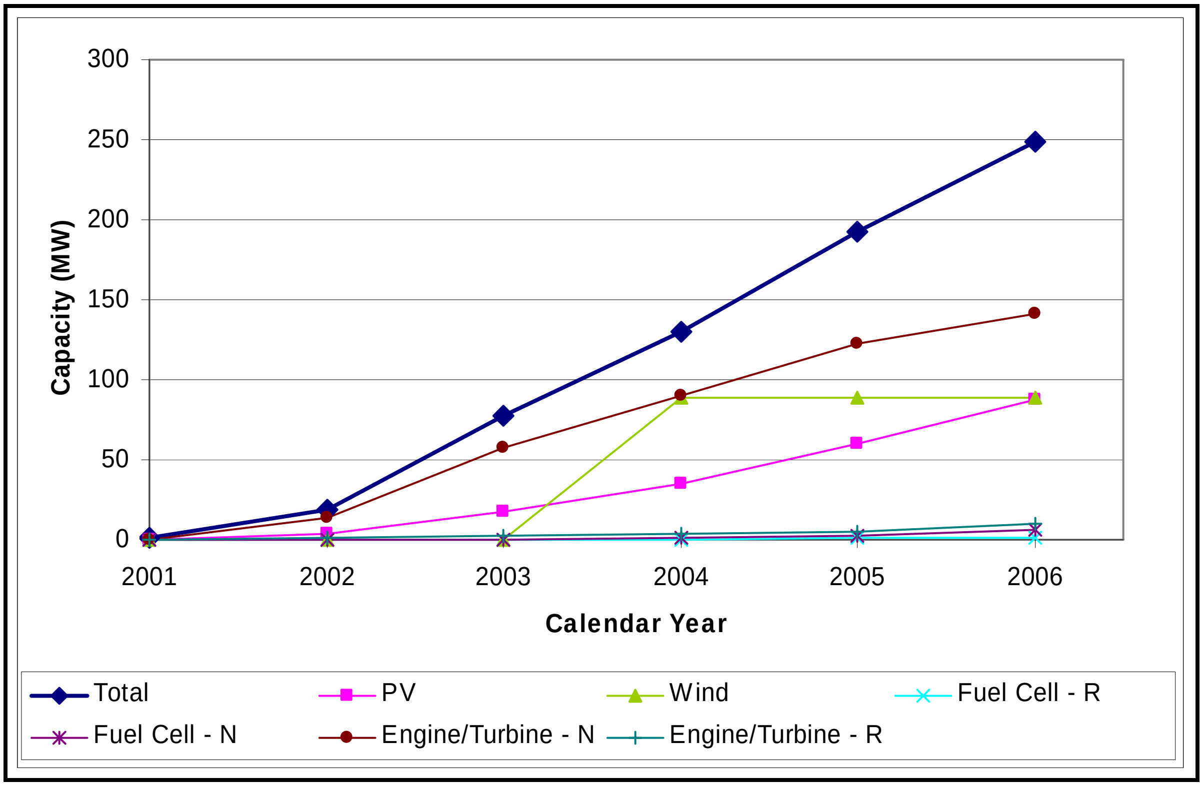
Table 3-2 provides information on the number and capacity of projects that are "on-line" even if they have not received incentive checks. The information is broken down by incentive level, technology type, and stage of implementation in the SGIP. By the end of 2006, "on-line" projects represented almost 1,000 projects and approximately 250 MW of rebated capacity.

Table 3-2: Quantity and Capacity of Projects On-Line as of 12/31/2006

Technology & Fuel	Complete		Active (On-Line)		Total On-Line Projects		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg Size (kW)
PV	638	81.1	34	6.7	671	87.7	131
Wind	2	1.6	0	0.0	2	1.6	824
Fuel Cell - Nonrenewable	10	5.8	1	1.0	11	6.8	614
Fuel Cell - Renewable	2	0.8	0	0.0	2	0.8	375
Engine/Turbine - Nonrenewable	270	135.0	12	5.7	282	140.8	499
Engine/Turbine - Renewable	26	9.3	2	1.3	28	10.6	377
All	**948**	**233.6**	**49**	**14.7**	**996**	**248.2**	**249**

Figure 3-2 shows the increase in rebated capacity of on-line (complete and active) projects extending from 2001 through the end of 2006 by technology and fuel type. The capacity of on-line projects more than tripled between the end of 2003 and the end of 2006 and the capacity of Complete[3] projects increased 23 percent (56 MW) from 2005 to 2006. PV systems installed between 2005 to 2006 contributed 28 MW of capacity, or approximately half of the growth of the SGIP during this period. Most of the remaining growth in capacity from 2005 to 2006 came from microturbines and IC engines. Wind and fuel cell systems had little, if any, growth during this same period.

Figure 3-2: Growth in On-Line Project Capacity from 2001-2006



Customers of the investor-owned utilities (IOUs) fund the SGIP through a cost recovery process administered by the CPUC. Every IOU customer is eligible to participate in the SGIP. In some cases, these same IOU customers are also customers of municipal utilities. Consequently, deployed SGIP projects can have impacts on both IOU and municipal utilities.

3 Complete projects are defined as those projects that are on-line and had received an SGIP incentive check, whereas active projects are those projects that are on-line but have not yet received an SGIP incentive check.

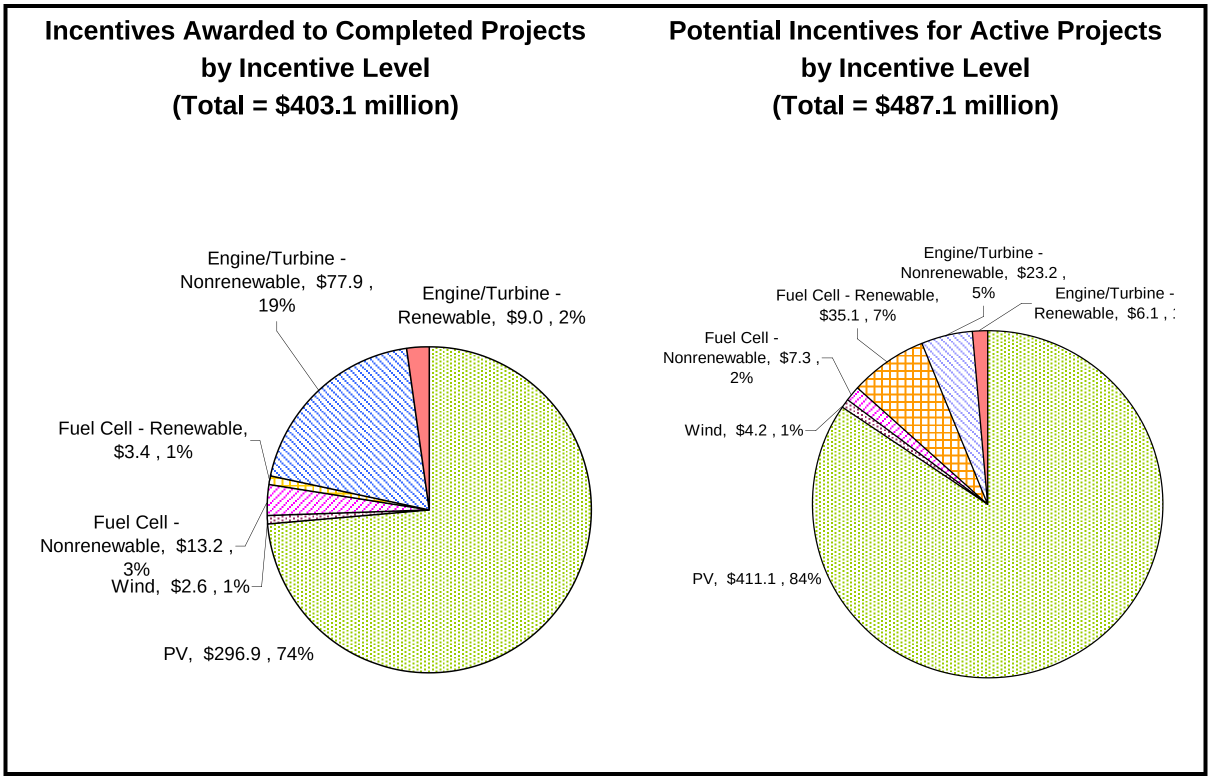
Table 3-3 shows the number of SGIP projects where the host site is an electric customer of an IOU or municipal utility. Generally, the largest project capacity overlap between IOU and municipal utilities occurs with PV systems. At the end of 2006, approximately 11 percent of the rebated PV capacity in the SGIP represented systems installed by sites that were also customers of municipal utilities. Approximately 2 percent of cogeneration (Engine/Turbine - Nonrenewable) capacity was dual-utility customers. Sixty-two of the 85 PV projects involving a municipal utility customer correspond to SoCalGas SGIP projects. Most of these projects were supported by the SGIP as well as by a solar PV program offered by the municipal utility.

Table 3-3: Electric Utility Type for Projects On-Line as of 12/31/2006

Technology & Fuel	IOU		Municipal		Total On-Line	
	(n)	(MW)	(n)	(MW)	(n)	(MW)
Photovoltaics	586	77.7	85	10.0	671	87.7
Wind	1	1.0	1	0.7	2	1.6
Fuel Cell - Nonrenewable	10	5.8	1	1.0	11	6.8
Fuel Cell - Renewable	2	0.8	0	0.0	2	0.8
Engine/Turbine - Nonrenewable	269	136.7	13	4.0	282	140.8
Engine/Turbine - Renewable	28	10.6	0	0.0	28	10.6
All	**896**	**232.5**	**100**	**15.7**	**996**	**248.2**

Another way to identify project status within the SGIP is by the stage of incentive payment. Incentives are reserved for Active projects; conversely, incentives are paid for Completed projects. PAs can use incentive payment status to examine the funding backlog of SGIP projects by incentive level. Figure 3-3 summarizes SGIP incentives paid or reserved as of December 31, 2006. By the end of PY06, over $403 million in incentive payments had been paid to Complete projects. The reserved backlog totals nearly $487 million.

Figure 3-3: Incentives Paid or Reserved for Complete and Active Projects



Characteristics of Complete and Active Projects

Key characteristics of Complete and Active projects include system capacity and project costs.

System Size (Capacity)

Table 3-4 summarizes the system capacity characteristics of all Complete projects by technology and incentive level. Generally, gas turbines deployed under the SGIP tend to have the largest installed capacities followed by engines. Maximum capacities for engines and gas turbines using nonrenewable fuel exceeded 1 MW, with average sizes of approximately 630 kW and 2.9 MW, respectively. Median and mean values indicate that while there are some large (i.e., greater than one MW) PV systems installed under the SGIP, most tend to be less than 150 kW in capacity. Similarly, microturbines deployed by December 31, 2006 under the SGIP tended to be less than 170 kW in capacity. The few wind and fuel cell systems deployed under the SGIP by the end of PY06 were medium-sized facilities with capacities of less than 1 MW.

Table 3-4: Installed Capacities of PY01-PY06 Projects Completed by 12/31/2006

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
Photovoltaic	638	127	28	62	1,050
Wind Turbine	2	824	699	824	950
Fuel Cell - Nonrenewable	10	575	200	500	1,000
Fuel Cell - Renewable	2	375	250	375	500
Internal Combustion Engine – Nonrenewable	174	630	60	500	4,110
Internal Combustion Engine – Renewable	10	626	160	602	991
Gas Turbine – Nonrenewable	4	2,905	1,210	2,942	4,527
Microturbine – Nonrenewable	92	150	28	106	928
Microturbine - Renewable	16	189	60	165	420

System capacities of Active projects may indicate incipient changes in SGIP project capacities. If a large number of Active projects have larger capacities than their complete project technology counterparts, migration of these Active projects into the Complete project category will act to increase the average installed capacity. This is important because impacts from technologies are more affected by capacity than number of projects. This was also the case at the end of 2005, and the mean system size of photovoltaic systems increased in 2006 from 115 to 127 kW, the mean size of gas turbines increased from 1297 kW to 2905 kW, and the mean size of microturbines increased from 147 kW to 156 kW.

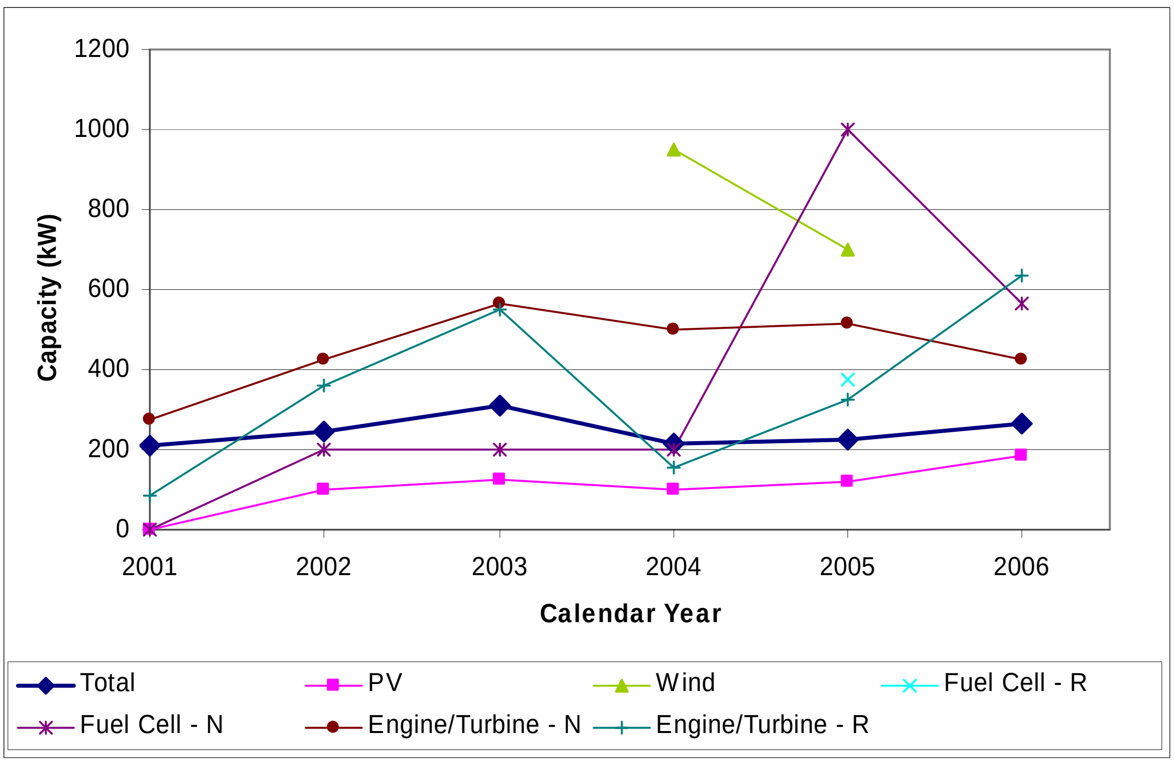
Table 3-5 summarizes the system capacity characteristics of Active projects by technology and incentive level. In general, the rated capacities of Active projects tend to be greater than their Complete project technology counterparts; therefore, the capacity of SGIP projects overall can be expected to increase again in 2007 as these larger, Active projects migrate to the Completed status.

Table 3-5: Rated Capacities of PY01-PY06 Projects Active as of 12/31/2006

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
Photovoltaic	605	255	30	132	2,495
Wind Turbine	4	704	250	783	1,000
Fuel Cell - Nonrenewable	6	508	250	400	1,000
Fuel Cell - Renewable	10	795	200	950	1,000
Internal Combustion Engine – Nonrenewable	62	682	75	425	3,992
Internal Combustion Engine – Renewable	8	714	36	765	1,516
Gas Turbine – Nonrenewable	4	2,754	1,000	2,744	4,527
Microturbine – Nonrenewable	28	322	56	170	2,253
Microturbine - Renewable	6	135	30	140	240

Figure 3-4 shows the trend of capacity for Complete projects from 2001 through the end of 2006. Largest increases in capacities in 2006 occurred with renewable-fueled engines/turbines, however, there were no new renewable-fueled fuel cell projects. There were also no new wind projects in 2006. Nonrenewable-fueled engines/turbines showed a decrease in capacity from 2003 to 2004, rose slightly from 2004 to 2005 but then decreased again in 2006. Average capacities of PV technologies ranged between 110 to 130 kW from 2002 through the end of 2005, but in 2006 increased to almost 200 kW. The net result has been that the average overall capacity of SGIP projects increased slightly from 2002 to 2003, but decreased back down in 2004 and 2005, but in 2006 the average capacity increased again to approximately 260 kW.

Figure 3-4: Trend of Capacity of Complete Projects from PY01-PY06



Total Eligible Project Costs

Total eligible project costs are regulated by SGIP guidelines and reflect the costs of the installed generating system and its ancillary equipment. Table 3-6 provides total and average project cost data for Complete and Active projects from PY01 through PY06. Average per-Watt eligible project costs represent capacity-weighted averages.

By the end of PY06, total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete projects exceeded one billion dollars. PV projects account for the vast majority (63 percent) of total eligible Complete project costs. Similarly, PV projects represent the single largest project cost category in either the Complete or Active project categories. From a system capacity perspective, PV projects made up approximately 35 percent of the total Complete project capacity installed through PY06. The combined costs of renewable and nonrenewable fueled engines and turbines account for the second highest total Complete project costs at $334 million (approximately 32 percent of the total eligible project costs), and correspond to 62 percent of the total Complete project installed capacity.

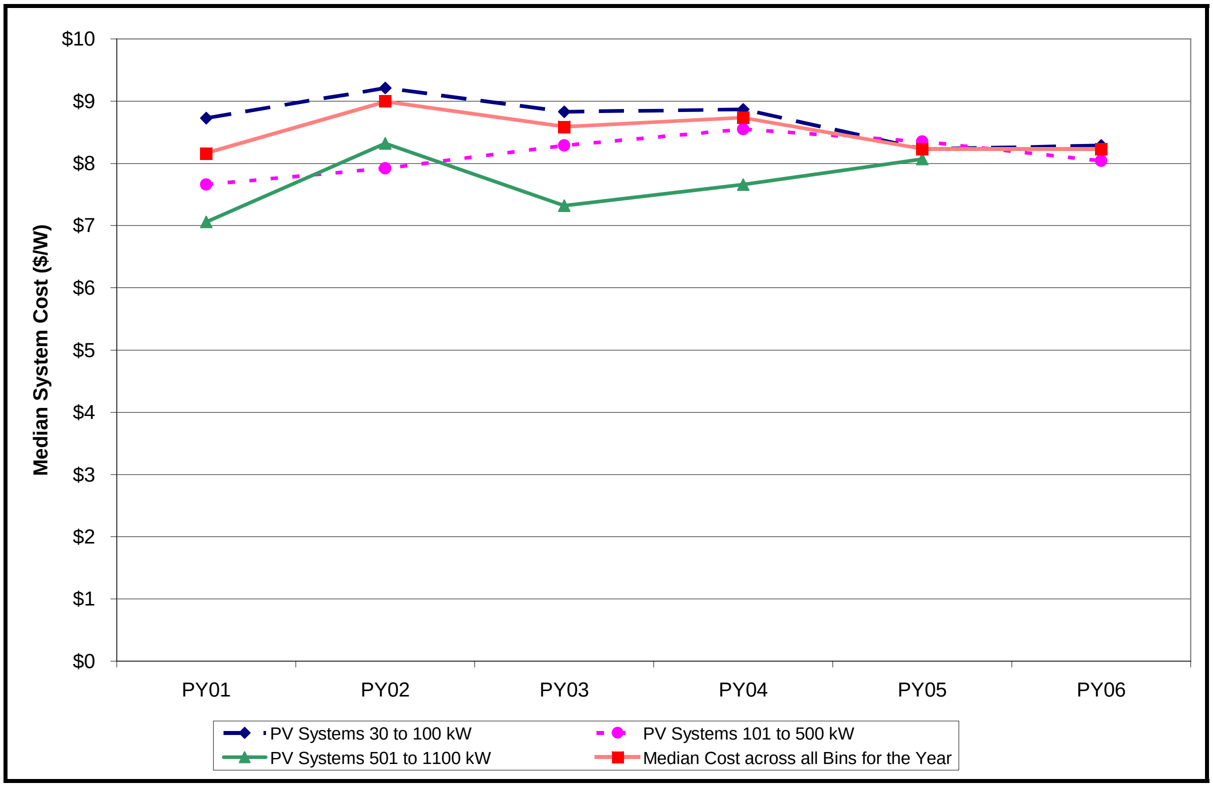
On an average cost-per-installed-Watt ($/Watt)-basis, fuel cell and PV projects are more costly than engine and microturbine projects. However, any comparison of these project costs must take into consideration the fundamentally different characteristics of the technologies. In the case of cogeneration projects fueled with natural gas, ongoing fuel purchase and maintenance costs account for the majority of the lifecycle cost of ownership and operation. For PV systems, the capital cost is by far the most significant cost component while the fuel is free and operations and maintenance costs are generally not as significant as those of cogeneration systems. Similarly, fuel cells, although having high upfront capital costs, operate at very high efficiencies (which reduce fuel requirements) and with very low air emissions (which precludes the need for expensive pollution control equipment).

Table 3-6: Total Eligible Project Costs of PY01–PY06 Projects

Technology & Fuel	Complete			Active		
	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)
Photovoltaic	81.1	$8.19	$664	154.2	$8.51	$1,312
Wind Turbine	1.6	$3.26	$5	2.8	$2.87	$8
Fuel Cell - Nonrenewable	5.8	$7.22	$41	3.1	$6.56	$20
Fuel Cell - Renewable	0.8	$9.70	$7	8.0	$6.35	$50
Internal Combustion Engine – Nonrenewable	109.6	$2.22	$243	42.3	$3.81	$161
Internal Combustion Engine – Renewable	6.3	$2.65	$17	5.7	$3.72	$21
Gas Turbine – Nonrenewable	11.6	$1.87	$22	11.0	$2.42	$27
Microturbine – Nonrenewable	13.8	$3.06	$42	9.0	$3.24	$29
Microturbine - Renewable	3.0	$3.23	$10	0.8	$4.09	$3
Total	**233.6**	**$4.50**	**$1,052**	**236.9**	**$6.89**	**$1,633**

Cost trends for Complete PV projects between PY01 through PY06 are shown in Figure 3-5. The cost trends are provided in terms of the median cost-per-Watt of rebated capacity. Several observations can be made from the PV cost trends. First, the overall median PV cost stayed between $8 to $9 per Watt from PY01 through PY06. Second, the smallest-sized PV systems (i.e., those between 30 to 100 kW) had the least change in cost over the first four program years. Third, the largest PV systems (i.e., those between 500 to 1100 kW) had the greatest change in cost and also ended up with the lowest installed costs by the end of 2005 (at $8.07 per Watt). Fourth, the medium-sized systems (i.e., those between 101 to 500 kW) had the lowest installed costs at the end of 2006 (at $8.04 per Watt). As of December 31, 2006, there were not yet any completed large PV projects that applied in 2006.

Figure 3-5: Cost Trend of Complete PV Projects



Cost trends for Complete natural gas-fired engines are shown in Figure 3-6. Median project costs for medium- to larger-sized engines (i.e., those between 100 kW to over 1 MW) showed relatively slow increases from PY01 through PY04, then the medium-sized engines median cost decreased by almost $0.60 per Watt in 2005. The costs of smaller systems increased substantially over the four program years, even though there were decreases in costs during PY02 to PY03. The dip and rise in costs for the smaller IC engines can be attributed to learning curves associated with the emergence of new systems in the marketplace. The engines that are the first to emerge generally represent prototypes equipped with significant monitoring or other extra features that tend to drive up the capital costs. The prototypes are replaced by lower cost, more "commercial" systems. However, as the technologies are still new, costs have increased to resolve operational issues as they are discovered. It appears that costs decreased in 2005, but the median of each group is only based on a few (no more than 4) systems. It is expected that the PY07 median system cost will increase relative to the previous years due to the addition of NOx control technologies that may be required to meet the NOx standard of 0.07 lbs/MW-hr for distributed generation.

Figure 3-6: Cost Trend of Complete Natural Gas Engine Projects

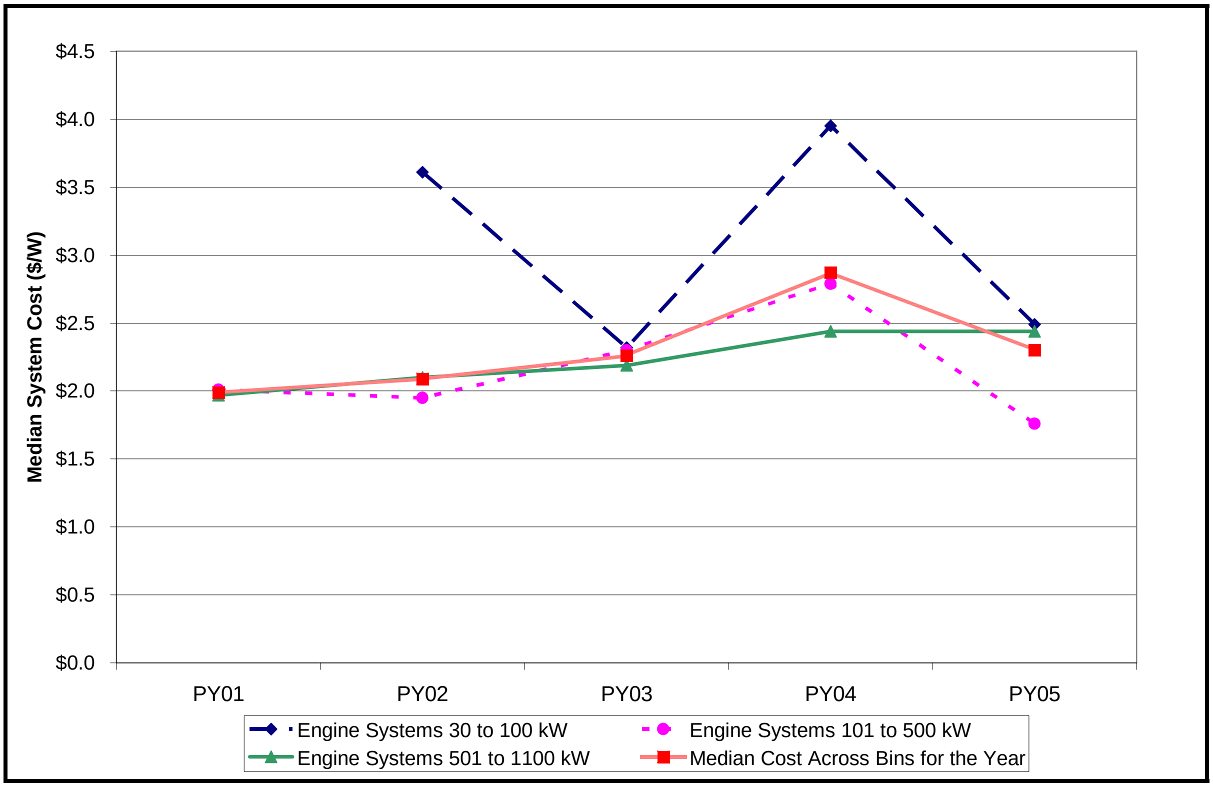
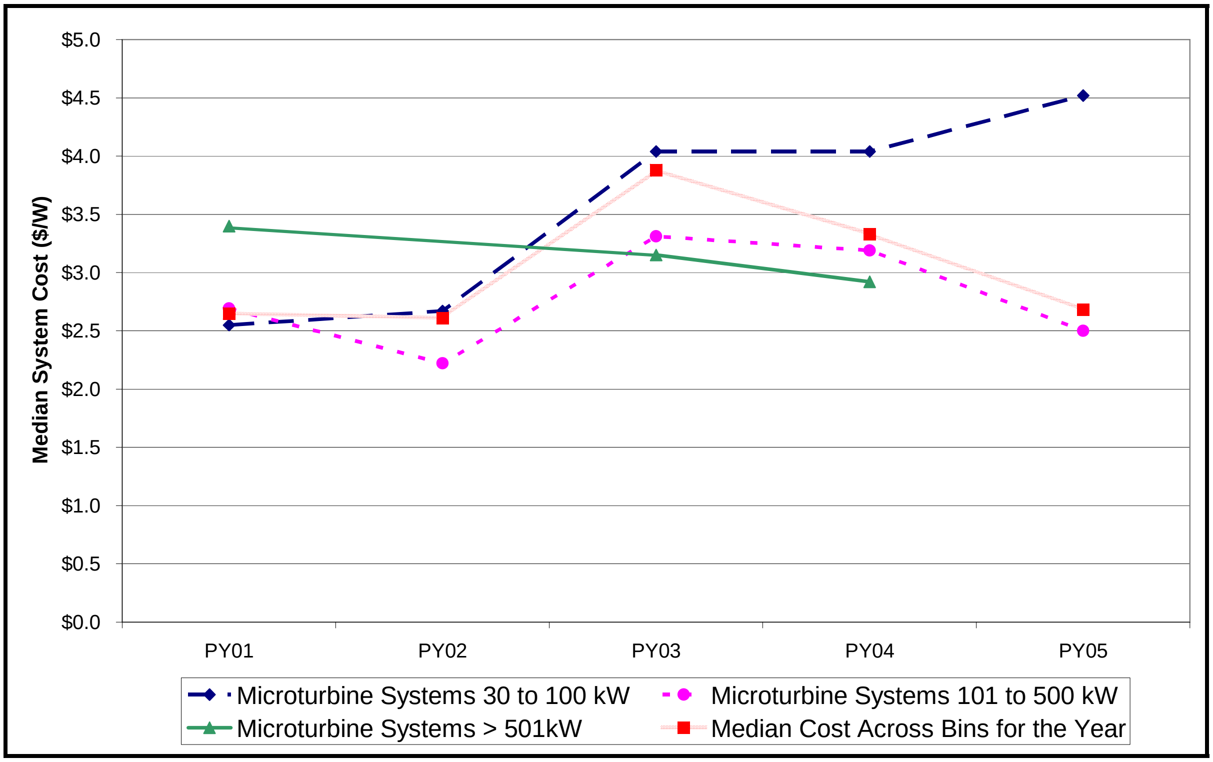


Figure 3-7 is a cost trend for natural gas-fired microturbines in the Complete project category. Generally, small to medium-sized microturbines demonstrated moderate increases in median costs from PY02 through PY04, with the costs of the 30 to 100 kW range rising more rapidly than the medium-sized microturbines.

The median of costs of systems less than 501 kW increased substantially during PY03. In 2005, the price of medium sized systems (101 to 500 kW) decreased back to the 2002 level, while the price of small systems (30 to 100 kW) increased again. However, the 2005 median price of the all size groups is based on no more than three projects each.

Figure 3-7: Cost Trend for Complete Natural Gas Microturbine Projects



Incentives Paid and Reserved

Incentives paid and reserved are presented in Table 3-7.[4] PV projects account for approximately 74 percent of the incentives paid for Complete projects, and 83 percent of the incentives reserved for Active projects.

Table 3-7: Incentives Paid and Reserved

Technology & Fuel	Complete Incentives Paid			Active Incentives Reserved		
	Total (MW)	**Avg. ($/W)**	**Total ($ MM)**	**Total (MW)**	**Avg. ($/W)**	**Total ($ MM)**
Photovoltaic	81.1	3.7	296.9	154.2	2.7	411.1
Wind Turbine	1.6	1.6	2.6	2.8	1.5	4.2
Fuel Cell - Nonrenewable	5.8	2.3	13.2	3.1	2.4	7.3
Fuel Cell - Renewable	0.8	4.5	3.4	8.0	4.4	35.1
Internal Combustion Engine – Nonrenewable	109.6	0.6	63.6	42.3	0.5	20.8
Internal Combustion Engine – Renewable	6.3	0.9	5.7	5.7	0.9	5.1
Gas Turbine – Nonrenewable	11.6	0.2	2.9	11.0	0.2	2.4
Microturbine – Nonrenewable	13.8	0.8	11.5	9.0	0.6	5.1
Microturbine - Renewable	3.0	1.1	3.4	0.8	1.3	1.1
Total	**233.6**	**$1.73**	**$403.1**	**236.9**	**$2.08**	**$492.1**

[4] The maximum possible incentive payment for each system is the system size (up to 1,000 kW) multiplied by the applicable dollar per kW incentive rate.

Participants' Out-of-Pocket Costs After Incentive

Participants' out-of-pocket costs (total eligible project cost less the SGIP incentive) are summarized in Table 3-8. Cost information was provided by each of the PAs and is summarized here. Insights are, by definition, speculative and are based on a combination of assumed project costs, additional monies obtained from other incentive programs, and professional judgment. On a dollar-per-Watt ($/Watt) rated capacity-basis, renewable- and nonrenewable-fueled fuel cells have the highest cost, followed by PV. The higher first cost of fuel cells is offset to some degree by their higher efficiency (reduced fuel purchases) and to a lesser degree by reduced air emission offsets. Higher costs for the renewable-fueled fuel cells likely include the cost of digester gas cleanup equipment. In certain instances, fuel cells also provide additional power reliability benefits that may drive project economics. PV is the next highest capital cost technology, followed by nonrenewable-fueled microturbines and renewable-fueled microturbines, respectively.

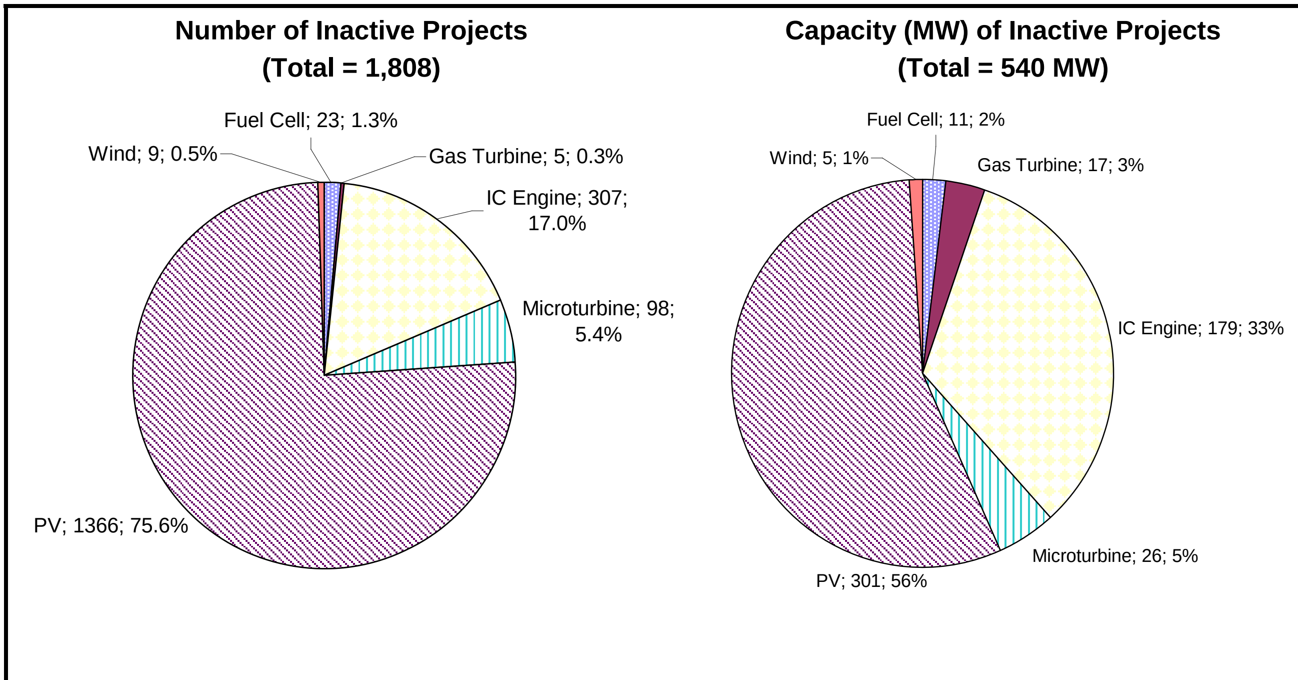
Table 3-8: SGIP Participants' Out-of-Pocket Costs after Incentive

Technology & Fuel	Complete			Active		
	Total (MW)	Avg. ($/W)	Total ($ MM)	Total (MW)	Avg. ($/W)	Total ($ MM)
Photovoltaic	81.1	$4.05	$328	154.2	$5.83	$898
Wind Turbine	1.6	$1.63	$3	2.8	$1.37	$4
Fuel Cell - Nonrenewable	5.8	$4.49	$26	3.1	$3.99	$12
Fuel Cell - Renewable	0.8	$5.20	$4	8.0	$1.87	$15
Internal Combustion Engine – Nonrenewable	11.6	$1.62	$19	11.0	$2.20	$24
Internal Combustion Engine – Renewable	109.6	$1.63	$179	42.3	$3.32	$140
Gas Turbine – Nonrenewable	6.3	$1.67	$10	5.7	$2.84	$16
Microturbine – Nonrenewable	13.8	$2.20	$30	9.0	$2.62	$24
Microturbine - Renewable	3.0	$2.05	$6	0.8	$2.79	$2
Total	**233.6**	**$2.78**	**$649**	**236.9**	**$4.81**	**$1,141**

3.3 Characteristics of Inactive Projects

As of December 31, 2006, there were 1,808 Inactive projects (those either withdrawn or rejected), representing 540 MW of generating capacity. Figure 3-8 presents the status of these Inactive projects.

Figure 3-8: Number and Capacity (MW) of Inactive Projects



It is interesting to note the following from Figure 3-8:

- PV projects constitute the largest share of number of Inactive projects (1,366 or 75.6 percent) and the largest share of total Inactive capacity (301 MW or 56 percent).
- IC Engines (fueled by either nonrenewable or renewable fuel) account for the second largest share of number of Inactive projects (307 or 17 percent) and the second largest share of total Inactive capacity (179 MW or 33 percent).
- The 98 Inactive Microturbine (fueled by either nonrenewable or renewable fuel) projects account for 26 MW of total Inactive capacity (5 percent).
- Five Inactive Gas Turbine projects account for 17 MW of total Inactive capacity (3 percent).
- Nine Inactive Wind projects account for 5 MW of total Inactive capacity (1 percent) and 23 Inactive Fuel Cell (fueled by either nonrenewable or renewable fuel) projects represent 11 MW of total Inactive capacity (2 percent).

4

Sources of Data for the Impact Evaluation

Data collection activities supporting the sixth-year impact evaluation are summarized in this section. First the several key types of data sources are presented. This is followed by a description of metered data collection issues and current metered data collection status.

4.1 Overview of Key Data Types

Project Files Maintained by Program Administrators

Administrators provided program evaluators regular updates of their program tracking database files. These files contain information that is essential for planning and implementing data collection activities supporting the impact evaluation. Information of particular importance includes basic project characteristics (e.g., incentive level, technology, size, fuel) and key participant characteristics (e.g., Host and Applicant names[1], addresses, and phone numbers). The program evaluator's initial M&E activities for each project were influenced by the project's technology type, program year, and Program Administrator. The program stage of each project was tracked by the program evaluator, and M&E activities initiated accordingly. Updated SGIP handbooks were used for planning and reference purposes.[2]

Reports from Monitoring Planning and Installation Verification Site Visits

During metering and data collection site visits, necessary facility information is collected to complete the project-specific metering and data collection plan in support of the impact evaluation. Meter nameplate information was recorded for meters used for billing purposes, as well as those used for information purposes. The date the system entered normal operations was also determined (or estimated) from the available operations data, as required. Information collected for Program M&E purposes augmented that developed by the Program

[1] The Host Customer is the customer of record at the site where the generating equipment is or will be located. An Applicant is a person or entity who applies to the Program Administrator for incentive funding. Third parties (e.g. a party other than the Program Administrator or the utility customer)
such as engineering firms, installing contractors, equipment distributors or Energy Service Companies (ESCO) are also eligible to apply for incentives on behalf of the utility customer, provided consent is granted in writing by the customer.

[2] SGIP Handbooks are available on Program Administrator Web sites.

Administrators' installation verification site inspectors. Inspection Reports produced by these independent consultants were provided to the program evaluator regularly, and their review contributed significantly to the project-level M&E planning efforts.

Metered Performance Data

Electric Net Generator Output (ENGO)

ENGO data collection activities for the sixth-year impact evaluation were aimed at obtaining available data from Hosts, Applicants, electric utilities, and metering installed by the evaluation contractor. One issue affecting collection of electric data concerns the relationship between meter type and project type. Some electric utilities may install different types of ENGO metering depending on project type. This was encountered with some cogeneration systems installed in schools, as well as with some renewable-fueled engine/turbine projects eligible for net metering. The evaluation contractor is working with the affected program administrators and electric utility companies on a plan to have these types of projects equipped with interval recording electric metering in the future.

Useful Thermal Energy

Useful thermal energy data collection typically involves an invasive installation of monitoring equipment (i.e., flow meters and temperature sensors). Many third parties or Hosts had this equipment installed at the time of system installation, either as part of their contractual agreement with a third party vendor or for internal process/energy monitoring purposes. In numerous cases the program evaluation contractor was able to obtain the relevant data these Hosts and third parties were already collecting. This approach was pursued initially in an effort to minimize both the cost- and disruption-related risks of installing monitoring equipment. The majority of useful thermal energy data for 2003-2004 were obtained in this manner.

The statewide evaluation contractor installed useful thermal energy metering for systems that were included in the sample but for which data from existing metering were not available. This meter installation activity began in summer 2003. The first nine useful thermal energy meters were installed by December 2003. Metering installation was put on hold for more than six months (late-fall 2003 through summer 2004) while the several contractual arrangements underlying the work were revised to extend its term. Installation of metering systems resumed in fall 2004 and continued through early 2006.

As the data collection effort grew it became clear that the team could no longer rely on data from third-party or host customer metering. In numerous instances agreements and plans concerning these data did not translate into validated data records available for analysis. Uninterrupted collection and validation of reliable metered performance data is labor- and expertise-intensive. Reliance on data collected by SGIP Host customers and third-parties created schedule and other risks that more than outweighed the benefits that had led to this initial strategy.

In mid-2006 the evaluation contractor responded to these issues from several fronts. Costs were escalating rapidly. The time spent collecting data from Hosts, Applicants, and third parties was increasing. System owners were increasingly reluctant to shut down their cogeneration systems for installation of invasive metering equipment, requiring expensive hot tapping. Communication efforts were failing at an unacceptable rate. As a result of these issues, the evaluation contractor moved to noninvasive metering equipment such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications. The increase in equipment costs was offset by a decrease in installation time and a potential decrease in maintenance problems. Appendix E provides detailed information on the new metering equipment.

Fuel Usage

Fuel usage data collection activities completed to date have involved natural gas monitoring. In the future it may also be necessary to monitor consumption of gaseous renewable fuel to assess compliance with renewable fuel usage requirements in place for renewable-fueled fuel cell and engine/turbine projects. Prior to 2005 all such on-line projects had utilized only 100 percent renewable fuel. During 2005 and 2006 four such projects utilizing both renewable fuel and natural gas came on-line. Current plans call for use of electric output and natural gas usage data to estimate renewable fuel usage (and hence compliance with the program's renewable fuel usage provisions). If initial results of this analysis indicate the project's compliance status is borderline then renewable fuel usage metering may be recommended.

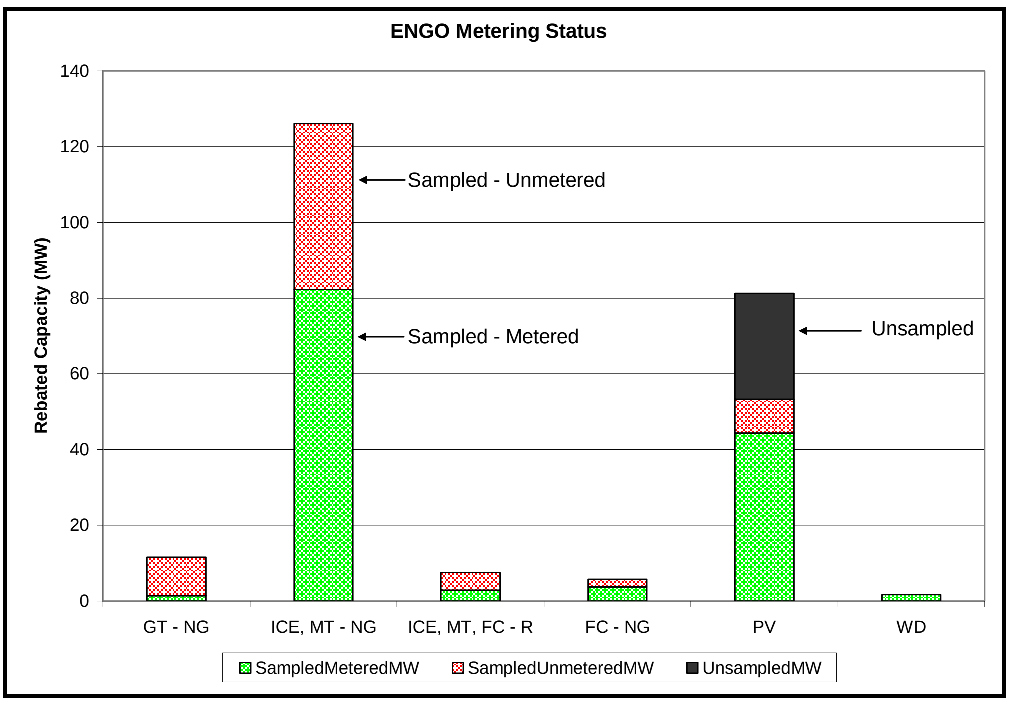
The natural gas usage data used in the sixth-year impacts evaluation were obtained from natural gas utilities, SGIP participants, and natural gas metering installed by the program evaluation contractor. The data were reviewed and their bases were documented prior to processing into a data warehouse. Reviews of data validity included combining fuel usage data with power output data to check for reasonableness of gross engine/turbine electrical conversion efficiency. In cases where validity checks were failed the data provider was contacted to further refine the basis of data. In some cases it was determined that data received were for a facility-level meter rather than from metering dedicated to the SGIP cogeneration system. These data were excluded from the impacts analysis.

Metered Performance Data Collection Status Summary

As of the end of 2006, 996 PY01-PY06 SGIP projects were determined to be on-line. These projects correspond to 248 MW of SGIP project capacity. It is necessary to collect metered data from a certain portion of on-line projects to support the impact evaluation analysis. This section presents summaries of actual data collection based on availability of metered data in December 2006. Data collection status by PA is discussed in Appendix D.

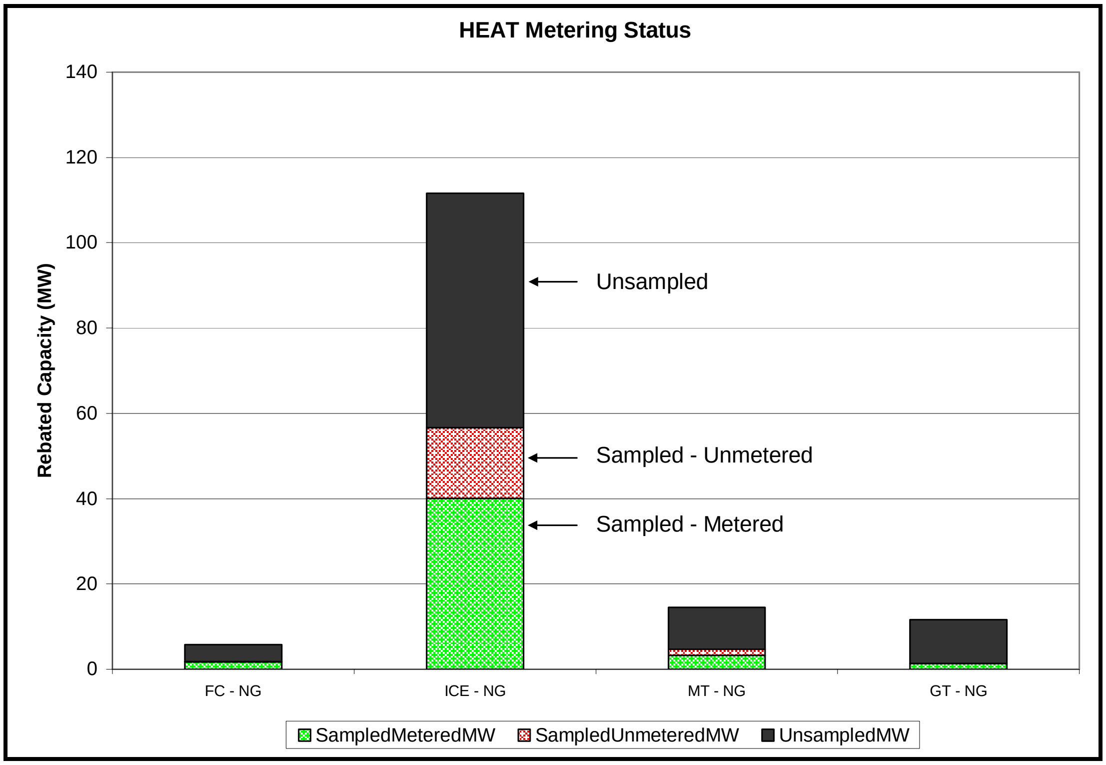
The status of ENGO data collection is summarized in Figure 4-1. A substantial quantity of ENGO metering installation activity remains to be completed. This activity is ongoing and is being carried out by the Program Administrators and the SGIP evaluation contractor. To date PV is the only technology for which some on-line capacity is unsampled. This group of projects includes PY03-PY06 projects smaller than 300 kW for which ENGO data are not available from existing metering. Of principal concern is Sampled-Unmetered capacity corresponding to technologies with small numbers of projects. It is worthy of note that the metering plan in place during 2006 that called for electric metering for all nonrenewable-fueled engine/turbine projects was based not on impacts evaluation accuracy criteria, but simply on the expectation that electric utility companies would be monitoring all of these systems for tariff purposes. The highest priority for 2007 is installation of additional ENGO metering for nonrenewable-fueled gas turbines and renewable-fueled engines/turbines.

Figure 4-1: ENGO Data Collection as of 12/31/2006



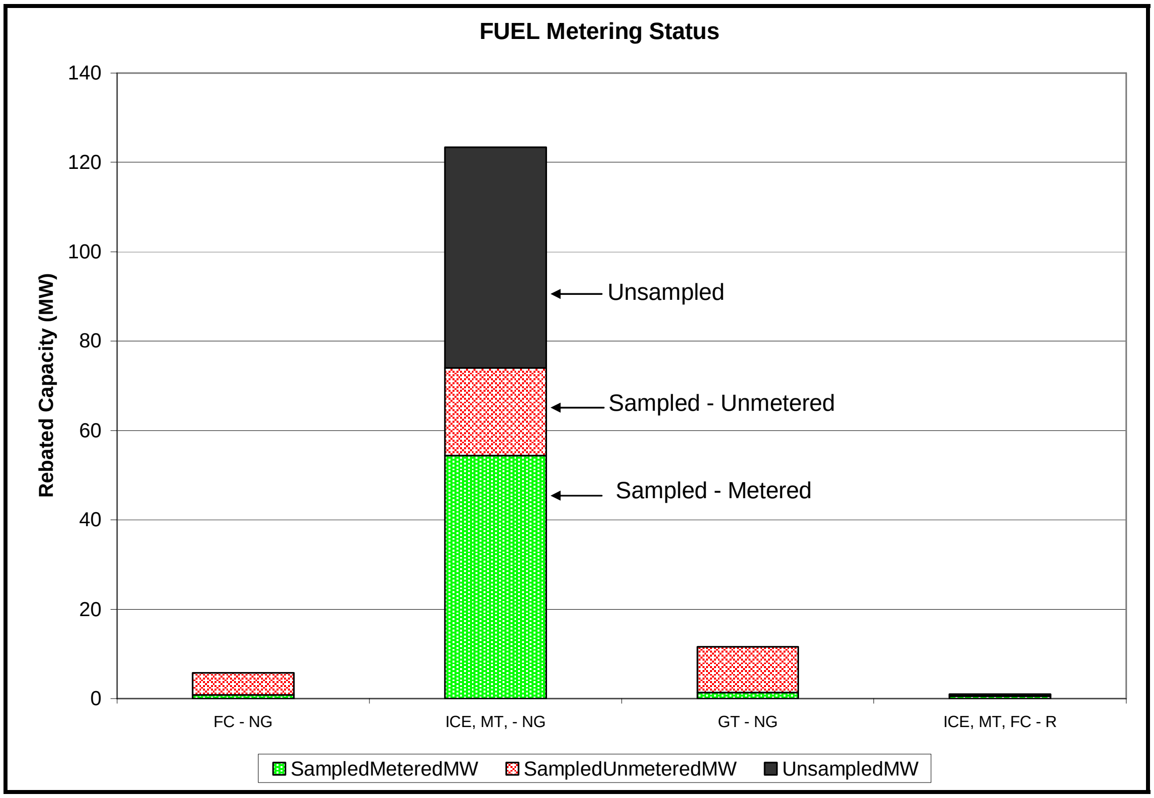
The status of HEAT data collection is summarized in Figure 4-2. Overall, more HEAT metering is needed for all technologies; however, the most important area for improvement for 2007 is nonrenewable-fueled Gas Turbines. These systems are relatively larger capacity and it is more likely that HEAT metering will be available from the Applicant. The evaluation contractor will install HEAT metering in situations where data are unavailable or of insufficient quality for the purposes of impacts evaluations.

Figure 4-2: HEAT Data Collection as of 12/31/2006



The status of FUEL data collection is summarized in Figure 4-3. Most of the FUEL data have been obtained from IOUs. A principal use of these data is to support calculation of electrical conversion efficiencies and cogeneration system efficiencies.

Figure 4-3: FUEL Data Collection as of 12/31/2006



5

Program Impacts

This section presents impacts from SGIP projects that were on-line through the end of PY06. Impacts examined include affects on energy delivery; peak demand; waste heat utilization and efficiency requirements; and greenhouse gas emission reductions.[1] Impacts of SGIP technologies are examined at a program-wide level and at PA-specific levels.

Impacts were estimated for all on-line projects regardless of their stage of advancement in the program, so long as they began normal generation operations prior to December 31, 2006. On-line projects include projects for which SGIP incentives had already been disbursed (Complete projects), as well as projects that had yet to complete the SGIP process (Active projects). This is the same assumption used in prior year impact evaluations. Not all projects for which impacts were determined were equipped with monitoring equipment. Similarly, some monitoring data had not been received from third party data providers. Consequently, this annual impact evaluation relies on a combination of metered data, statistical methods, and engineering assumptions. A description of the methods used for estimating performance of non-metered facilities is contained in Appendix D. Data availability and corresponding analytic methodologies vary by program level and technology.

This section is composed of the following five subsections:

5.1. Energy and Non-coincident Demand Impacts
5.2. Peak Demand Impacts
5.3. Transmission and Distribution Impacts
5.4. Efficiency and Waste Heat Utilization
5.5. Greenhouse Gas Emission Reductions

[1] Renewable fuel use compliance had been discussed in the 2005 Impacts Evaluation Report. Per direction from the Working Group, this topic has been dropped from the impacts evaluation report and will instead be discussed in the Renewable Fuel Use Reports.

5.1 Energy and Non-Coincident Demand Impacts

Overall Program Impacts

Electrical energy and demand impacts were calculated for Complete and Active projects that began normal operations prior to December 31, 2006. Impacts were estimated using available metered data for 2006 and system characteristics information from program tracking systems maintained by the PAs, and were augmented with information obtained over time by Itron.

By the end of 2006, 996 SGIP facilities were on-line, representing over 248 MW of electricity generating capacity. Some of these facilities (e.g., PV and wind) provided their host sites with only electricity, while cogeneration facilities provided both electricity and thermal energy (i.e., heating or cooling). Table 5-1 provides information on the amount of electricity delivered by SGIP facilities throughout calendar year 2006. Energy delivery is described by technology and fuel.

Table 5-1: Statewide Energy Impact in 2006 by Quarter (MWh)

		Q1-2006	Q2-2006	Q3-2006	Q4-2006	Total
Technology	**Fuel**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
FC	**N**	4,573	4,874	6,932	9,792	26,170
FC	**R**	646	614	520	718	2,498
GT	**N**	13,686	12,189	13,009	16,403	55,287
ICE	**N**	85,833	91,147	92,170	84,286	353,436
ICE	**R**	1,484	2,547	3,161	3,218	10,409
MT	**N**	10,463	12,027	12,193	12,508	47,191
MT	**R**	1,697	2,331	2,032	3,221	9,281
PV		17,586	31,507	35,199	19,718	104,010
WD		521	651	707	394	2,274
	TOTAL	**136,489**	**157,886**	**165,923**	**150,259**	**610,557**

Overall, natural gas-fueled technologies provided nearly 80 percent of the electricity generated by SGIP systems during 2006. Natural gas-fueled ICE, a technology composing almost half of the total program generating capacity, contributed the single largest share (58 percent) of the total annual delivered energy. PV, comprising just under 40 percent of total program capacity, followed in a distant second, providing 17 percent of the total annual delivered energy.

Capacity factor represents the fraction of rebated capacity that is actually generating over a specific time period. Consequently, capacity factor is useful in providing insight into the capability of a generating technology to provide power during a particular time period. For example, annual capacity factors indicate the fraction of rebated capacity that could, on average, be expected from that technology over the course of a year. Annual weighted average capacity factors for SGIP technologies were developed by comparing annual generation against rebated capacity. Table 5-2 lists these annual capacity factors by technology. Appendix A provides further discussion of annual capacity factors by both technology and basis.

Table 5-2: Annual Capacity Factors by Technology

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	0.700 †
GT	0.843 [a]
ICE	0.359 †
MT	0.404 [a]
PV	0.162
WD	0.157 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Some of the technologies listed in Table 5-2 are fueled by natural gas or renewable fuels (e.g., biogas). In those instances, the capacity factors represent an average over both fuel types. Table 5-3 provides a fuel-specific weighted average annual capacity factors for those technologies that might use natural gas or renewable methane gas.

Table 5-3: Annual Capacity Factors by Technology and Fuel

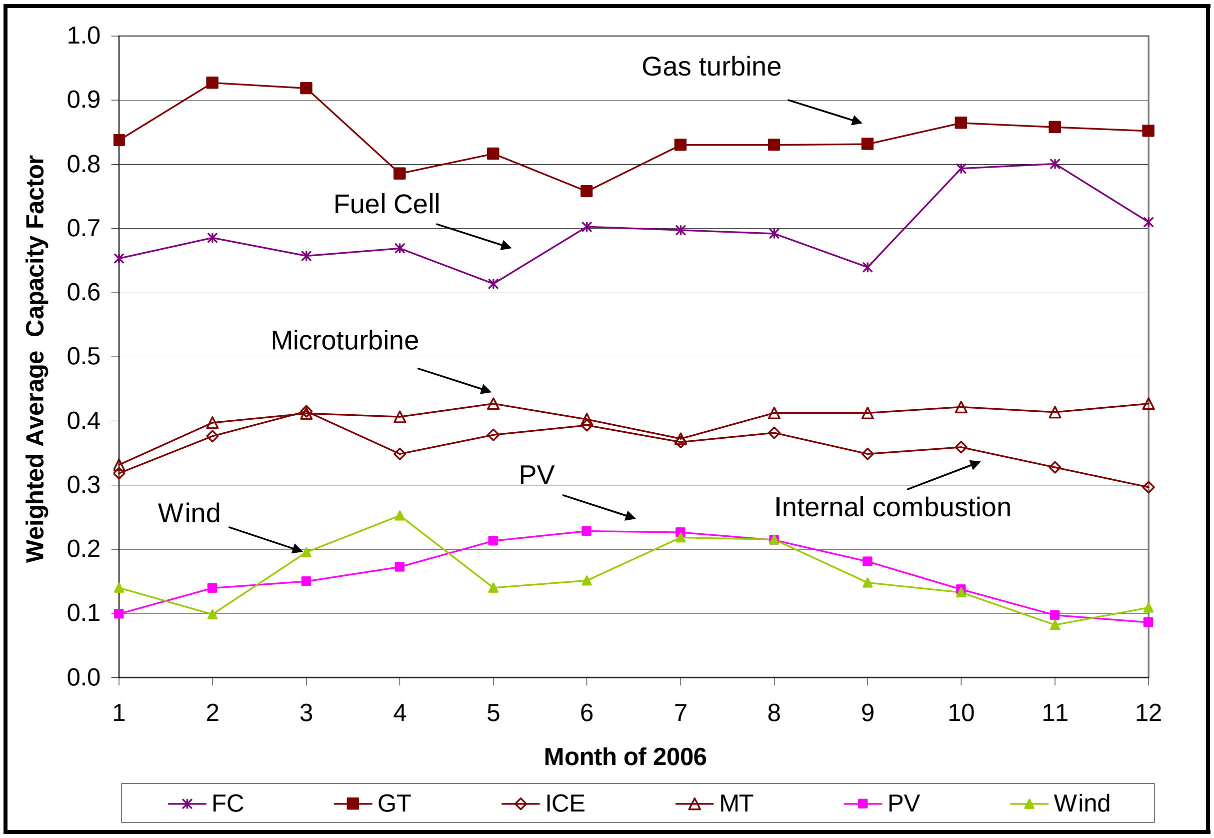
	Annual Capacity Factor* (kWyear/kWyear)	
Technology	**Natural Gas**	**Renewable Fuel**
FC	0.762 †	0.380 †
GT	0.843 †	NA
ICE	0.366	0.218
MT	0.414	0.358 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Not unexpectedly, natural gas-fueled gas turbines and fuel cells showed the highest average annual capacity factors; staying at or above 0.7. Both of these technologies are known to be efficient and tend to operate as base load capacity, which drives up their average capacity factor. Conversely, technologies with intermittent energy resources, such as wind and PV, tend to show lower average annual capacity factors. Similarly, the emerging status of using biogas resources in fuel cells is reflected in its significantly lower capacity factor, when compared to its natural gas fueled counterpart.

The average annual capacity factor provides a single point in time view of the generating capability of a technology. A more useful view is provided by examining how the capacity factor varies throughout the year. Figure 5-1 shows monthly weighted average capacity factors for SGIP technologies through 2006. As expected, natural gas turbines in the program maintained the highest monthly capacity factors throughout the year, seldom falling below 0.8. Fuel cells maintained monthly capacity factors above 0.6. However, the monthly capacity factors shown in Figure 5-1 for fuel cells represent a mix of fuel cells; some powered by natural gas and some powered by biogas. Fuel cells are extremely sensitive to fuel quality. As a result of the lower fuel quality of biogas, biogas-powered fuel cells encounter additional operational issues that reduce their capacity factors. Monthly capacity factors for natural gas-powered fuel cells would be significantly higher than the combined natural gas/biogas capacity factors shown here for fuel cells. Appendix A provides similar capacity factor charts that distinguish technologies by fuel type. Another interesting observation from Figure 5-1 is that both IC engines and microturbines have monthly capacity factors that tend to run consistently between 0.3 and 0.4 throughout the year.

Figure 5-1: Weighted Average Capacity Factor by Technology and Month



PA-specific Program Impacts

Aggregating projects by PA, Table 5-4 provides annual energy impacts for SGIP technologies deployed within each PA service territory. Again, energy delivery is described by system type. Appendix A provides similar tables of annual energy impacts that distinguish technologies by fuel type.

Table 5-4: Annual Energy Impacts by PA (MWh)

Technology	PG&E (MWh)	SCE (MWh)	SCG (MWh)	SDREO (MWh)	Total (MWh)
FC	14,893 †	2,991	1,921 [a]	8,863	28,668 †
GT	17,944 [a]	HIDDEN TO MAINTAIN CONFIDENTIALITY			55,287 [a]
ICE	161,048 †	44,067 †	130,897 †	27,833	363,845 †
MT	18,798 †	17,175 †	17,211 †	3,289	56,473 †
PV	56,509	20,372	13,093	14,036	104,010
WD		2,274 †			2,274 †
Total	**269,193**	**86,879**	**197,815**	**56,671**	**610,557**

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

SGIP systems operating in PG&E's service territory accounted for over 40 percent of the total electricity delivered by the program during 2006; with nearly 60 percent of PG&E's contribution stemming from IC engines. A similar association is seen with SGIP systems in SCG's service territory, which delivered over 30 percent of the total electricity delivered by the program; with over 65 percent of that derived from IC engines. However, because SCG does not provide electricity services, PV system contribution to annual electricity delivery is less than 10 percent. In all the other PA areas, PV contributes at least 20 percent of the annual electricity delivery.

Table 5-5 presents annual weighted average capacity factors for each technology and PA for the year 2006. Where entries are blank the PA had no on-line systems of that technology. Additional tables in Appendix A differentiate annual capacity factors by fuel type.

Table 5-5: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	SDREO
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
FC	0.687 †	0.420	0.894 [a]	0.889
GT	0.790 [a]		0.880	0.762
ICE	0.396 †	0.236 †	0.386 †	0.344
MT	0.387 †	0.455 †	0.439 †	0.231
PV	0.167	0.141	0.165	0.175
WD		0.157 †		

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Capacity factors in Table 5-5 mimic the program-wide capacity factors shown earlier with the exception of the fuel cell capacity factor for SCE. The 0.42 capacity factor for fuel cells in SCE reflects the influence of biogas fuel. As noted earlier, additional operational issues are encountered when using biogas in fuel cells, which can significantly impact rating and overall availability. During 2006, SCE was the only IOU that had biogas-powered fuel cells. This substantially lowered the overall fuel cell capacity factor for SCE.

5.2 Peak Demand Impacts

Overall Peak Demand Impacts

The ability of SGIP projects to supply electricity during times of peak demand represents a critical impact. Table 5-6 summarizes the overall SGIP program impact on electricity demand coincident with the 2006 CAISO system peak load. The table shows the number of facilities on-line at the time of the peak, the operating capacity at peak, the demand impacts, and the hourly capacity factor. In 2006, the CAISO system peak reached a maximum value of 50,198 MW on July 24 during the hour from 3:00 to 4:00 P.M. (PDT). This was substantially above the peak load of 45,380 MW that occurred at the same hour of day on July 20 of 2005. There were 905 SGIP projects known to be on-line when the CAISO experienced the 2006 summer peak, but generator electric interval-metered data were available for only 568 of them. While the total capacity of these on-line projects exceeded 221 MW, the total impact of the SGIP projects coincident with the CAISO peak load is estimated at slightly above 103 MW. Tables in Appendix A differentiate peak demand impacts by natural gas versus renewable methane fuel.

Table 5-6: Demand Impact Coincident with 2006 CAISO System Peak Load

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	8	4,800	3,372	0.703 [a]
GT	3	7,093	5,789	0.816 †
ICE	185	116,184	49,942	0.430 [a]
MT	98	16,182	5,465	0.338 [a]
PV	609	75,808	38,744	0.511 [a]
WD	2	1,649	53	0.032
TOTAL	**905**	**221,715**	**103,365**	

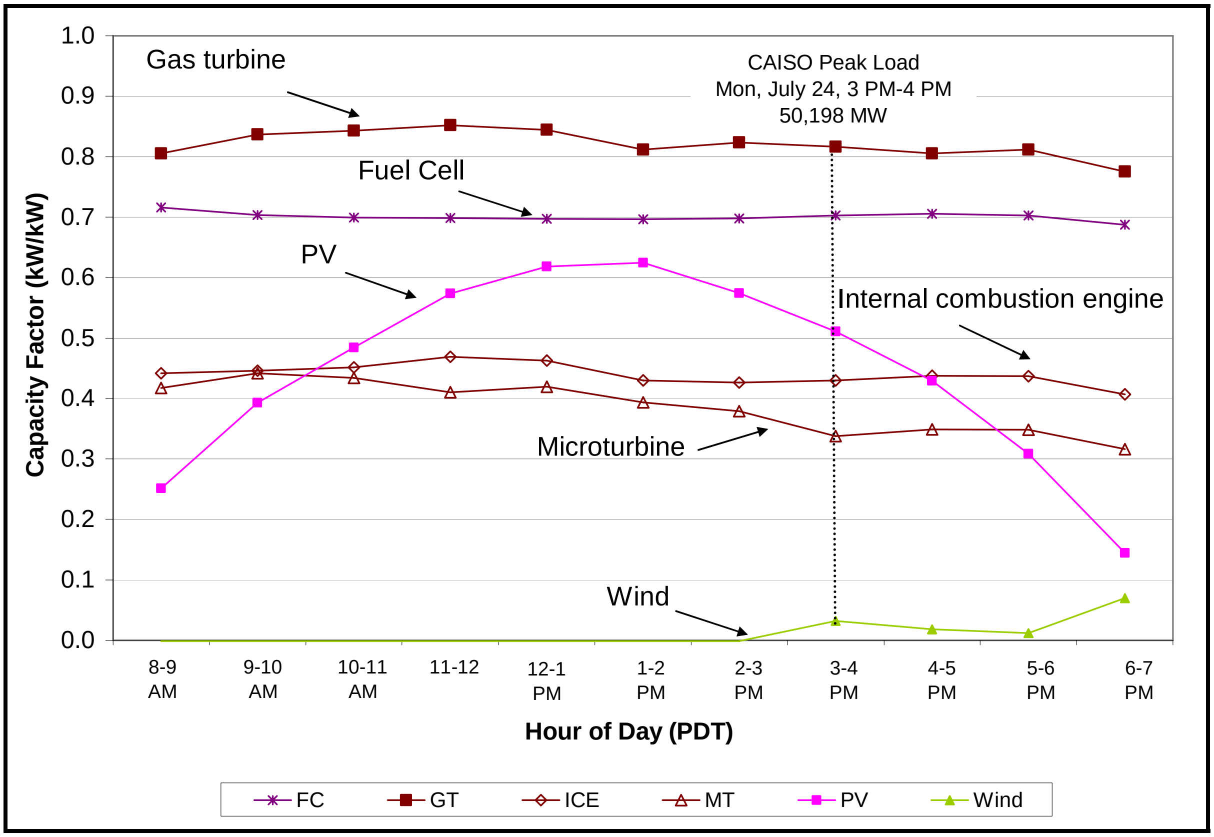
* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Average annual and average monthly capacity factors are indicators of the capability of a technology to provide power over the course of a year or seasonally within a year. The hourly capacity factor at peak measures the capability of a technology to provide power when electricity demand is highest and the additional generation is most needed in the electricity system. For the summer peak in 2006, gas turbines and fuel cells operating in the SGIP demonstrated very high peak capacity factors; both above 70 percent. Microturbines and IC engines had average peak capacity factors well below 70 percent; typically falling below 45 percent. Under the 2006 summer peak conditions, PV systems demonstrated an average peak capacity factor exceeding 50 percent. The average peak capacity factor for wind was very low; falling below 5 percent. However, as there were only two wind systems operating in the

SGIP during 2006, this hourly peak capacity factor should not be considered representative of wind performance in general.[2]

Timing of peak demand is an important factor in the hourly peak capacity factor for intermittent technologies, such as wind or solar. Figure 5-2 profiles the hourly weighted average capacity factor for each technology from morning to early evening during the 2006 peak day. The plot also indicates the hour and value of the CAISO peak load. The influence of timing of peak demand is readily apparent with PV. If the CAISO peak hour had occurred at 1.00-2.00 P.M. on July 24th, the hourly peak capacity factor for PV would have exceeded 60 percent. Appendix A provides similar charts that differentiate by natural gas versus renewable methane fuel.

Figure 5-2: CAISO Peak Day Capacity Factors by Technology



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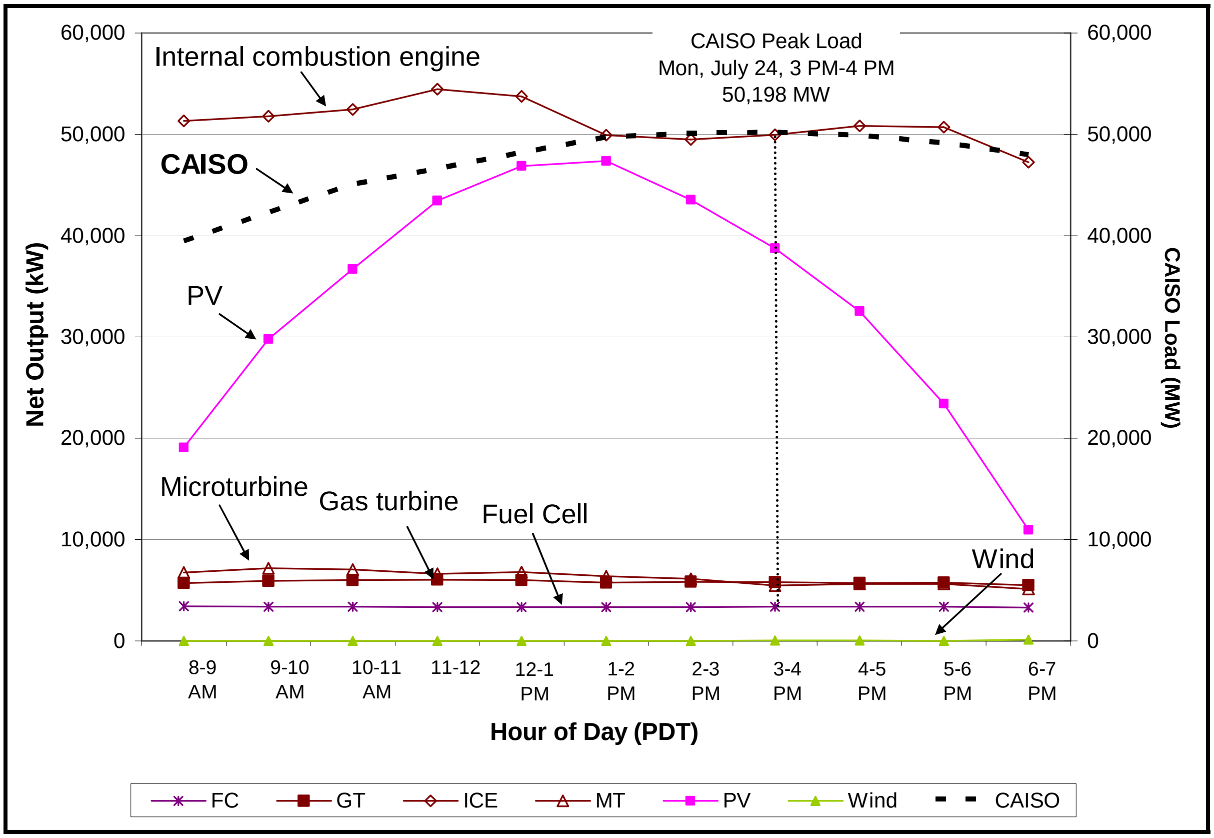
[2] The California Energy Commission has collected and reported wind capacity factors for wind energy systems operating in the state over a number of years. Average annual wind capacity factors range from 14 to 26 percent. Peak hour capacity factors range from 30 to as high as 60 percent at 6 pm (California Energy Commission, "Wind Power Generation Trends at Multiple California Sites," CEC-500-2005-185, December 2005)

Figure 5-3 plots the hourly total net electrical contribution for each SGIP technology from morning to early evening during the 2006 peak day. This figure is useful in assessing the potential impact of increasing amounts of a particular SGIP technology on meeting peak hour energy delivery. For example, SGIP's 609 PV systems provided approximately 40,000 kW of power to the grid during the peak hour. These 609 PV systems represented approximately 76 MW of operational PV capacity. In comparison to the CAISO peak hourly demand for 2006 of nearly 40,000 MW, SGIP's PV contribution is 0.1 percent of the total. However, if these results are translated to 3000 MW (i.e., the amount targeted in the California Solar Initiative) of solar PV, this means PV could have potentially contributed over 1,500 MWhr of electricity during the peak hour; or nearly 4 percent of the required peak demand. However, because PV's contribution occurs primarily at the distribution system level, this 4 percent could prove to be a very valuable contribution to the grid. In addition, California's electricity mix relies on approximately 3000 MW of older, more polluting and costly peaking units to help meet peak summer demand.[3] Consequently, 3000 MW would represent sufficient peaking capability to displace nearly half the capacity of the peaking units. Moreover, it should be noted that the performance results shown in Figure 5-3 represent PV systems with predominately a southern exposure. PV systems with a southwestern orientation would have a significantly higher contribution to peak.[4]

[3] California Energy Commission, "2007 Data based of California Power Plants," from http://www.energy.ca.gov/database/index.html#powerplants

[4] A southwestern orientation could increase peak hour electricity delivery by as much as 30 percent, depending on location. See "PV Solar Costs and Incentive Factors," Itron report to the CPUC Self-Generation Incentive Program, February 2007

Figure 5-3: Hourly Profiles by Incentive Level on CAISO Peak Day



PA-Specific Peak Demand Impacts

Table 5-7 through Table 5-9 present the total net electrical output during the respective peak hours of the three large, investor-owned electric utilities. The top portions of each table list the date, hour, and load of the utility's peak hour day. The tables also show the number of SGIP type facilities on line at the time of the peak, the operating capacity at peak, and the demand impact. Tables in Appendix A differentiate electric utility peak demand impacts by natural gas versus renewable methane fuel.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table 5-7: Electric Utility Peak Hours Demand Impacts – PG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
PG&E	22,544	25-Jul-06	6 PM

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	6	3,250	2,295	0.706
GT	2	2,593	1,930	0.744
ICE	78	48,267	21,534	0.446
MT	33	5,868	2,431	0.414
PV	276	38,039	7,759	0.204
WD	0	0	0	
TOTAL	**395**	**98,017**	**35,949**	**0.367**

PG&E's peak demand occurred at 6.00 P.M. on July 25th. Gas turbines and fuel cells that were operating under the SGIP at that time reflected high hourly capacity factors; both exceeding 70 percent. IC engines and microturbines operating under the SGIP showed capacity factors in the 40 to 45 percent range. PV systems, due to the limited amount of insolation available at 6.00 P.M. had an average peak capacity factor of 20 percent. The combined SGIP contribution to peak generation provided an overall SGIP peak capacity factor of 37 percent. Note also that the electricity contribution from the combined SGIP facilities operating in PG&E's service territory during the 2006 summer peak provided 0.2 percent of the required demand.

Table 5-8: Electric Utility Peak Hours Demand Impacts – SCE

Elec PA	Peak (MW)	Date	Hour (PDT)
SCE	23,148	25-Jul-06	4 PM

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	2	750	171	0.228
GT	1	HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
ICE	82	54,176	26,553	0.490
MT	45	7,722	3,748	0.485
PV	177	19,179	6,372	0.332
WD	2	1,649	310	0.188
TOTAL	**309**	**87,976**	**41,074**	**0.467**

SCE's peak demand occurred at 4.00 P.M., slightly earlier than PG&E's peak. Like PG&E, the gas turbine operating under the SGIP showed a very high peak capacity factor. Unlike PG&E, the SGIP fuel cells operating in SCE's service territory demonstrated a low peak capacity factor. As explained earlier, one of the fuel cells is powered with biogas, which resulted in an overall lower capacity factor. IC engines and microturbines operating under the SGIP showed very similar peak capacity factor for SCE as for PG&E. This observation is significant in that it strongly suggests that the majority of the IC engine and microturbine capacity operating under the SGIP in both PG&E and SCE do not load follow.[5] The SGIP PV facilities had a better peak capacity in SCE than in PG&E for 2006, primarily due to the peak demand occurring earlier in the afternoon. The electricity contribution from the combined SGIP facilities operating in SCE's service territory during the 2006 summer peak provided 0.2 percent of the required demand. Lastly, wind peak capacity factor for SCE was close to 20 percent, but should be recognized as representing only two wind systems.

Table 5-9: Electric Utility Peak Hours Demand Impacts – SDG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
SDG&E	4,502	22-Jul-06	2 PM

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	1	HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
GT	0	0	0	
ICE	19	12,225	2,157	0.176
MT	15	1,622	322	0.199
PV	76	8,848	5,987	0.677
WD	0	0	0	
TOTAL	**111**	**23,696**	**8,858**	**0.374**

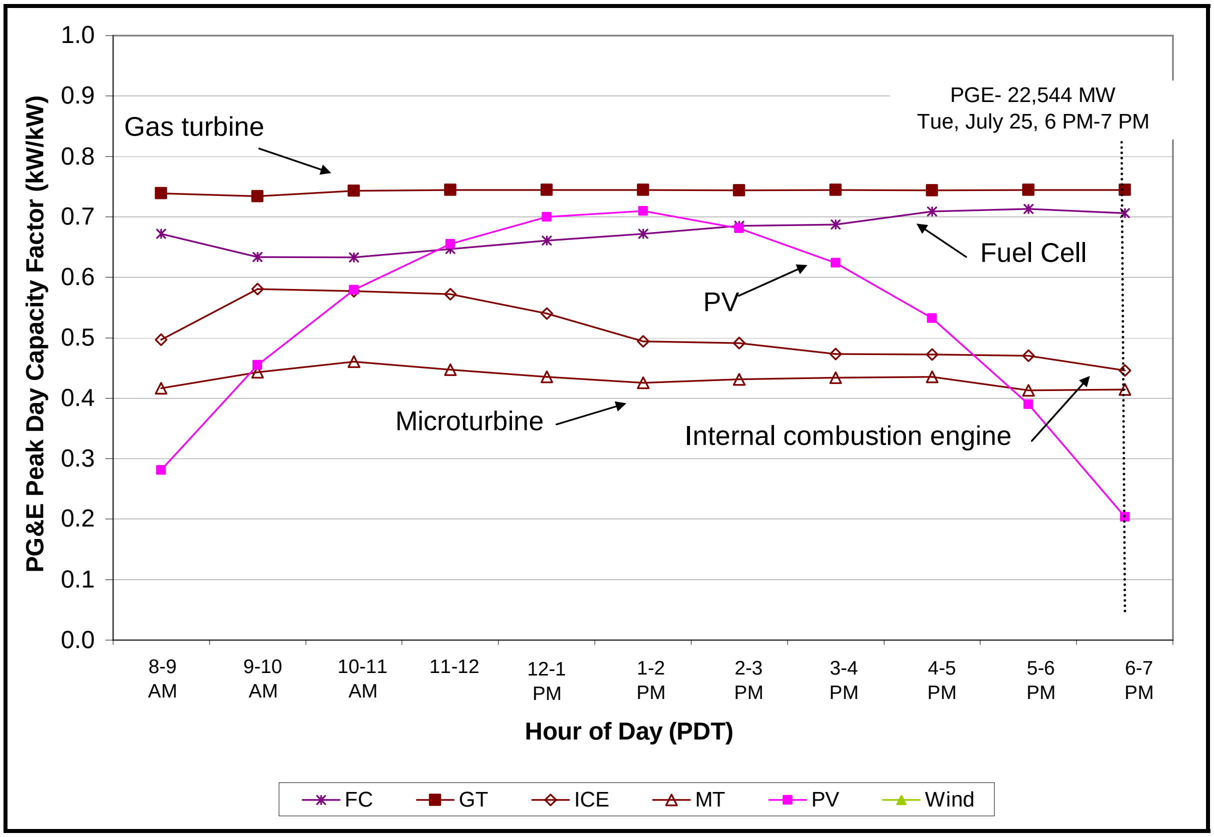
Of the three IOUs with SGIP facilities operating during the 2006 peak, SDG&E had the earliest peak, occurring at 2.00 P.M. on, Saturday, July 22, 2006. As a result of the earlier timing of SDG&E's peak demand, the PV peak capacity factor was 67 percent. However, the peak capacity factor for the single fuel cell operating in SDG&E during its peak was 39 percent. Similarly, IC engines and microturbines showed significantly lower peak capacity factors than their counterparts in PG&E and SCE; at 20 percent, nearly half the value. The unusual timing of SDG&E's peak hour on a weekend day may explain these low capacity factors. Onsite operators may have had reduced demand for both power and heat on a

5 Another possibility is that ratings of IC engines and microturbines are significantly lower than their rebated capacities. Similarly, these results represent aggregated values. As such, there may be load following aspects of projects that get smoothed out when the individual capacity factors are aggregated.

Saturday. The electricity contribution from the combined SGIP facilities operating in SDG&E's service territory during the 2006 summer peak also provided 0.2 percent of the required demand.

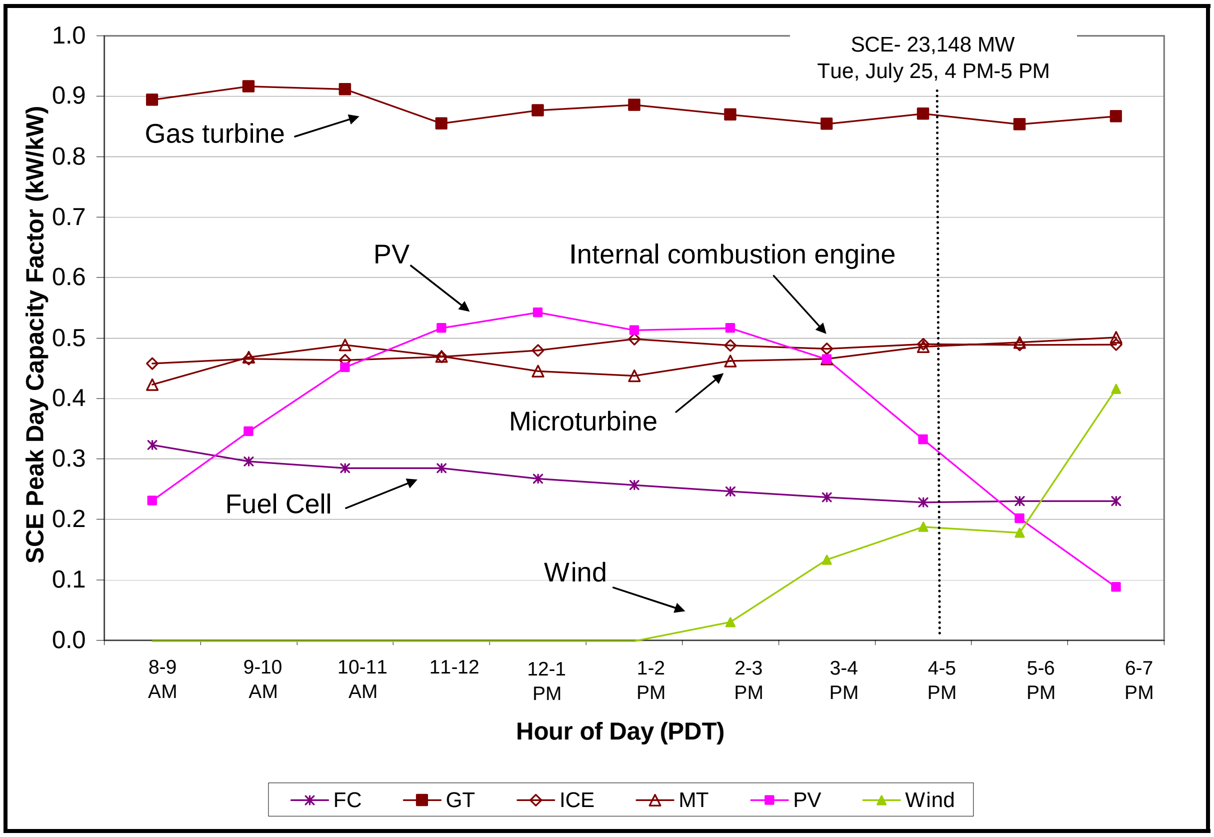
Figure 5-4 through Figure 5-6 plot profiles of hourly weighted average capacity factors by technology for the SGIP systems directly feeding the utilities on the dates of their respective peak demand. The plots also indicate the date, hour, and value of the peak load for the electric utility. Note that the plots include only those technologies that were operational for the electric utility, so not all technologies appear for all electric utilities. Again, results presented for the peak days of the three individual electric utility do not strictly include all systems or only systems administered by the PA associated with the electric utility. Appendix A plots separately those technologies that can use natural gas versus renewable fuel.

Figure 5-4: Electric Utility Peak Day Capacity Factors by Technology – PG&E



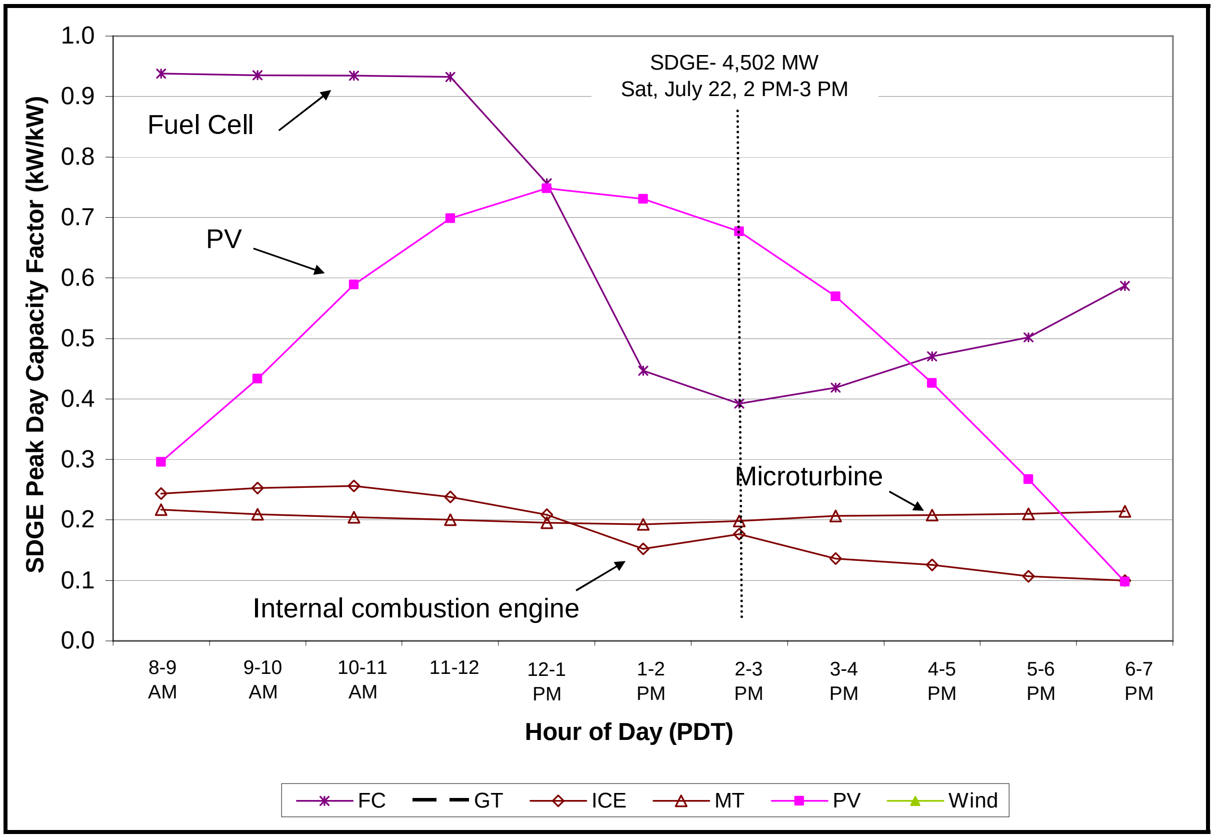
The hour-by-hour peak day capacity factor plot for PG&E reflects the almost flat generation profiles exhibited on average from natural gas-fired cogeneration facilities operating under the SGIP. For fuel cells and gas turbines, which operated at high capacity factors during the peak hour, this profile provided benefit to PG&E. However, the 40-45 percent capacity factors exhibited by microturbines and IC engines during the peak hour meant that as much as 60 percent of the rebated capacity of these technologies was not available when most needed. In the case of IC engines, the capacity factor decreased in the morning from a high of nearly 60 percent to a low of almost 40 percent by 6.00 P.M.. Because these results represent a capacity-weighted average, it is unclear what role individual cogeneration systems played in displacing peak demand at their respective customer sites.

Figure 5-5: Electric Utility Peak Day Capacity Factors by Technology – SCE



The hour-by-hour peak day capacity factor plot for SCE shows similar trends to that seen with PG&E. In particular, gas turbines exhibited a very high and flat capacity factor across the day, including the peak hour at 2.00 P.M.. IC engines and microturbines also showed a flat profile; staying consistently in the 40-50 percent range. The wind capacity factor picks up from essentially zero at 1.00 P.M. to nearly 20 percent by 4.00 P.M., which is consistent with the diurnal wind patterns found with wind resource in the particular area of the wind systems located in that specific region of the SCE service territory.

Figure 5-6: Electric Utility Peak Day Capacity Factors by Technology – SDG&E



As indicated earlier, SDG&E's peak occurred on a Saturday. This may explain the unusually low hourly capacity factors observed for IC engines and microturbines. The high hourly capacity factor seen for PV at the 2.00 P.M. peak reflects the increased insolation available at that time of the day.

5.3 Transmission and Distribution Impacts

In addition to providing electricity over the course of the year and during times of peak demand, distributed generation (DG) technologies being deployed under the SGIP impact the distribution and transmission sections of California's electricity system. If DG facilities successfully displace electricity that would otherwise have to be provided to electricity customers during peak demand, they can reduce loading on the distribution and transmission lines. That reduced loading can potentially result in a decreased need to expand or build new transmission and distribution infrastructure, thereby saving utility and ratepayer monies. Moreover, by providing multiple pathways for electricity to be delivered to the grid, DG facilities can potentially lower risk of transmission outages, which in turn increases overall system reliability.

This section presents the impacts of SGIP facilities on the IOU transmission and distribution system during 2006. Data sources, methodology, and detailed results of the transmission and distribution impacts analyses are presented in Appendix B. Distribution system impacts are discussed first, followed by transmission system impacts.

Distribution System Impacts

SGIP facilities are located at a utility customer's site with the intention of displacing all or a portion of the customer's electricity demand. As such, SGIP facilities are distributed generation (DG) systems that connect directly to the distribution side of the electricity system. Impacts to the overall transmission and distribution system are encountered first at the lower voltage distribution system. A number of DG facilities can be connected to a single distribution feeder. Impacts to the distribution feeder will increase as the cumulative capacity of DG facilities connected to a single distribution feeder increases.

<u>Distribution Systems Analysis Approach</u>

Distribution system impacts were assessed by comparing SGIP hourly generation profiles against hourly distribution line loadings. Line loadings were limited to those distribution lines serving utility customers hosting SGIP DG facilities. Metered electrical net generator output (ENGO) interval data collected for 313 metered SGIP DG facilities were isolated to the specific date and hour of the 2006 and 2005 summer peak conditions for each IOU participating in the SGIP.[6] Similarly, distribution line loadings corresponding to the same peak day and hour were isolated to enable identification of SGIP output coincident with peak loading at each substation. The coincident SGIP peak load was then summarized by feeder type, IOU, and climate zone. This allowed extrapolation of the observed coincident peak load from interval-metered SGIP facilities to the entire SGIP DG population.

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6 Although 2006 impacts are the focus of this study, both 2006 and 2005 transmission and distribution impacts were evaluated.

Table 5-10 shows the breakdown of metered SGIP DG facilities and distribution feeders by climate zone and IOU service territory. The PG&E Coast group includes 31 generators in climate zones 2-5. The SCE Coast group includes 128 generators in climate zones 6-10 while the SDG&E Coast group includes 112 generators in the same zones. Due to a limited number of generators, it was not possible to separate the inland climate zones by utility. The inland climate group includes a total of 42 generators in climate zones 11-15. Since we do not expect significant differences by utility in the central valley, this should not affect the robustness of the analysis.

Table 5-10: Number of Metered Observations by Climate Zone and IOU (2005/2006)

	Climate Zone	PG&E	SCE	SDG&E	Total
North Coast	2	6			6
	3	22			22
	4	2			2
	5	1			1
	Sub Total	*31*			*31*
South Coast	6		23		23
	7			90	90
	8		42	1	43
	9		33		33
	10		30	21	51
	Sub Total		*128*	*112*	*240*
Inland	11	8			8
	12	15			15
	13		12		12
	14		4	1	5
	15			2	2
	Sub Total	*23*	*16*	*3*	*42*
	Total	31	128	112	313

In addition to climate zone, the analysis also grouped installations by the type of customers served by the distribution system. However, even with a threshold as low as 50 percent of energy sales to a specific class, a large number of feeders in the system could only be categorized as mixed. The distribution of the feeder peak hours by feeder type across all of the utilities is shown in Figure 5-7. The commercial and industrial feeders tend to peak earlier in the day, with hour ending (HE) 13 being the most common peak hour. Residential and mixed feeders tended to peak in the evening (HE 17 & 18) or at night (HE 22).

Figure 5-7: Distribution of Feeder Peak Hour by Customer Types

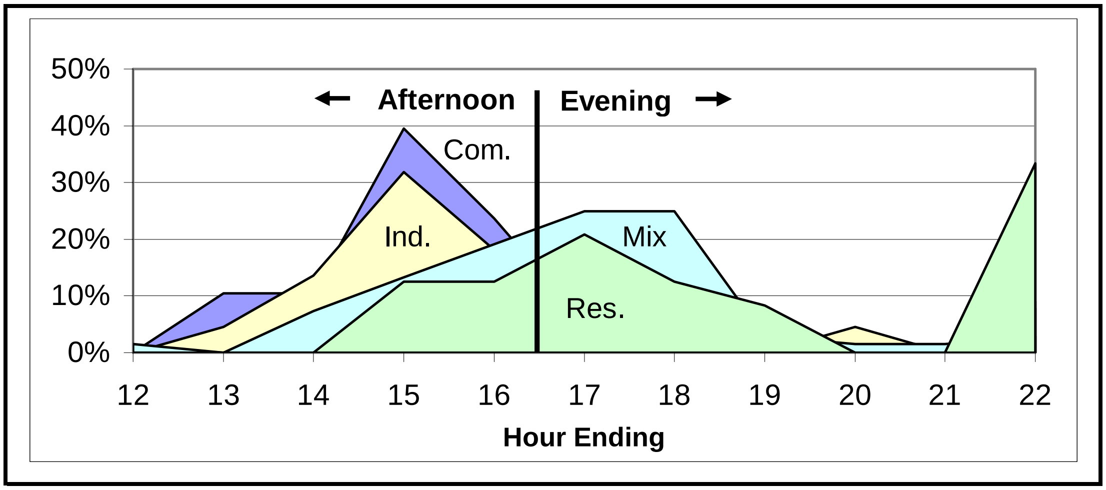
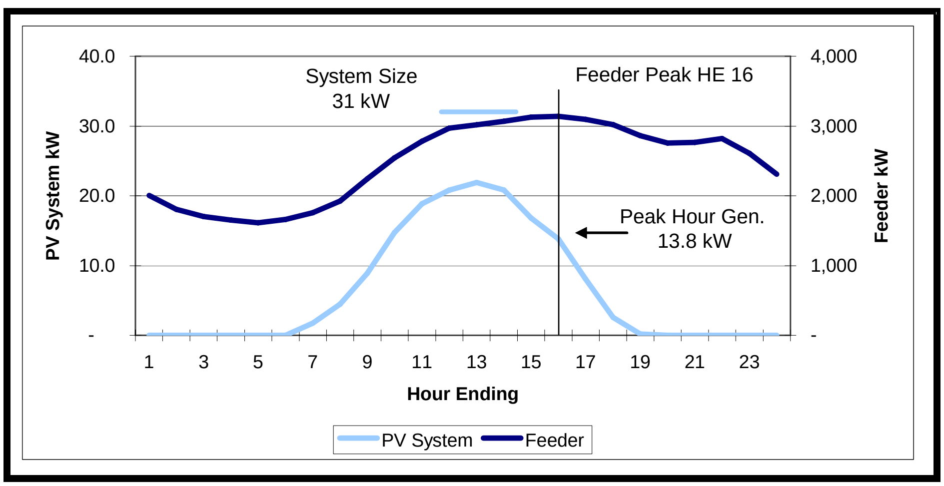


Figure 5-8 illustrates the concept of comparing SGIP DG generation to peak loading on a single distribution feeder. In this example, the feeder has a load shape typical of residential loads, peaking at a demand slightly above 3,000 kW at Hour Ending (HE) 16. Here, the SGIP generator is a 31 kW PV system with peak generation of 21 kW at HE 13. During the feeder peak at HE16, however, the PV system is only producing 13.8 kW. Consequently, the 13.8 kW of PV generation coincident with the peak loading at HE 16 is used in this analysis of distribution impacts.

Figure 5-8: Example of Feeder Peak Hour Generation for a PV System



Distribution System Analysis Results

In her May 18, 2006 ruling, the Administrative Law Judge (ALJ) asked for an assessment of the "impacts of distributed generation investments on utility grid and transmission planning".[7] This distribution analysis provides an impact assessment for 2005 and 2006. The distribution analysis also provides a "look-up" table of distribution peak load coincidence factors to help facilitate integration of DG in utility planning. In addition, the analysis provides an approach to evaluate the level of certainty that the SGIP output will provide distribution peak load relief. This information is based on the measurements of the SGIP installations in place, and should facilitate the integration of SGIP in utility system planning as the SGIP continues to expand and penetration of distributed generation increases in California.

The distribution analysis was designed to answer three main questions:

1. **Measured Impact**: What was the measured distribution system impact in 2005 and 2006 for each utility?
2. **System Planning Impact**: How can we incorporate the impacts of distributed generation on distribution system planning?
3. **Cost Savings**: Have there been any distribution system cost savings associated with SGIP?

<u>1. What was the measured distribution system impact for each utility?</u>

The estimated distribution peak load reduction associated with SGIP facilities in 2006 in the three IOU service territories was 46.1 MW, 37.1 MW and 6.8 MW for PG&E, SCE and SDG&E respectively, totaling 90.0 MW for California.[8] These results include only the 313 systems which had sufficient metered data available during the peak day and hour of the corresponding feeder or substation.

Figure 5-9 shows the coincident peak load reduction by SGIP technology program-wide in 2006. As described earlier, the metered kW is based on a direct comparison of metered SGIP output and the measured loadings on the distribution feeder or substation serving the customers with the SGIP installation. Not all SGIP installations have interval metering and distribution loading information. Therefore, a set of distribution peak load factors was

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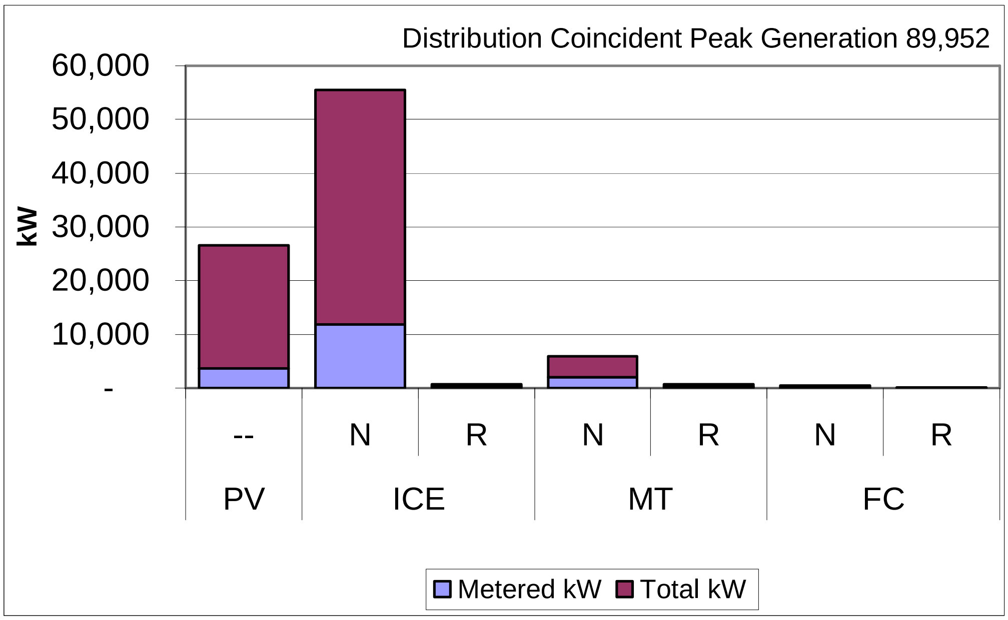
[7] CPUC Ruling R06-03-004

[8] Section 5.2 refers to a coincident peak generation for SGIP facilities at the 2006 peak of 103 MW. The 90 MW of coincident peak reduction referred to here represents coincident peak for the family of distribution feeders. As distribution feeders can have a peak loading at a different day and hour from the IOU peaks, this can lead to a difference in peak loading definitions. In addition, differences can also be due to lack of distribution feeder loading data.

developed (see Table 5-11) and used to estimate the total coincident distribution peak load reduction.

Figure 5-9: Distribution Coincident Peak Load Reduction by Technology – California 2006



Metered kW	3,636	11,914	360	2,024	203	0	0
Total kW	26,516	55,515	744	5,975	688	467	67
Metered #	78	55	3	28	4	1	1
Total #	569	165	9	81	16	9	2

Notes: 'metered kW' is the distribution peak load reduction directly metered, 'total kW' is the estimated total distribution peak load reduction, 'Metered #'is the number of SGIP installations metered, 'Total #' is the total number of SGIP installations

<u>2. How can the impacts of distributed generation be integrated in distribution system planning?</u>

The most important factor for achieving distribution savings from distributed generation is being able to anticipate the peak load reductions resulting from the DG generation, and then integrating this information in utility planning and operation decisions. This requires knowledge of the location of SGIP DG installations, the expected load reductions, and the level of certainty associated with the expected peak load reductions. We have developed a "look-up table" that shows the relationships between the measured distribution coincident peak load reduction across different SGIP technologies, utilities, feeder types and climate zones based on measured data in 2005 and 2006. The "look-up table" should provide utility planners with additional insights into DG impacts on distribution lines which they can begin to incorporate in their distribution planning decisions.

Table 5-11 is the "look-up table" that reports the distribution peak load coincident factors based on measured SGIP installations in 2005 and 2006. The peak load reduction factor represents the effective peak load reduction that can be expected on a particular type of feeder from the various types of DG technologies. For example, PV SGIP installations located in SCE coastal climate zones on feeders that peak in the afternoon (prior to HE 16) demonstrated average peak reduction effectiveness equal to 46 percent of the rebated PV capacity. This means that for each kW of rebated PV capacity in the SCE coastal zone, it will provide 0.46 kW of peak reduction in the distribution system. Program-wide peak reduction effectiveness factors were also developed for each technology. The overall coincident peak load impacts measured across the SGIP are 35 percent (PV), 48 percent (ICE), 44 percent (MT), and 9 percent (FC). The categories developed to report the coincidence factors are a balance between what is the most useful and having enough observations to have confidence in the results. Further investigation of PV SGIP installations by tilt and climate zone are reported in Appendix B.

Table 5-11: Distribution Coincident Peak Load Reduction as a Percent of Rebated Capacity – California 2005 & 2006

		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon	56%	85%					
	Evening	30%						
SCE Coast	Afternoon	46%	65%		44%			
	Evening	6%	48%		52%			
SDG&E Coast	Afternoon	42%	33%		40%			
	Evening	1%						
Inland	Afternoon	63%	29%					
	Evening	26%						
Total by Technology/Fuel		35%	50%	12%	50%	23%	16%	0%
Total by Technology		35%	48%		44%		9%	

Notes: Climate Zones

PG&E Coast (CEC Title 24 Climate Zones 2, 3, 4, 5)

SCE Coast (CEC Title 24 Climate Zones 6, 7, 8, 9, 10 in SCE service territory)

SDG&E Coast (CEC Title 24 Climate Zones 7, 8, 10 in SDG&E service territory)

Inland (CEC Title 24 Climate Zones 11, 12, 13, 14, 15 for all utilities)

Distribution Peak Hour

Afternoon (Peak occurs on Hour Ending (HE) 16 or earlier)

Evening (Peak occurs after HE 16)

Probability of Achieving Distribution Load Impacts

The lookup table provides *average* values for different SGIP output coincident with the local distribution peak. However, average values must be used with caution in distribution system planning since there is some probability of having less than the average value. To address this problem, the project team has also developed probability distributions of output expressed as a function of rebated capacity. These distributions are based on the different output levels measured across the metered SGIP installations.

Table 5-12 and Table 5-13 show the likelihood of the SGIP generator having an output at least as great as a given percentage of the rebated capacity. Table 5-12 shows the probability distributions for feeders that peak on Hour Ending 16 or earlier, and Table 5-13 shows the probability distribution for feeders which peak after Hour Ending 16. For example, there is a 71 percent probability of having an output at least as great as 40 percent of the rebated capacity of a PV system in the SCE Coastal zones on a feeder that peaks on or before 4pm (example highlighted).

Table 5-12: Probability Distribution of Output from SGIP for Feeder Peak <=HE 16

Technology	PV	PV	PV	PV	PV	ICE	MT	FC
Percent of Rebated Capacity	PG&E Coast	SCE Coast	SDG&E Coast	Inland	All Zones	All Zones	All Zones	All Zones
0%	100%	100%	100%	100%	100%	100%	100%	100%
5%	100%	94%	100%	100%	99%	65%	64%	20%
10%	100%	94%	98%	100%	98%	65%	64%	20%
15%	100%	94%	92%	100%	94%	65%	64%	20%
20%	100%	94%	86%	100%	91%	61%	64%	20%
25%	100%	88%	82%	100%	87%	60%	64%	20%
30%	100%	88%	80%	86%	85%	57%	64%	20%
35%	100%	88%	80%	86%	85%	57%	62%	20%
40%	93%	71%	73%	86%	77%	57%	61%	20%
45%	86%	65%	69%	86%	72%	54%	52%	20%
50%	86%	35%	55%	86%	59%	51%	52%	20%
55%	79%	29%	45%	71%	49%	50%	51%	20%
60%	79%	18%	31%	43%	37%	48%	41%	20%
65%	50%	18%	12%	14%	20%	41%	36%	20%
70%	29%	12%	12%	14%	15%	35%	30%	20%
75%	29%	0%	6%	14%	9%	30%	25%	20%
80%	7%	0%	6%	14%	6%	20%	11%	20%
85%	0%	0%	2%	14%	2%	14%	0%	20%
90%	0%	0%	0%	14%	1%	9%	0%	20%
95%	0%	0%	0%	14%	1%	7%	0%	20%
100%	0%	0%	0%	0%	0%	4%	0%	20%
Number of Observations	24	25	62	26	87	108	61	5

Table 5-13: Probability Distribution of Output from SGIP for Feeder Peak >HE 16

Technology	PV	PV	PV	PV	PV	ICE	MT	FC
Percent of Rebated Capacity	PG&E Coast	SCE Coast	SDG&E Coast	Inland	All Zones	All Zones	All Zones	All Zones
0%	100%	100%	100%	100%	100%	100%	100%	100%
5%	50%	38%	23%	95%	58%	65%	64%	20%
10%	40%	38%	23%	89%	54%	65%	64%	20%
15%	40%	38%	23%	84%	52%	65%	64%	20%
20%	40%	25%	15%	68%	42%	61%	64%	20%
25%	40%	0%	15%	58%	34%	60%	64%	20%
30%	30%	0%	15%	53%	30%	57%	64%	20%
35%	30%	0%	15%	26%	20%	57%	62%	20%
40%	20%	0%	15%	11%	12%	57%	61%	20%
45%	10%	0%	0%	5%	4%	54%	52%	20%
50%	10%	0%	0%	5%	4%	51%	52%	20%
55%	10%	0%	0%	0%	2%	50%	51%	20%
60%	0%	0%	0%	0%	0%	48%	41%	20%
65%	0%	0%	0%	0%	0%	41%	36%	20%
70%	0%	0%	0%	0%	0%	35%	30%	20%
75%	0%	0%	0%	0%	0%	30%	25%	20%
80%	0%	0%	0%	0%	0%	20%	11%	20%
85%	0%	0%	0%	0%	0%	14%	0%	20%
90%	0%	0%	0%	0%	0%	9%	0%	20%
95%	0%	0%	0%	0%	0%	7%	0%	20%
100%	0%	0%	0%	0%	0%	4%	0%	20%
Number of Observations	24	25	62	26	50	108	61	5

The probability distributions above provide the probability achieving a given level of output for a single SGIP installation. However, as penetration of SGIP generators increases on the system, it is possible to have multiple generators on the same feeder. Therefore, the project team has developed a spreadsheet tool to compute the combined probability of achieving a given level of output in the case of multiple generators. The spreadsheet combines the cumulative probability distributions to compute a single distribution that can be used in the distribution planning assessment.

Figure 5-10 provides a 'screen shot' of the spreadsheet tool to illustrate the use of the analysis tool. To use the tool, the user selects the feeder peak period (either <=HE 16 or >HE16), the climate zone, the technology type, and the rebated capacity of each generator. The analyst then pushes the 'Calculate' button and the spreadsheet computes the combined probability distribution. The algorithm works by computing the probability of each combination of generator output based on the individual probability distributions, and then summing the probability of all the combinations that result at a total combined output for each output level.

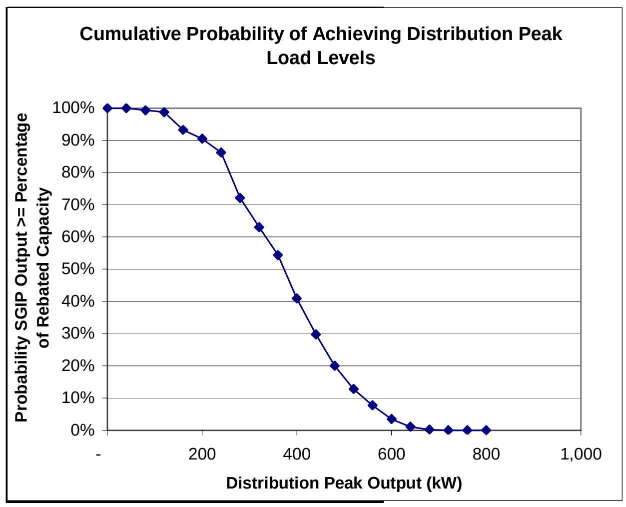
Figure 5-10: Screenshot from Spreadsheet Tool for Multiple SGIP Units

Number of DG Units	4
Total Capacity	800 kW

Feeder P Afternoon: <=HE 16

DG #	Type	Zone	Rebated Capacity (kW)
1	PV	PG&E Coast	200
2	ICE	PG&E Coast	200
3	ICE	PG&E Coast	200
4	ICE	PG&E Coast	200
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			

* Note that all PV should be entered on one line since the probability of output is not independent



3. Have there been any distribution system cost savings associated with SGIP?

The May 18, 2006 ALJ Ruling requests an evaluation of cost savings associated with performance, reliability, and operations. The results of this analysis were completed in two steps: (1) identifying the potential areas of cost reductions associated with SGIP installations, and (2) estimating the potential magnitude of any savings.

There have been numerous studies completed that list and quantify the benefits of distributed generation and distributed resources, but these are typically planning studies[9]. Very few M&E studies quantify distribution system benefits based on measured savings.

[9] For comprehensive assessment of the value of distributed generation, see Energy and Environmental Economics, Inc and Distributed Utility Associates, Joe Iannucci.

Distribution system benefits are typically due to three types of distribution improvements: (1) performance improvements, (2) reliability improvements, and (3) operations improvements. Performance improvement benefits can be quantified as a reduction in losses, improvement in voltage profile, and improvement of power quality. Reliability improvement can be quantified as the reduced capital investment necessary to meet the established distribution reliability criteria with SGIP in place. Operations improvement can be quantified in terms of reduced crew time and maintenance costs.

Given the available data, this study focused on the two categories of benefits that represent the largest benefit categories: performance improvements based on reduced distribution system losses, and reliability improvements based on reduced distribution capital expenditures. Information to evaluate other potential sources of benefits such as improvement in voltage profiles, power quality, reduced crew time, and maintenance costs was not readily available. In addition, these potential benefits are difficult to attribute specifically to SGIP facilities and in some cases may be very small.

Table 5-14 shows the estimated value of distribution loss savings from SGIP facilities in 2005 and 2006 by IOU service territory. At over $2 million per year, the total value is similar for 2005 and 2006, with a slight decrease in 2006 due to less generation identified overall in 2006 than 2005. While we are not certain, this reduction is likely due to higher natural gas prices for natural gas powered CHP units. The calculation is simply the energy generated times the distribution loss factor for each utility times the estimated wholesale value of energy.

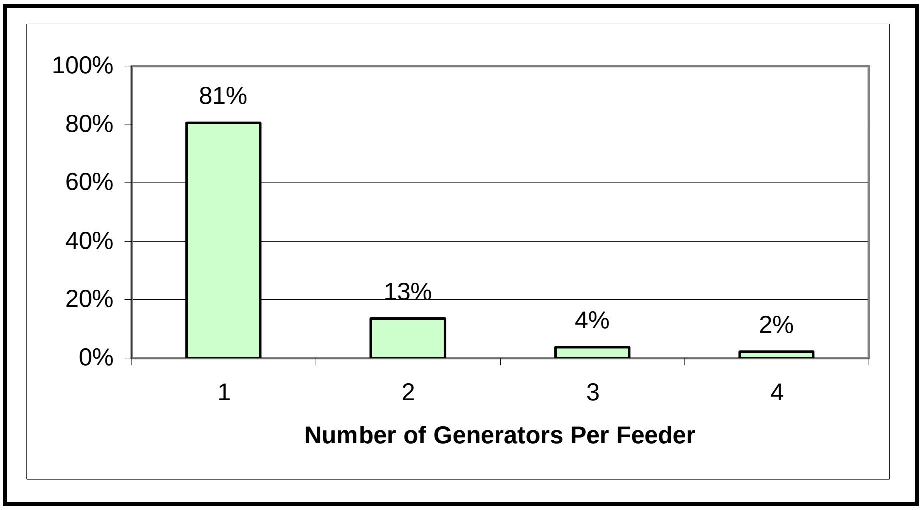
Table 5-14: Estimated Value of Distribution System Loss Savings

Year	Utility	SGIP Generation (MWh)	Distribution Loss Savings (MWh)	Loss Savings ($/year)	Total Savings ($/year)
2005	PG&E	432,451	15,003	$ 864,512	
	SCE	625,546	14,707	$ 861,491	
	SDG&E	249,062	10,669	$ 624,948	$ 2,350,951
2006	PG&E	460,797	15,986	$ 921,177	
	SCE	478,397	11,247	$ 658,840	
	SDG&E	247,761	10,613	$ 621,682	$ 2,201,699

A potentially larger benefit is the distribution capacity value associated with the SGIP installations. A key driver for providing distribution capacity value is achieving sufficient peak load reductions to defer planned capital additions without exceeding the N-1 peak load ratings on distribution system equipment. This requires enough distribution coincident peak load reduction to defer investments.

To evaluate the potential for capital investment deferrals, the project team tabulated the penetration of SGIP installations per feeder, and then the total amount of measured load reduction. The percentage of feeders serving one or more SGIP generators is shown in Figure 5-11.

Figure 5-11: Number of SGIP Generators per Distribution Feeder

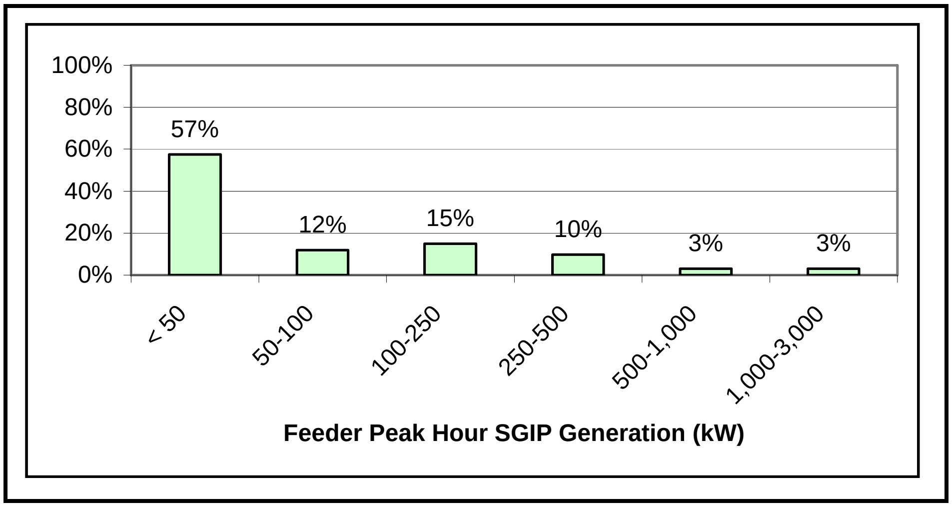


Based on the available data, 81 percent of distribution feeders serving a customer with a SGIP generator have a single SGIP installation. Approximately 2 percent of feeders serving an SGIP generator have four SGIP generators.[10]

The amount of peak load reduction per substation or feeder is also critical for evaluating the potential for distribution capacity savings. The percentage of substations or feeders with varying amounts of observed distribution peak load reduction is shown in Figure 5-12. Of the feeders evaluated, 57 percent of those with SGIP installations had a peak load reduction of less than 50kW. Only 3 percent of substations or feeders had load reductions from 1MW to 3MW.

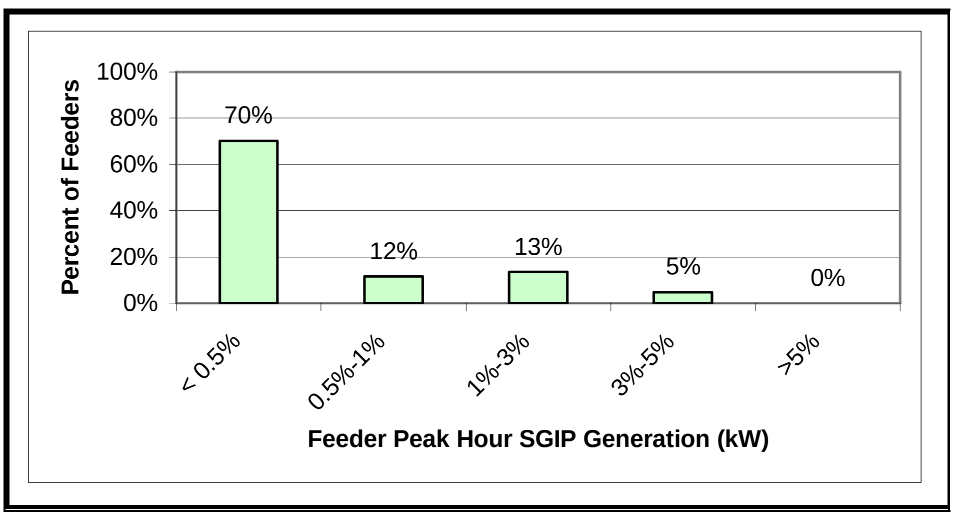
[10] Note that one utility submitted data for substations rather than feeders and that some of the substations with multiple SGIP generators will likely have numerous feeders. Therefore, even if there are four distributed generators, they may not be connected to the same feeder or substation transformer.

Figure 5-12: Feeder Peak Reduction as Percentage of All Measured Feeders



The amount of distribution load reduction achieved with SGIP reduction can also be expressed as the percentage of feeders that have achieved 'significant' peak load reductions. The frequency of different levels of peak load reduction achieved in 2006 is shown in Figure 5-13. In 2006, no feeder or substation had a measured peak load reduction of greater than 5 percent. The results from 2006 suggest that SGIP generators were not running during the distribution peak hour in 2006. The reason for the generation was not running is not known, but could be due to high natural gas prices, a forced outage, or something else.

Figure 5-13: Distribution of SGIP Generation as Percent of Feeder Peak – 2006



Taken together, the results of the distribution capacity evaluation indicate that there is not a sufficient penetration of SGIP distributed generators to provide distribution capacity value. With greater penetration overall, or targeted penetration on a specific distribution system in danger of an overload, it would be possible to capture distribution capacity savings.

In addition to limited penetration of SGIP facilities within the distribution system, a number of other factors contribute to a lack of distribution capital savings. One of these is that the SGIP generators operate independently of the distribution system. Therefore, the SGIP owner does not know when the distribution peak is, nor do they have any incentive to operate during the peak even if they did know. In fact, the current SGIP rules prohibit an additional incentive to operate during the local capacity peak. Similarly, the distribution utility planners do not necessarily know which SGIP generators are being served by overloaded equipment, likely because the penetration of SGIP generators is not currently high enough to warrant close attention for capacity planning at the distribution level. In addition, SGIP owners choose where to install their systems, not the utility; therefore, they are not a concentrated number of installations in a single area of need that could provide significant load relief on a particular overloaded feeder or substation.

Transmission System Impacts

Customer self-generation can potentially improve transmission and distribution system reliability. The transmission reliability benefits depend on the location and size of self-generation, penetration potential, capacity availability at time of system peak, and other attributes. As load reduces due to self-generation on the distribution network, there is a corresponding reduction on the distribution transformers, sub-transmission lines, transmission substations and the ultimately the high voltage lines. However, the system needs very high penetrations to provide significant benefits to the high voltage transmission lines. The major benefit is a reduction in the loading of substation equipment (including transformers) and the sub-transmission lines (line voltages below 230 kV). Any delays or elimination of upgrades in the transmission system due to self-generation saves electric customers money.

Due to the relatively small capacities of DG systems, impacts are more easily observed at the distribution level than at the transmission level. However, as the number of DG facilities increases, the cumulative capacity increases the likelihood for significant impact at the transmission level. For this reason, the approach was taken to model the aggregated capacity (MW) of SGIP DG facilities at each substation. The assumption was made that SGIP DG facilities act to reduce loading on distribution and transmission lines. Consequently, if generation from DG facilities is not available, then total load at the substations is higher by the otherwise contributed capacity of the aggregated DG facilities. The transmission substation configuration includes both the SGIP DG facility capacity and a corresponding load equal to the SGIP DG capacity. When a DG facility is considered out of service under a contingency analysis case, then the load at the substation increases because the DG facility is not available to offset the load. This representation simulates the benefits provided by DG facilities acting to reduce loading on substations and transmission lines.

Transmission System Analysis Approach

The methodology for evaluating the transmission benefits of DG facilities located at different locations is termed the Aggregated MegaWatt Contingency Overload (AMWCO). Power flow simulations are completed under first contingency (N-1) conditions for each scenario for the summer peak hour. One at a time, each power flow element (e.g., a transmission line, transformer, or generator) is temporarily removed from service and a power flow simulation is completed. This process is repeated for each element in the power flow case. For an N-1 simulation of the California transmission system, this can represent up to 7,000 simulations. One or more of these individual simulations may cause an overload on one or more elements. The percent overload of the element is weighted by the number of outage occurrences and the percent overload. The summation of the weighted overloads is the AMWCO. The difference between the AMWCO for the base case and each DG facility case divided by the capacity of the installed DG is the Distributed Generation Transmission Benefit Ratio (DGTBR). AMWCO is a transmission reliability index with a unit of measure in megawatts. As a result, the DGTBR is the improvement in the reliability index per megawatt of installed DG. For the cases with and without the DG modeled, the AMWCO is calculated. The difference between the two AMWCO values divided by the DG capacity determines the DGTBR. A negative DGTBR represents an improvement in system reliability. A positive DGTBR indicates a probable decrease in system reliability. This approach is based on a similar approach used for assessing transmission impacts due to integration of renewable energy facilities[11].

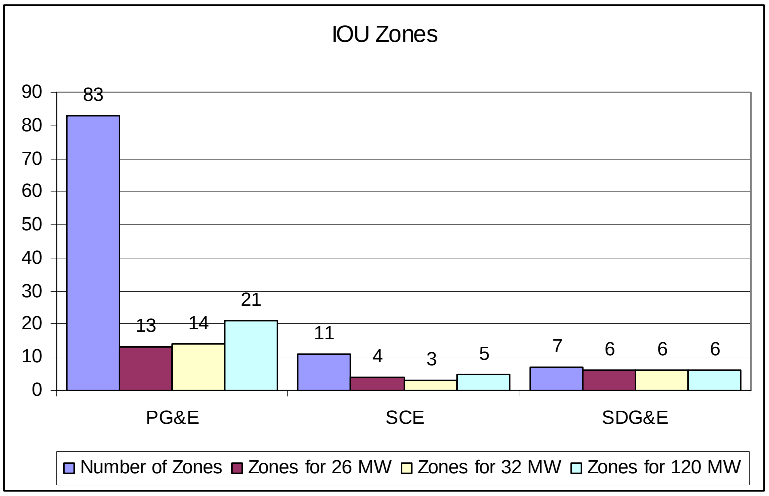
Three power flow scenarios were conducted to assess transmission impacts of aggregated DG capacities. The first scenario assessed the impact of all of the SGIP DG resources on a state-wide basis. The first power flow simulation excludes all of the DG facilities. A power flow simulation was completed for approximately 7,000 first contingency (N-1) conditions. The first contingency condition represents an outage of one transmission line or one generator. To model every line and transformer outage requires 7,000 different simulations. The second case included the SGIP DG resources. The number of simulations was slightly larger than the first simulation due to the increase in generators represented by the SGIP DG resources. The DGTBR value was determined by subtracting the AMWCO value from the first case from the AMWCO from the second case and dividing by the aggregated DG value. A negative value indicates that the aggregated DG provides a transmission reliability value to the statewide electricity system.

[11] California Energy Commission, "Strategic Value Analysis for Integrating Renewable Technologies in Meeting Renewable Penetration Targets," CEC-500-2005-106, June 2005

The second scenario assessed the impacts to each IOU. The same two simulations were completed as described above except that instead of a state-wide study, the studies concentrated on each utility system. The DGTBR was calculated using the same method employed for the state level scenario.

Each IOU divides its service area into transmission zones. Consequently, the third scenario examined the transmission impact to IOU transmission zones containing SGIP DG resources. Figure 5-14 shows the total number of zones for each IOU and the number of zones that includes at least one DG facility.

Figure 5-14: IOU Transmission Zones in California



<u>Transmission System Analysis Results</u>

There was approximately 32 MW of SGIP DG resources with peak generated metered during the 2006 peak day and hour. The distribution of SGIP DG resources examined in the transmission analysis is shown in Figure 5-15. The location of these resources is approximated since their exact GIS locations are unknown. Instead, locations on the map reflect the approximate location of the connection point of the SGIP DG facilities to their associated transmission bus.

Figure 5-15: Locations of SGIP Facilities Analyzed for 2006 Transmission Impacts

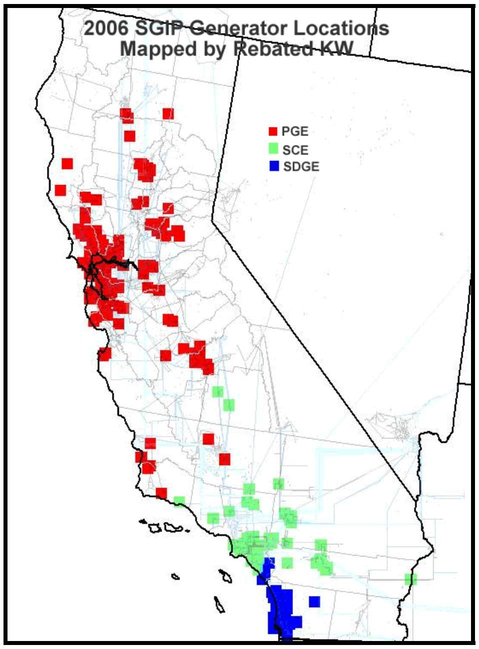


Figure 5-16 shows the distribution of the 32 MW of peak coincident capacity of the SGIP DG for the three IOUs during the 2006 peak. The number of SGIP DG facilities for the IOU and for the IOU transmission zones should be the same as the utility assigned the DG facilities to specific zones. As seen, the majority of the SGIP DG facilities showing generation coincident to the summer 2006 peak are located in SCE service area.

Figure 5-16: Distribution of SGIP DG during 2006 Peak

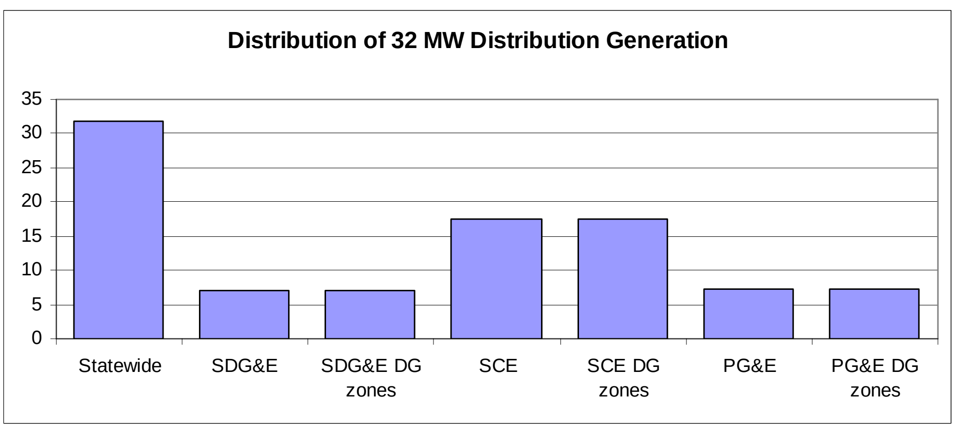
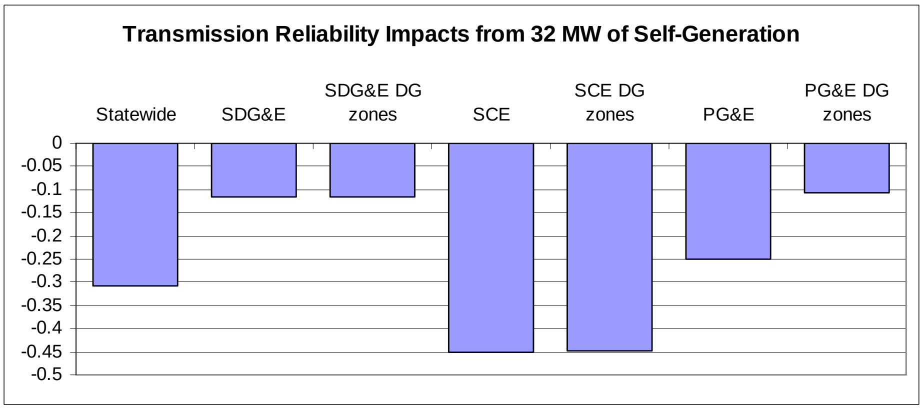


Figure 5-17 shows the results of the DGTBR analysis for the 2006 summer peak. Because DG facilities act to reduce load at the load centers, they should show some degree of transmission benefit. As expected, the DGTBR values are negative across all scenarios for the summer 2006 peak.

Figure 5-17: Transmission Reliability Impacts for 2006 Peak



The magnitude and distribution of the DGTBR values reveals several observations. SCE has the largest number of DG facilities that contributed generation during peak demand. As a result, the DGTBR benefit is expected to be higher for SCE than for other utilities; and in fact is nearly twice the value for any other IOU. As there is not a large difference between the total number of zones and the number of zones with DG facilities, the DGTBR is expected to be the about the same in the SCE transmission zones.

Almost every zone in the SDG&E service area contains DG facilities. As such, the DGTBR is expected to be the same in the SDG&E transmission zones. The DGTBR values are negative and provide a transmission benefit to SDG&E even though the self-generation is only 7 MW. For 2006, the SDG&E DGTBR value means that for every MW of SGIP DG on line during the peak, it provided 1.1 MW of increased system reliability.

PG&E's results may be the most interesting of the group. As shown in Figure 5-14, PG&E is divided into 83 transmission zones but only 14 contain DG facilities. The DGTBR values should therefore be different for PG&E as compared to the zones having equal DG resources. The bar charts shown in Figure 5-17 confirm that the DGTBR values are significantly different in PG&E. The concentration of DG facilities across fewer zones results in the DGTBR being lower within the zones as compared to the total PG&E system. This result occurs because there is less load in the zone and fewer transmission lines to impact the DGTBR under contingency analysis. By inadvertently compressing DG facilities into fewer zones, the DGTBR may not always produce consistent results.

The total state-wide DGTBR is also shown in Figure 5-17. Even though the total aggregated capacity of the SGIP DG facilities is only 32 MW out of the 42,000 MW of demand occurring under the 2006 summer peak conditions, these DG facilities were still found to provide overall DGTBR benefits to the system.

For sensitivity purposes, DGTBR analyses were conducted for three different penetration levels of DG. One case represented the amount of SGIP DG (26 MW) that was metered for the 2005 peak conditions. Another case involved the amount of SGIP DG (32 MW) that was metered for the 2006 peak conditions. The last case assumed that all 120 MW of SGIP available in 2006, even though not actually available, was available for peak conditions.

Figure 5-18 shows the distribution of SGIP DG for the three DG penetration cases. The distribution of SGIP DG resources under the 120 MW case is based on actual IOU distributions in 2006.

Figure 5-18: Distribution of SGIP DG under Different Penetration Cases

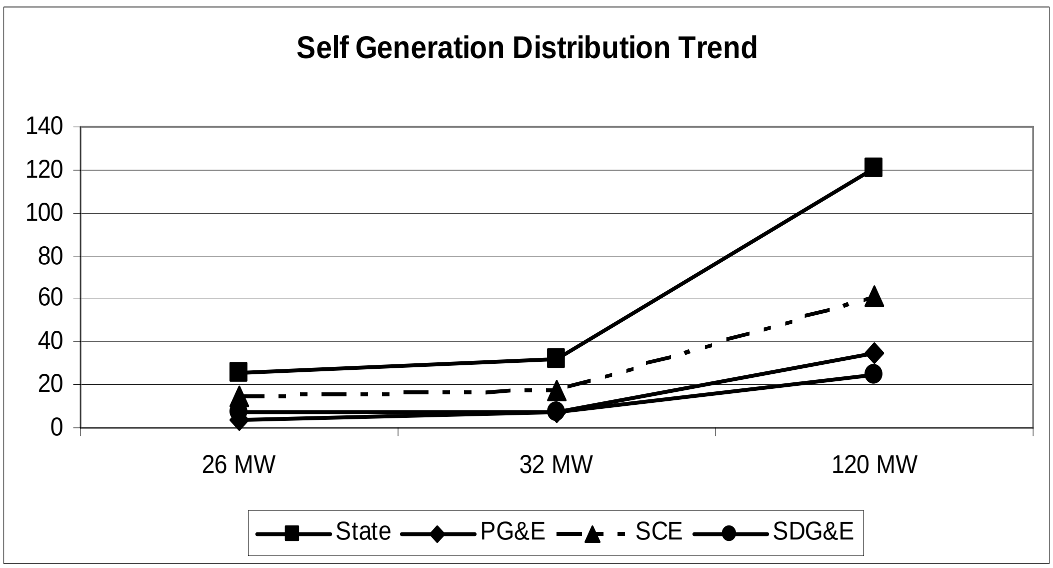
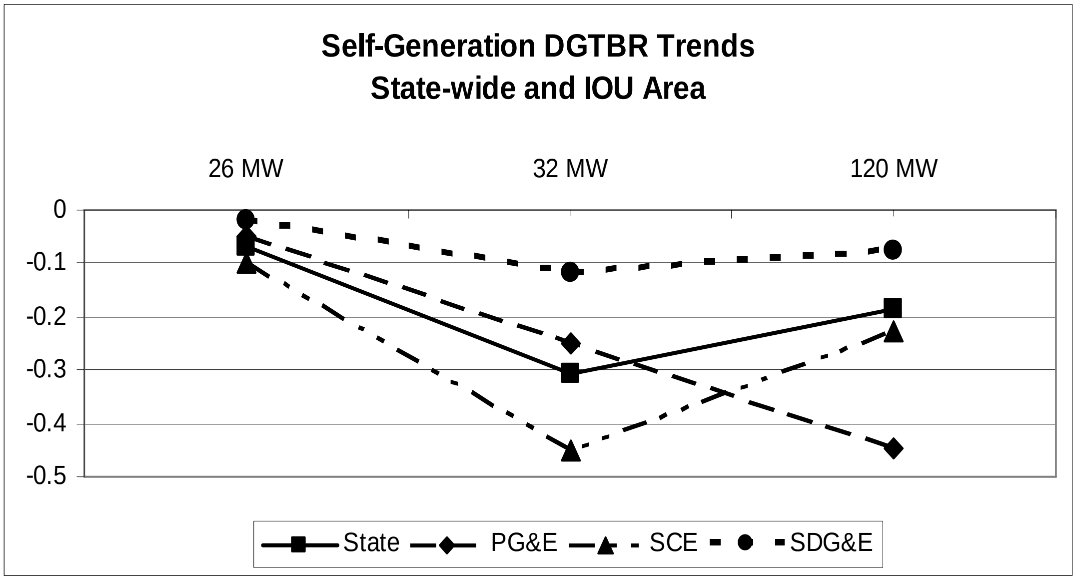


Figure 5-19 shows the DGTBR values by IOU area for the three penetration cases on one graph. There is a drop in the DGTBR from the 26 MW DG penetration to the 32 MW DG penetration for all three IOUs and for the state-wide scenario. What is interesting and the most confusing is the decline in the DGTBR from the 32 MW scenario to the 120 MW scenario for the state-wide, SCE, and SDG&E. There is consistency in the slope of the DGTBR lines for the state-wide, SCE, and SDG&E results. Since the DG penetration levels are so low compared to the IOU loads, the changes in the DGTBR are almost undetectable. One explanation to the changes in the slope could be the slight adjustment in the dispatch of the generating units. Depending on the concentration of the DG across the zones, there could be a very slight change in the dispatch that could have altered the calculation or the index value. However, more analysis would be needed to verify this is the case.

Figure 5-19: Results of DGTBR Impacts under Different Penetration Cases



The PG&E results for the three penetration cases are more consistent with what would have been expected. The DGTBR continues to increase in the negative direction indicating that the higher DG penetrations continue to improve system reliability.

From a transmission perspective, the SGIP DG facilities were found to provide direct benefits to the sub-transmission and transmission networks by reducing load at the load centers. Even on a transmission system that has a total connected load of over 40,000 MW, the methodology used in this analysis can calculate the transmission benefits for only 32 MW of self-generation. The IOU representation of their transmission system into zones allows for detailed power flow analysis into sub-regions. Because of the small penetration of DG capacity in the system, the DGTBR value is relatively small. However, the results seem to indicate that higher penetrations of DG capacity coincident with peak demand would result in higher DGTBR values.

Given the uncertainties associated with modeling of aggregated DG capacity at low penetration levels, the actual impacts cannot be accurately determined until a higher penetration of DG capacity is achieved along with a better understanding of the availability of DG facilities at time of peak. The analysis described in this study concentrates on the summer peak time period only. To improve the analytical results and conclusions, additional seasons such as spring and fall should be considered along with a time step analysis of self generation over a pre-determined time period.

5.4 Efficiency and Waste Heat Utilization

Cogeneration facilities represent a significant portion of the on-line generating capacity of the SGIP. To ensure that these facilities harness waste heat and realize high overall system and electricity efficiencies, Public Utility Code (PUC) 216.6[12] requires that participating nonrenewable-fueled fuel cells and engines/turbines meet minimum levels of thermal energy utilization and overall system efficiency.

PUC 216.6(a) requires that recovered useful waste heat from a cogeneration system exceeds five percent of the combined recovered waste heat plus the electrical energy output of the system. PUC 216.6(b) requires that the sum of the electric generation and half of the heat recovery of the system exceeds 42.5 percent of the energy entering the system as fuel. A summary of these requirements is presented in Table 5-15.

Table 5-15: Program Required PUC 216.6 Minimum Performance

Element	Definition	Minimum Requirement
216.6 (a)	Proportion of facilities' total annual energy output in the form of useful heat	5.0 percent
216.6 (b)	Overall system efficiency (50 percent credit for useful heat)	42.5 percent

SGIP facilities use a variety of means to recover heat for useful purposes, and apply that heat to provide various forms of heating and cooling services. The end-uses served by recovered useful thermal energy are summarized in Table 5-16, which includes all projects on-line through December 2006.

Table 5-16: End-Uses Served by Recovered Useful Thermal Energy (Total n and kW as of 12/31/2006)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	182	69,935
Heating & Cooling	58	35,526
Cooling Only	28	20,673
To Be Determined	20	23,171
Total	288	149,305

[12] PUC 216.6 has replaced PUC 218.5; however the requirements remain the same.

PY 2005/06 PUC 216.6 Compliance

Available metered thermal data collected from on-line cogeneration projects were used to calculate overall system efficiency by incorporating both the electricity produced as well as the useful recovered heat. Actual operating efficiencies from these metered systems were used to estimate heat recovery from non-metered systems where electricity production data were available. Results are summarized in Table 5-17.

Table 5-17: Cogeneration System Efficiencies (n=288)

Technology	n	216.6 (a) proportion	216.6 (b) Efficiency
Fuel Cell	11	43 percent	55 percent
IC Engine	181	42 percent	39 percent
Microturbine	96	50 percent	28 percent†

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

At least 10 months of operating data were available for 21 systems. In over 50 other cases less than 10 months of data were available for 2006. Because the basis of the PUC 216.6 proportions and efficiencies are annual, when at least nine months of data from several seasons are available, the calculated results were annualized and thus were considered representative of what could be expected on an annual basis.

Metered and estimated data collected to date suggest that roughly 17 out of 288 cogeneration projects achieved the 216.6 (b) overall system efficiency target of 42.5 percent. The limited quantities of cogeneration system data available for this impact analysis suggest the possibility that actual system efficiencies are systematically lower than planned system efficiencies. However, collection and analysis of additional data is required before definitive conclusions can be drawn. Data were available or estimated for 11 fuel cell projects, all of which satisfied the requirements of PUC 216.6 (a) and PUC 216.6 (b) system efficiency.

One of the fundamental objectives of the SGIP is to provide power at times of peak demand. Electrical production results were provided earlier in this section. Heat recovery results were produced specific to each of the pertinent peak days. Figure 5-20 provides normalized heat recovery by technology during the CAISO peak day. Results for each electric IOU are provided in Figure 5-21 through Figure 5-23.

Figure 5-20: Heat Recovery Rate during CAISO Peak Day

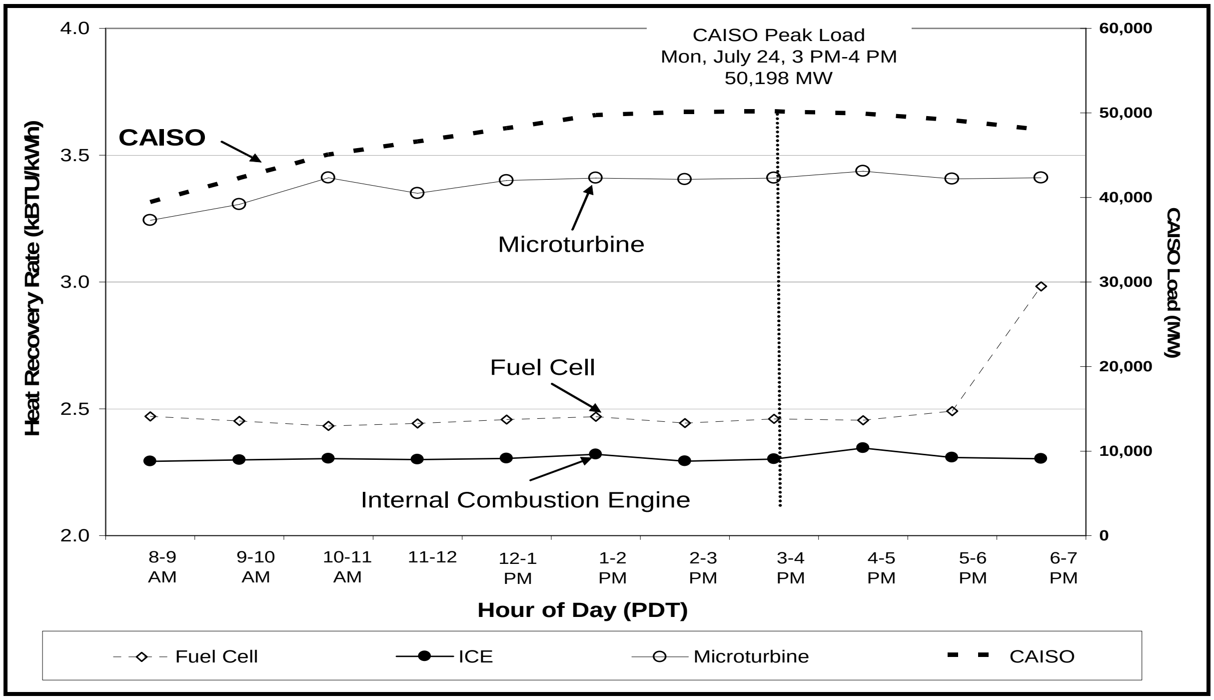


Figure 5-21: Heat Recovery Rate during PG&E Peak Day

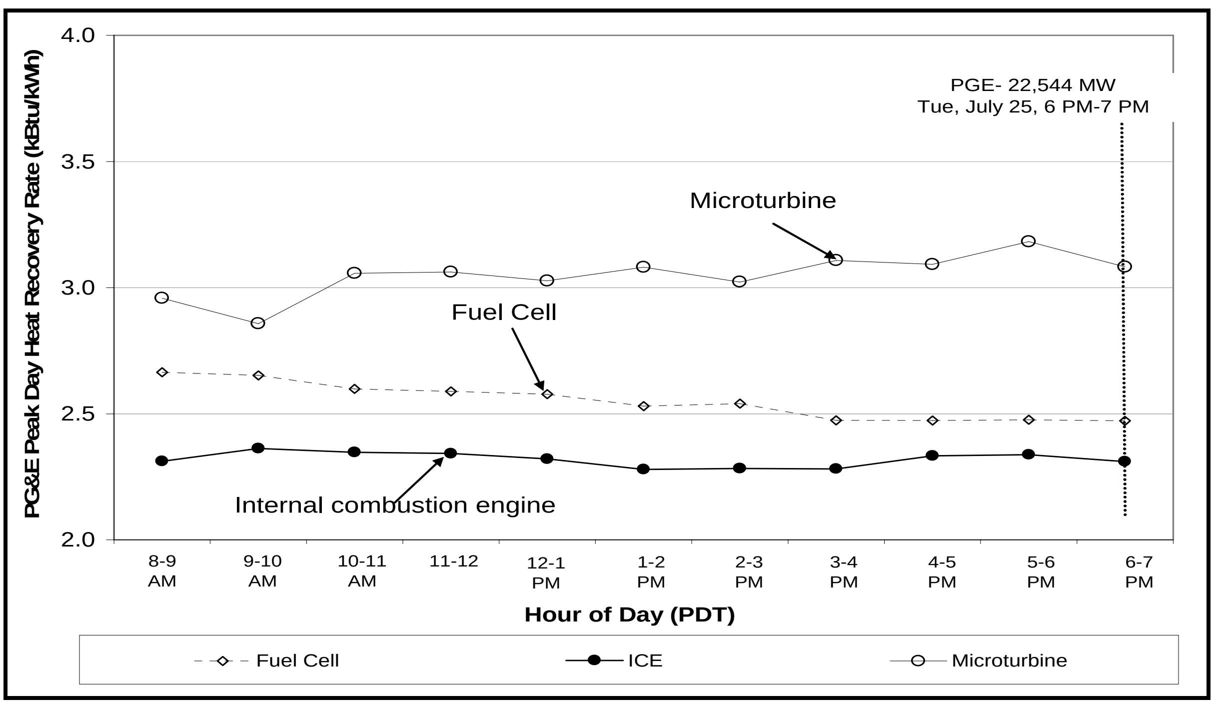


Figure 5-22: Heat Recovery Rate during SCE Peak Day

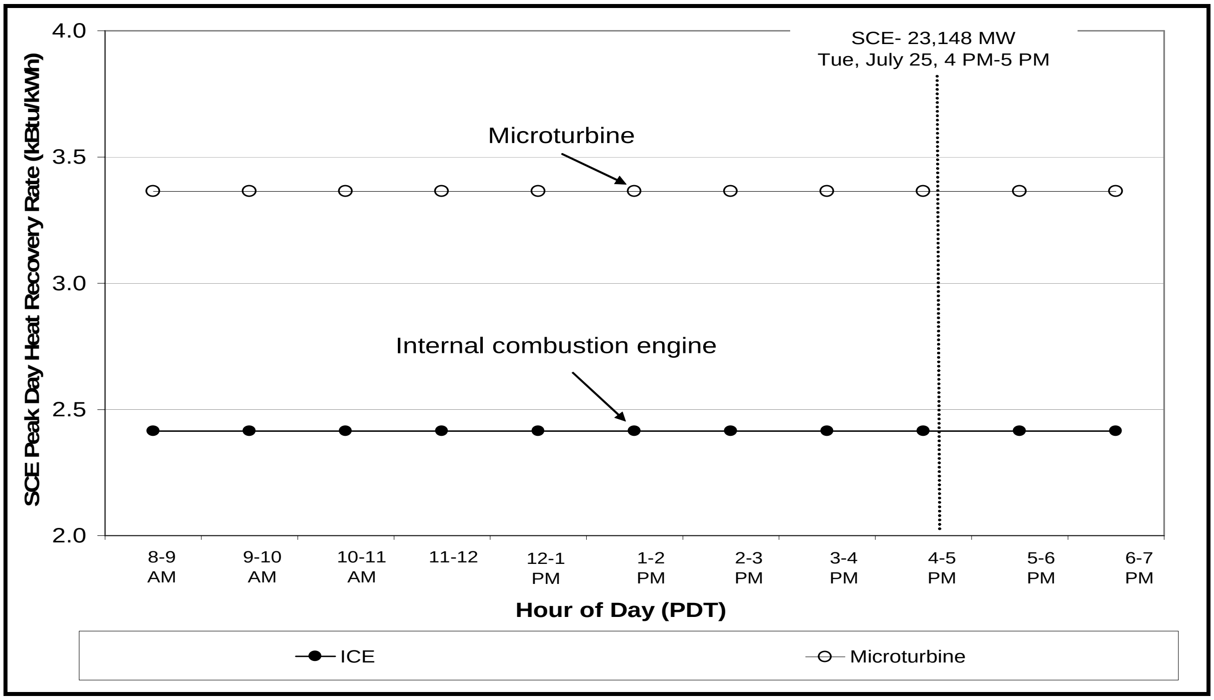
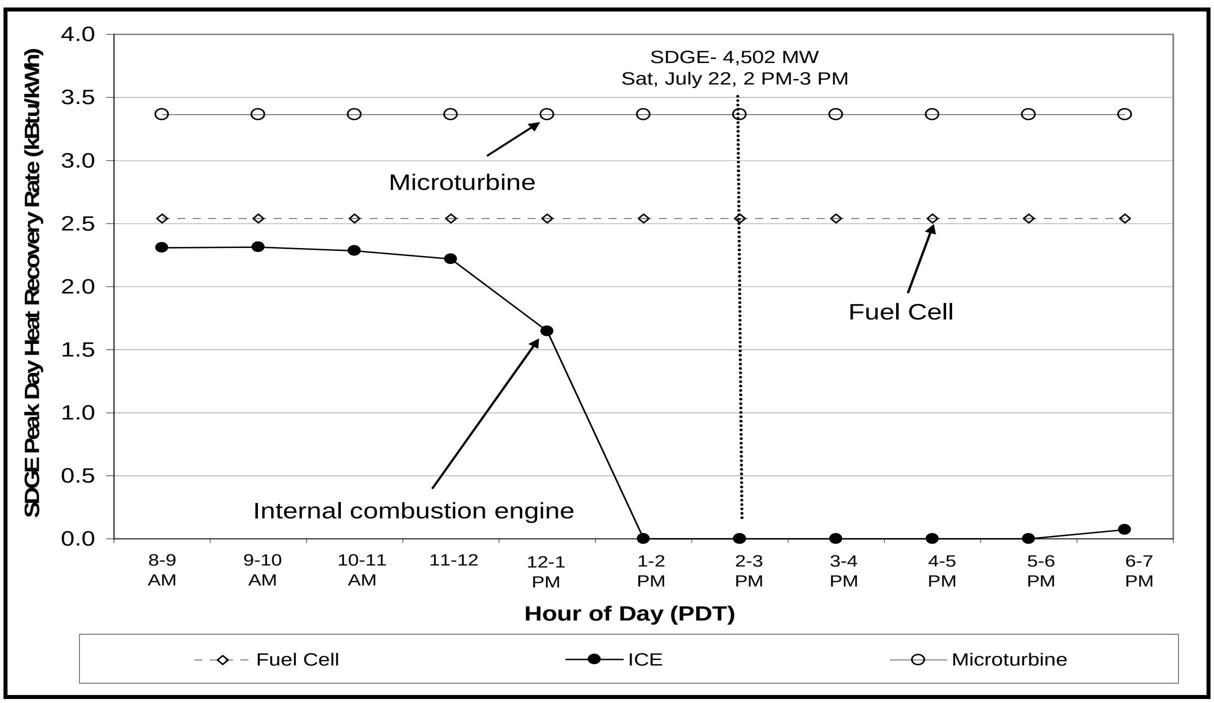


Figure 5-23: Heat Recovery Rate during CCSE Peak Day



Observations of interest from the above figures include:

- Microturbines recover more heat than fuel cells and ICEs. This is explained in part by the relatively lower electrical efficiency of microturbines. Lower electrical efficiency leaves more potential heat available for recovery.[13]
- Variability is not significant throughout the day
- There were no Fuel Cells active in SCE service territory during peak
- During SDG&E peak ICE heat recovery was unavailable. Combining this with the electrical production figure reveals that there was a decrease in capacity factor over the same time period, which corroborates the finding
- Straight lines imply estimated rather than metered heat recovery

AB 1685 (60 percent) Efficiency Status

System efficiencies were calculated for each nonrenewable-fueled cogeneration technology active in 2006. Table 5-18 provides summary statistics for each technology at the program level.

Table 5-18: Overall System Efficiency

Technology	n	Median Overall System Efficiency
Fuel Cell	11	70 percent†
IC Engine	181	50 percent
Microturbine	96	37 percent†

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

As shown, fuel cells are most successful in meeting the AB 1685 efficiency standard. In fact, only one of the eleven fuel cell systems failed to meet this standard. On the other hand, only four ICE systems met the standard and no MT systems met the standard. This result has important program design implications and should be examined periodically to assess improvement.

California Air Resources Board (CARB) NOx Compliance

Beginning in 2005, in addition to meeting the waste heat utilization requirement, nonrenewable-fueled engine/turbine projects submitting applications to the SGIP also have to meet the 2005 CARB NOx emission standard of 0.14 lbs/MWhr. This standard can be met by using a fossil fuel combustion emission credit for waste heat utilization so long as the

[13] Itron for the CPUC, "In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems," February 2007.

system meets the 60 percent minimum efficiency standard. The following formula is used to determine system efficiency:

$$SystemEfficiency = \frac{(E+T)}{F}$$

Where E is the generating system's rated electric capacity converted into equivalent Btu per hour, T is the generating system's waste heat recovery rate (Btu per hour) at rated capacity, and F is the generating system's higher heating value (HHV) fuel consumption rate (Btu per hour) at rated capacity.

The waste heat utilization credit is calculated by the following equation:

$$MW_{WH} = \frac{UtilizedWasteHeat\left(\frac{1}{3.4}\right)}{EFLH}$$

Where *UtilizedWasteHeat* is the annual utilized waste heat in MMBtu per year, 3.4 is the conversion factor from MWh to MMBtu, and *EFLH* is the system's annual equivalent full load hours of operation.

The following equation is used to determine if the system meets the NOx requirement:

$$NO_x = \frac{NO_x emissionrate}{MW_r + MW_{WH}}$$

Where *NOxemissionrate* is the system's verified emissions in pounds per MWh without thermal credit, MW_r is the system's rated capacity in MW, and MW_{WH} is the waste heat utilization credit in MW. The result will be a NOx emission rate (lbs per MWh) which utilizes the thermal credit. If this rate is less than 0.14 lbs per MWh then the system qualifies.

As of December 31, 2006, 20 nonrenewable-fueled engines/turbines have come online under this new program requirement. Of the 20 systems, seven are microturbines, two are gas turbines, and 11 are internal combustion engines. With the addition of the NOx requirement it appears that less internal combustion projects are being completed due to the additional cost of installing NOx controls, while more microturbine projects are being completed because microturbines have low NOx emissions before using NOx controls. All 20 systems have gone through NOx emission tests and theoretically meet the CARB NOx requirement. However it cannot be determined if these systems are meeting the standard under normal operating conditions because HEAT data is not yet available for any of these systems.

5.5 Greenhouse Gas Emission Reductions

Due to the continued interest and concern over the release of energy-related greenhouse gas (GHG) emissions, the impact of GHG emissions from SGIP projects during the 2006 program year was examined using a methodology similar to the one used to calculate the net change in GHG emissions in the SGIP Fifth Year Impact Evaluation Final Report[14]. While the basic approach remains the same, impacts presented in this report are refined to a greater level of detail. Instead of reporting net GHG emission reductions by incentive level (e.g., Level 1, 2, 3, 3-N, and 3-R) as they were before, impacts are presented in this report by technology and fuel group (e.g., renewable fueled microturbines, nonrenewable fueled gas turbines, renewable fueled fuel cells, etc.). This more detailed presentation allows for a deeper understanding of the type of cogeneration systems leading to the greatest net change in CO_2- and CH_4-specific GHG emissions.

GHG Analysis Approach

As in 2005, the net change in GHG emissions due to the operation of SGIP systems on-line during PY06 was based on metered electricity data. GHG emission reduction estimates derive from three sources:

1. Net differences in CO_2 emissions resulting from electricity supplied to utility customers from central station generation facilities versus electricity supplied by the customer's own SGIP generator;
2. Net CO_2 emission reductions due to electricity normally supplied from central station generation facilities to drive electrical chillers, but which instead is supplied by waste heat recovered from SGIP facilities and used to drive absorption chillers; and
3. Methane captured and used by biogas-fired SGIP facilities.

The only difference in the analysis approach used in the Fifth Year Impacts Evaluation Report and this Sixth Year Report is the waste heat recovery rates and the derivation of technology specific methane emission factors based on electrical efficiencies that vary by technology type. Recovery and use of waste heat at cogeneration sites reduces reliance on electricity generated from conventional power plants. Rates of waste heat recovery are therefore an essential part of estimating reductions of GHG emissions due to the SGIP. Average waste heat recovery rates were used in the 2005 Impacts Evaluation Report. The 2006 analysis approach uses technology-specific waste heat recovery rates based upon actual and estimated data from SGIP projects.

[14] Itron, Inc. CPUC Self-Generation Incentive Program Fifth Year Impact Evaluation: Final Report. Submitted to Pacific Gas and Electric Company and the Self-Generation Incentive Program Working Group. March 1, 2007.

GHG Analysis Results

Due to their different GHG emission sources, results are broken down by wind and PV facilities; non-renewable cogeneration facilities; and renewable-fuel (i.e., biogas-fueled) SGIP facilities.

GHG Reductions from PV and Wind Projects

The only source of GHG reductions from PV and wind projects is due to direct displacement of electricity that would have otherwise been generated from natural gas fired central station power plants. As a result, GHG emission reductions are based on the amount of CO_2 that would have been generated by the mix of utility electricity generation sources. Table 5-19 shows the reduction of CO_2-specific GHG emissions for PV and wind turbine projects. PV projects have greater GHG reductions relative to wind turbines (62,000 tons compared to just over 1,200 tons), because PV projects generated a much larger quantity of energy in comparison to wind turbine projects (103,306 MWh versus 2,102 MWh).

Table 5-19: Reduction of CO_2 Emissions from PV and Wind Projects in 2006 (Tons of CO_2)

Technology	Tons of CO_2 Emissions Reduced	Annual Energy Impact (MWhr)	CO_2 Factor (Tons/MWhr)
Photovoltaics	62,253	103,306	0.60
Wind Turbines	1,265	2,102	0.60
Total	**63,518**	**105,408**	**0.60**

GHG Reductions from Non-renewable Cogeneration Projects

Unlike PV and wind projects, non-renewable cogeneration projects realize GHG reductions from more than just direct displacement of grid-based electricity. Non-renewable cogeneration facilities also realize GHG reductions due to displacement of natural gas burned in boilers to provide process heating. The natural gas is displaced through the use of waste heat recovery systems incorporated into the SGIP facilities. In addition, some of the non-renewable cogeneration SGIP facilities use recovered waste heat in absorption chillers to provide facility cooling. If the absorption chillers replaced electric chillers, then net CO_2 reductions can accrue from the displaced electricity that would otherwise have driven the electric chiller. Table 5-20 provides a breakdown of CO_2 emissions from the various CO_2 sources possible for non-renewable SGIP cogeneration facilities and the overall net CO_2 reduction. Review of the net overall CO_2 reductions for each technology illustrates the importance of waste heat recovery on CO_2 reduction. For example, CO_2 emissions from IC engines exceed the amount of CO_2 associated with the direct displacement of grid electricity. Without waste heat recovery, IC engines would show a net gain in CO_2. Instead, indirect displacement of CO_2 through waste heat recovery provided IC engines with a net overall reduction in CO_2.

Table 5-20: Reduction of CO_2 Emissions from Non-renewable Cogeneration Projects in 2006 Categorized by Direct/Indirect Displacement (Tons of CO_2)

Technology	Direct Displacement from Grid	Cogeneration Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net CO_2 Emission Reductions
Fuel Cells	14,623	-11,750	3,240	63	6,176
Microturbines	25,936	-42,600	5,808	550	-10,306
IC Engines	195,745	-230,815	30,038	5,104	72
Gas Turbines	30,414	-49,896	11,967	90	-7,425
Total	**266,718**	**-335,061**	**51,053**	**5,807**	**-11,483**

It is beneficial to have a net CO_2 reduction factor when assessing the overall GHG implications associated with SGIP DG facilities and making comparisons between DG technologies. Table 5-21 is a listing of net CO_2 factors (in tons of CO_2 reduced per MWhr of electricity generated) for non-renewable cogeneration technologies. Negative net CO_2 reduction factors represent a net increase in CO_2 relative to electricity generated from the mix of utility central station power plants. The CO_2 factors for non-renewable projects range from a high of 0.24 tons per MWh for fuel cells to a low of -0.22 tons per MWh for microturbines. The non-renewable cogeneration CO_2 reduction factors are much smaller than the 0.6 tons per MWh factor calculated for PV and wind turbines.

Table 5-21: Reduction of CO_2 Emissions from Non-renewable Cogeneration Projects in 2006 (Tons of CO_2)

Technology	Tons of CO_2 Emissions Reduced	Annual Energy Impact (MWhr)	CO_2 Factor (Tons/MWhr)
Fuel Cells	6,176	26,170	0.24
Microturbines	-10,306	47,202	-0.22
IC Engines	72	353,436	0.0002
Gas Turbines	-7,245	55,287	-0.13
Total	**-11,303**	**482,095**	**-0.024**

<u>GHG Reductions from Renewable (Biogas) Projects</u>

The last fuel and technology combinations considered in this GHG emission reduction impact analysis are fuel cells, microturbines, and IC engines fueled with renewable biogas. Some of the biogas powered SGIP facilities generate only electricity, but others are cogeneration facilities that use waste heat recovery to produce process heating or cooling.

Consequently, biogas powered cogeneration facilities can reduce CO_2 emissions in the same way as non-renewable cogeneration facilities, but can also include GHG emission reductions due to captured methane (CH_4).

Table 5-22 provides a listing of CO_2 reductions occurring from biogas powered cogeneration facilities. Similar to the non-renewable cogeneration facilities, CO_2 reductions can accrue from direct displacement and indirect displacement sources. The net CO_2 reduction factors for renewable fuel technologies are presented in Table 5-23. These results show that renewable IC engines and fuel cells have similar CO_2 reduction factors while renewable microturbines lead to increases in carbon dioxide in a similar manner to its non-renewable fuel counterpart.

Table 5-22: Reduction of CO_2 Emissions from Renewable Cogeneration Projects in 2006 Categorized by Direct and Indirect Displacement (Tons of CO_2)

Technology	Direct Displacement from Grid	Cogeneration Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net CO_2 Emission Reductions
Fuel Cells	1,379	-1,121	328	0	586
Microturbines	5,109	-8,377	587	281	-2,400
IC Engines	5,600	-6,683	1,346	0	263
Total	**12,088**	**-16,180**	**2,261**	**281**	**-1,551**

Table 5-23: Reduction of CO_2 Emissions from Renewable Cogeneration Projects in 2006 (Tons of CO_2)

Technology	Tons of CO_2 Emissions Reduced	Annual Energy Impact (MWhr)	CO_2 Factor (Tons/MWhr)
Fuel Cells	586	2,498	0.2
Microturbines	-2,400	9,281	-0.26
IC Engines	263	10,233	0.26
Total	**-1,551**	**22,012**	**0.07**

As indicated earlier, biogas powered SGIP facilities not only realize GHG reductions due to CO_2 reductions, but also due to captured methane. In particular, this is methane that would have otherwise been emitted to the atmosphere. When reporting GHG emission reductions from different types of greenhouse gases, the convention is to report the GHG reductions in terms of tons of CO_2 equivalent. Methane has a GHG equivalence twenty-one times that of CO_2 and so methane reductions from biogas powered SGIP facilities can be converted to CO_2 equivalent through this conversion factor.

An analysis of the SGIP tracking data showed a list of 20 facilities that relied upon renewable biogas fuels during 2006. The total electricity generated from these sites was multiplied by technology-specific emission factors for CH_4 to calculate the total CH_4 emissions avoided by relying upon methane to generate power from these SGIP facilities.[15] Table 5-24 presents the tons of CH_4 emissions avoided and tons of CO_2 equivalent[16] by renewable fuel technology type. The largest reduction of methane-specific GHG emissions comes from renewable fueled microturbines, which are responsible for almost 75 percent of the total methane emission reductions. Renewable fuel cells and renewable IC engine cogeneration systems are responsible for much smaller fractions of the total methane-specific GHG emission reductions. This difference in tons of emissions reduced by renewable fuel technology type stems from the number of facilities using each type of technology. Of the cogeneration systems that rely upon renewable fuel sources, 15 are microturbine, 1 is fuel cell, and 4 are internal combustion engine facilities.

Table 5-24: Reduction of CH_4 Emissions from Renewable Cogeneration Projects in 2006 (in Tons of CH_4 and Tons of CO_2 equivalent)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells	149	3,129
Internal Combustion Engines	390.5	8,200.5
Microturbines	2,331	48,951
Total	**2,870.5**	**60,280.5**

Total Net Change in GHG Emissions

To determine the total net GHG impact of SGIP facilities during 2006, the net GHG reductions must be reported in units of CO_2 equivalent to allow a basis of comparison. Table 5-25 shows the tons of GHG emissions reduced in tons of CO_2 equivalent, broken down by the different SGIP fuel and technology combinations. [17] The total reduction of GHG

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[15] See Appendix C for the derivation of renewable fuel technology -specific CH_4 emission factors. They are equal to 237 grams per kWhr for IC Engines, 327.8 grams per kWhr for microturbines, and 163.9 grams per kWhr for fuel cells.

[16] Carbon dioxide equivalent is a metric measure used to compare the emissions of various greenhouse gases based upon their global warming potential (GWP). The carbon dioxide equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP. For example, the global warming potential of methane over 100 years is 21. This means that one million metric tons of methane are equivalent to emissions of 21 million metric tons of carbon dioxide over the 100 year time horizon. OECD Glossary of Statistical Terms, http://stats.oecd.org/glossary/detail.asp?ID=285

[17] Note that the results in Table 5-I can be developed by adding the equivalent CO_2 values in Table 5-22 to the direct CO_2 values in Table 5-17, Table 5-19, and Table 5-21 (note, due to rounding, this sum is approximately equal to the sum of total GHG emissions reduced presented in Table 5-23)..

emissions measured in CO_2 equivalent units is approximately 100,630 tons with the largest portions of this reduction coming from photovoltaic projects, followed by renewable fueled microturbines. During the 2005 program year, the total GHG emission reduction calculated for the SGIP projects was slightly less at 93,000 tons of CO_2 equivalent. Most of these reductions also came from PV projects as well. We can also see that the fuel/technology cogeneration group contributing the largest energy impact is non-renewable fueled IC engines.

The last column in Table 5-25 presents ratios of the tons of GHG emissions reduced per MWh generated by each fuel and technology category for the 2006 program year. Renewable fuel technologies have the highest ratios (mostly due to the potent CH_4 emission reductions), while non-renewable microturbines have the lowest. Unlike in the 2005 Impact Report where a single ratio for the Level 3, 3-R, and 3-N projects was presented, we were able to disaggregate our results to the fuel/technology level because annual energy impacts were available at this level for this evaluation. The CO_2 factors range from a high of 5.0 for renewable fuel microturbines to a low of -0.22 for non-renewable fueled microturbines. It is interesting to note that the ratio of tons of CO_2 equivalent reduced per MWh is now positive for renewable fueled microturbines because methane reductions from this group of projects is considered in the table below. When only CO_2 emissions are considered, this project group emits more emissions than it reduces.

Table 5-25: Net Reduction of GHG Emissions from SGIP Systems Operating in Program Year 2006 (Tons of CO_2 eq.) by Fuel and Technology and Ratios of Tons of GHG Reductions per MWh

Technology	Tons of CO_2 eq. Reduced	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWhr)
Photovoltaics	62,253	103,306	0.60
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	6,176	26,170	0.24
Non-renewable MT	-10,306	47,202	-0.22
Non-renewable fueled ICE	72	353,436	0.0002
Non-renewable and waste gas fueled small gas turbines	-7,245	55,287	-0.13
Renewable fueled fuel cells	3,715	2,498	1.49
Renewable fueled MT	46,551	9,281	5.01
Renewable fueled IC Engines	8,463.5	10,233	0.82
TOTAL	**110,945**	**609,515**	**0.18**

Net Change in GHG Emissions by Program Administrator

Table 5-26 through Table 5-29 present the reduction of CO_2 emissions in 2006 by Program Administrator and fuel/technology group.[18] These tables also include the annual energy impact and the CO_2 factor for each group as well. A comparison of these tables show that the PA responsible for the largest reduction of CO_2 emissions is PG&E (28,884 tons) followed by SCE (10,901 tons), CCSE (9,192), and SCG (1,550 tons). In fact, PG&E projects reduce more than two times the amount of emissions than SCE. As far as energy impacts are concerned, PG&E's projects generate the most overall (268,480 MWh), followed by SCG (197,823 MWh), SCE (86,601 MWh), and CCSE (56,611 MWh).

Table 5-26: Technology Specific CO_2 Reductions for PG&E

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	32,727	55,796	0.59
Wind turbines	-	-	-
Non-renewable fuel cells (6 projects)	3,377	14,893	0.23
Non-renewable MT (33 projects)	-3,239	15,250	-0.21
Non-renewable fueled ICE (73 projects)	-661	156,163	-0.004
Non-renewable and waste gas fueled small gas turbines (2 projects)	-2,565	17,944	-0.14
Renewable fueled fuel cells	-	-	-
Renewable fueled MT (9 projects)	-882	3,549	-0.25
Renewable fueled ICE (6 projects)	87	4,885	0.11
TOTAL	**28,884**	**268,480**	**0.11**

[18] Note that the California Center for Sustainable Energy (CCSE) is the program administrator for San Diego Gas and Electric Company.

Table 5-27: Technology Specific CO_2 Reductions for SCE

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	12,782	20,442	0.63
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	134	493	0.27
Non-renewable MT	-2,597	11,821	-0.22
Non-renewable fueled ICE	1	38,543	0.00
Non-renewable and waste gas fueled small gas turbines	-	-	-
Renewable fueled fuel cells	586	2,498	0.23
Renewable fueled MT	-1,446	5,354	-0.27
Renewable fueled IC Engines	176	5,348	0.03
TOTAL	**10,901**	**86,601**	**0.13**

Table 5-28: Technology Specific CO_2 Reductions for SCG

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	8,063	13,093	0.62
Wind turbines	-	-	-
Non-renewable fuel cells	533	1,921	0.28
Non-renewable MT	-3,889	17,220	-0.22
Non-renewable fueled ICE	1,218	130,897	0.009
Non-renewable and waste gas fueled small gas turbines	-4,375	34,692	-0.13
Renewable fueled fuel cells	-	-	-
Renewable fueled MT	-	-	-
Renewable fueled IC Engines	-	-	-
TOTAL	**1,550**	**197,823**	**0.008**

Table 5-29: Technology Specific CO_2 Reductions for CCSE

Technology	Tons of CO_2 Reduced	Energy Impact in MWh	CO_2 Factor (Tons/MWhr)
Photovoltaics	8,681	13,976	0.62
Wind turbines	-	-	-
Non-renewable fuel cells	2,132	8,863	0.24
Non-renewable MT	-580	2,911	-0.20
Non-renewable fueled ICE	-484	27,833	-0.02
Non-renewable and waste gas fueled small gas turbines	-486	2,650	-0.18
Renewable fueled fuel cells	-	-	-
Renewable fueled MT	-71	378	-0.19
Renewable fueled IC Engines	-	-	-
TOTAL	**9,192**	**56,611**	**0.16**

The overall CO_2 factor is shown for each PA and is calculated by dividing the total CO_2 emissions reduced by the total annual energy impact. A comparison of these factors show that CCSE has the highest ratio (0.17), followed by PG&E and SCE (both with ratios of 0.14). A more detailed examination of the CO_2 factors shows that the PA-specific ratios are highest for PV projects and tend to be lowest for renewable and non-renewable fueled microturbines.

The next three tables, Table 5-30 through Table 5-32, show the methane reductions by PA and renewable fuel technology group (the renewable fuel technologies are the only types to have measurable impacts on CH_4-specific GHG emissions). Again, PG&E reduces the largest quantity of emissions (1,418 tons), followed closely behind by SCE (1,329 tons). The renewable fuel projects under CCSE are responsible for a much smaller fraction of CH_4 reductions at just under 125 tons. This is due to the fact that CCSE oversees only 3 microturbine projects while SCE oversees 1 fuel cell, 1 internal combustion engine, and 3 microturbine projects. It is interesting to not that PG&E oversees even more projects (9 microturbine and 3 internal combustion engine projects) but does not reduce more methane emissions than SCE.

Table 5-30: Technology Specific CH_4 Reductions for PG&E (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells	-	-
Microturbines (9 projects)	1,162	24,402
IC Engines (3 projects)	256	5,376
TOTAL	**1,418**	**29,778**

Table 5-31: Technology Specific CH_4 Reductions for SCE (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells (1 project)	149	3,129
Microturbines (3 projects)	1,045	21,945
IC Engines (1 project)	135	2,835
TOTAL	**1,329**	**27,909**

Table 5-32: Technology Specific CH_4 Reductions for CCSE (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Reduced	Tons of CO_2 eq. Reduced
Fuel Cells	-	-
Microturbines (3 projects)	124	2,604
IC Engines	-	-
TOTAL	**124**	**2,604**

The last set of tables presents the total GHG emission reduction impact by program administrator. The total GHG emission reduction represents the sum of methane emission reductions as converted to CO_2 equivalent and with the non-methane CO_2 reductions. Table 5-33 through
Table 5-35 present the CO_2 equivalent factors by PA and technology. Note that SCG did not have any renewable fueled DG projects. As a result, no methane-specific GHG emission reductions stemmed from projects administrated by SCG. For this reason, their results remain the same as those presented in Table 5-29.

Table 5-33: Technology Specific GHG Emission Reductions and CO_2 eq. Factors for PG&E (in tons of CO_2 eq.)

Technology	Tons of CO_2 eq. Reduced	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWhr)
Photovoltaics	32,727	55,796	0.59
Wind turbines	-	-	-
Non-renewable fuel cells	3,377	14,893	0.23
Non-renewable MT	-3,239	15,250	-0.21
Non-renewable fueled ICE	-661	156,163	-0.004
Non-renewable and waste gas fueled small gas turbines	-2,565	17,944	-0.14
Renewable fueled fuel cells	-	-	-
Renewable fueled MT	23,520	3,549	6.63
Renewable fueled IC Engines	5,463	4,885	1.12
TOTAL	**58,622**	**268,480**	**0.22**

Table 5-34: Technology Specific GHG Emission Reductions and CO_2 eq. Factors for SCE (in tons of CO_2 eq.)

Technology	Tons of CO_2 eq. Reduced	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWhr)
Photovoltaics	12,782	20,442	0.63
Wind turbines	1,265	2,102	0.60
Non-renewable fuel cells	134	493	0.27
Non-renewable MT	-2,597	11,821	-0.22
Non-renewable fueled ICE	1	38,543	0.00
Non-renewable and waste gas fueled small gas turbines	-	-	-
Renewable fueled fuel cells	3,715	2,498	1.49
Renewable fueled MT	20,499	5,354	3.83
Renewable fueled IC Engines	3,011	5,348	0.56
TOTAL	**38,810**	**86,601**	**0.45**

Table 5-35: Technology Specific GHG Emission Reductions and CO_2 eq. Factors for CCSE (in tons of CO_2 eq.)

Technology	Tons of CO_2 eq. Reduced	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWhr)
Photovoltaics	8,681	13,976	0.62
Wind turbines	-	-	-
Non-renewable fuel cells	2,132	8,863	0.24
Non-renewable MT	-580	2,911	-0.20
Non-renewable fueled ICE	-484	27,833	-0.02
Non-renewable and waste gas fueled small gas turbines	-486	2,650	-0.18
Renewable fueled fuel cells	-	-	-
Renewable fueled MT	2,533	378	6.7
Renewable fueled IC Engines	-	-	-
TOTAL	**11,796**	**56,611**	**0.21**

Appendix A

System Costs and Energy and Demand Impacts

A.1 Overview

This appendix summarizes system costs and energy and demand impacts and relative performance, described in terms of capacity factors for specific time periods, of the fifth-year impacts evaluation. It describes demand impacts and capacity factors for the CAISO peak day as well as for the individual electric utility peak days. This appendix is divided into three sections. The first sections presents results for the program overall. The second and third sections present results for renewable and non-renewable technologies respectively. The sequence of each section is as follows:

1. Costs
   Eligible Costs
   Incentives
   Other Incentives
   Total Incentives
2. Annual Energy
   Annual Electric Energy Totals by PA
   Quarterly Electric Energy Totals
3. Peak Demand
   CAISO Peak Hour Demand Impacts
   Electric Utility Peak Hours Demand Impacts
4. Capacity Factors
   Annual Capacity Factors
   Annual Capacity Factors by Technology
   Annual Capacity Factors by Technology and PA
   Monthly Capacity Factors by Technology
   CAISO Peak Day Capacity Factors by Technology
   Electric Utility Peak Day Capacity Factors by Technology

Reporting of overall program results and of annual energy by technologies includes a distinction between metered and estimated values. Metered values have very little uncertainty, most meters having accuracies within one percent. The uncertainty of estimated values is greater and is the primary determinant of the margin of error of results.

Results presented for the peak days of the three individual electric utility do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

This appendix summarizes relative performance of groups of systems in terms of their weighted average capacity factors for specific time periods. These measures describe electric net generation output relative to a unit of system rebated capacity. For example, an hourly capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system rebated capacity.

A.2 Program Totals

Costs

Table A-1 lists total eligible costs, SGIP incentives, and other incentives by system type and fuel.

Table A-1: Completed and Active System Costs by Technology and Fuel

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
FC	**N**	Eligible Cost	$41.5	$20.0
		Incentive	$13.2	$7.3
		Other Incentive	$2.5	$0.5
		Total Incentive	$15.7	$7.8
FC	**R**	Eligible Cost	$7.3	$50.5
		Incentive	$3.4	$35.1
		Other Incentive	$0.0	$0.5
		Total Incentive	$3.4	$35.6
GT	**N**	Eligible Cost	$21.7	$26.6
		Incentive	$2.9	$2.4
		Other Incentive	$0.0	$0.0
		Total Incentive	$2.9	$2.4
ICE	**N**	Eligible Cost	$243.0	$161.3
		Incentive	$63.6	$20.8
		Other Incentive	$0.8	$0.1
		Total Incentive	$64.3	$20.9
ICE	**R**	Eligible Cost	$16.6	$21.3
		Incentive	$5.7	$5.1
		Other Incentive	$0.5	$0.0
		Total Incentive	$6.1	$5.1
MT	**N**	Eligible Cost	$42.4	$29.2
		Incentive	$11.5	$5.1
		Other Incentive	$0.5	$0.6
		Total Incentive	$12.0	$5.6
MT	**R**	Eligible Cost	$9.8	$3.3
		Incentive	$3.4	$1.1
		Other Incentive	$0.5	$0.6
		Total Incentive	$3.9	$1.6
PV		Eligible Cost	$664.4	$1,312.3
		Incentive	$296.9	$411.1
		Other Incentive	$0.5	$0.6
		Total Incentive	$297.4	$411.7
WD		Eligible Cost	$5.4	$8.1
		Incentive	$2.6	$4.2
		Other Incentive	$0.5	$0.6
		Total Incentive	$3.1	$4.8
		Total Eligible Cost	$1,052.0	$1,632.7
		Total Incentive	$403.1	$492.1
		Total Other Incentive	$5.7	$3.3
		Total All Incentives	$408.8	$495.5

Annual Energy

Table A-2 presents annual total net electrical output in MWH for the program and for each PA. It also shows subtotals for each PA and technology. Later tables in this appendix differentiate by natural gas versus renewable methane fuel. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-2: Annual Electric Energy Totals by Technology and PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	**Total**	**14,893**	**2,991**	**1,921**	**8,863**	**28,668**
	M	6,407	1,672	0	7,794	15,873
	E	8,486	1,319	1,921	1,069	12,795
GT	**Total**	**17,944**	**0**	INFORMATION		**55,287**
	M	HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
	E					
ICE	**Total**	**161,048**	**44,067**	**130,897**	**27,833**	**363,845**
	M	33,387	22,448	77,042	27,627	160,504
	E	127,661	21,619	53,855	207	203,342
MT	**Total**	**18,798**	**17,175**	**17,211**	**3,289**	**56,473**
	M	2,671	9,801	5,677	3,232	21,381
	E	16,126	7,374	11,535	57	35,092
PV	**Total**	**56,509**	**20,372**	**13,093**	**14,036**	**104,010**
	M	27,334	2,647	4,872	10,429	45,282
	E	29,175	17,725	8,221	3,607	58,729
WD	**Total**	**0**	**2,274**	**0**	**0**	**2,274**
	M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
	E					
	Total	**269,193**	**86,879**	**197,815**	**56,671**	**610,557**

Table A-3 presents quarterly total net electrical output in MWH for the program. It also shows subtotals for each technology and fuel, natural gas versus renewable methane. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-3: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
FC	**N**	**Total**	**4,573**	**4,874**	**6,932**	**9,792**	**26,170**
		M	3,619	3,542	3,428	3,612	14,201
		E	954	1,332	3,504	6,179	11,969
FC	**R**	**Total**	**646**	**614**	**520**	**718**	**2,498**
		M	646	614	173	239	1,672
		E	0	0	347	479	825
GT	**N**	**Total**	**13,686**	**12,189**	**13,009**	**16,403**	**55,287**
		M	8,584	10,249	10,969	11,489	41,291
		E	5,102	1,939	2,040	4,914	13,996
ICE	**N**	**Total**	**85,833**	**91,147**	**92,170**	**84,286**	**353,436**
		M	38,354	41,498	41,442	35,991	157,283
		E	47,479	49,649	50,729	48,296	196,153
ICE	**R**	**Total**	**1,484**	**2,547**	**3,161**	**3,218**	**10,409**
		M	802	919	777	723	3,220
		E	682	1,628	2,384	2,495	7,189
MT	**N**	**Total**	**10,463**	**12,027**	**12,193**	**12,508**	**47,191**
		M	4,433	4,781	4,179	5,448	18,841
		E	6,030	7,246	8,014	7,060	28,351
MT	**R**	**Total**	**1,697**	**2,331**	**2,032**	**3,221**	**9,281**
		M	498	629	554	859	2,540
		E	1,199	1,703	1,478	2,362	6,741
PV		**Total**	**17,586**	**31,507**	**35,199**	**19,718**	**104,010**
		M	8,437	13,963	13,891	8,991	45,282
		E	9,149	17,544	21,308	10,727	58,729
WD		**Total**	**521**	**651**	**707**	**394**	**2,274**
		M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
		E					
		TOTAL	**136,489**	**157,886**	**165,923**	**150,259**	**610,557**

Peak Demand

Table A-4 presents total net electrical output in kW for the program during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows for each technology and basis the subtotals of output, of counts of systems, and of total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate peak demand impacts by natural gas versus renewable methane fuel.

Table A-4: CAISO Peak Hour Demand Impacts

CAISO Peak (MW)	Date	Hour (PDT)
50,198	24-Jul-06	3 PM

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC	**Total**	**8**	**4,800**	**3,372**	0.703 [a]
	M	3	2,250	1,735	0.771 [a]
	E	5	2,550	1,637	0.642 †
GT	**Total**	**3**	**7,093**	**5,789**	0.816 †
	M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			
	E				
ICE	**Total**	**185**	**116,184**	**49,942**	0.430 [a]
	M	84	52,565	22,245	0.423 [a]
	E	101	63,619	27,697	0.435 †
MT	**Total**	**98**	**16,182**	**5,465**	0.338 [a]
	M	43	6,370	1,883	0.296 †
	E	55	9,812	3,581	0.365 †
PV	**Total**	**609**	**75,808**	**38,744**	0.511 [a]
	M	203	33,443	16,553	0.495 [a]
	E	406	42,365	22,192	0.524 †
WD	**Total**	**2**	**1,649**	**53**	0.032
	M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			
	E				
	TOTAL	**905**	**221,715**	**103,365**	

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-1 plots profiles of hourly total net electrical output in kW for each technology from morning to early evening during the day of the annual peak hour, July 24, 2006. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. The preceding table shows the values of net output for each technology during the peak hour. Again, later tables and charts in this appendix differentiate by natural gas versus renewable methane fuel.

Figure A-1: CAISO Peak Day Output by Technology

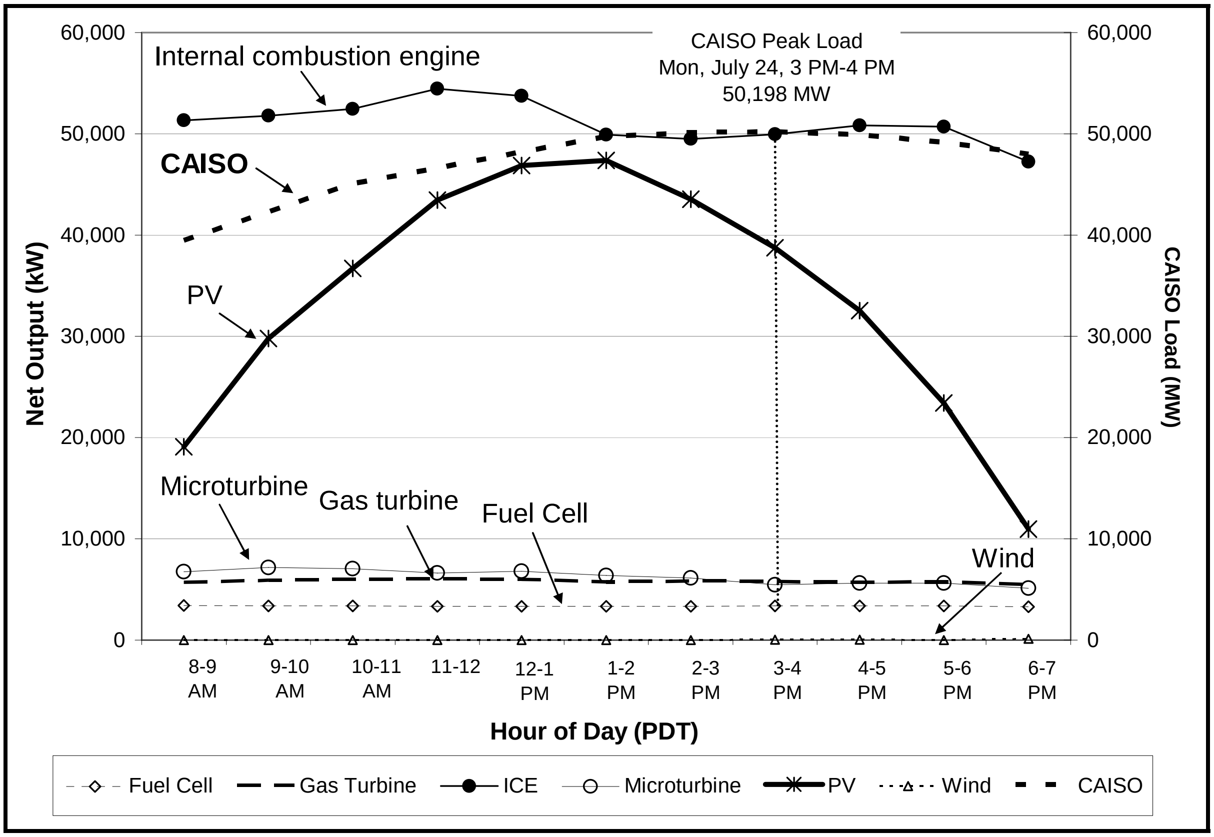


Table A-5, Table A-6, and Table A-7 list for each electric utility the hourly total net electrical output in kW during the annual peak hour from 3-4 p.m., July 24, 2006. The tables also list the number of systems on-line, their combined capacities, and their hourly capacity factors. The last three rows of each table summarize the results across all technologies and fuels. Results presented for the three individual electric utilities for the CAISO peak hour do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table A-5: CAISO Peak Hour Output by Technology, Fuel, Basis and Electric Utility—PG&E

			On-Line Systems	Operational	Impact	Hourly Capacity Factor
Technology	**Fuel**	**Basis**	**(n)**	**(kW)**	**(kW)**	**(kWh/kWh)**
FC	**N**	**Total**	**5**	**3,050**	**2,260**	0.741
		M	1	1,000	801	0.801
		E	4	2,050	1,459	0.712
FC	**R**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
GT	**N**	**Total**	**2**	**2,593**	**1,933**	0.746
		M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			
		E				
ICE	**N**	**Total**	**73**	**44,897**	**21,544**	0.480
		M	18	9,439	4,506	0.477
		E	55	35,458	17,038	0.481
ICE	**R**	**Total**	**5**	**3,370**	**533**	0.158
		M	0	0	0	
		E	5	3,370	533	0.158
MT	**N**	**Total**	**24**	**4,448**	**1,497**	0.337
		M	4	960	156	0.163
		E	20	3,488	1,341	0.385
MT	**R**	**Total**	**9**	**1,420**	**311**	0.219
		M	0	0	0	
		E	9	1,420	311	0.219
PV		**Total**	**276**	**38,039**	**23,260**	0.611
		M	91	18,920	11,722	0.620
		E	185	19,119	11,538	0.603
WD		**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
		TOTAL	**394**	**97,817**	**51,339**	0.525
		M	115	31,702	18,204	0.574
		E	279	66,115	33,135	0.501

Table A-6: CAISO Peak Hour Output by Technology, Fuel, Basis and Electric Utility—SCE

			On-Line Systems	Operational	Impact	Hourly Capacity Factor
Technology	**Fuel**	**Basis**	**(n)**	**(kW)**	**(kW)**	**(kWh/kWh)**
FC	**N**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
FC	**R**	**Total**	**2**	**750**	**178**	0.237
		M	1	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
		E	1			
GT	**N**	**Total**	**1**			
		M	1			
		E	0			
ICE	**N**	**Total**	**78**	**51,685**	**22,160**	0.429
		M	46	30,706	13,960	0.455
		E	32	20,979	8,199	0.391
ICE	**R**	**Total**	**4**	**2,491**	**174**	0.070
		M	2	1,695	0	
		E	2	796	174	0.219
MT	**N**	**Total**	**40**	**6,622**	**2,382**	0.360
		M	24	3,488	1,187	0.340
		E	16	3,134	1,195	0.381
MT	**R**	**Total**	**4**	**1,040**	**443**	0.426
		M	1	420	179	0.426
		E	3	620	264	0.425
PV		**Total**	**177**	**19,179**	**8,523**	0.444
		M	27	2,580	1,262	0.489
		E	150	16,599	7,261	0.437
WD		**Total**	**2**	**1,649**	**53**	0.032
		M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			
		E				
		TOTAL	**308**	**87,916**	**37,768**	0.430
		M	104	45,288	20,497	0.453
		E	204	42,628	17,271	0.405

Table A-7: CAISO Peak Hour Output by Technology, Fuel, Basis and Electric Utility—SDG&E

			On-Line Systems	Operational	Impact	Hourly Capacity Factor
Technology	**Fuel**	**Basis**	**(n)**	**(kW)**	**(kW)**	**(kWh/kWh)**
FC	**N**	**Total**	**1**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
		M	1			
		E	0			
FC	**R**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
GT	**N**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
ICE	**N**	**Total**	**18**	**10,725**	**3,779**	0.352
		M	18	10,725	3,779	0.352
		E	0	0	0	
ICE	**R**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
MT	**N**	**Total**	**12**	**1,058**	**370**	0.350
		M	11	938	328	0.350
		E	1	120	42	0.350
MT	**R**	**Total**	**3**	**564**	**33**	0.059
		M	3	564	33	0.059
		E	0	0	0	
PV		**Total**	**76**	**8,848**	**1,904**	0.215
		M	73	8,631	1,858	0.215
		E	3	217	45	0.209
WD		**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
		TOTAL	**110**	**22,196**	**7,020**	0.316
		M	106	21,858	6,933	0.317
		E	4	337	87	0.259

Figure A-2, Figure A-3, and Figure A-4 plot for each electric utility profiles of hourly total net electrical output in kW for each technology from morning to early evening during the day of the annual peak hour, July 24, 2006. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. The preceding tables list the values associated with these charts for the peak hour. Results presented for the three individual electric utilities on the CAISO peak day do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Figure A-2: CAISO Peak Day Output by Technology, Fuel, and Electric Utility —PG&E

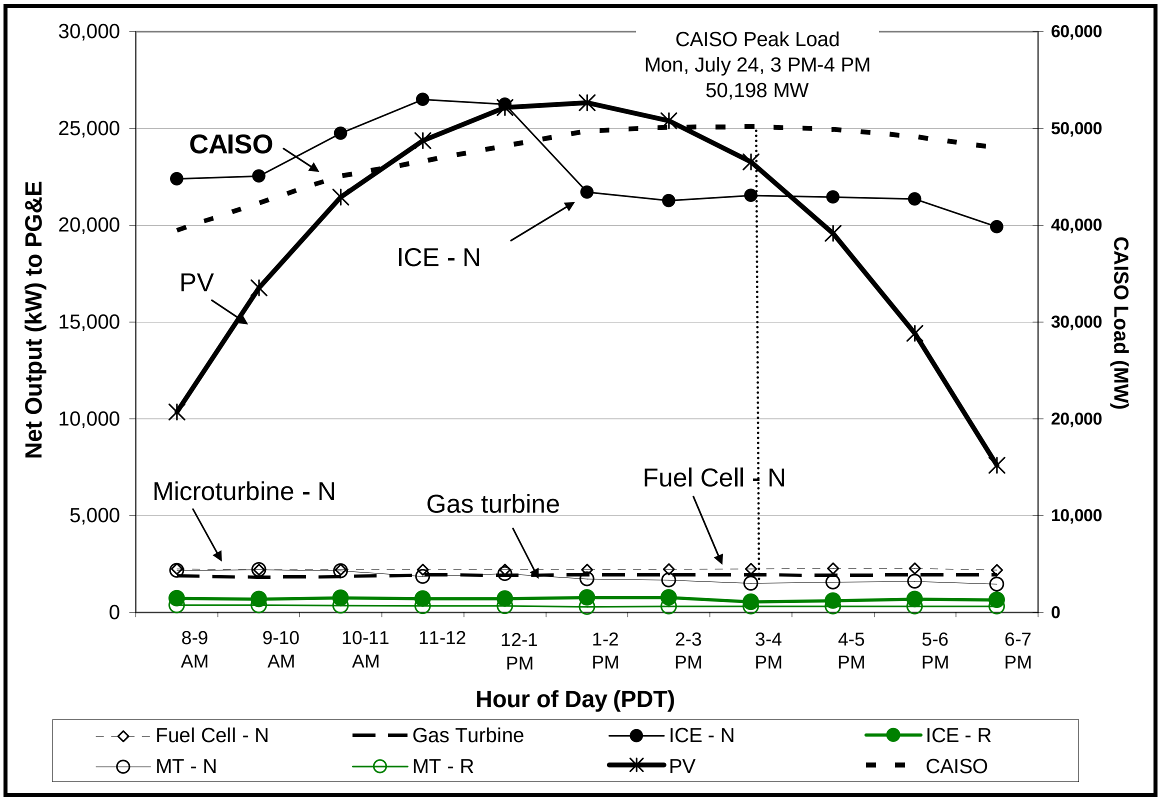


Figure A-3: CAISO Peak Day Output by Technology, Fuel, and Electric Utility —SCE

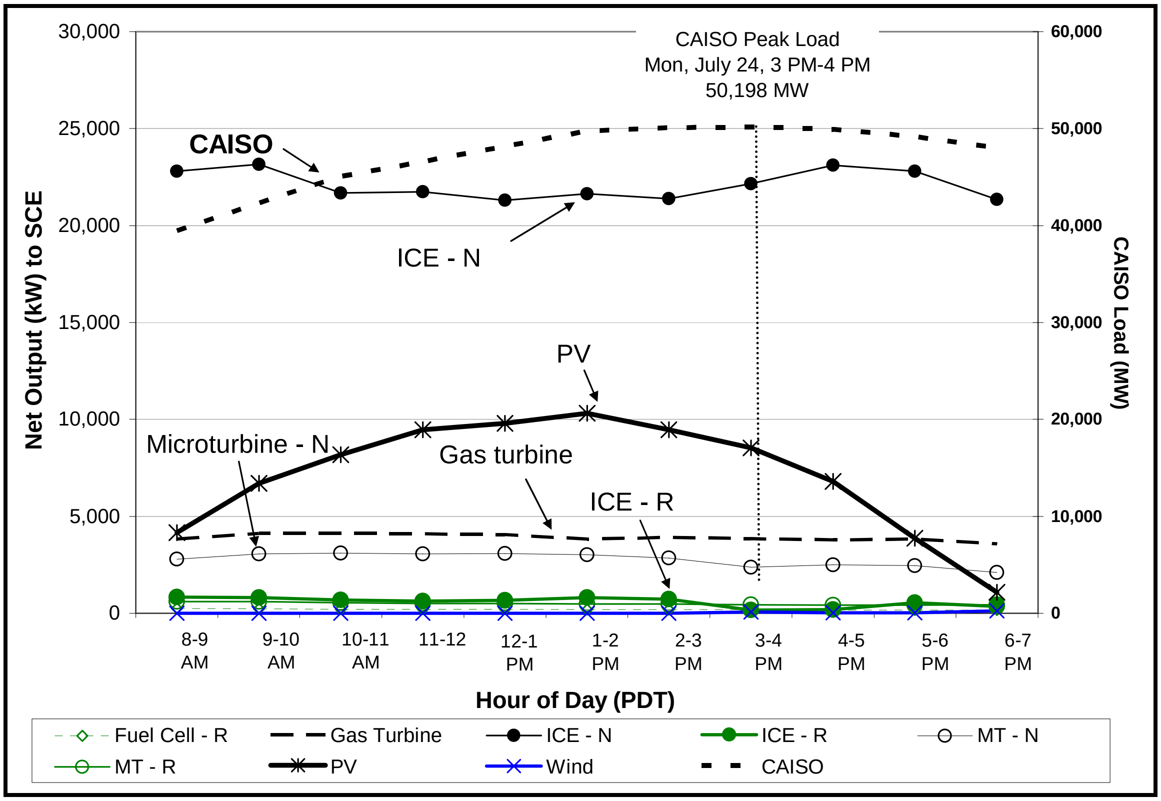


Figure A-4: CAISO Peak Day Output by Technology, Fuel, and Electric Utility —SDG&E

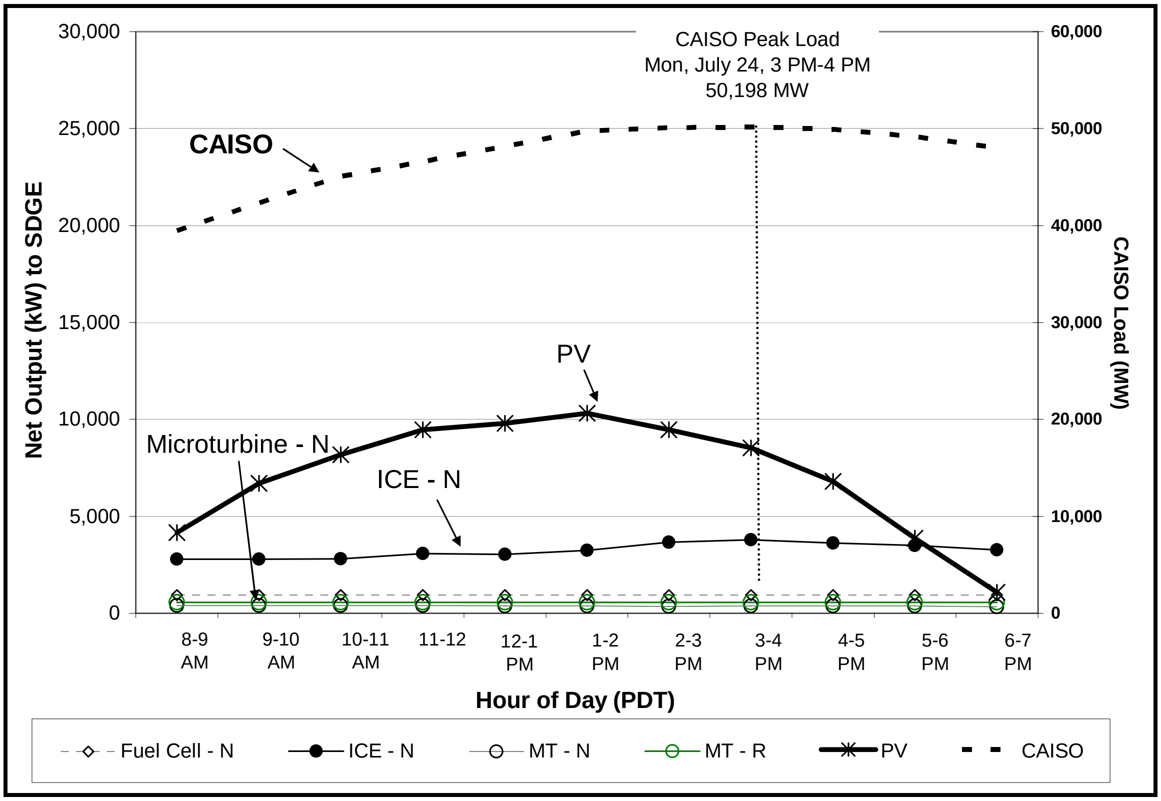


Table A-8, Table A-9, and Table A-10 present the total net electrical output in kW during the respective peak hours of the three large, investor-owned electric utilities. Preceding each of these are small tables listing the date, hour, and load of the utility's peak hour day. The tables also show for each technology and basis the subtotals of output, of counts of systems, and of total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate Electric utility peak demand impacts by natural gas versus renewable methane fuel.

Results presented for the peak days of the three individual electric utility do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Table A-8: Electric Utility Peak Hours Demand Impacts—PG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
PG&E	**22,544**	**25-Jul-06**	**6 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**6**	**3,250**	**2,295**	**0.706**
	M	1	1,000	723	0.723
	E	5	2,250	1,572	0.699
GT	**Total**	**2**	**2,593**	**1,930**	**0.744**
	M	1	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
	E	1			
ICE	**Total**	**78**	**48,267**	**21,534**	**0.446**
	M	18	9,439	4,353	0.461
	E	60	38,828	17,181	0.442
MT	**Total**	**33**	**5,868**	**2,431**	**0.414**
	M	4	960	406	0.423
	E	29	4,908	2,025	0.413
PV	**Total**	**276**	**38,039**	**7,759**	**0.204**
	M	94	19,835	4,254	0.214
	E	182	18,204	3,506	0.193
WD	**Total**	**0**	**0**	**0**	
	M	0	0	0	
	E	0	0	0	
	TOTAL	**395**	**98,017**	**35,949**	**0.367**

Table A-9: Electric Utility Peak Hours Demand Impacts—SCE

Elec PA	Peak (MW)	Date	Hour (PDT)
SCE	**23,148**	**25-Jul-06**	**4 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**2**	**750**	**171**	**0.228**
	M	1	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
	E	1			
GT	**Total**	**1**			
	M	1			
	E	0			
ICE	**Total**	**82**	**54,176**	**26,553**	**0.490**
	M	48	32,401	16,587	0.512
	E	34	21,775	9,966	0.458
MT	**Total**	**45**	**7,722**	**3,748**	**0.485**
	M	24	3,308	1,630	0.493
	E	21	4,414	2,118	0.480
PV	**Total**	**177**	**19,179**	**6,372**	**0.332**
	M	27	2,580	1,088	0.422
	E	150	16,599	5,283	0.318
WD	**Total**	**2**	**1,649**	**310**	**0.188**
	M	2	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
	E	0			
	TOTAL	**309**	**87,976**	**41,074**	**0.467**

Table A-10: Electric Utility Peak Hours Demand Impacts—SDG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
SDG&E	**4,502**	**22-Jul-06**	**2 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**1**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
	M	1			
	E	0			
GT	**Total**	**0**	**0**	**0**	
	M	0	0	0	
	E	0	0	0	
ICE	**Total**	**19**	**12,225**	**2,157**	**0.176**
	M	19	12,225	2,157	0.176
	E	0	0	0	
MT	**Total**	**15**	**1,622**	**322**	**0.199**
	M	14	1,502	289	0.192
	E	1	120	33	0.274
PV	**Total**	**76**	**8,848**	**5,987**	**0.677**
	M	73	8,631	5,838	0.676
	E	3	217	149	0.684
WD	**Total**	**0**	**0**	**0**	
	M	0	0	0	
	E	0	0	0	
	TOTAL	**111**	**23,696**	**8,858**	**0.374**

Capacity Factors

This section describes weighted average capacity factors that indicate system performance relative to system rebated kilowatt for specific time periods. For example, an hourly weighted average capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system rebated capacity.

Table A-11 presents annual weighted average capacity factors for each technology for the year 2006. The table shows the annual weighted average capacity factors for each technology using all metered and estimated values, and by bases of metered and of estimated. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. The distinction by basis indicates simply that different sets of observations were used in the calculations, not that estimated capacity factors were systematically lower or higher than metered capacity factors. Again, later tables in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Table A-11: Annual Capacity Factors

		Annual Capacity Factor*
Technology	**Basis**	**(kWyear/kWyear)**
FC	**Total**	0.700 †
	M	0.725 [a]
	E	0.672 †
GT	**Total**	0.843 [a]
	M	0.851
	E	0.818 [a]
ICE	**Total**	0.359 †
	M	0.350 [a]
	E	0.366 [a]
MT	**Total**	0.404 [a]
	M	0.372 [a]
	E	0.426 [a]
PV	**Total**	0.162
	M	0.192 †
	E	0.144
WD	**Total**	0.157 [a]
	M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY
	E	

*For rows with basis of Total only [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-12 presents annual weighted average capacity factors for each technology and PA for the year 2006. These values arise from the combination of all metered and estimated values. Where entries are blank the PA had no operational systems of the technology type. Later tables in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Table A-12: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
FC	0.687 †	0.420 †	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY	
GT	0.790 [a]			
ICE	0.396 [a]	0.236 †	0.386 [a]	0.344
MT	0.387 [a]	0.455 †	0.439 †	0.231 [a]
PV	0.167	0.141	0.165	0.175
WD		0.157 †		

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-13 presents annual weighted average capacity factors for the technologies that can be fueled with either natural gas or renewable methane gas. Where entries are blank the PA had no operational systems of the technology type. This table allows easy comparison of these technologies by fuel type.

Table A-13: Annual Capacity Factors by Technology and Fuel

	Annual Capacity Factor* (kWyear/kWyear)	
Technology	**Natural Gas**	**Renewable Fuel**
FC	0.762 †	0.380 †
GT	0.843 [a]	
ICE	0.366 †	0.218 [a]
MT	0.414	0.358 [a]

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-5 plots profiles of monthly weighted average capacity factors for each technology. Again, later charts in this appendix differentiate capacity factors by natural gas versus renewable methane fuel

Figure A-5: Monthly Capacity Factors by Technology

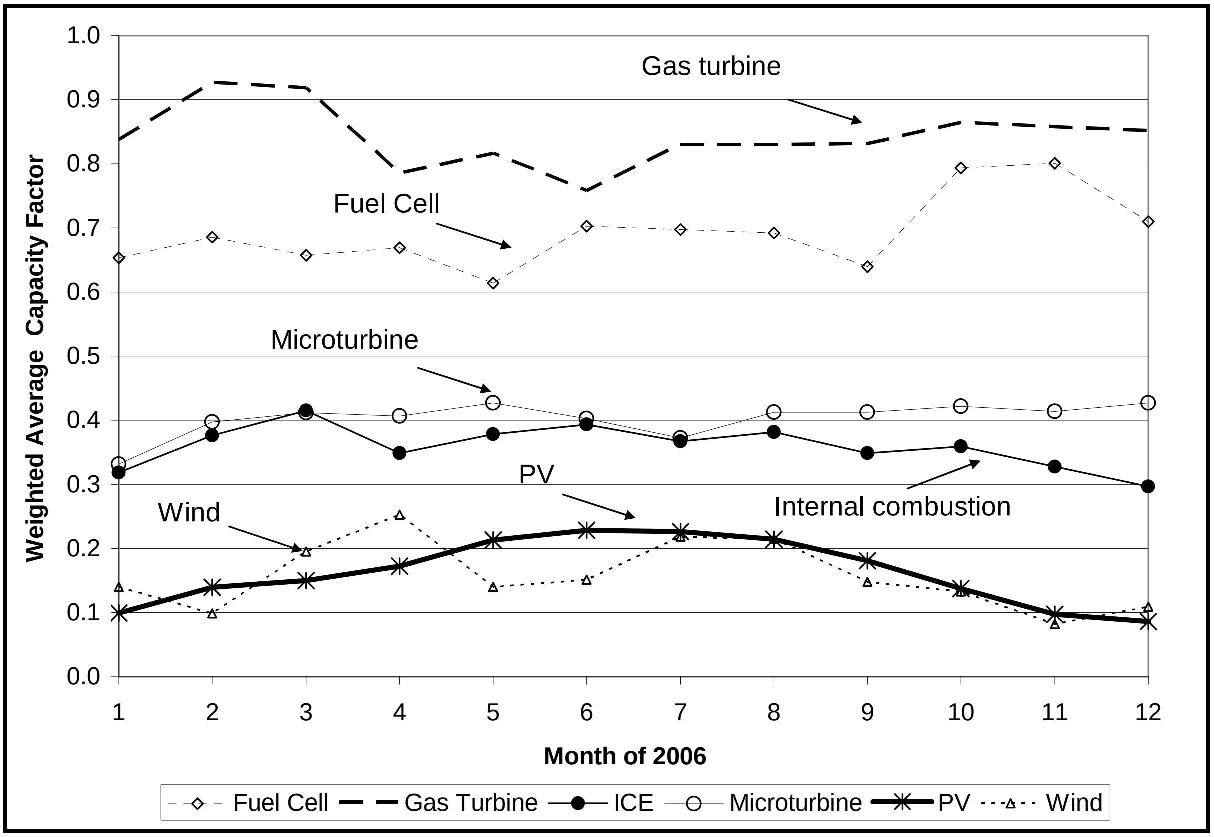


Figure A-6 plots profiles of hourly weighted average capacity factor for each technology from morning to early evening during the day of the annual peak hour, July 24, 2006. The plot also indicates the hour and value of the CAISO peak load. Again, later charts in this appendix differentiate by natural gas versus renewable methane fuel.

Figure A-6: CAISO Peak Day Capacity Factors by Technology

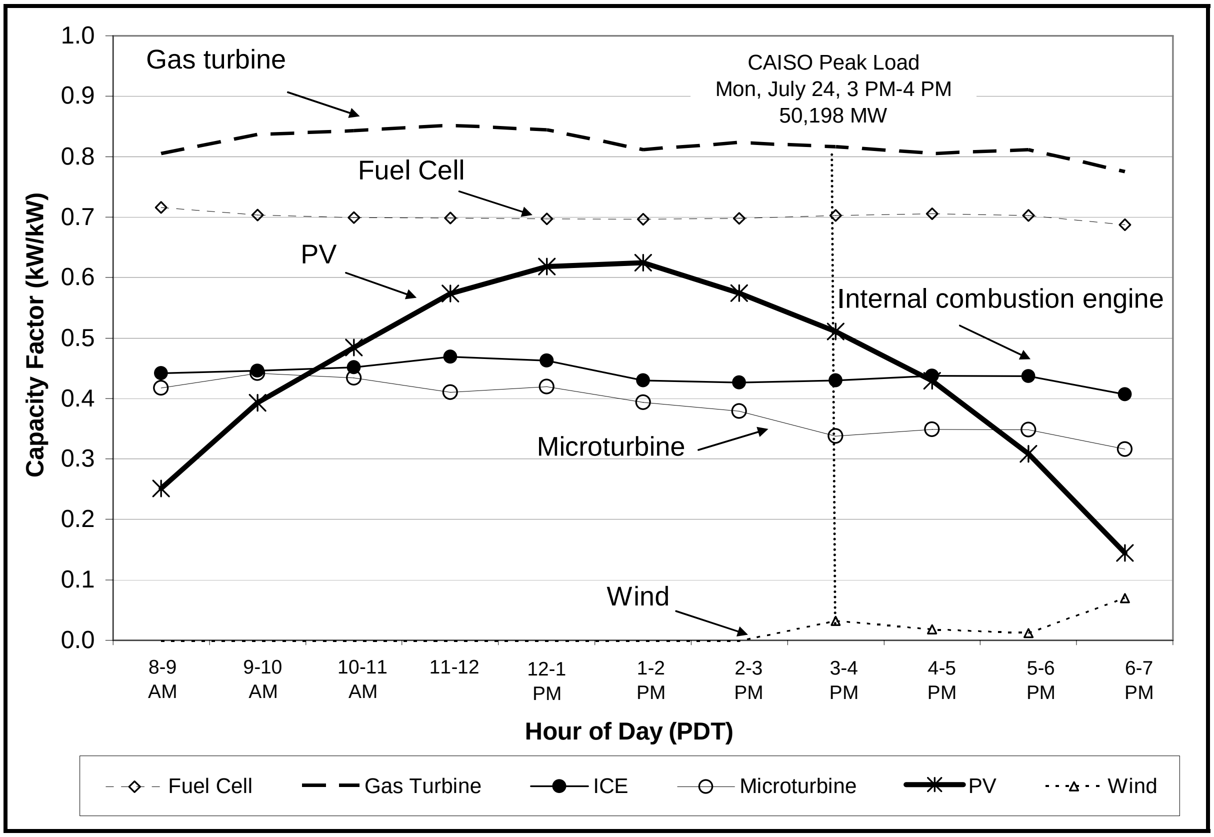


Figure A-7, Figure A-8, and Figure A-9 plot profiles of hourly weighted average capacity factors by technology for the systems directly feeding the utilities on the dates of their respective annual peak hours. The plots also indicate the date and hour and value of the peak load for the electric utility. The plots include only those technologies that were operational for the electric utility, so not all technologies appear for all electric utilities. In later sections, this appendix describes separately those technologies that can use natural gas versus renewable fuel.

Results presented for the peak days of the three individual electric utility do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of all systems administered by SCG feed SCE's distribution grid, while a small number feed PG&E or SDG&E and the remainder feed small electric utilities. A small number of PG&E's systems feed directly into distribution grids for small electric utilities.

Figure A-7: Electric Utility Peak Day Capacity Factors by Technology —PG&E

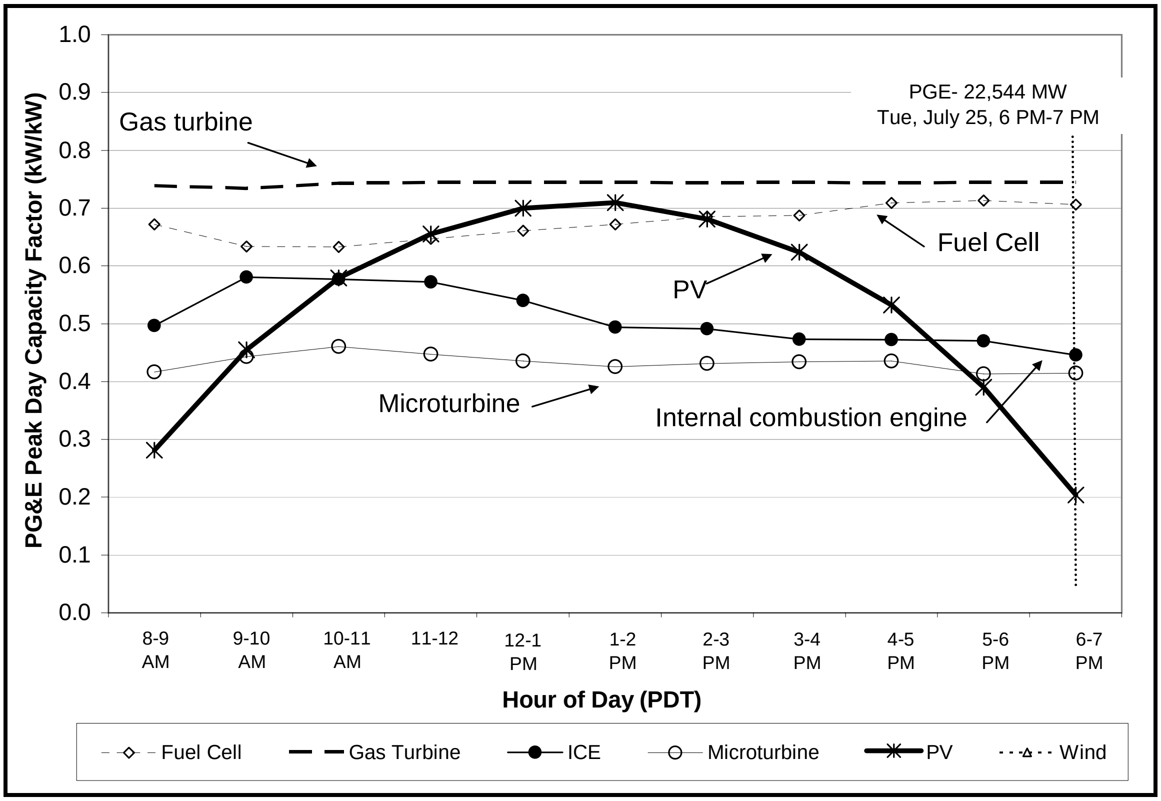


Figure A-8: Electric Utility Peak Day Capacity Factors by Technology —SCE

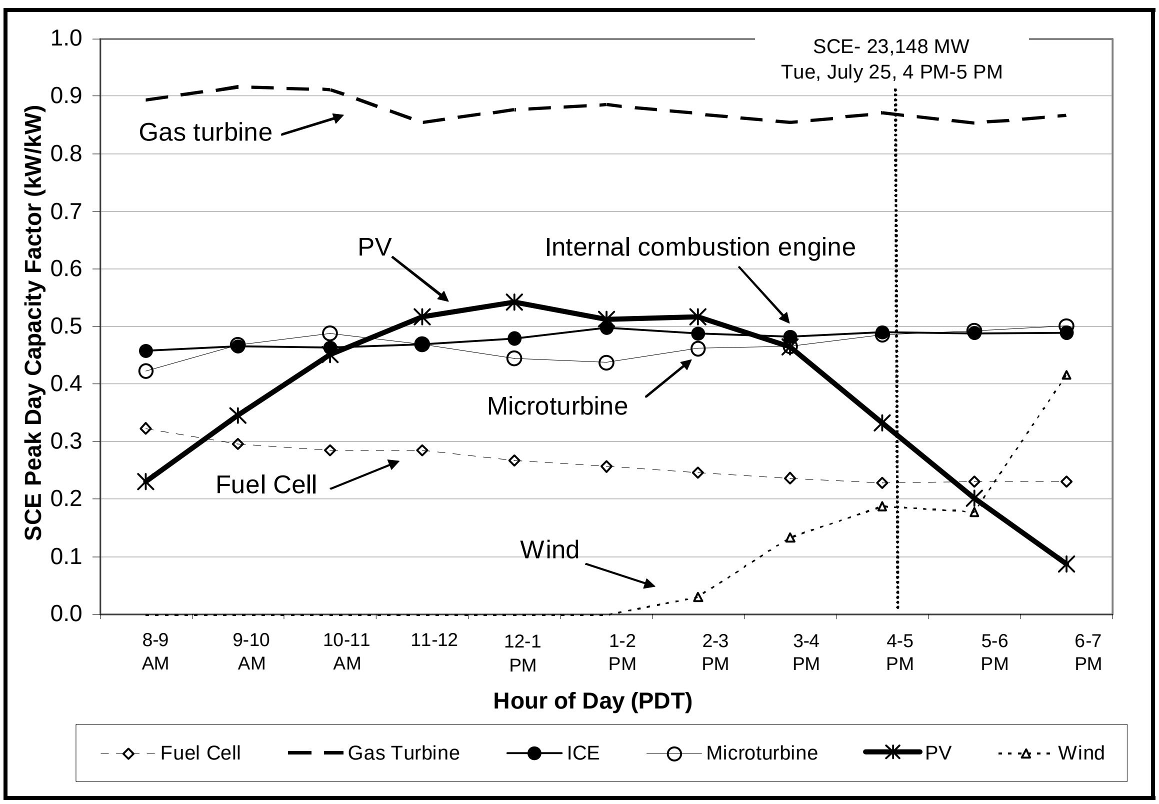
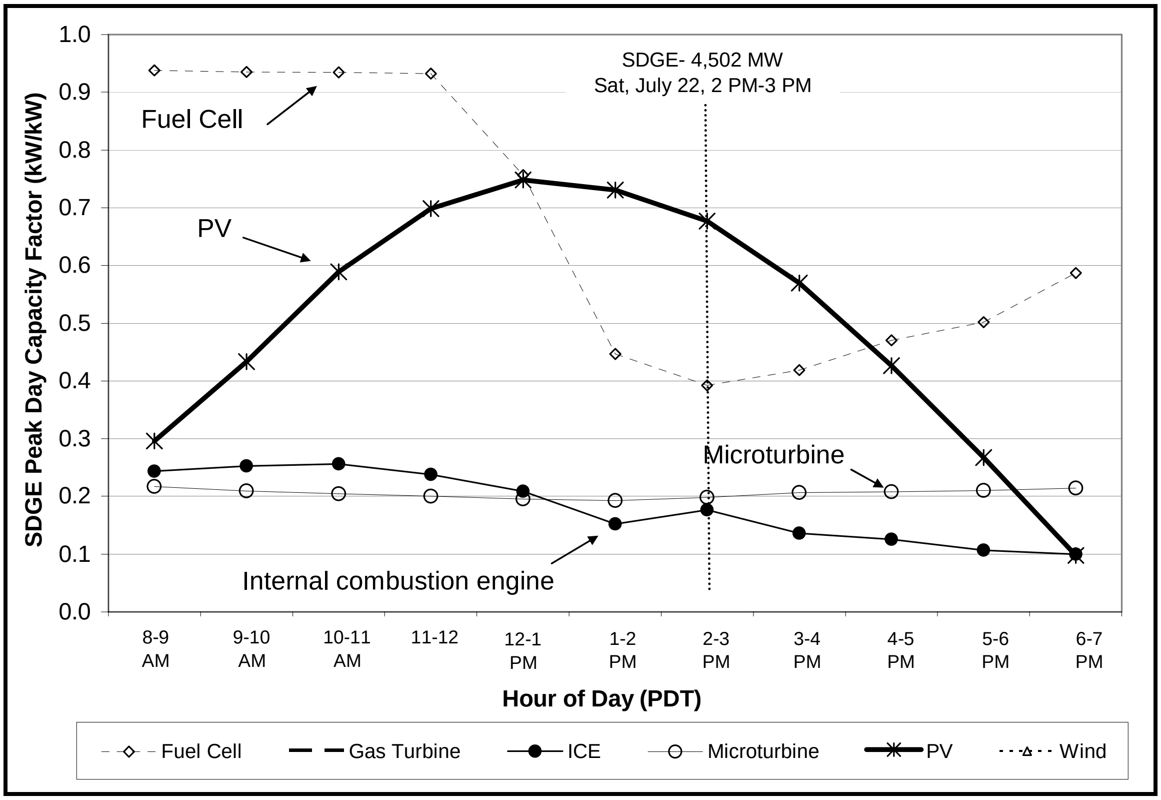


Figure A-9: Electric Utility Peak Day Capacity Factors by Technology — SDG&E



A.3 Renewable Power Systems

This section describes impacts of renewable power systems. It begins with PV, followed by wind, renewable fuel cells, and finally renewable internal combustion engines and microturbines. There are no renewable gas turbines in the program. The section after this describes non-renewable power systems.

Solar Photovoltaic

Costs

Table A-14 lists total eligible costs, SGIP incentives, and other incentives for PV systems.

Table A-14: Completed and Active System Costs by Technology

Technology	Cost Component	Completed Projects (M$)	Active Projects (M$)
PV	Eligible Cost	$664.4	$1,312.3
	Incentive	$296.9	$411.1
	Other Incentive	$0.5	$0.6
	Total Incentive	$297.4	$411.7

Annual Energy

Table A-15 presents annual total net electrical output in MWH from PV for the program and for each PA. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-15: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
PV	**Total**	**56,509**	**20,372**	**13,093**	**14,036**	**104,010**
	M	27,334	2,647	4,872	10,429	45,282
	E	29,175	17,725	8,221	3,607	58,729

Table A-16 presents quarterly total net electrical output in MWH for PV. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-16: Quarterly Electric Energy Totals

Technology	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
PV	**Total**	**17,586**	**31,507**	**35,199**	**19,718**	**104,010**
	M	8,437	13,963	13,891	8,991	45,282
	E	9,149	17,544	21,308	10,727	58,729

Peak Demand

Table A-17 presents total net electrical output in kW for PV during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows counts of systems and total operational system capacity in kW.

Table A-17: CAISO Peak Hour Demand Impacts

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)
PV	**Total**	**609**	**75,808**	**38,744**

Table A-18 presents the total net electrical output in kW for PV during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-18: Electric Utility Peak Hours Demand Impacts

PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	22,544	7/25/2006	18	**PV**	276	38,039	7,759
SCE	23,148	7/25/2006	16	**PV**	177	19,179	6,372
SDG&E	4,502	7/22/2006	14	**PV**	76	8,848	5,987

Capacity Factors

Weighted average capacity factors indicate PV performance relative to a system rebated kilowatt for specific time periods. Capacity factors for PV for time periods of a whole day or more are typically less than 0.3 as there generally is no net output between sunset and dawn. Table A-19 presents annual weighted average capacity factors for PV for the year 2006.

Table A-19: Annual Capacity Factors

Technology	Annual Capacity Factor (kWyear/kWyear)
PV	0.162

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-20 presents annual weighted average capacity factors for PV for each PA for the year 2006.

Table A-20: Annual Capacity Factors by PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
PV	0.167	0.141	0.165	0.175

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-10 plots profiles of monthly weighted average capacity factors for PV for each PA. This particular plot uses a reduced height for the vertical axis, with a maximum of 0.3 to allow easier differentiation of capacity factor variations by month.

Figure A-10: Monthly Capacity Factors by PA

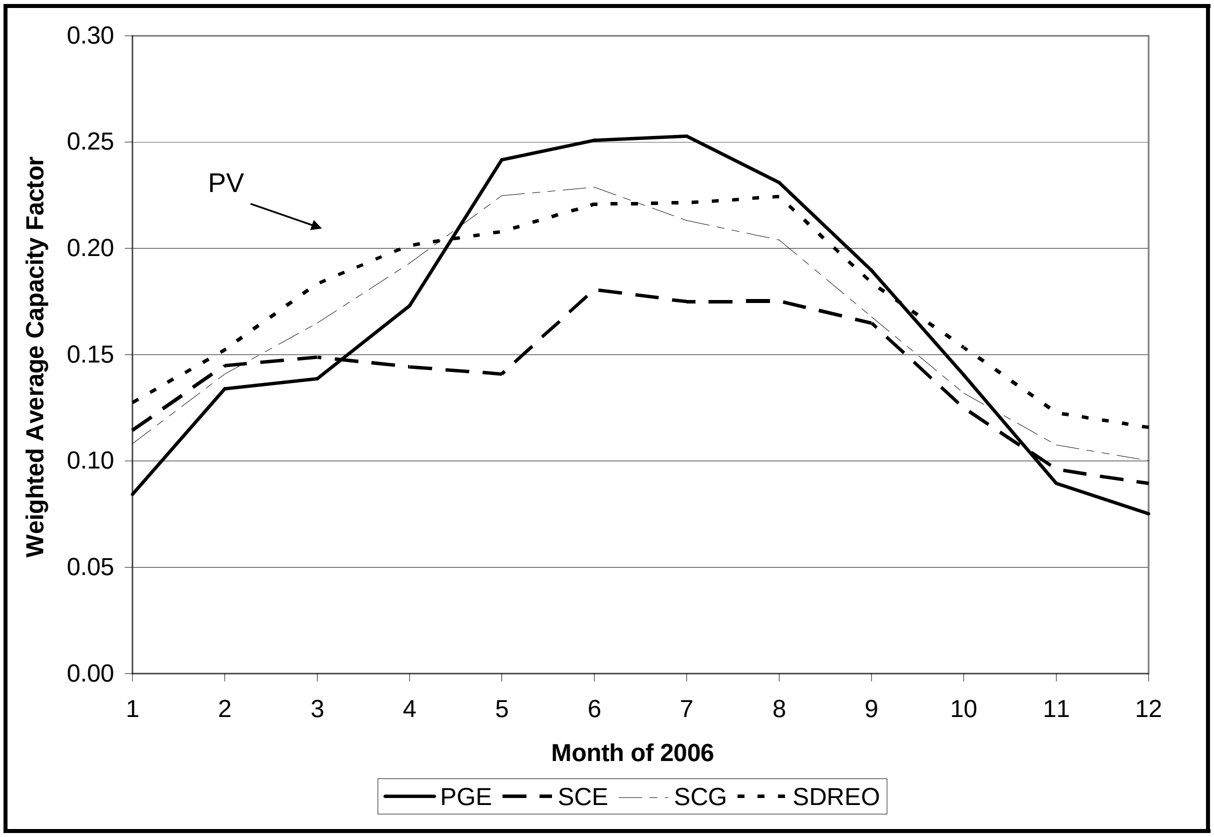


Figure A-11 plots the profiles of hourly weighted average capacity factor for PV for each PA from the morning to early evening during the day of the annual peak hour, July 24, 2006. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-11: CAISO Peak Day Capacity Factors by PA

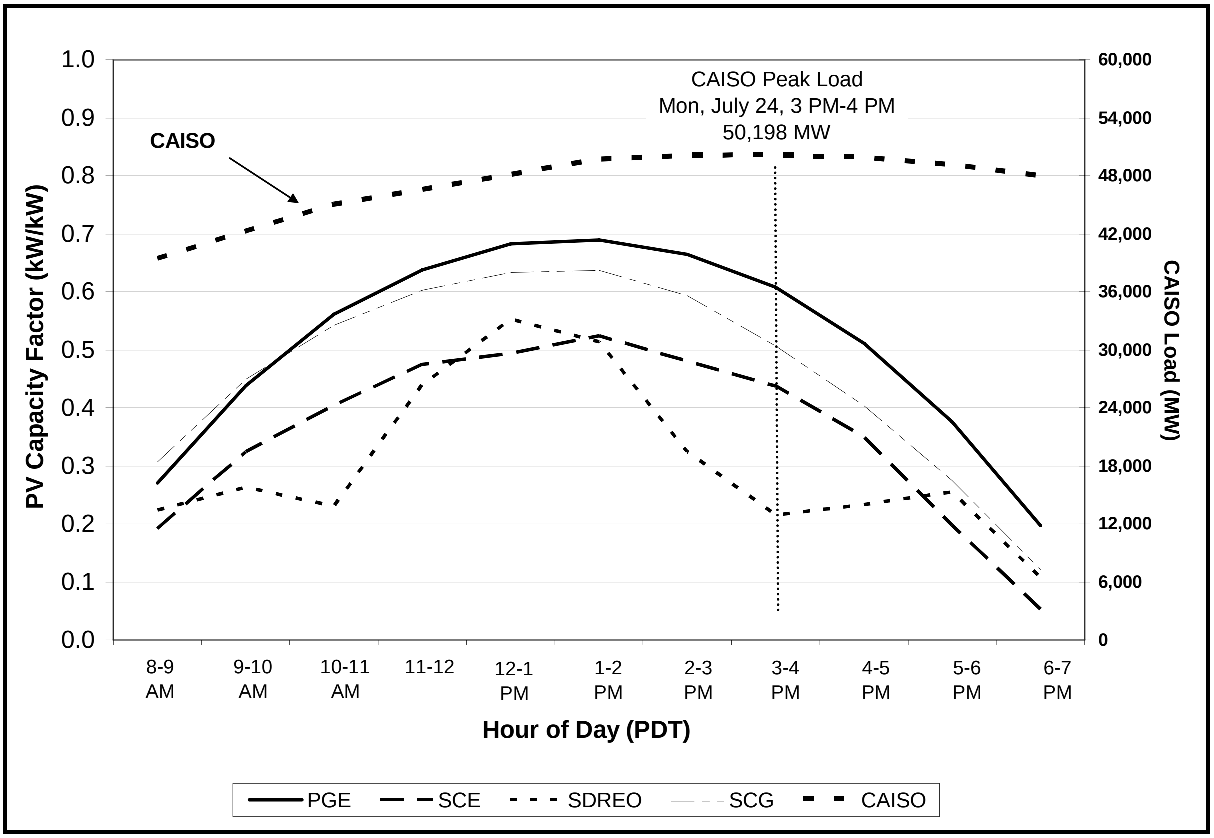


Figure A-12, Figure A-13, and Figure A-14 plot profiles of hourly weighted average capacity factors for PV systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-12: Electric Utility Peak Day Capacity Factors by Technology — PG&E

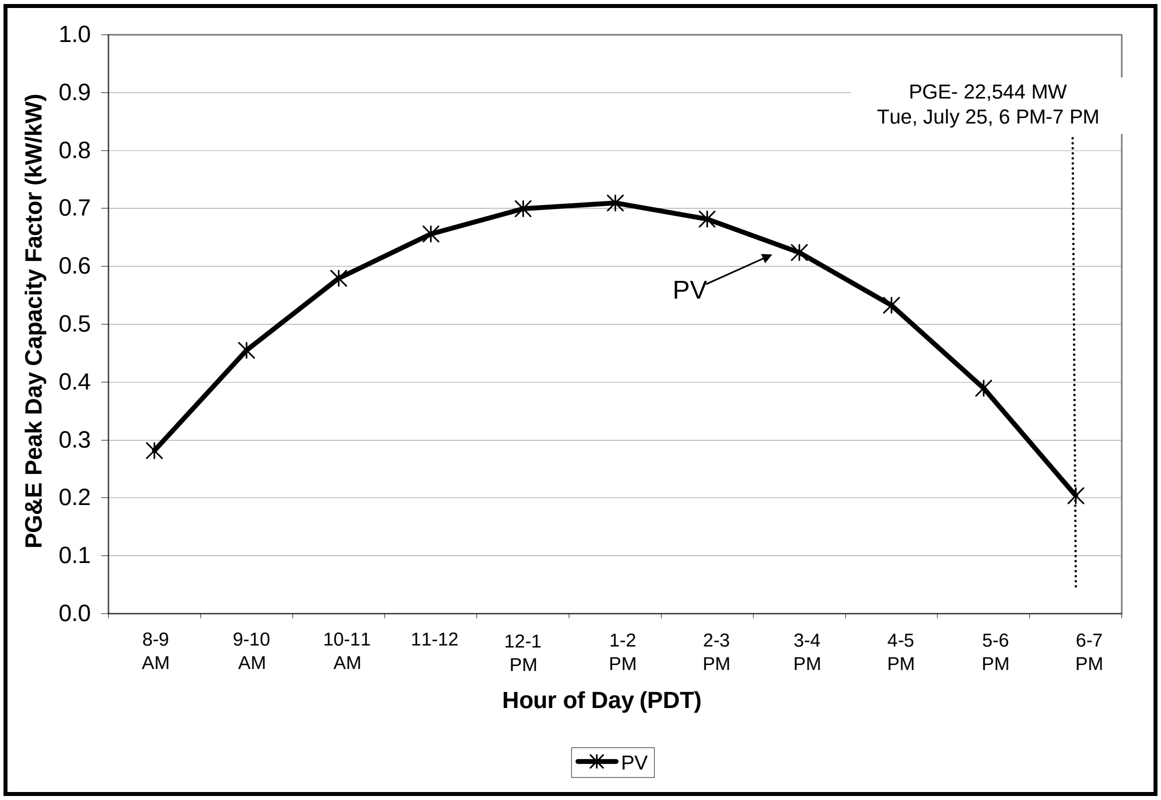


Figure A-13: Electric Utility Peak Day Capacity Factors by Technology —SCE

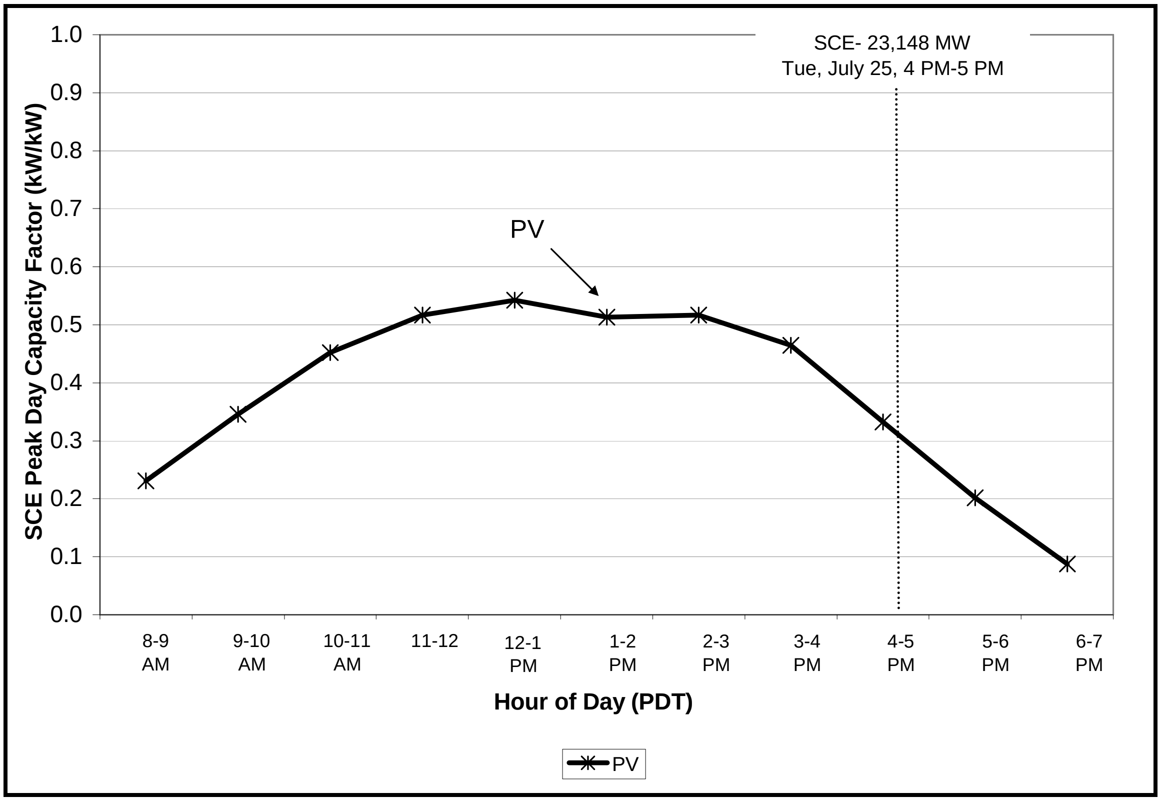
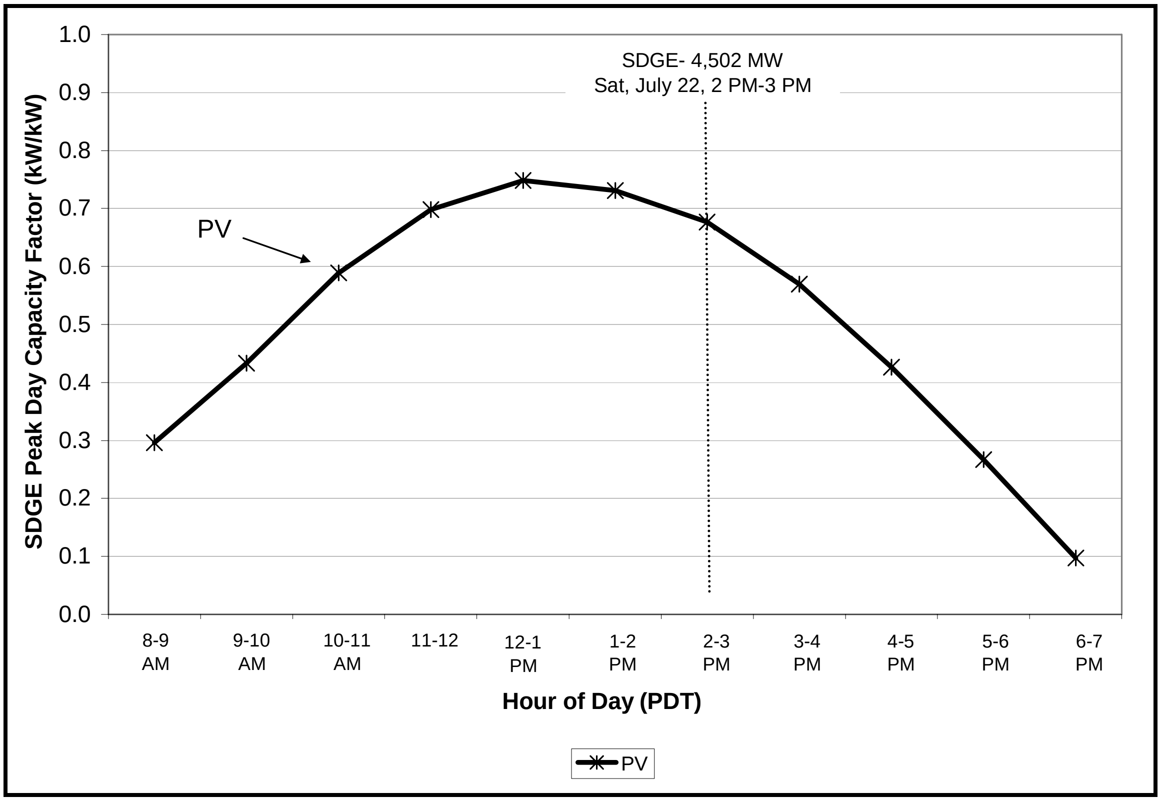


Figure A-14: Electric Utility Peak Day Capacity Factors by Technology — SDG&E



Wind

Due to the small numbers both of wind and of renewable fuel cell power systems and need for privacy, this information should be considered confidential to the Working Group.

Costs

Table A-21 lists total eligible costs, SGIP incentives, and other incentives for Wind systems.

Table A-21: Completed and Active System Costs by Technology

Technology	Cost Component	Completed Projects (M$)	Active Projects (M$)
WD	Eligible Cost	$5.4	$8.1
	Incentive	$2.6	$4.2
	Other Incentive	$0.5	$0.6
	Total Incentive	$3.1	$4.8

Annual Energy

Table A-22 presents annual total net electrical output in MWH from Wind for the program and for each PA. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-22: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
WD	**Total**	**0**	**2,274**	**0**	**0**	**2,274**
	M					
	E					

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Table A-23 presents quarterly total net electrical output in MWH for Wind. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-23: Quarterly Electric Energy Totals

Technology	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
WD	**Total**	**521**	**651**	**707**	**394**	**2,274**
	M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
	E					

Peak Demand

Table A-24 presents total net electrical output in kW for Wind during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows counts of systems and total operational system capacity in kW.

Table A-24: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
WD	2	1,649	53

Table A-25 presents the total net electrical output in kW for Wind during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-25: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	22,544	7/25/2006	18	**WD**	0	0	0
SCE	23,148	7/25/2006	16	**WD**	2	1,649	310
SDG&E	4,502	7/22/2006	14	**WD**	0	0	0

Capacity Factors

Weighted average capacity factors indicate Wind performance relative to a system rebated kilowatt for specific time periods. Capacity factors for Wind for time periods extending over many days or more here have been observed to be typically less than 0.3. Table A-26 presents annual weighted average capacity factors for Wind for the year 2006.

Table A-26: Annual Capacity Factors

Technology	Annual Capacity Factor (kWyear/kWyear)
WD	0.157 [a]

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-27 presents annual weighted average capacity factors for Wind for each PA for the year 2006.

Table A-27: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
Technology	Annual Capacity Factor* (kWyear/kWyear)			
WD		0.157 [a]		

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-15 plots profiles of monthly weighted average capacity factors for Wind for each PA. This particular plot uses a reduced height for the vertical axis, with a maximum of 0.3 to allow easier differentiation of capacity factor variations by month. Only SCE appears in the charts as it is the only PA with Wind systems.

Figure A-15: Monthly Capacity Factors by PA

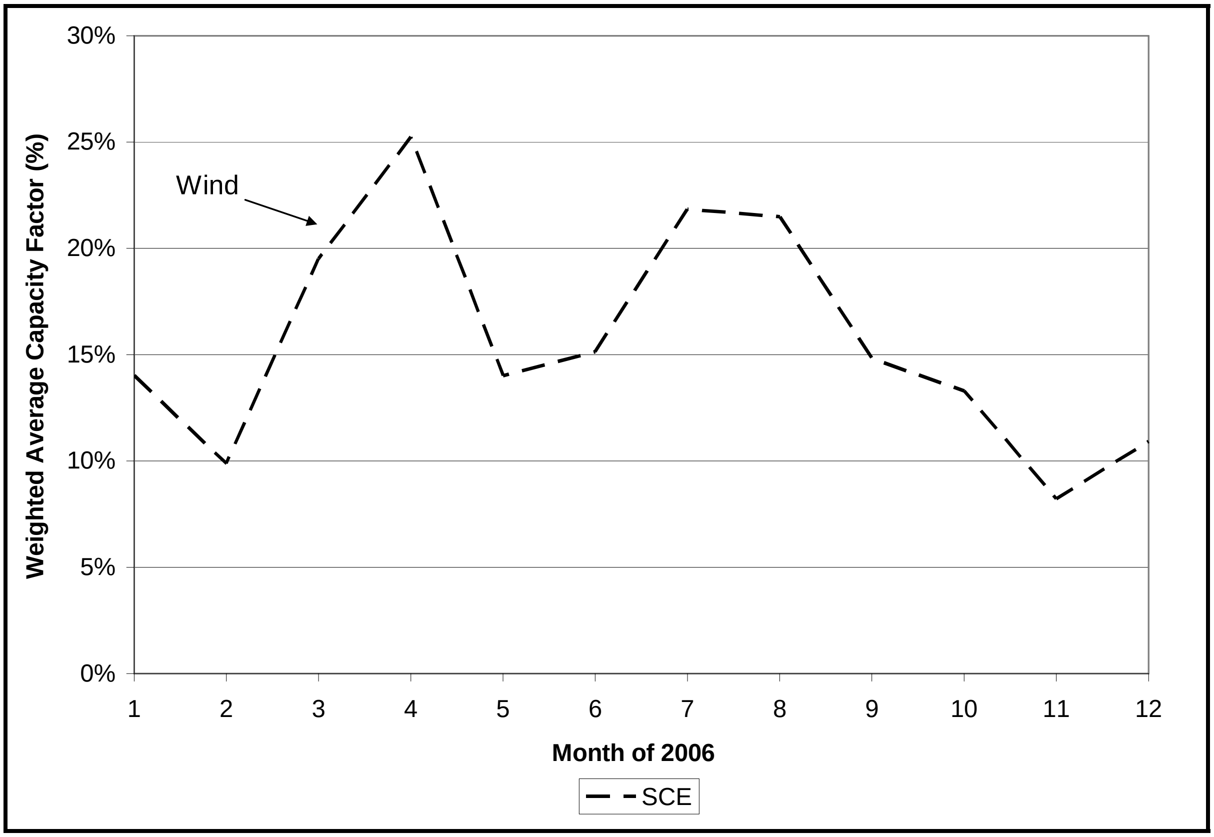


Figure A-16 plots the profiles of hourly weighted average capacity factor for Wind for each PA from the morning to early evening during the day of the annual peak hour, July 24, 2006. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. SCE is the sole PA with Wind systems, so no other PAs appear in the chart.

Figure A-16: CAISO Peak Day Capacity Factors by PA

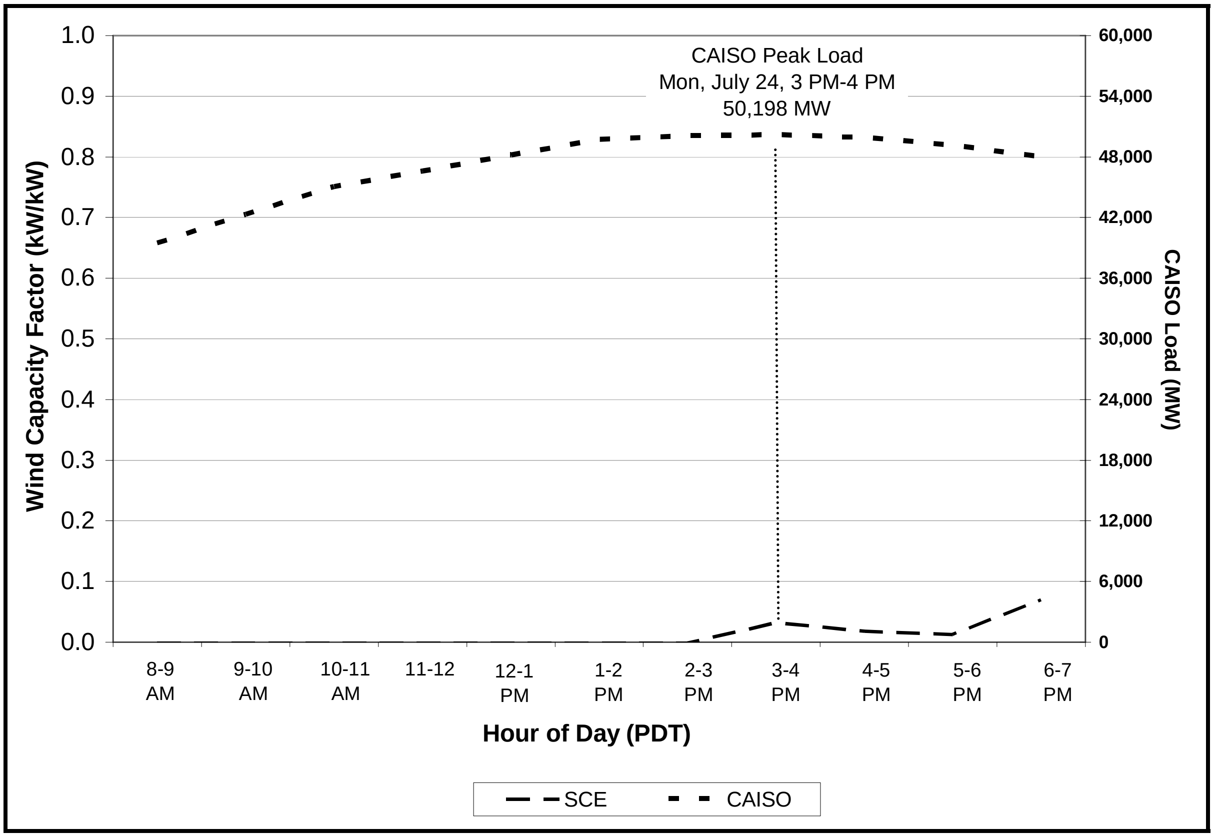
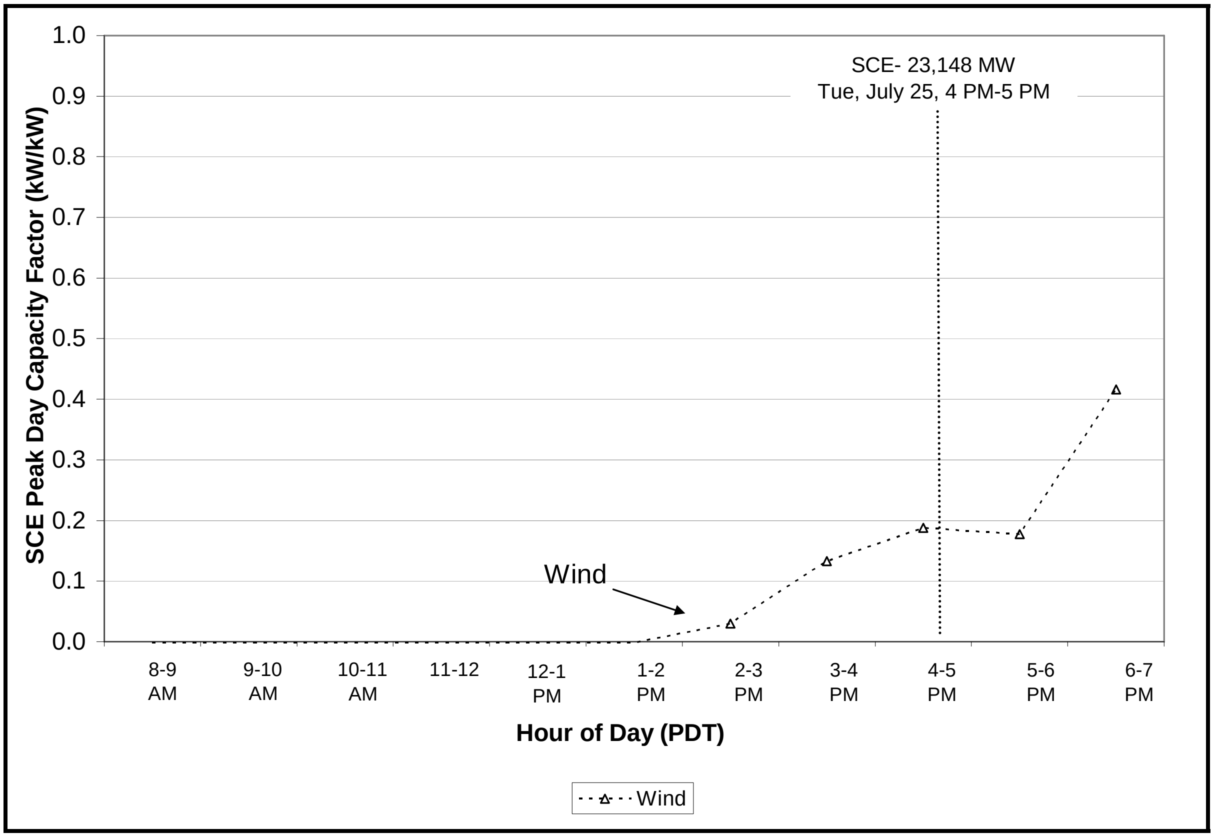


Figure A-17 plot profiles of hourly weighted average capacity factors for Wind systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SCE is the only PA with Wind systems, so no charts are shown for peak days for PG&E or SDG&E.

Figure A-17: Electric Utility Peak Day Capacity Factors by Technology —SCE



Fuel Cells Renewable

Due to the small numbers both of wind and of renewable fuel cell power systems and need for privacy, this information should be considered confidential to the Working Group.

Costs

Table A-28 lists total eligible costs, SGIP incentives, and other incentives for Renewable Fuel Cell systems.

Table A-28: Completed and Active System Costs by Technology

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
FC	**N**	Eligible Cost	$41.5	$20.0
		Incentive	$13.2	$7.3
		Other Incentive	$2.5	$0.5
		Total Incentive	$15.7	$7.8

Annual Energy

Table A-29 presents annual total net electrical output in MWH from Renewable Fuel Cells for the program and for each PA. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-29: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	**Total**	**0**	**2,498**	**0**	**0**	**2,498**
	M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
	E					

Table A-30 presents quarterly total net electrical output in MWH for Renewable Fuel Cells. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-30: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
FC	**R**	**Total**	**646**	**614**	**520**	**718**	**2,498**
		M	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
		E					

Peak Demand

Table A-31 presents total net electrical output in kW for Renewable Fuel Cells during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows counts of systems and total operational system capacity in kW.

Table A-31: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
FC	2	750	178

Table A-32 presents the total net electrical output in kW for Renewable Fuel Cells during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-32: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	22,544	7/25/2006	18	**FC**	0	0	0
SCE	23,148	7/25/2006	16	**FC**	2	750	171
SDG&E	4,502	7/22/2006	14	**FC**	0	0	0

Capacity Factors

Weighted average capacity factors indicate Renewable Fuel Cell performance relative to a system rebated kilowatt for specific time periods. Table A-33 presents annual weighted average capacity factors for Renewable Fuel Cells for the year 2006.

Table A-33: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	0.380 †

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-34 presents annual weighted average capacity factors for Renewable Fuel Cells for each PA for the year 2006.

Table A-34: Annual Capacity Factors by PA

	PG&E	SCE	SCG	CCSE
Technology	**Annual Capacity Factor (kWyear/kWyear)**			
FC		0.380		

Figure A-18 plots profiles of monthly weighted average capacity factors for Renewable Fuel Cells for each PA. Only SCE appears in the charts as it is the only PA with Renewable Fuel Cells.

Figure A-18: Monthly Capacity Factors by PA

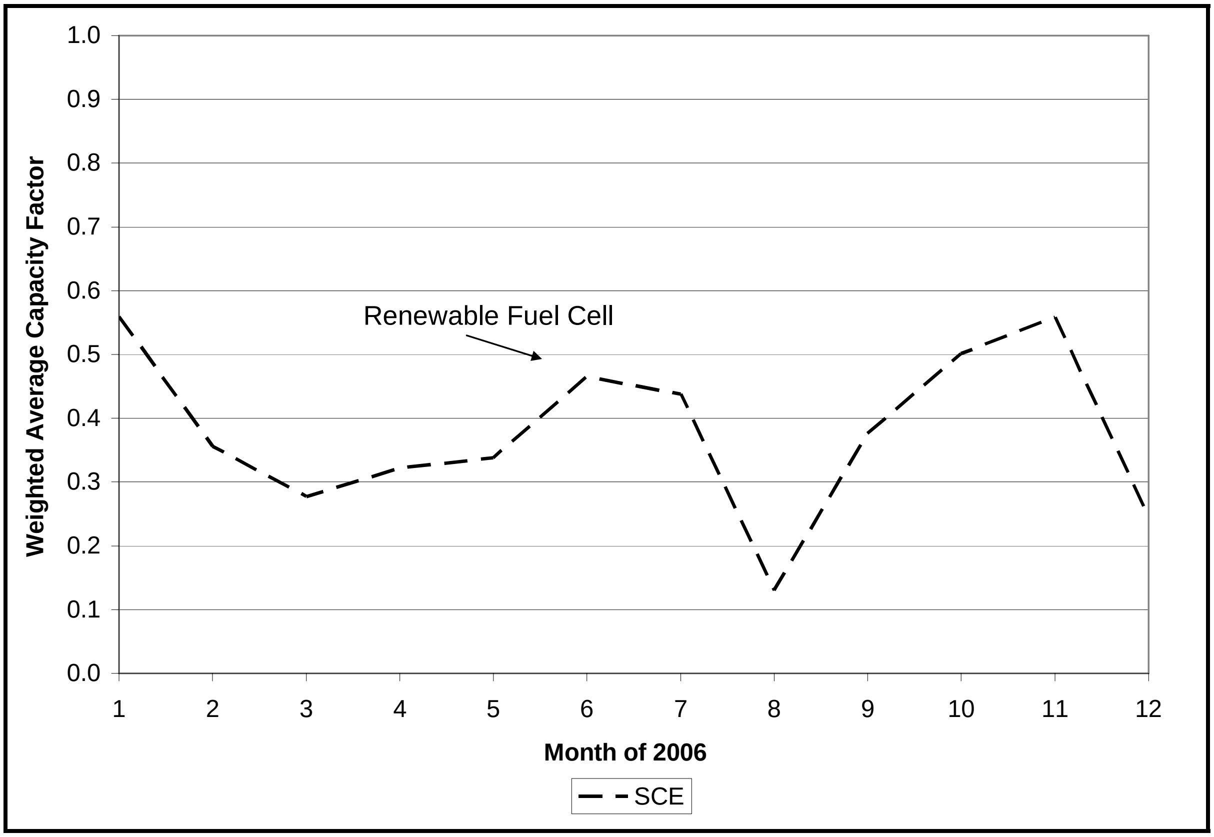


Figure A-19 plots the profiles of hourly weighted average capacity factor for Renewable Fuel Cells for each PA from the morning to early evening during the day of the annual peak hour, July 24, 2006. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. SCE is the sole PA with Renewable Fuel Cells, so no other PAs appear in the chart.

Figure A-19: CAISO Peak Day Capacity Factors by PA

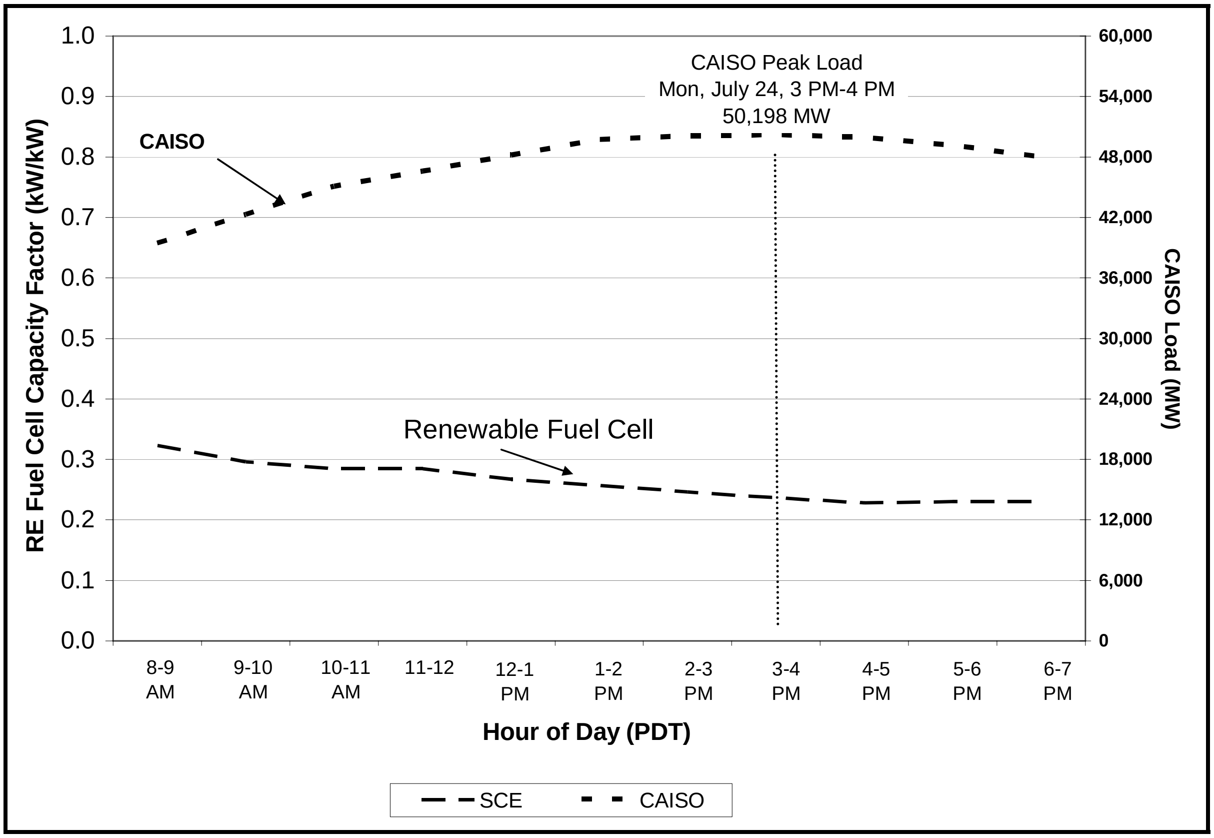
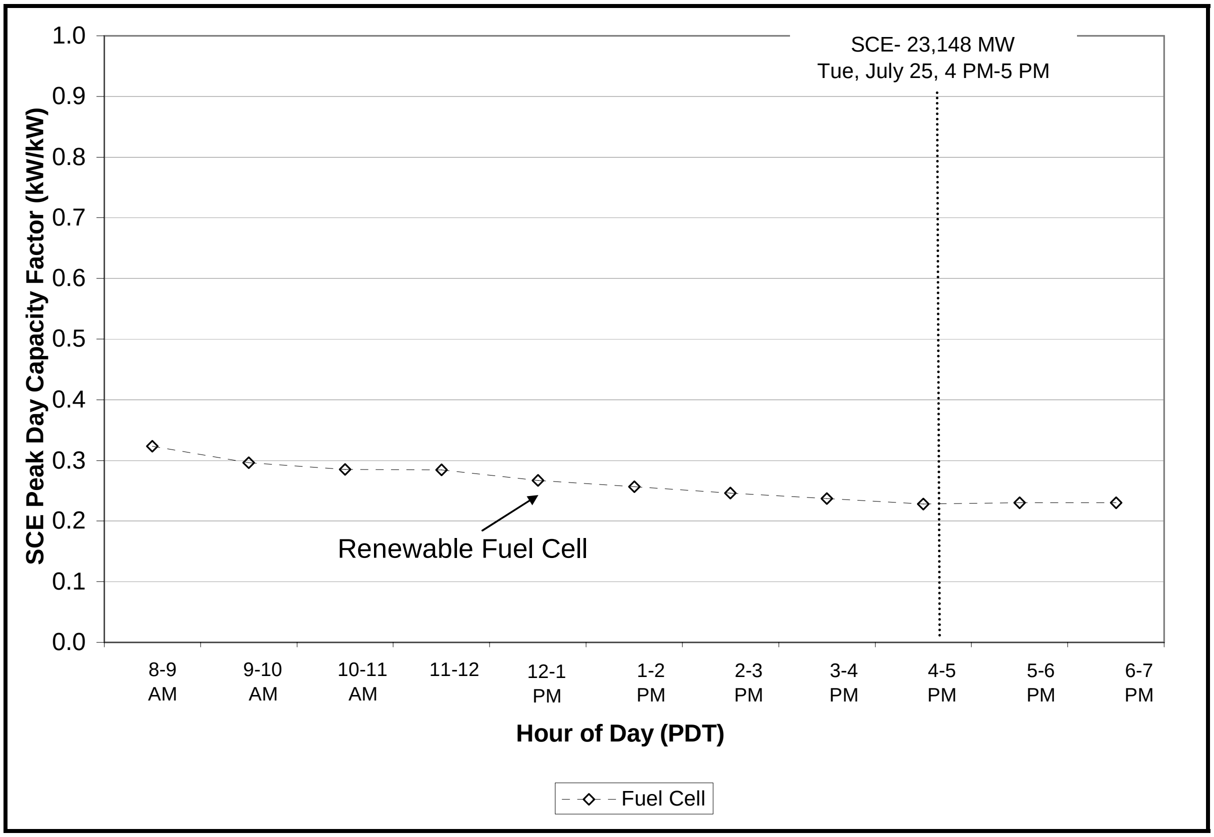


Figure A-20 plot profiles of hourly weighted average capacity factors for Renewable Fuel Cells directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SCE is the only PA with Renewable Fuel Cells, so no charts are shown for peak days for PG&E or SDG&E.

Figure A-20: Electric Utility Peak Day Capacity Factors by Technology —SCE



MT and ICE Renewable

Costs

Table A-35 lists total eligible costs, SGIP incentives, and other incentives for Renewable ICE and MT systems.

Table A-35: Completed and Active System Costs by Technology

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
ICE	**R**	Eligible Cost	$16.6	$21.3
		Incentive	$5.7	$5.1
		Other Incentive	$0.5	$0.0
		Total Incentive	$6.1	$5.1
Technology	**Fuel**	**Cost Component**	**Completed Projects (M$)**	**Active Projects (M$)**
MT	**R**	Eligible Cost	$9.8	$3.3
		Incentive	$3.4	$1.1
		Other Incentive	$0.5	$0.6
		Total Incentive	$3.9	$1.6

Annual Energy

Table A-36 presents annual total net electrical output in MWH from Renewable ICE and MT for the program and for each PA. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-36: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
ICE	**Total**	**4,885**	**5,524**	**0**	**0**	**10,409**
	M	0	3,220	0	0	3,220
	E	4,885	2,304	0	0	7,189
Technology	**Basis**	**PG&E (MWh)**	**SCE (MWh)**	**SCG (MWh)**	**CCSE (MWh)**	**Total (MWh)**
MT	**Total**	**3,549**	**5,354**	**0**	**378**	**9,281**
	M	0	2,162	0	378	2,540
	E	3,549	3,192	0	0	6,741

Table A-37 presents quarterly total net electrical output in MWH for Renewable ICE and MT. These tables also show subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-37: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
ICE	**R**	**Total**	**1,484**	**2,547**	**3,161**	**3,218**	**10,409**
		M	802	919	777	723	3,220
		E	682	1,628	2,384	2,495	7,189

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
MT	**R**	**Total**	**1,697**	**2,331**	**2,032**	**3,221**	**9,281**
		M	498	629	554	859	2,540
		E	1,199	1,703	1,478	2,362	6,741

Peak Demand

Table A-38 presents total net electrical output in kW for Renewable ICE and MT during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows counts of systems and total operational system capacity in kW.

Table A-38: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
ICE	9	5,861	708
MT	16	3,024	787

Table A-39 presents the total net electrical output in kW for Renewable ICE and MT during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-39: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak	Date	Hour		On-Line Systems	Operational	Impact
	(MW)		(PDT)	Technology	(n)	(kW)	(kW)
PG&E	22,544	7/25/2006	18	**ICE**	5	3,370	650
SCE	23,148	7/25/2006	16	**ICE**	4	2,491	728
SDG&E	4,502	7/22/2006	14	**ICE**	0	0	0

Elec PA	Peak	Date	Hour		On-Line Systems	Operational	Impact
	(MW)		(PDT)	Technology	(n)	(kW)	(kW)
PG&E	22,544	7/25/2006	18	**MT**	9	1,420	318
SCE	23,148	7/25/2006	16	**MT**	4	1,040	545
SDG&E	4,502	7/22/2006	14	**MT**	3	564	32

Capacity Factors

Weighted average capacity factors indicate Renewable ICE and MT performances relative to a system rebated kilowatt for specific time periods. Table A-40 presents annual weighted average capacity factors for Renewable ICE and MT for the year 2006.

Table A-40: Annual Capacity Factors by Technology

	Annual Capacity Factor*
Technology	(kWyear/kWyear)
ICE	0.218 [a]
MT	0.358 [a]

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-41 presents annual weighted average capacity factors for Renewable ICE and MT for each PA for the year 2006.

Table A-41: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor			
Technology	(kWyear/kWyear)			
ICE	0.212	0.222		
MT	0.299	0.588		0.077

Figure A-21 and Figure A-22 plot profiles of monthly weighted average capacity factors for Renewable ICE and MT for each PA.

Figure A-21: Monthly Capacity Factors by Technology and PA—ICE

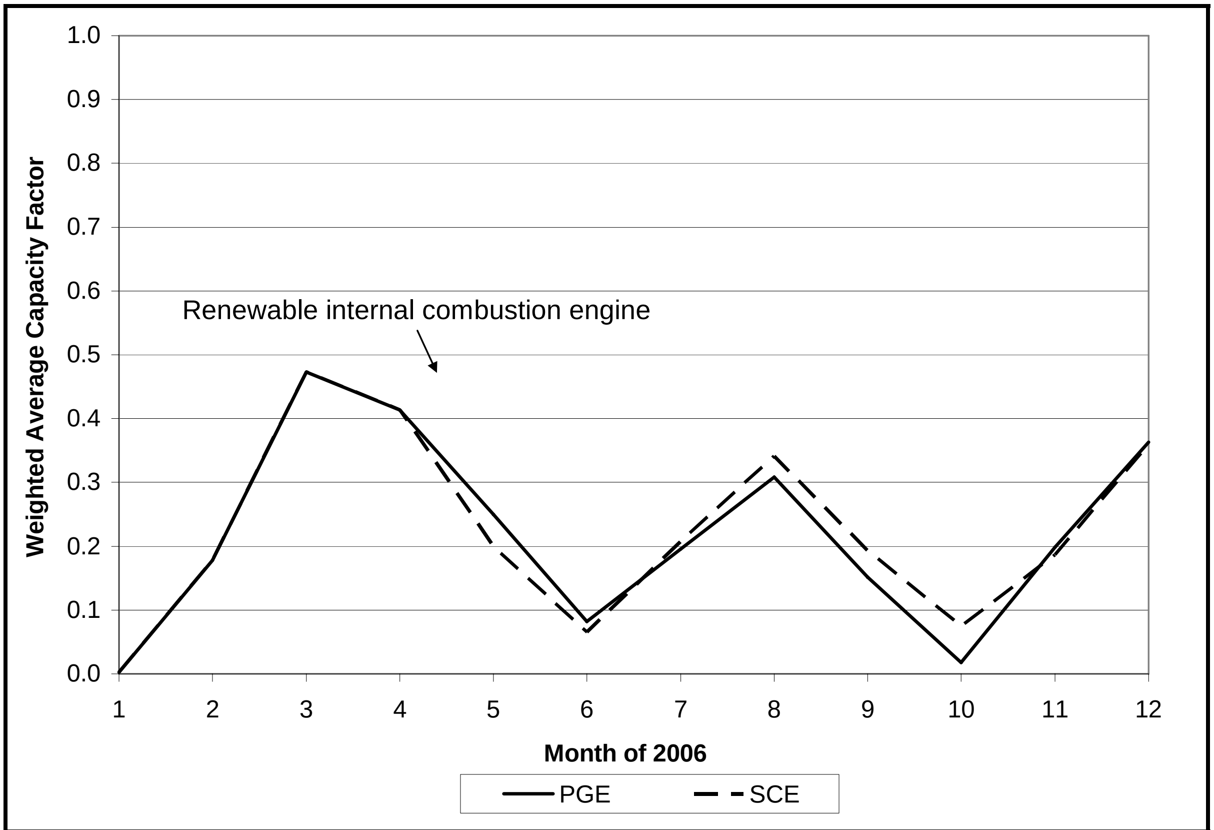


Figure A-22: Monthly Capacity Factors by Technology and PA—MT

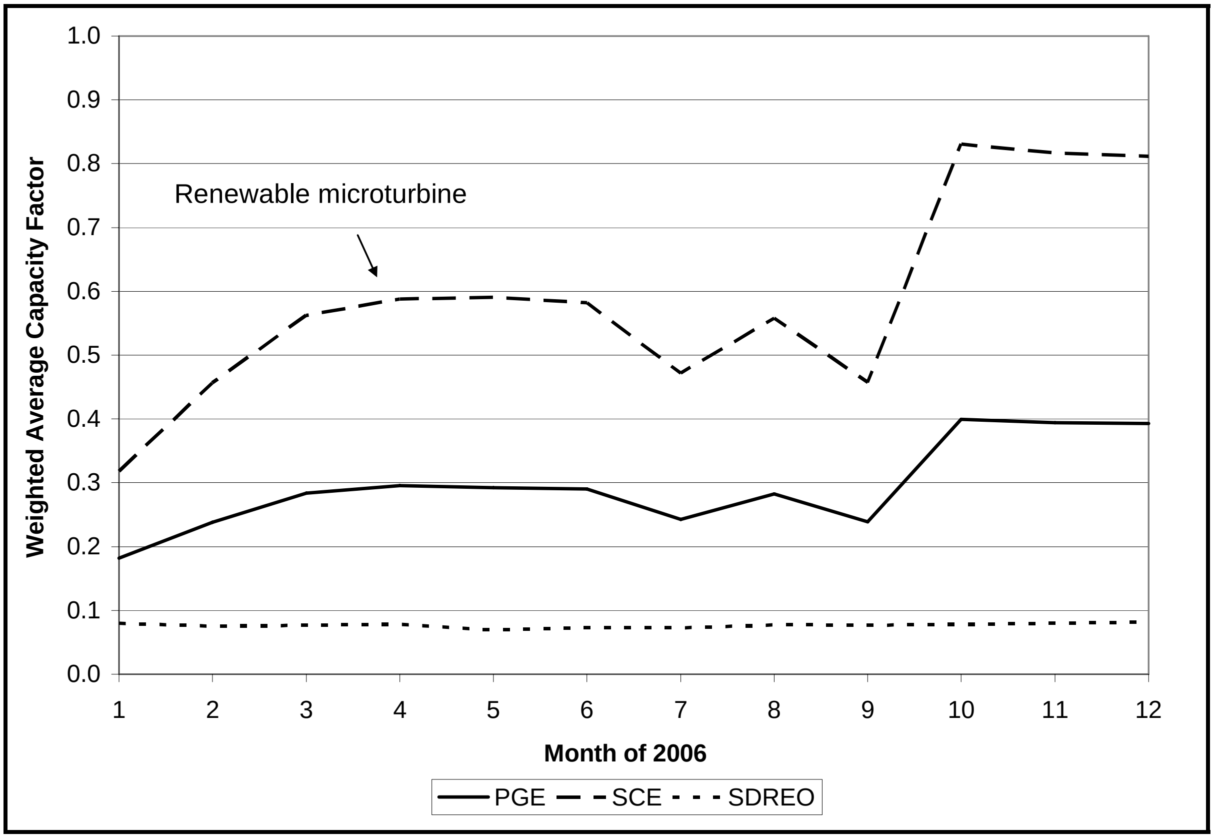


Figure A-23 and Figure A-24 plot the profiles of hourly weighted average capacity factor for Renewable ICE and MT for each PA from the morning to early evening during the day of the annual peak hour, July 24, 2006. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the charts.

Figure A-23: CAISO Peak Day Capacity Factors by PA—ICE

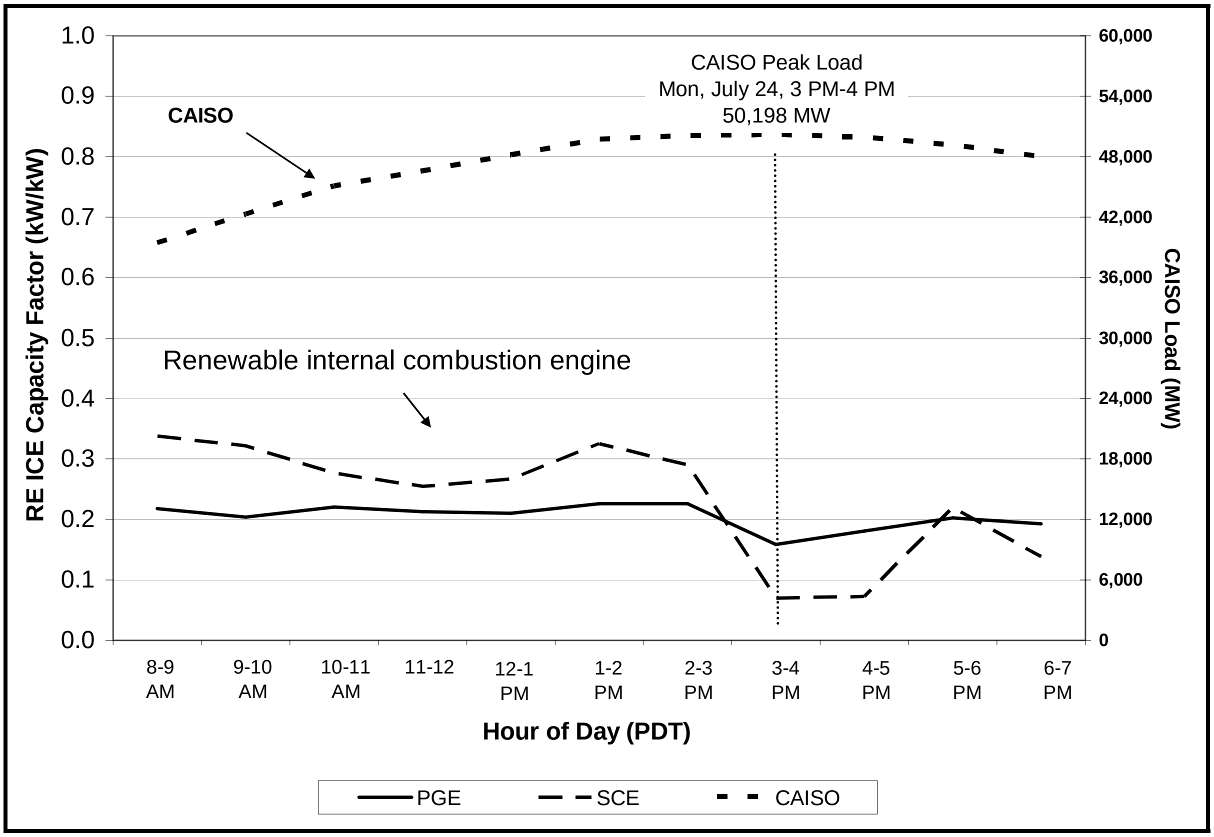


Figure A-24: CAISO Peak Day Capacity Factors by PA—MT

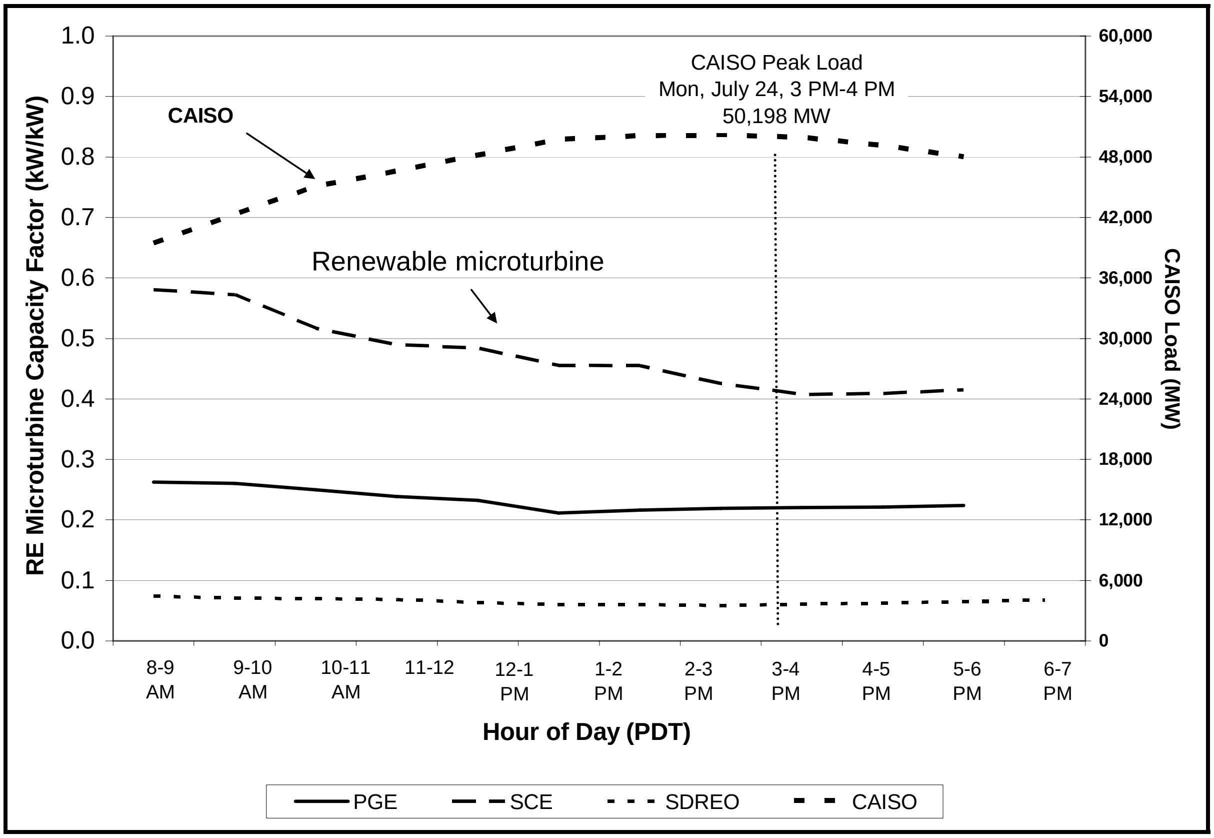


Figure A-25, Figure A-26, and Figure A-27 plot profiles of hourly weighted average capacity factors for Renewable ICE and MT directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SDG&E is the only electric utility without Renewable ICE, so no curve appears for that technology on its peak day.

Figure A-25: Electric Utility Peak Day Capacity Factors by Technology—PG&E

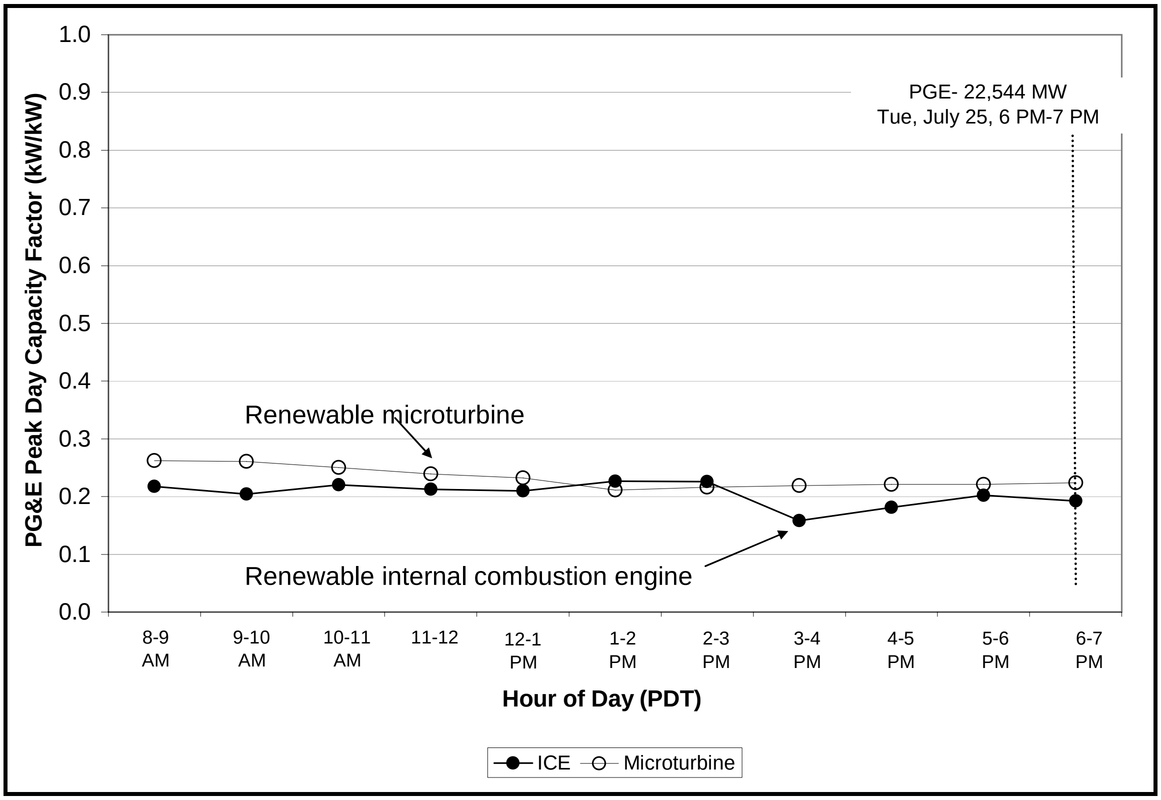


Figure A-26: Electric Utility Peak Day Capacity Factors by Technology—SCE

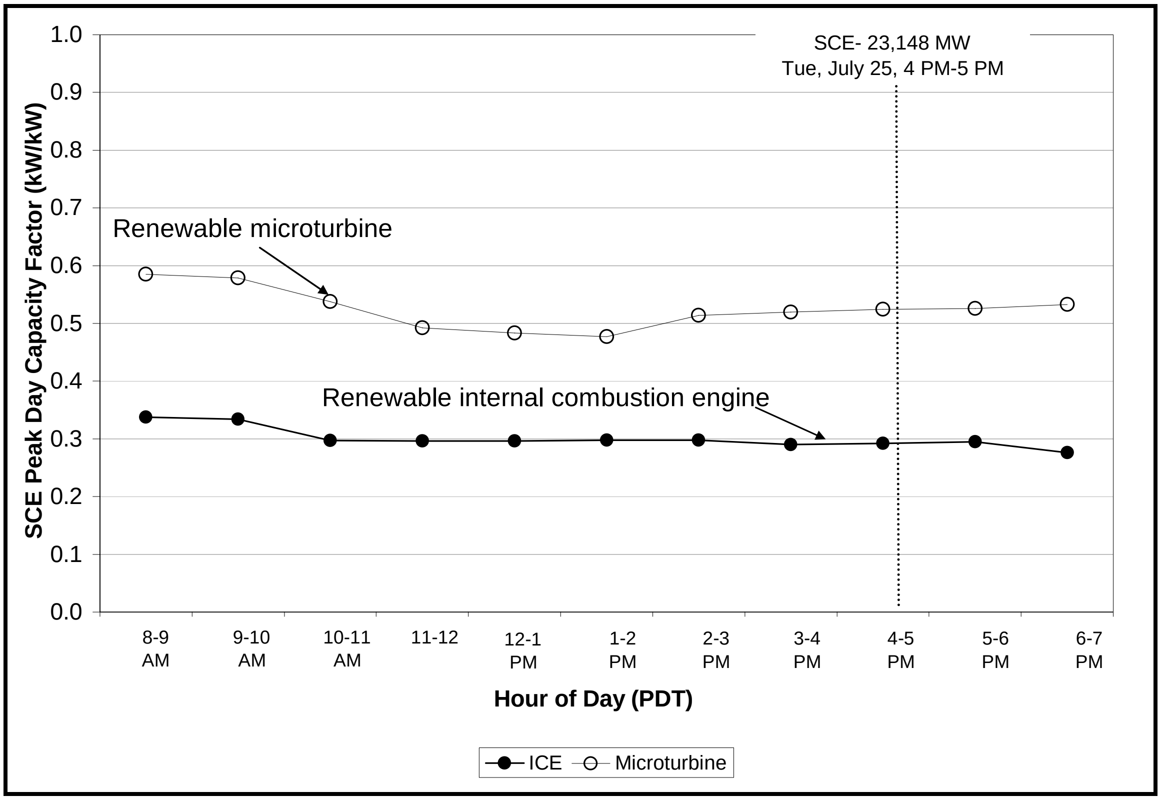
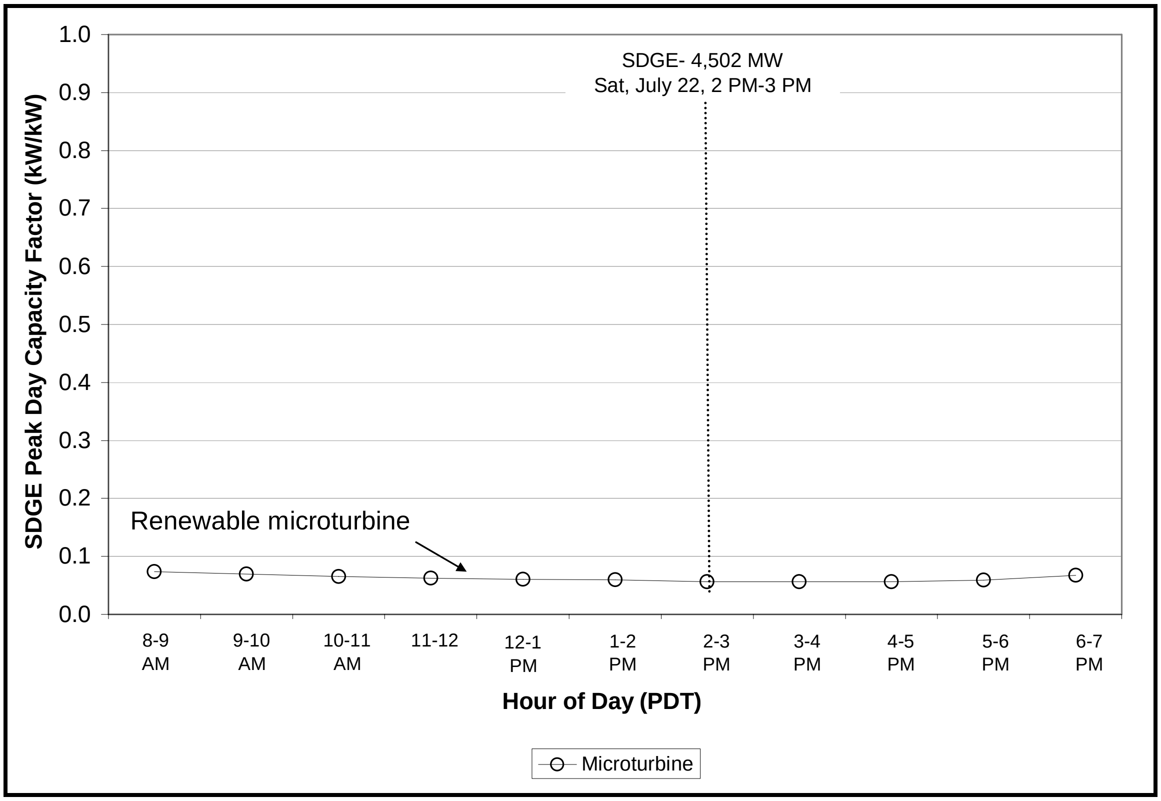


Figure A-27: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



A.4 Non-Renewable Power Systems

This section describes impacts of non-renewable power systems. It begins with fuel cells and proceeds to gas turbines, internal combustion engines, and microturbines.

Natural Gas Fuel Cells

Costs

Table A-42 lists total eligible costs, SGIP incentives, and other incentives for Natural Gas Fuel Cells.

Table A-42: Completed and Active System Costs by Technology

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
FC	**N**	Eligible Cost	$41.5	$20.0
		Incentive	$13.2	$7.3
		Other Incentive	$2.5	$0.5
		Total Incentive	$15.7	$7.8

Annual Energy

Table A-43 presents annual total net electrical output in MWH from Natural Gas Fuel Cells for the program and for each PA. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-43: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	**Total**	**14,893**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			**26,170**
	M	6,407				14,201
	E	8,486				11,969

Table A-44 presents quarterly total net electrical output in MWH for Natural Gas Fuel Cells. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-44: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
FC	**N**	**Total**	**4,573**	**4,874**	**6,932**	**9,792**	**26,170**
		M	3,619	3,542	3,428	3,612	14,201
		E	954	1,332	3,504	6,179	11,969

Peak Demand

Table A-45 presents total net electrical output in kW for Natural Gas Fuel Cells during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows counts of systems and total operational system capacity in kW.

Table A-45: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
FC	6	4,050	3,194

Table A-46 presents the total net electrical output in kW for Natural Gas Fuel Cells during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-46: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	22,544	7/25/2006	18	**FC**	6	3,250	2,295
SCE	23,148	7/25/2006	16	**FC**	0	0	0
SDG&E	4,502	7/22/2006	14	**FC**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		

Capacity Factors

Weighted average capacity factors indicate Natural Gas Fuel Cell performance relative to a system rebated kilowatt for specific time periods. Table A-47 presents annual weighted average capacity factors for Natural Gas Fuel Cells for the year 2006.

Table A-47: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	0.762 †

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-48 presents annual weighted average capacity factors for Natural Gas Fuel Cells for each PA for the year 2006.

Table A-48: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
Technology	Annual Capacity Factor (kWyear/kWyear)			
FC	0.687			0.889

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Figure A-28 plots profiles of monthly weighted average capacity factors for Natural Gas Fuel Cells for each PA. Monthly capacity factors for SCG and SCE Natural Gas Fuel Cells directly overlap those of CCSE from early August and September respectively. This overlap is a result of the metered data for CCSE systems being used to estimate output for the SCG and SCE systems.

Figure A-28: Monthly Capacity Factors by Technology and PA

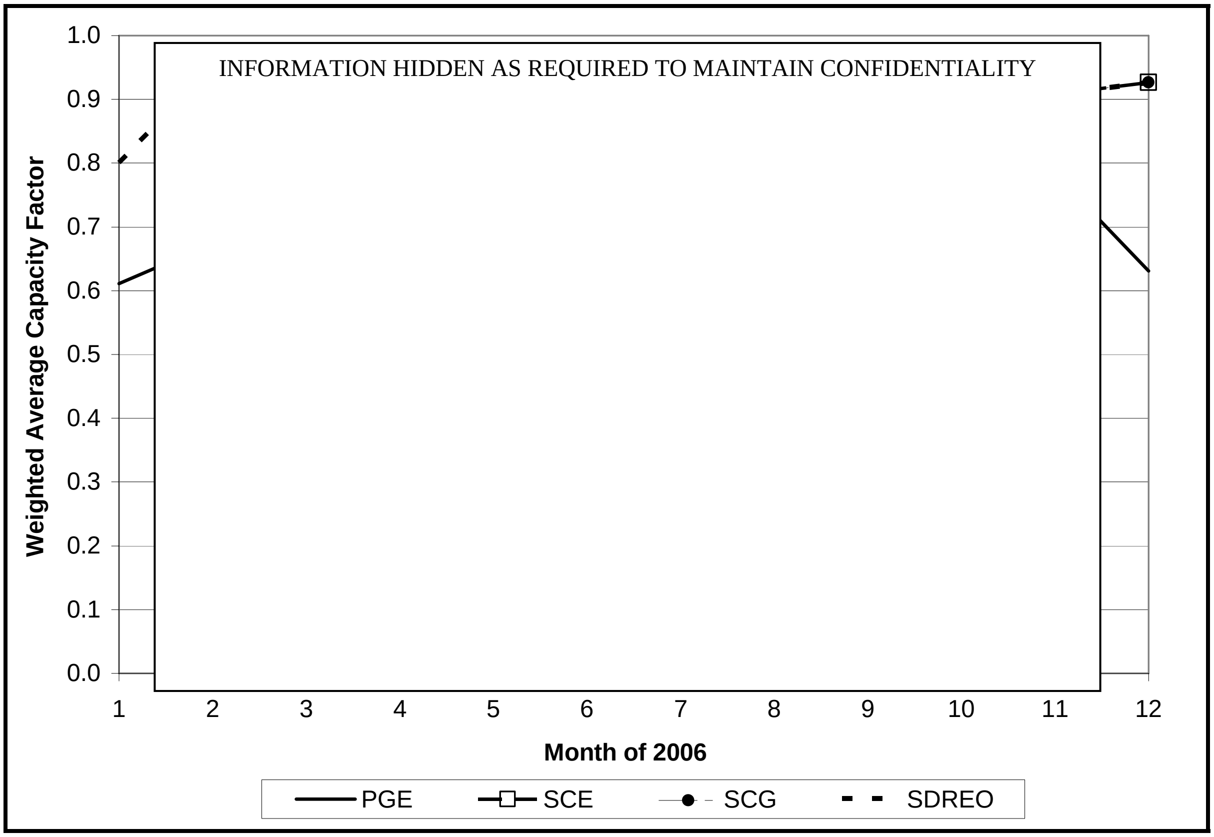


Figure A-29 plots the profiles of hourly weighted average capacity factor for Natural Gas Fuel Cells for each PA from the morning to early evening during the day of the annual peak hour, July 24, 2006. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-29: CAISO Peak Day Capacity Factors by PA

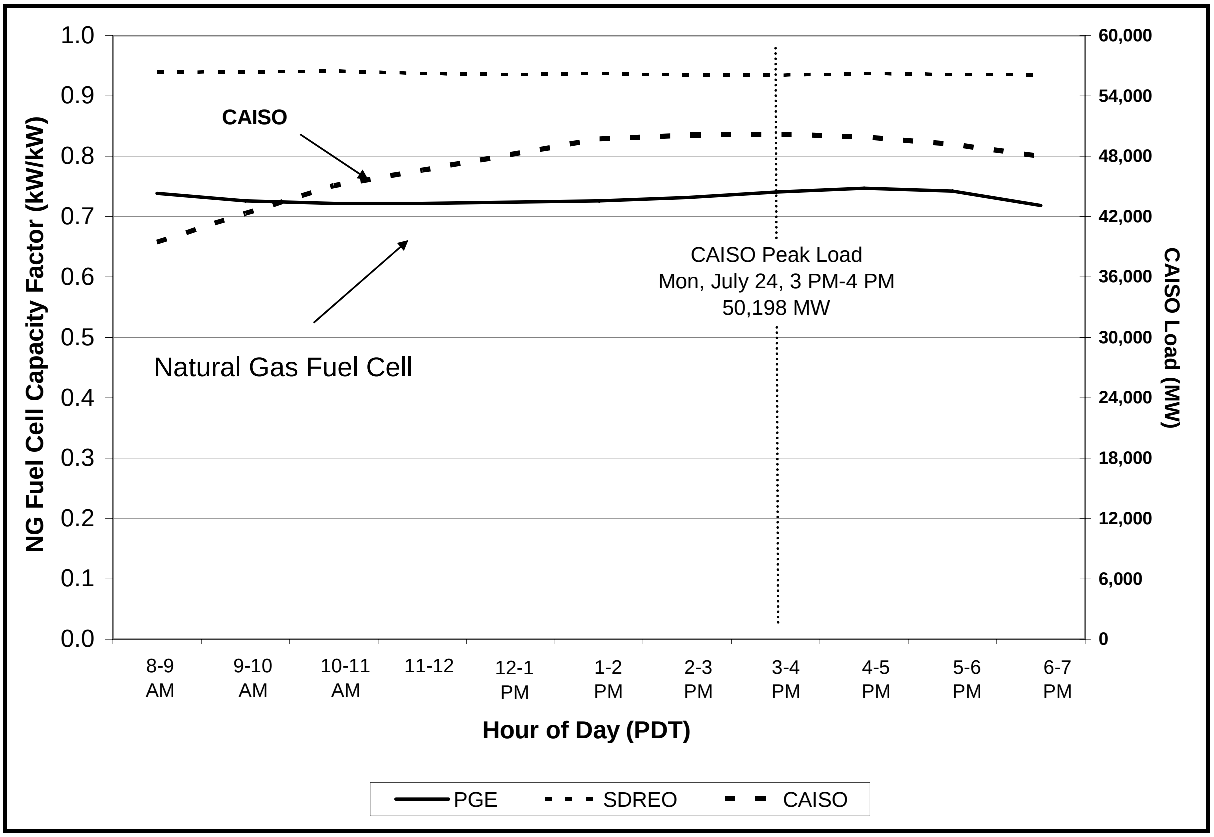


Figure A-30 and Figure A-31 plot profiles of hourly weighted average capacity factors for Natural Gas Fuel Cells directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. SCE and SCG both administer Natural Gas Fuel Cell systems, but no chart appears for SCE because none of these systems fed directly into SCE's distribution system on SCE's peak day. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-30: Electric Utility Peak Day Capacity Factors by Technology—PG&E

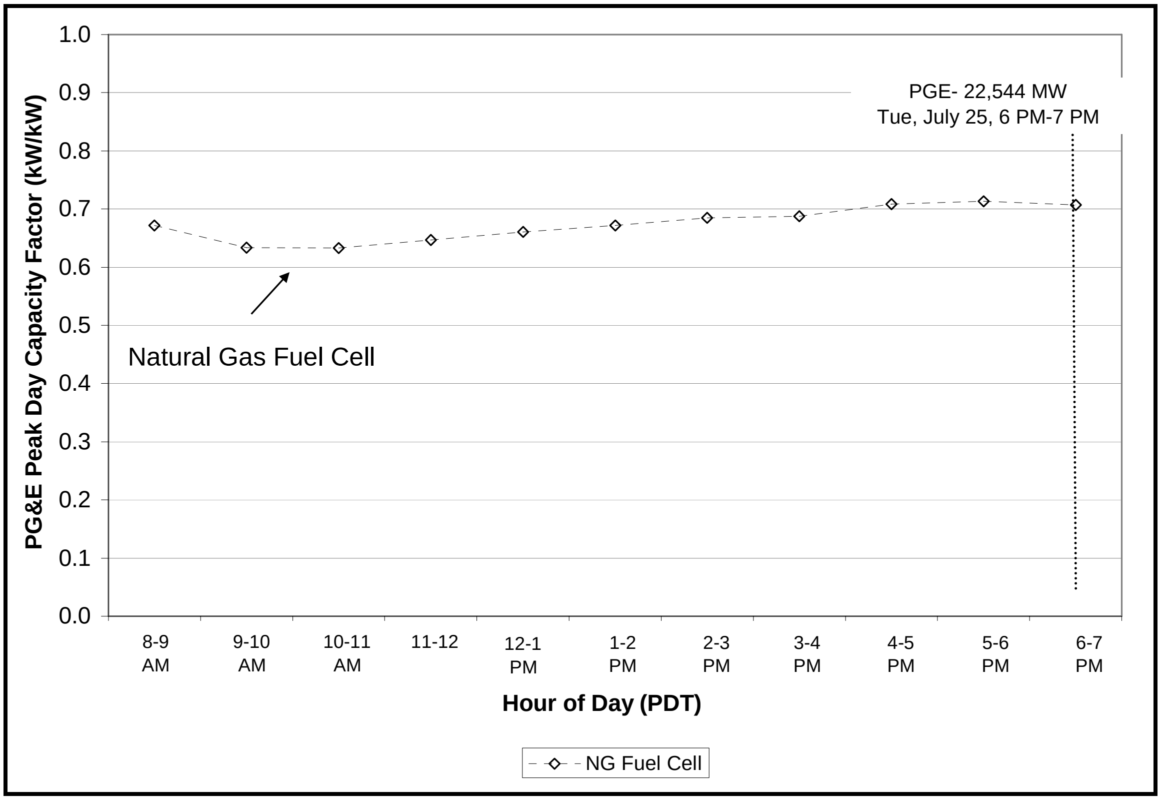
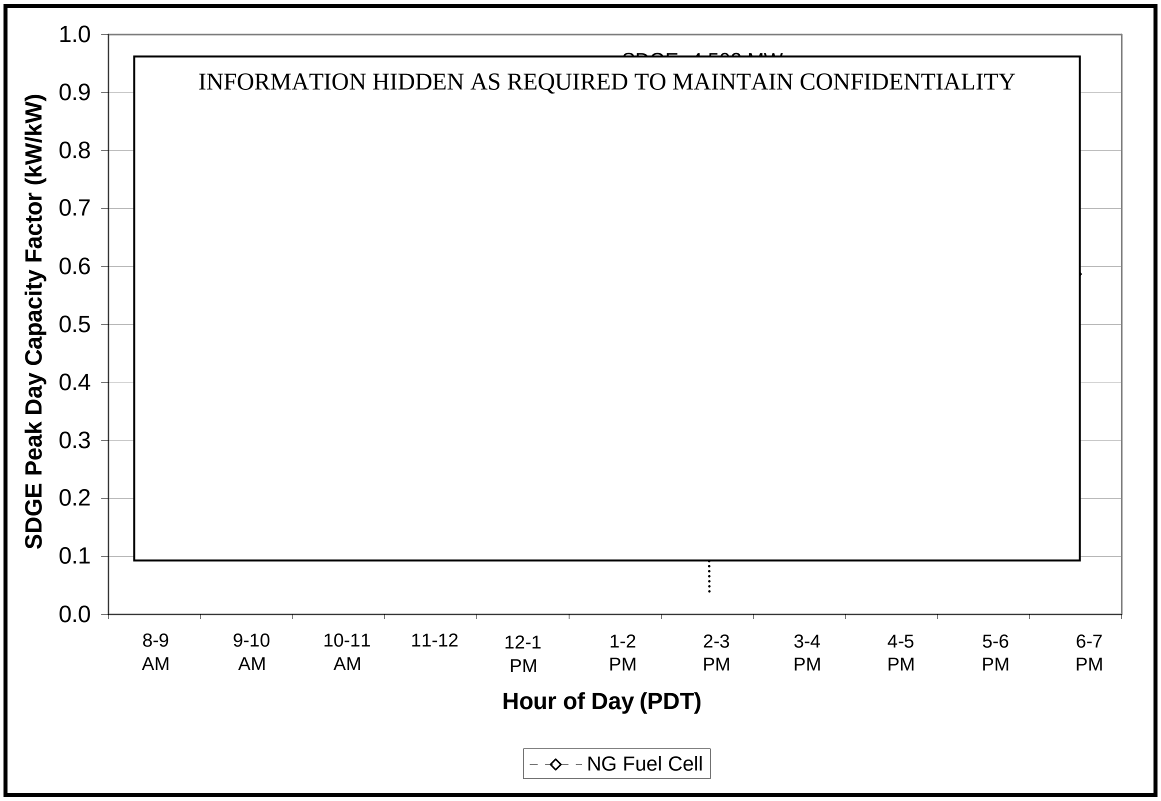


Figure A-31: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



Natural Gas GT, ICE, and MT

Costs

Table A-49 lists total eligible costs, SGIP incentives, and other incentives for Natural Gas GT, ICE, and MT systems.

Table A-49: Completed and Active System Costs by Technology

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
GT	**N**	Eligible Cost	$21.7	$26.6
		Incentive	$2.9	$2.4
		Other Incentive	$0.0	$0.0
		Total Incentive	$2.9	$2.4

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
ICE	**N**	Eligible Cost	$243.0	$161.3
		Incentive	$63.6	$20.8
		Other Incentive	$0.8	$0.1
		Total Incentive	$64.3	$20.9

Technology	Fuel	Cost Component	Completed Projects (M$)	Active Projects (M$)
MT	**N**	Eligible Cost	$42.4	$29.2
		Incentive	$11.5	$5.1
		Other Incentive	$0.5	$0.6
		Total Incentive	$12.0	$5.6

Annual Energy

Table A-50 presents annual total net electrical output in MWH from Natural Gas GT, ICE, and MT systems for the program and for each PA. This table also shows subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-50: Annual Electric Energy Totals by PA

		PG&E	SCE	SCG	CCSE	Total
Technology	**Basis**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
GT	**Total**	**17,944**	**0**	INFORMATION		**55,287**
GT	M	HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
GT	E					
ICE	**Total**	**156,163**	**38,543**	**130,897**	**27,833**	**353,436**
ICE	M	33,387	19,228	77,042	27,627	157,283
ICE	E	122,776	19,315	53,855	207	196,153
MT	**Total**	**15,248**	**11,821**	**17,211**	**2,911**	**47,191**
MT	M	2,671	7,639	5,677	2,853	18,841
MT	E	12,577	4,182	11,535	57	28,351
	Total	**189,356**	**50,364**	**182,800**	**33,394**	**455,914**

Table A-51 present quarterly total net electrical output in MWH for Natural Gas GT, ICE, and MT systems. These tables also show subtotals by basis, metered and estimated, indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-51: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
GT	**N**	**Total**	**13,686**	**12,189**	**13,009**	**16,403**	**55,287**
		M	8,584	10,249	10,969	11,489	41,291
		E	5,102	1,939	2,040	4,914	13,996

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
ICE	**N**	**Total**	**85,833**	**91,147**	**92,170**	**84,286**	**353,436**
		M	38,354	41,498	41,442	35,991	157,283
		E	47,479	49,649	50,729	48,296	196,153

Technology	Fuel	Basis	Q1-2006 (MWh)	Q2-2006 (MWh)	Q3-2006 (MWh)	Q4-2006 (MWh)	Total (MWh)
MT	**N**	**Total**	**10,463**	**12,027**	**12,193**	**12,508**	**47,191**
		M	4,433	4,781	4,179	5,448	18,841
		E	6,030	7,246	8,014	7,060	28,351

Peak Demand

Table A-52 presents total net electrical output in kW for Natural Gas GT, ICE, and MT systems during the peak hour of 3 pm (PDT) on July 24, 2006. The table also shows counts of systems and total operational system capacity in kW.

Table A-52: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
GT	3	7,093	5,789
ICE	176	110,323	49,234
MT	82	13,158	4,678
Total	261	130,574	59,701

Table A-53 presents the total net electrical output in kW for Natural Gas GT, ICE, and MT systems during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-53: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PG&E	22,544	7/25/2006	18	**GT**	2	2,593	1,930
				ICE	73	44,897	20,884
				MT	24	4,448	2,113
				Total	99	51,938	24,927
SCE	23,148	7/25/2006	16	**GT**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALI		
				ICE	78	51,685	25,824
				MT	41	6,682	3,203
				Total	120	62,867	32,947
SDG&E	4,502	7/22/2006	14	**GT**	0	0	0
				ICE	19	12,225	2,157
				MT	12	1,058	290
				Total	31	13,283	2,447

Capacity Factors

Weighted average capacity factors indicate Natural Gas GT, ICE, and MT systems performance relative to a system rebated kilowatt for specific time periods. Table A-54 presents annual weighted average capacity factors for Natural Gas GT, ICE, and MT systems for the year 2006.

Table A-54: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
GT	0.843 [a]
ICE	0.366 †
MT	0.414 †

* [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-55 presents annual weighted average capacity factors for Natural Gas GT, ICE, and MT systems for each PA for the year 2006.

Table A-55: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor (kWyear/kWyear)			
Technology				
GT	0.790			
ICE	0.407	0.238	0.386	0.344
MT	0.416	0.413	0.439	0.312

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Figure A-32, Figure A-33, and Figure A-34 plot profiles of monthly weighted average capacity factors for Natural Gas GT, ICE, and MT systems for each PA. The gas turbine administered by CCSE did not come online until November 2006, so its plot includes only two months rather than 12.

Figure A-32: Monthly Capacity Factors by Technology—Natural Gas Turbine

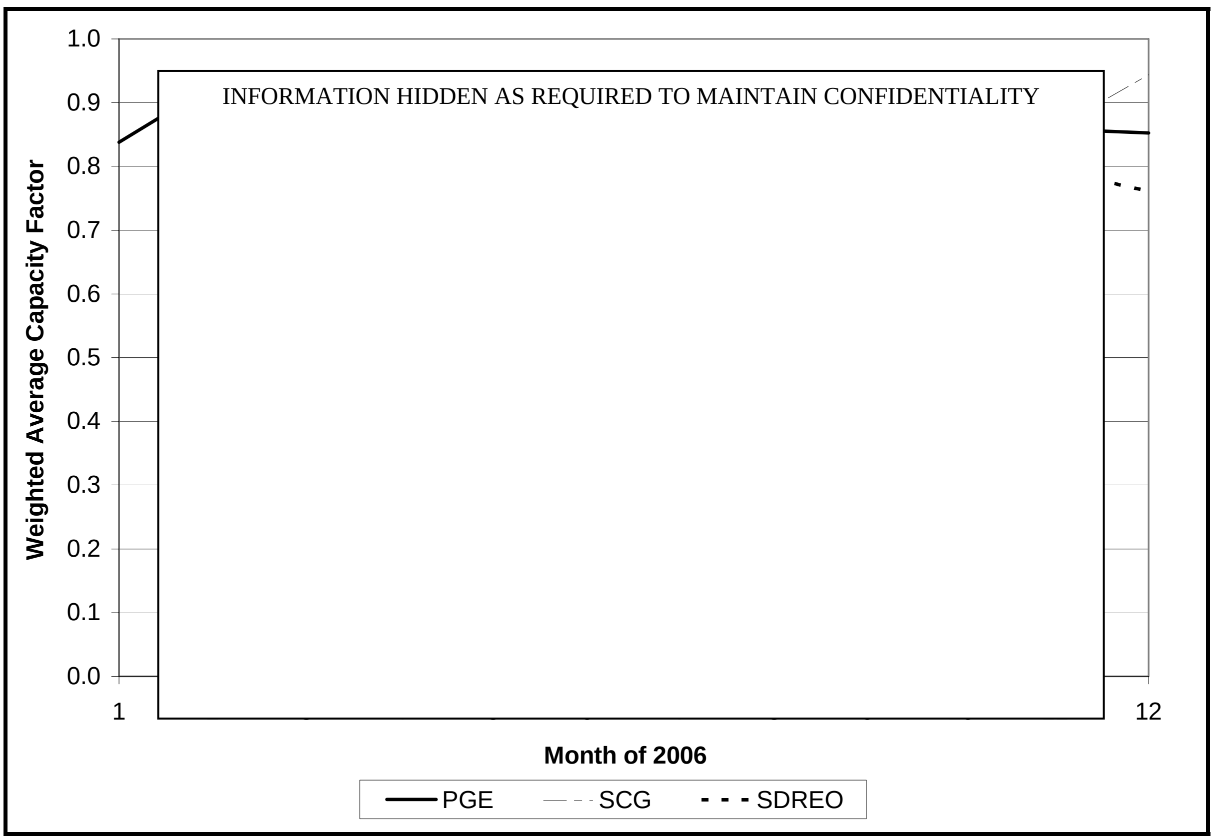


Figure A-33: Monthly Capacity Factors by Technology—Natural Gas ICE

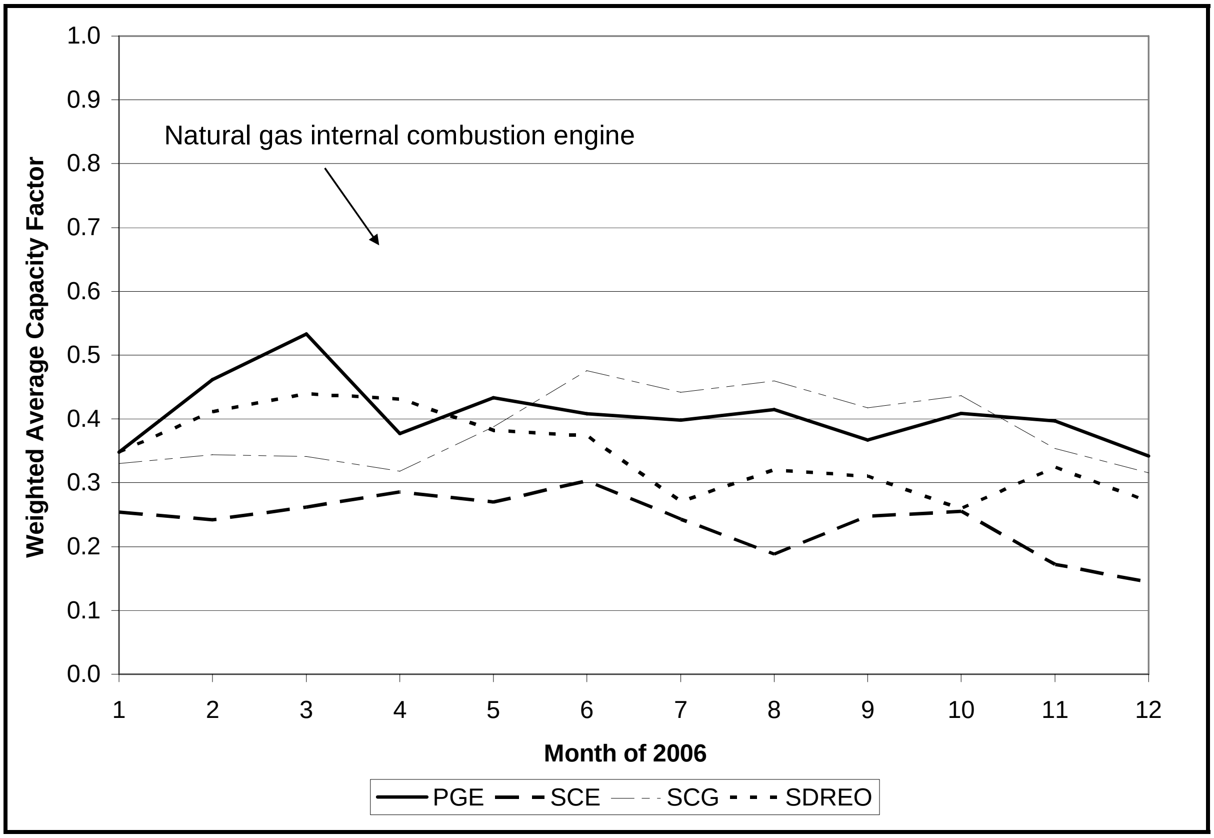


Figure A-34: Monthly Capacity Factors by Technology—Natural Gas MT

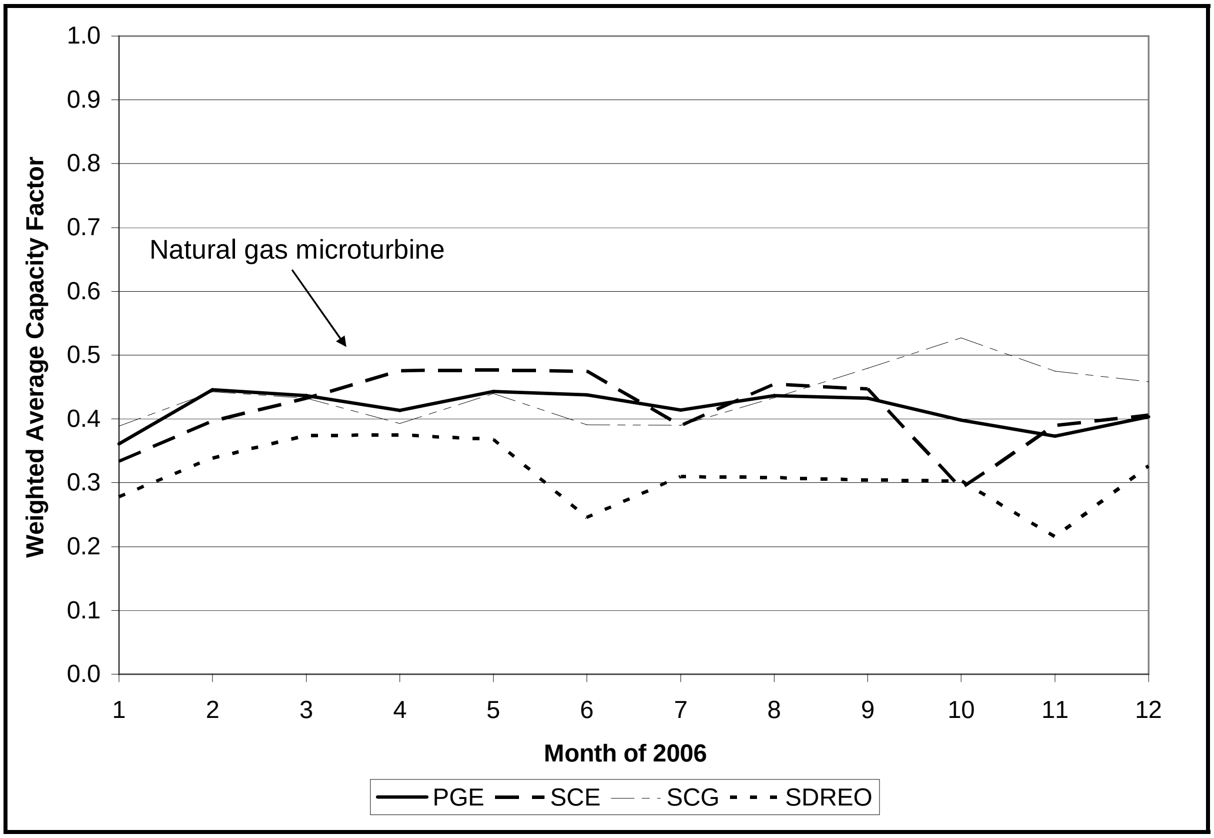


Figure A-35 plots the profiles of hourly weighted average capacity factor for Natural Gas GT, ICE, and MT systems from the morning to early evening during the day of the annual peak hour, July 24, 2006. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-35: CAISO Peak Day Capacity Factors by Technology

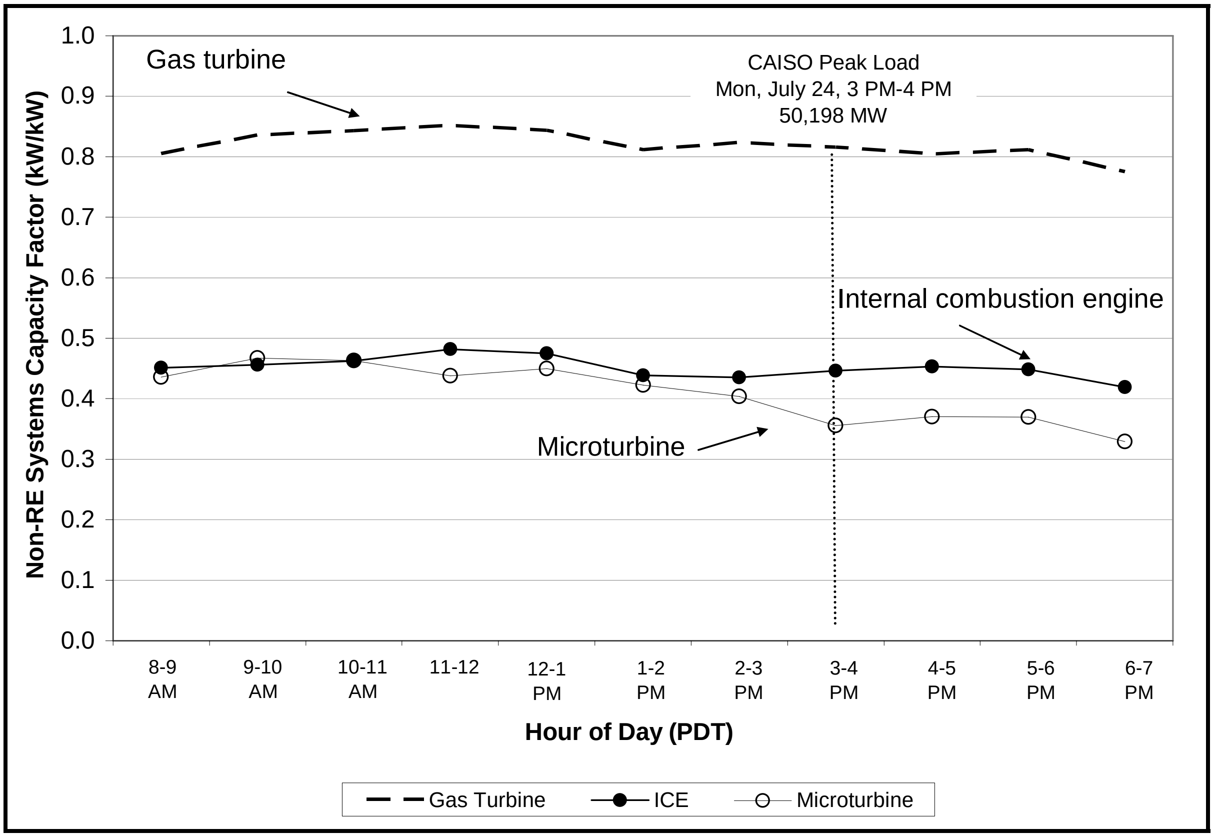


Figure A-36, Figure A-37, and Figure A-38 plot the profiles of hourly weighted average capacity factor for Natural Gas GT, ICE, and MT systems for each PA from the morning to early evening during the day of the annual peak hour, July 24, 2006. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-36: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas Turbine

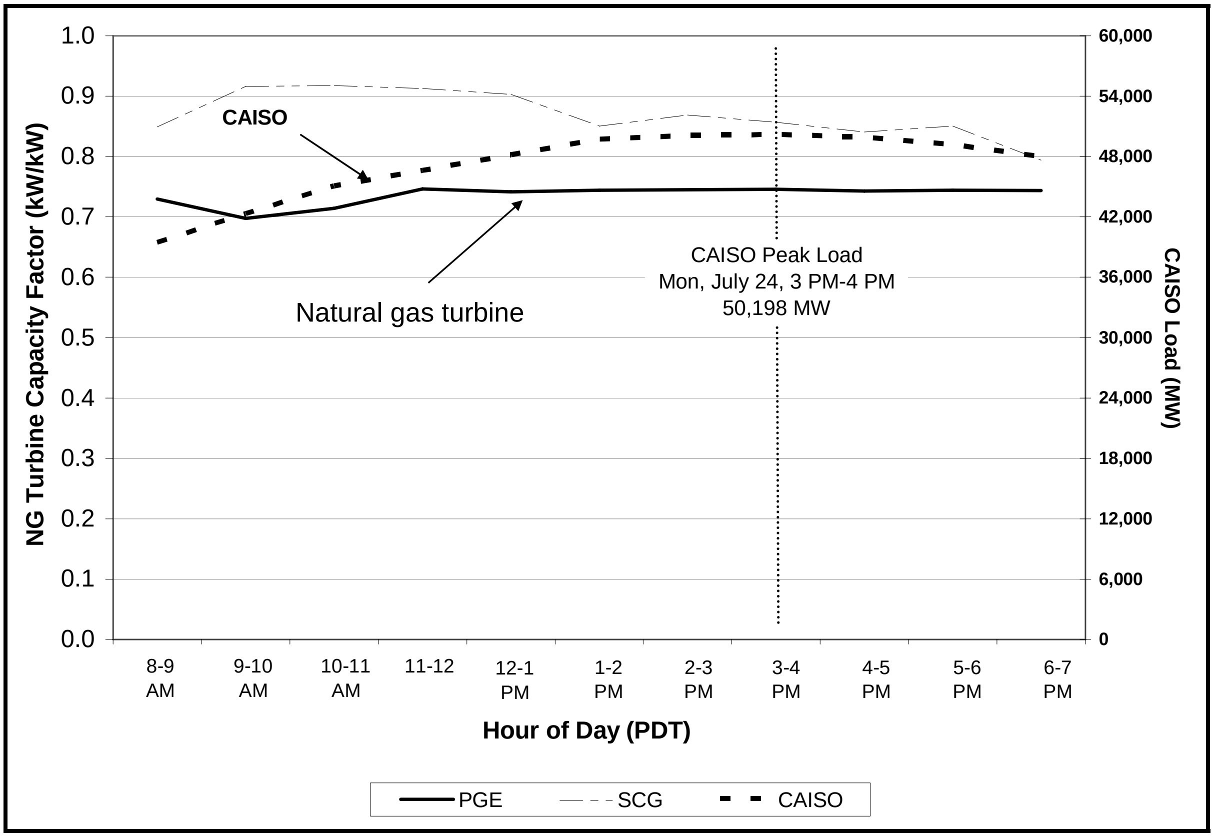


Figure A-37: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas ICE

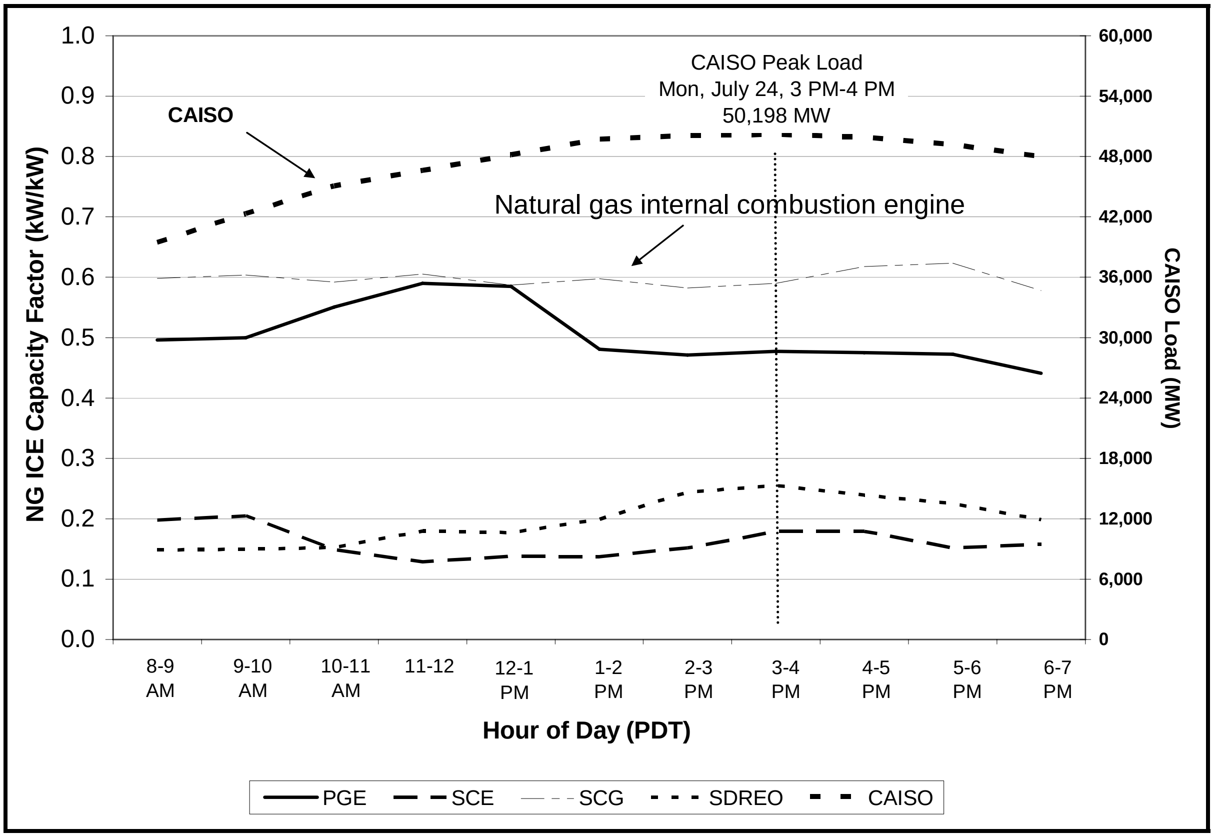


Figure A-38: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas MT

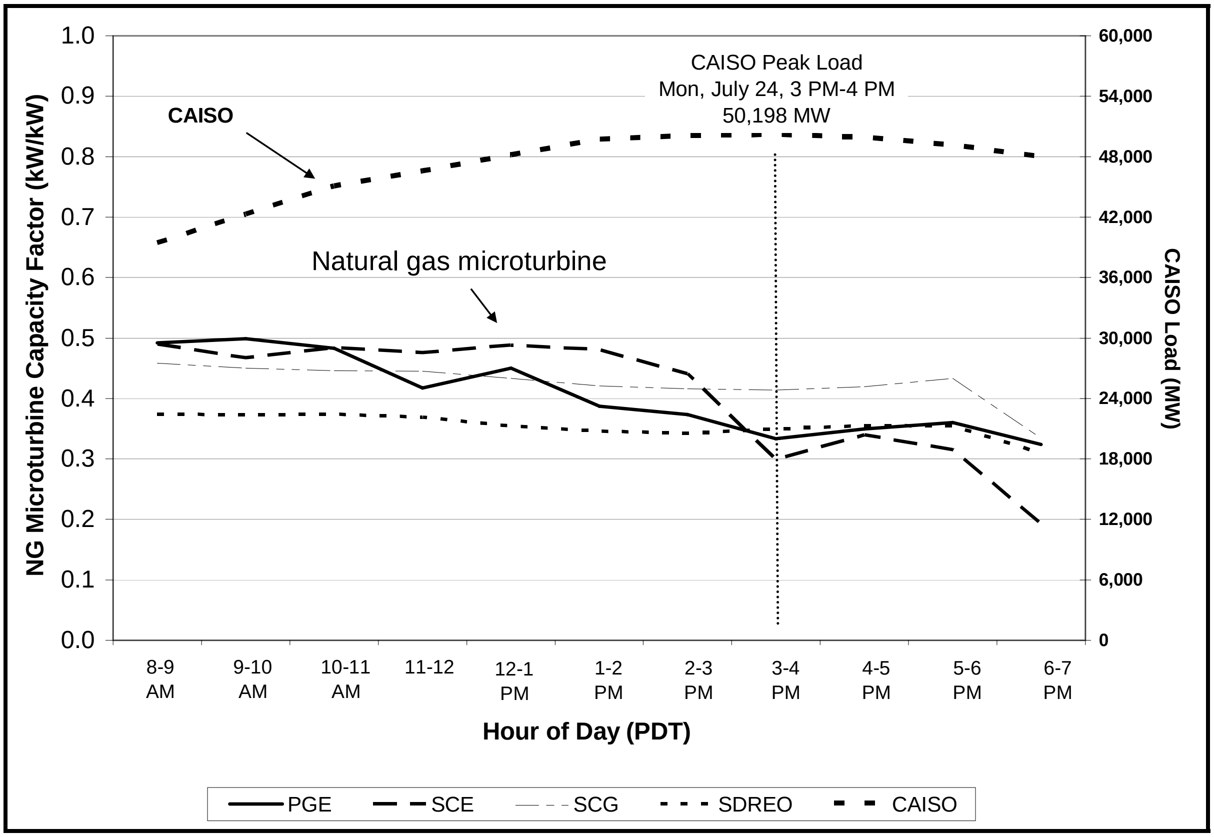


Figure A-39, Figure A-40, and Figure A-41 plot profiles of hourly weighted average capacity factors for Natural Gas GT, ICE, and MT systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-39: Electric Utility Peak Day Capacity Factors by Technology—PG&E

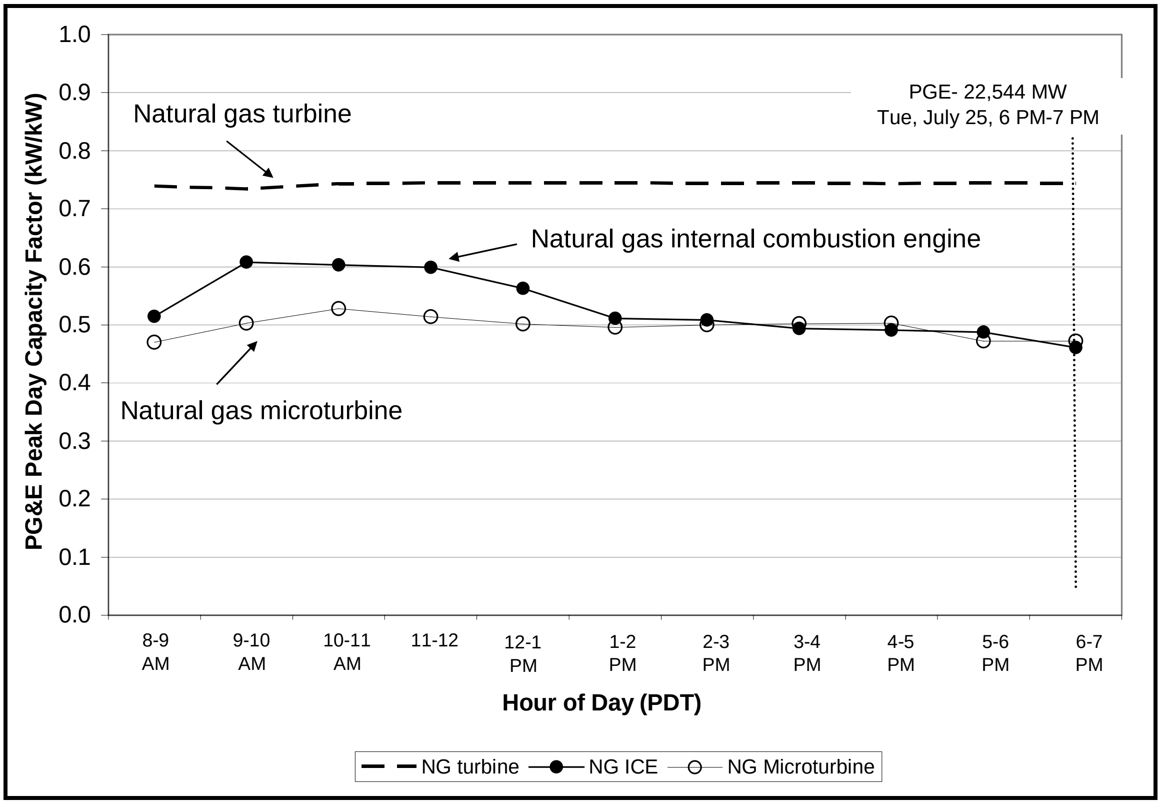


Figure A-40: Electric Utility Peak Day Capacity Factors by Technology—SCE

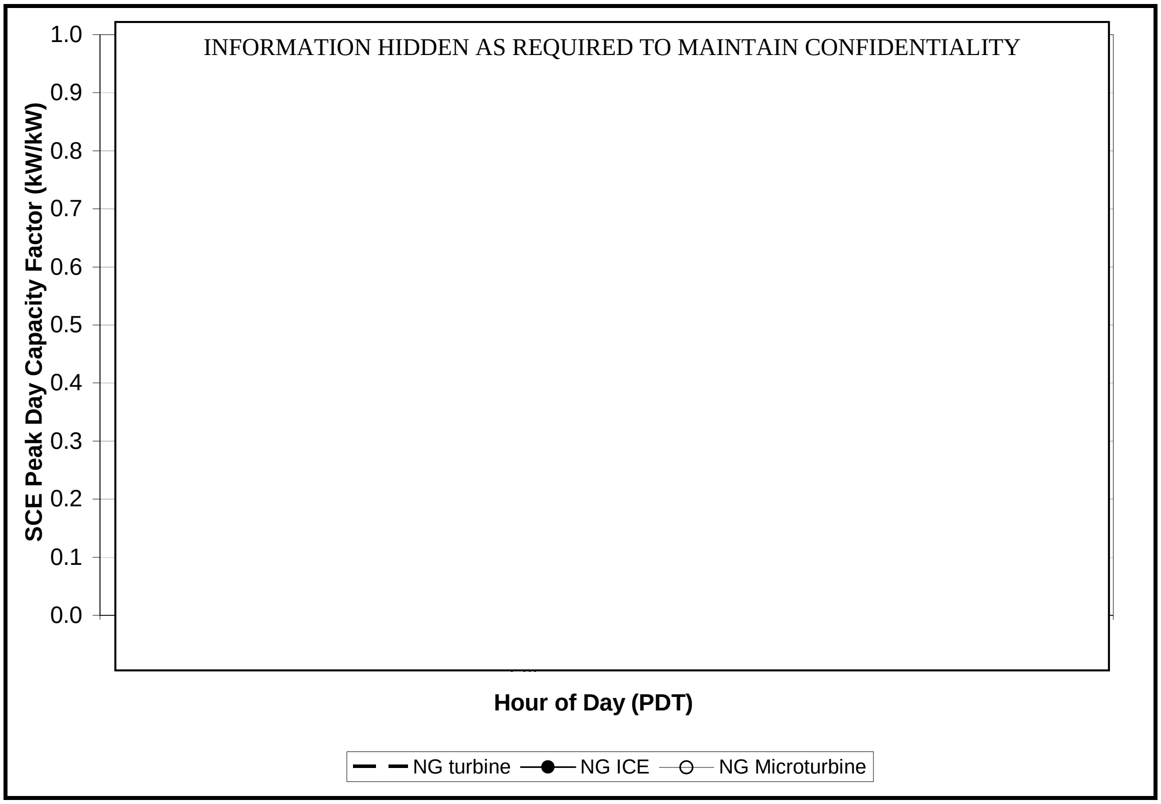
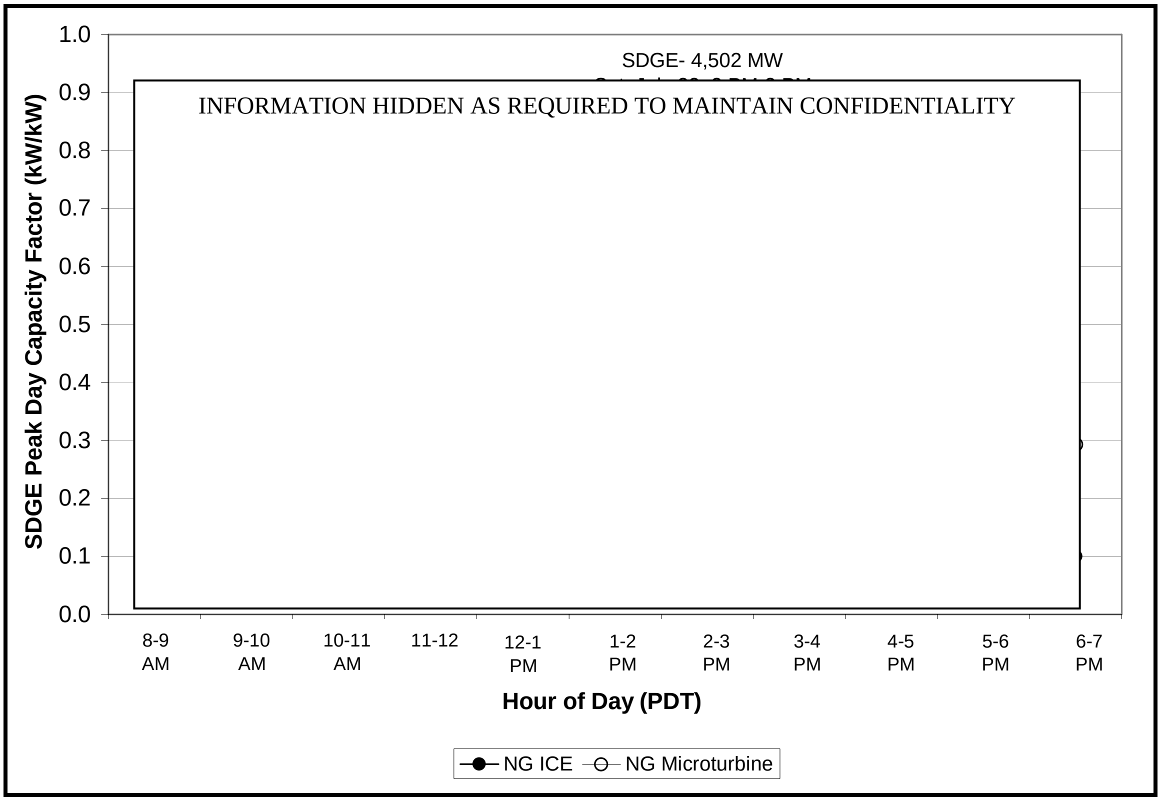


Figure A-41: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



Appendix B

Transmission and Distribution Impacts

This appendix outlines the methodology and results of the transmission and distribution impacts which were presented in Section 5.3.

B.1 Transmission System Impacts Methodology and Results

The transmission system impacts methodology and results are supplemental to Section 5.3, which discussed the transmission system impacts.

Data Resources

There are numerous data resource requirements. These include:

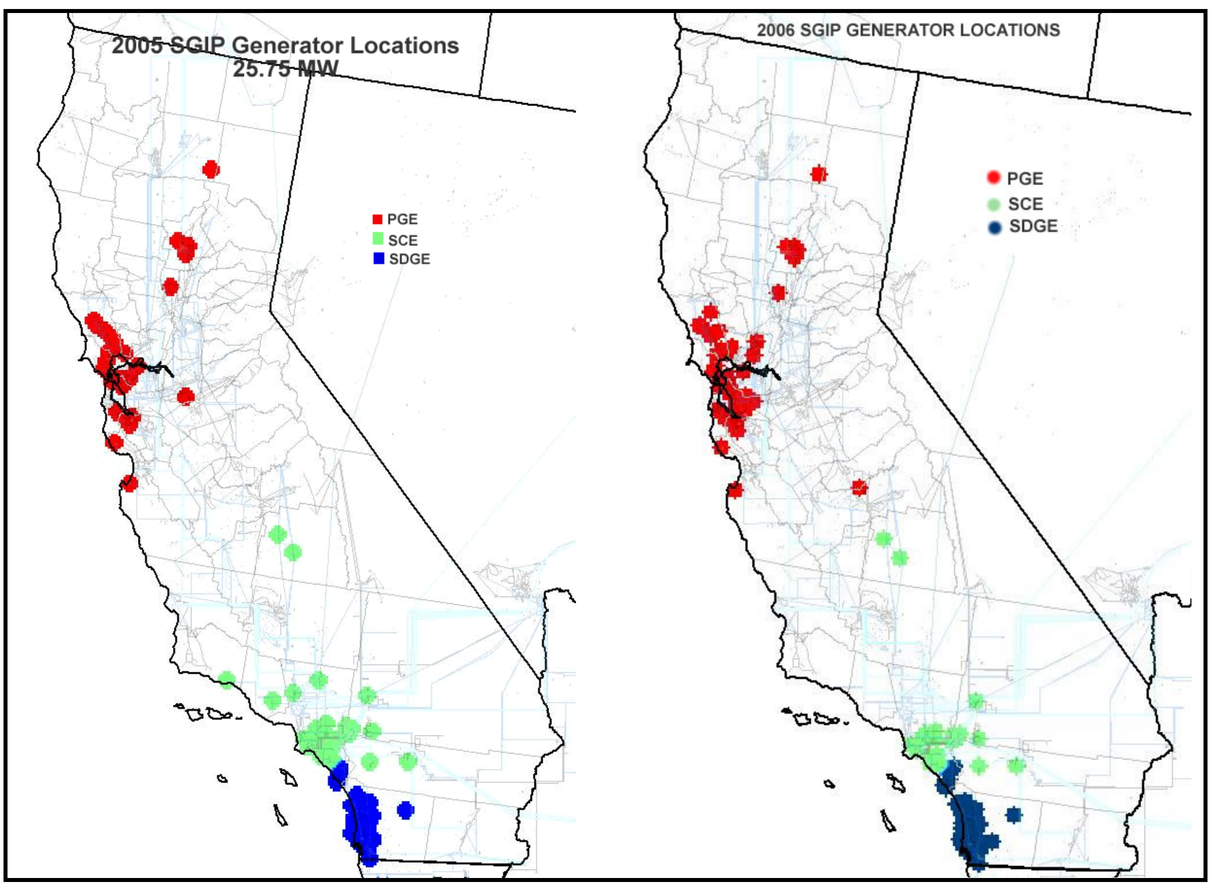
- Updated transmission power flow data sets for the time periods studied
- List of self-generator facilities in California
- Assignment of the self generators to distribution feeders that connect to distribution substations that connects to transmission substations
- Self-generation capacity at time of system peak from Itron meters
- IOU rebated kW capacity for self-generators

DPC signed an umbrella non-disclosure agreement (NDA) with Pacific Gas and Electric (PG&E) that covers material and data provided by PG&E, Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). PG&E did provide 2006, 2007 and 2008 WECC-approved power flow data sets for the entire WECC region. The power flow data sets are loaded into the PowerWorld transmission power flow simulation model that is used for this project. This is the same model that developed the SVA methodology. These data sets are sent to SCE and SDG&E for review and approval of their respective system modeling. The IOUs determined that the 2008 power flow data set is a special data set developed for southern California and the Desert Southwest and is not appropriate for the self-generation study. The 2005 data set is not available from WECC. The 2006 data set is adjusted to loads and generation to represent 2005. The WECC 2006 power flow data set is named “06hs4a”.

A list of self-generators is developed for PG&E, SCE, SDG&E, and Southern California Gas (SCG). The WECC transmission power flow data sets do not model every substation and every sub-transmission line within each IOU. For example, if the sub-transmission line is a radial line, the line may not be modeled in the WECC power flow. The aggregated load and generation may be modeled at the next higher voltage substation. The IOUs' transmission and distribution staff are very helpful in determining the feeders that each self-generator is connected, the sub-transmission substation and line that the feeder is connected, then the next higher voltage transmission substation that the sub-transmission is connected. This is no easy task since there are over 655 self-generators locations in 2006. There are approximately 225 in PG&E, 310 in SCE/SCG and 120 in SDG&E.

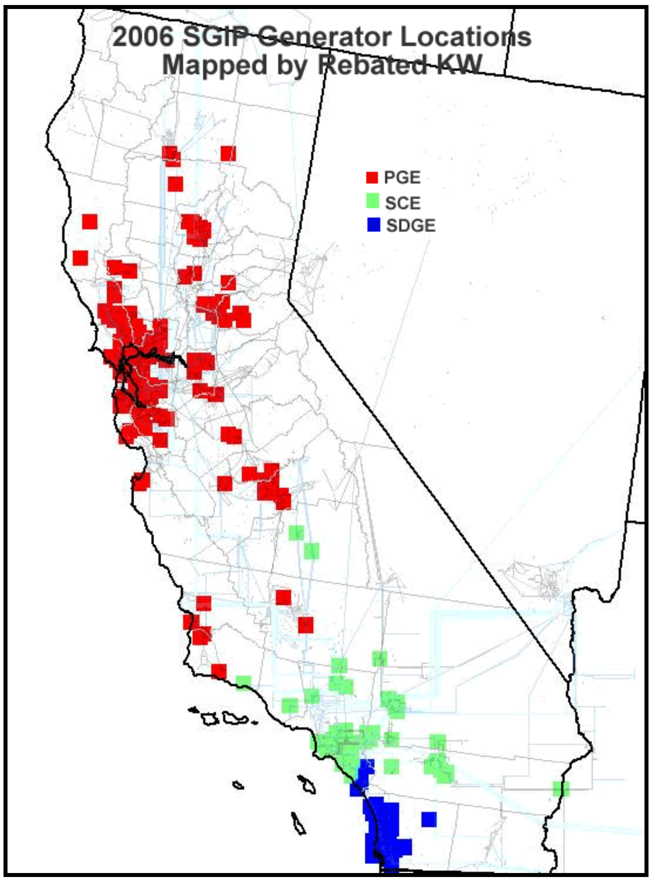
Since the main objective of the project is to evaluate self-generator (DG) locations that are metered by Itron, the number of locations is reduced to only the Itron-metered locations. The DG capacity that is metered by Itron is 25.75 MW for 2005 and 31.73 MW for 2006. When compared to a California system load of over 40,000 MW, the transmission impacts that 26 or 32 MW has on the system can be difficult to capture. Figure B-1 below shows the approximate locations of the self-generating resources for the 26 MW and 32 MW.

Figure B-1: Self-Generator Locations for 2005 (26 MW) and 2006 (32 MW)



However, for sensitivity analysis, the DG locations with an IOU rebated kW value that are identified with a substation within the transmission power flow data set are studied. It is realized that the 120 MW of total connected DG resources are not available and generating at the time of system summer peak, but the objective is to determine the value of these additional resources if available. For example, PV may not be generating at its maximum connected capacity at the time of peak since the peak usually occurs when residential customers come home and turn up the air conditioners. Figure B-2 shows the approximate location of the self-generating resources that comprise the 120 MW.

Figure B-2: Self-Generator Locations for 2006 120 MW



Since these individual DG locations metered by Itron are less than 2 MW each and total is less than 26 MW in 2005 and less than 32 MW in 2006, it makes little sense to undertake a transmission power flow analysis for each site. A statewide California transmission power flow simulation for first contingency analysis is over 7,000 cases and takes more then two hours to complete. The accuracy and benefit analyses may be too small compared to the man-hour time to complete. For example, if the total number of self-generators is 655 and the total generating capacity is 120 MW, the average generating capacity per DG is 0.18 MW. For this reason, the individual DG locations are aggregated together into utility-specified transmission zones. The power flow simulation can now be completed for a higher penetration of DG. Table B-1 below shows the breakdown of the MW total in each utility for the three scenarios that were completed.

Table B-1: DG MW Breakdown per IOU

	26 MW Case	32 MW Case	120 MW Case
PG&E	3.16	7.1617	34.76
SCE	15.28	17.5	61.07
SDG&E	7.31	7.07	24.92
Total	**25.75**	**31.73**	**120.75**

Analytical Methodology

For each substation with DG, the aggregated MW of the self-generators is added together. Since this DG is load reducers, if the DG are not available, then the total load at the substations are higher by the amount of DG. The transmission substation configuration in the power flow data set is adjusted to include both the aggregated DG capacity and a corresponding aggregated load equal to the DG capacity. When the DG is simulated out of service for a contingency case, then the load at the substation increases since the DG is not available to reduce load. This representation simulates the benefits that DG provides by reducing load on substations and transmission lines.

The methodology for evaluating the transmission benefits of DG is the Aggregated MegaWatt Contingency Overload (AMWCO) that was developed under the Energy Commission's PIER program for evaluating renewable penetrations and reliability benefits in 2005. Power flow simulations are completed under first contingency (N-1) conditions. One at a time, each power flow element (transmission line, transformer or generator) is temporarily removed from service and a new power flow simulation is completed. This process is repeated for each element in the power flow case until all of the individual elements are studied. For an N-1 simulation of the California transmission system, there could be up to 7,000 simulations completed for one scenario. One or more of these individual simulations may cause an overload on one or more elements. The percent overload of the element is weighted by the number of outage occurrences and the percent overload. The summation of the weighted overloads is the AMWCO. The difference between the AMWCO for the base case and each renewable case divided by the capacity of the installed renewable is the Renewable Transmission Benefit Ratio (RTBR).

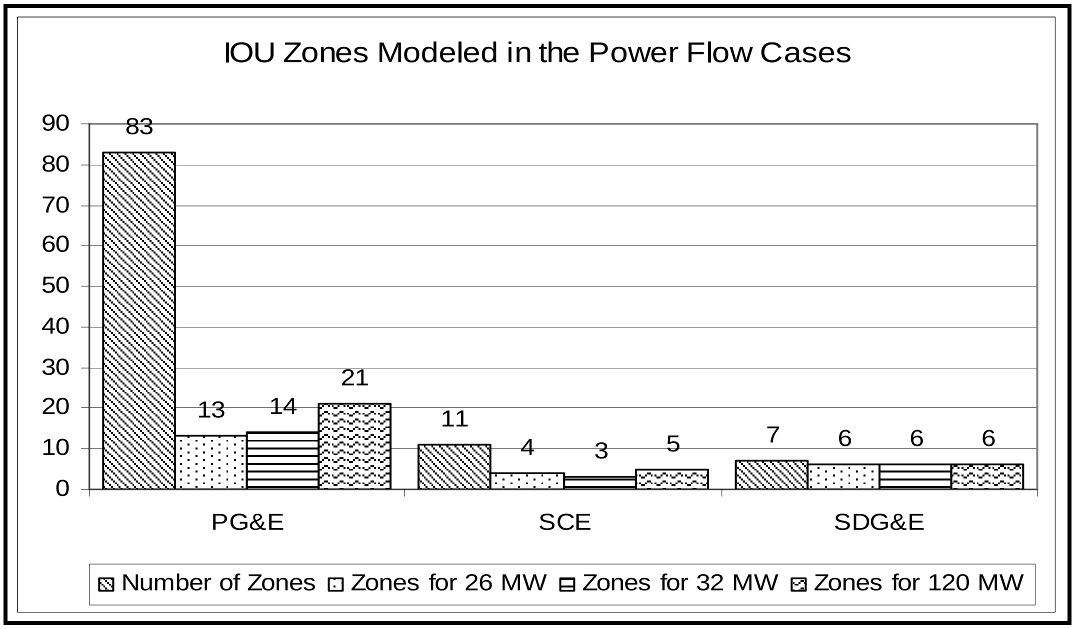
For the cases with and without DG, the AMWCO is calculated. The difference between the two AMWCO values divided by the DG capacity determines the RTBR. The magnitude of the negative RTBR is an indication of the improvement in transmission reliability. For example, if 10 MW of DG reduces the AMWCO by a negative 12, then the RTBR benefit is a negative 1.2. A positive RTBR indicates that the reliability is not improving. More information on AMWCO and RTBR can be found in the Energy Commission's report "Strategic Value Analysis for Integrating Renewable Technologies in Meeting Renewable Penetration Targets, June 2005, CEC-500-2005-106". Since this is a DG study, the RTBR will be referred to as DGTBR in this report.

Several power flow scenarios are completed. The first scenario is a DGTBR analysis for all of the DG resources on a statewide basis. The first power flow simulation excludes all of the DG. A power flow simulation is completed for about 7,000 first contingency (N-1) conditions. The first contingency analysis (N-1) is the outage of one transmission line or one generator. To model every line and transformer outage requires 7,000 different simulations. The second scenario includes all of the DG resources. The number of simulations is slightly larger given the increase in generators for the DG resources. The DGTBR value is determined by subtracting the AMWCO value of the first simulation from the AMWCO of the second simulation and dividing by the DG capacity. A negative value indicates that the DG provides a transmission reliability benefit to the system.

The second scenario is the DGTBR impacts or benefits to each IOU. Each IOU system is individually studied in the power flow. The same two simulations are completed as described above except that instead of a state-wide study, the studies concentrate on each utility system. The DGTBR is calculated the same way as above.

The third scenario is the transmission impact and benefits on the zones that have DG resources. Each IOU divides its service area into transmission zones. Not all of the zones contain DG resources. For example, Figure B-3 shows the total number of zones for each IOU and the number of zones that include at least one DG resource.

Figure B-3: IOU Zones



PG&E divides its system into numerous zones but only a few have DG resources. For PG&E, less than 25 percent of the zones have DG. The SDG&E service area is so small compared to the other two IOUs that at least one DG resource is located in each zone. For SCE, the percentage of zones that have at least one DG ranges from 25 percent to 45 percent.

DG Resource Transmission Results

The results of the transmission system impacts analysis are presented for 2005 (26 MW of DG) and 2006 (32 MW of DG).

2005 Transmission Results (26 MW)

Figure B-4 below shows the distribution of the 26 MW of DG for the three IOUs for 2005. The number of DG for the IOU and for the IOU zones should be the same since the utility assigned the self-generators to specific zones. The majority of the self-generators are located in SCE service area.

Figure B-4 compares the distribution of the 26 MW of DG across the three IOUs. The IOU area and the IOU zones have the same DG capacity since the DG is assigned to specific zones.

Figure B-4: Self-Generation 26 MW Generation Distribution

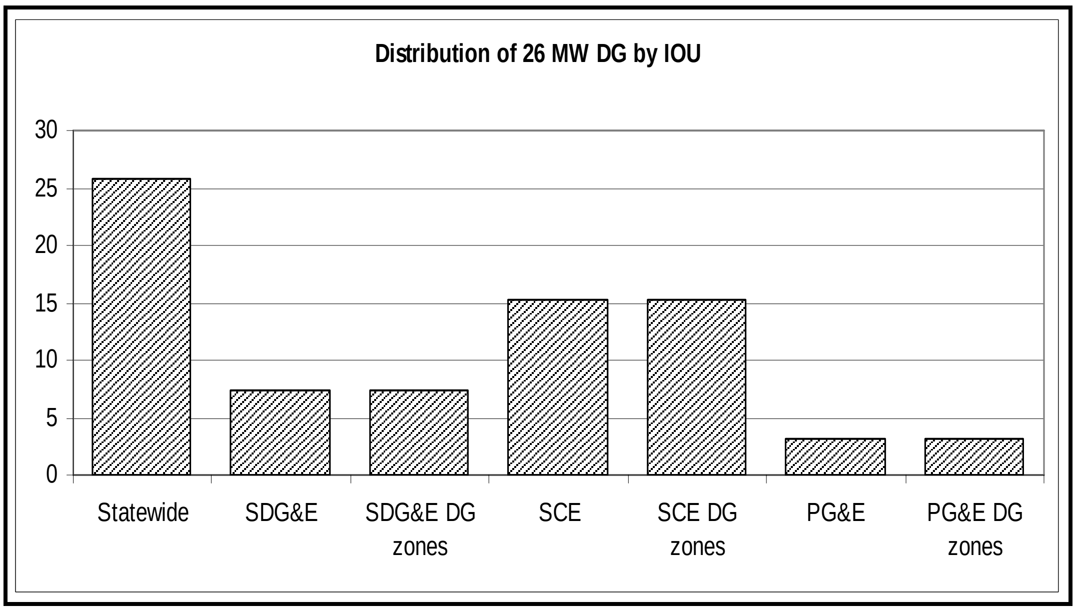
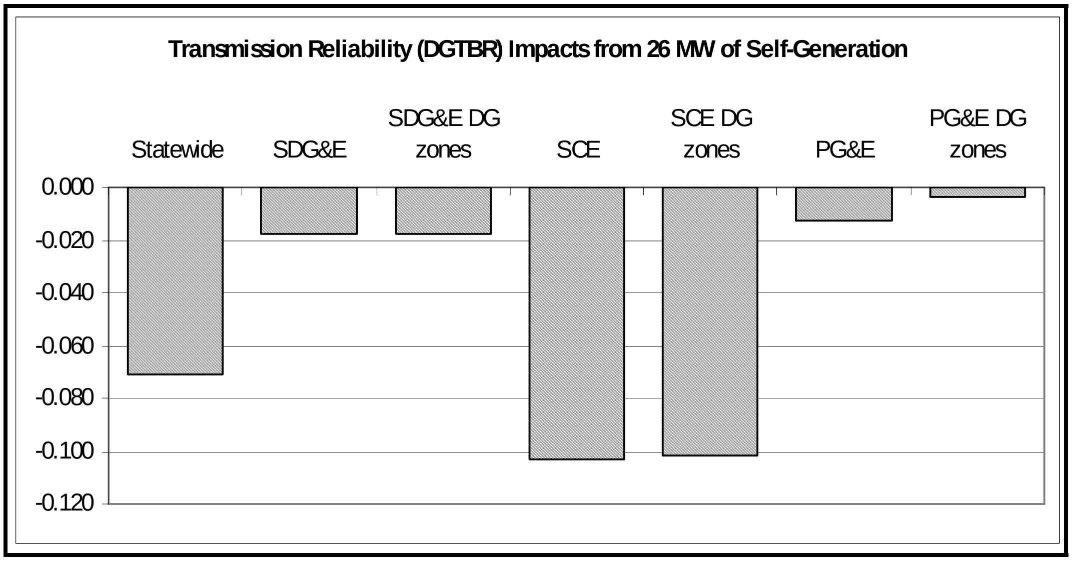


Figure B-5 shows the results of the DGTBR analysis. The DGTBR values are all negative across all scenarios as expected. Since DG is a load reducer at the load centers, the DG is expected to show transmission benefits.

Figure B-5: Transmission Reliability Impacts from 26 MW of Self-Generation



The magnitude and distribution of the DGTBR values are the most interesting. As expected, the largest number of DG is located in the SCE area so the benefit is expected to be higher. Since there is not a large difference between the total number of zones and the number of zones with DG, the DGTBR is expected to be the about the same.

Almost every zone in the SDG&E service area contains DG. As such, the DGTBR is expected to be the same. The DGTBR values are negative and provide a transmission benefit to SDG&E even though the DG is only 7 MW.

PG&E results are the most interesting. As shown in Figure B-3, PG&E is divided into 83 zones but only 13 contain DG totaling 3.16 MW. The DGTBR values are therefore different for PG&E as compared to the zones having DG resources. This is shown on the above figure. The concentration of DG across fewer zones results in the DGTBR being neutral within the zones as compared to the total PG&E system.

The total statewide DGTBR is also shown in the figure. Even though the total megawatt of DG is 26 MW, the DG continues to provide DGTBR benefits to the system.

To better illustrate the impacts that zonal load and zonal DG have on the DGTBR, Table B-2 compares the IOU load to the zonal load and the number of IOU transmission elements to the zonal elements. SDG&E and SCE have a high percentage of load in the DG zones as well as a high percentage of transmission elements. This results in the DGTBR values for the area and zone for SDG&E and SCE to be almost the same as shown in Figure B-5.

Table B-2: IOU Load / Zonal Load Comparison

2005 DG 26 MW	PG&E	SDG&E	SCE
Total Load for DG Zones	9,848	4,488	18,351
Total Load for Area	24,640	4,488	20,055
Percent Difference	40%	100%	92%
	PG&E	**SDG&E**	**SCE**
Number of Elements in Contingency List for DG Zones	1,938	476	889
Number of Elements in Contingency List for Area	4,452	476	1,231
Percent Difference	44%	100%	72%

The PG&E DGTBR values are quite different between the area and zonal analyses. Table B-2 identifies the main reasons for this occurrence. The PG&E load in the DG zones is only 40 percent of the total load in the PG&E area. The percentage of transmission elements in the DG zones is only 44 percent of the total number of elements in the PG&E area. Under contingency analysis, there are less lines and loads for the DG resources to provide transmission benefits. Additional research of the transmission capacity rating of the lines in the zones is required to determine if the lines are sized sufficiently that an outage of DG causes little impact on the system. This same research is needed on the load to element ratings to determine if excess transmission capacity is available to result in a lower DGTBR.

2006 Transmission Results (32 MW)

Figure B-6 below shows the distribution of the 32 MW of DG for the three IOUs. The number of DG for the IOU and for the IOU zones should be the same since the utility assigned the DG to specific zones. The majority of the DG is located in SCE service area. The interesting observation from the figure is that PG&E and SDG&E have the same number of DG.

Figure B-6: Self Generation 32 MW Generation Distribution

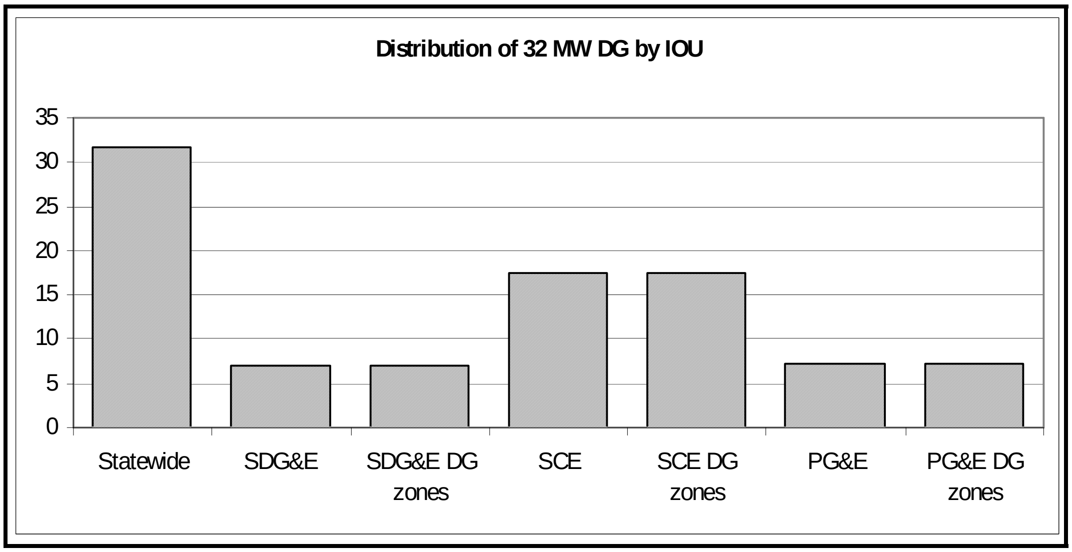
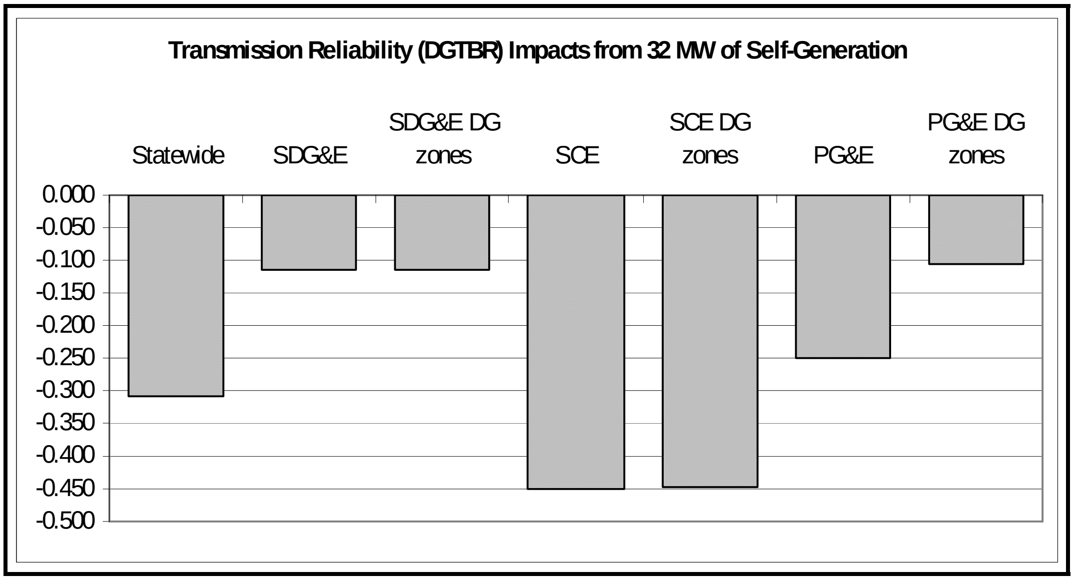


Figure B-7 shows the results of the DGTBR analysis. The DGTBR values are all negative across all scenarios as is expected. Since there are load reducers at the load centers, the DG is expected to show transmission benefits.

Figure B-7: Transmission Reliability Impacts from 32 MW of Self-Generation



The magnitude and distribution of the DGTBR values is the most interesting. As expected, SCE has the largest number of DG so the benefit is expected to be higher for SCE. Since there is not a large difference between the total number of zones and the number of zones with DG, the RTBR is expected to be the about the same.

Almost every zone in the SDG&E service area contains DG. As such, the DGTBR is expected to be the same. The DGTBR values are negative and provide a transmission benefit to SDG&E even though the DG is only 7 MW.

PG&E results continue to be the most interesting. As shown in the previous figures, PG&E is divided into 83 zones but only 14 contain DG. Also, the distribution of load and transmission elements remains approximately the same as shown in Figure B-6. The DGTBR values are therefore different for PG&E as compared to the zones having DG and the PG&E area as shown in the above figure. The concentration of DG across fewer zones results in the DGTBR being lower within the zones as compared to the total PG&E area.

The total state-wide DGTBR is also shown in Figure B-7. Even though the total megawatt of DG is 32 MW, DG continues to provide DGTBR benefits to the system.

<u>Transmission Benefit Results for 120 MW of DG</u>

For the 120 MW analysis, the distribution of DG between the three IOUs is different than for the 32 MW DG distribution shown previously. The distribution of the 120 MW of DG is shown in Figure B-8. For SG&E and SCE, the percent increase in the number of DG from the 32 MW scenario is about 240 percent as compared to an increase of 400 percent for PG&E. There may be fewer DG resources metered by Itron in the PG&E area as compared to SCE and SDG&E.

Figure B-8: Self-Generation 120 MW Generation Distribution

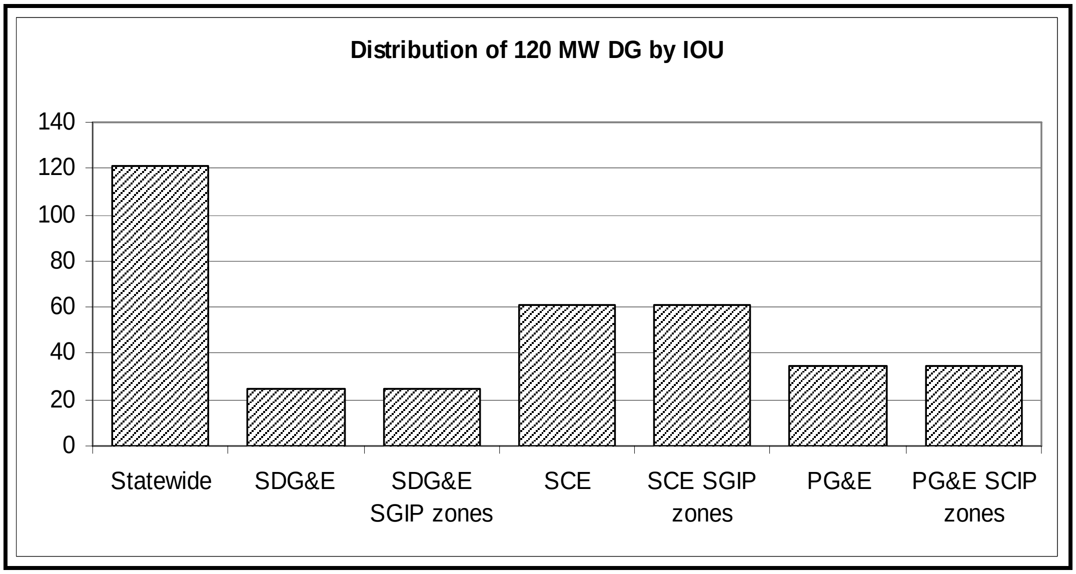
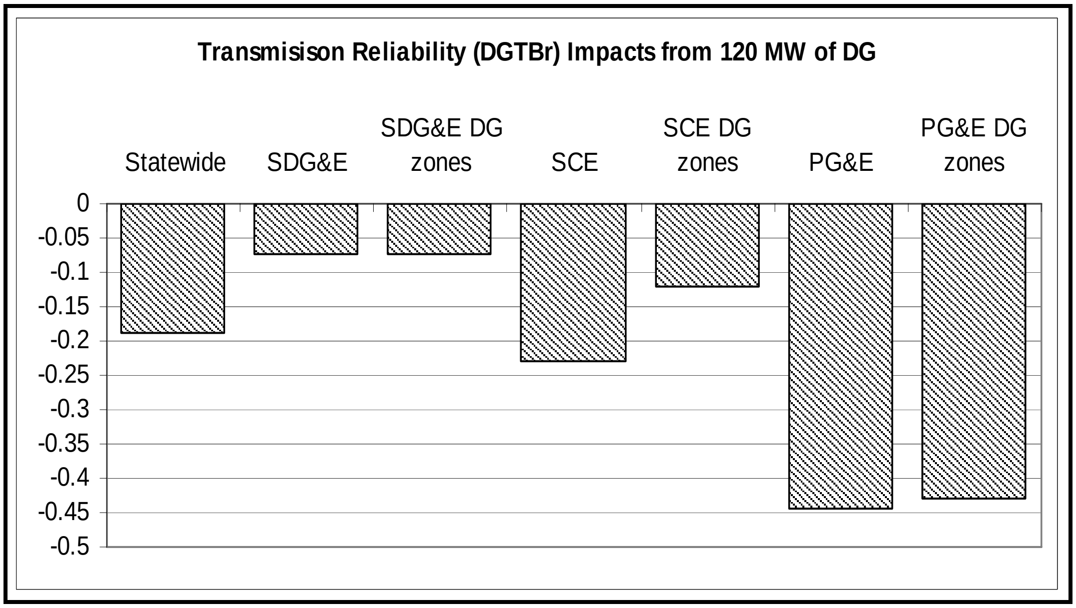


Figure B-9 shows the RTBR results for the 120 MW scenario. There are some interesting results for the higher DG penetration. PG&E has the highest change in the DGTBR value. The DGTBR between the area and the zones are almost the same. There was an increase in the number of DG resources and a 60 percent increase in the number of zones containing at least one DG.

Figure B-9: Transmission Reliability Impacts from 120 MW of Self-Generation



What is the most interesting is the change in the SCE DGTBR values between area and zone. The comparison looks more like the PG&E results for the 32 MW DG scenario. The SCE zonal DGTBR is lower than for the SCE area. This could be caused by the distribution of load and transmission elements between the zones and area.

B.2 Distribution System Impacts Methodology & Results

This section is supplemental to the distribution system impacts results discussed in Section 5.3.

Methodology

Data Resources

The data used for the distribution system analysis included the following types of information:

- Individual SGIP Data
  - Technology type, fuel type, installation year, nameplate capacity, and location on the distribution system
  - 15-minute interval metered SGIP output
- Distribution System Data
  - Distribution system peak date and hour
  - Peak load level on the distribution feeder or substation

Data on all SGIP generators were provided by each IOU (PG&E, SCE, SCG, and SDG&E) for the SGIP applications that they have processed. The data provided include installation year, size, incentive level, technology, fuel type and location. These data were used to calculate the total installed SGIP capacity by technology, fuel type and climate zone.

SGIP output was developed from 15-minute interval data for the metered SGIP generators for 2005 and 2006. These data are metered by Itron on an ongoing basis.

Distribution system data for each distribution feeder serving a customer with a metered SGIP installation were provided by each electric utility in order to perform the distribution impacts analysis. In addition, for each metered facility, the utilities identified the feeder serving the facility and provided metered load data for those feeders. SDG&E provided electronic interval meter data for the peak week in 2006 for each feeder. SCE also provided electronic interval data for distribution substations and feeders. Since the mapping of SGIP installations to individual feeders would have been difficult for SCE[1], the distribution substation interval data were used in the analysis to identify the SCE distribution peaks. In each case, SAS statistical software was used to identify the peak day and hour for each feeder/substation. PG&E supplied paper copies of circular watt charges at the feeder level for each of the distribution feeders with SGIP installations. These charts are useful for identifying the peak day and hour visually. However, the magnitude of the peak load on the

[1] In order to identify the SCE feeders serving the SGIP installations, the one-line diagrams of SCE distribution substations would have had to be analyzed.

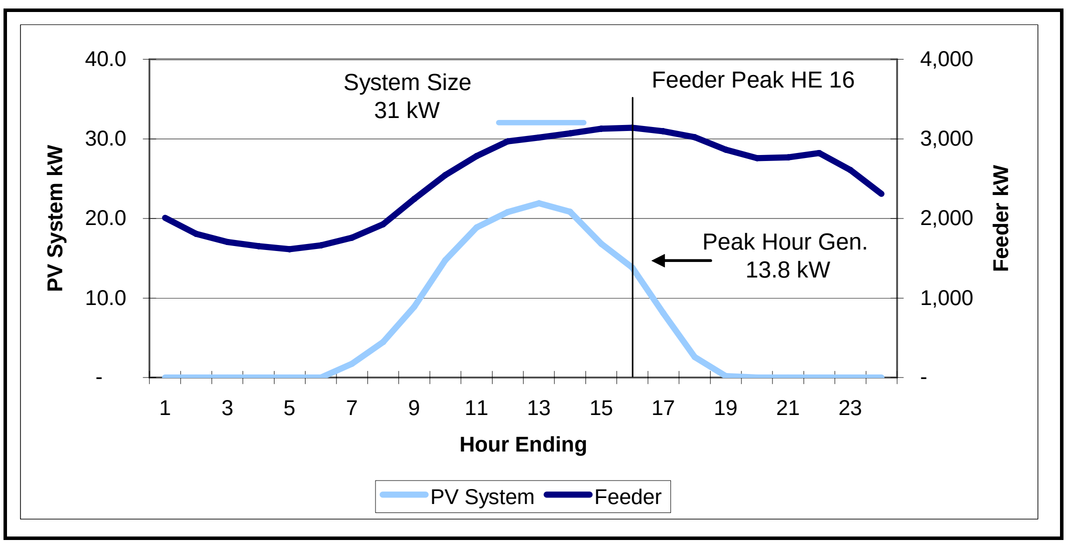
feeders is difficult to determine from the PG&E watt charts due to time constraints, and difficulty locating meter multipliers to convert units consistently on the charts. Therefore, analyses that require the magnitude of the peak were not completed for PG&E installations. Across the three electric utilities, the metered point was either feeder load or substation load. The terms 'feeder' or 'distribution system' will be used for the remainder of the document to refer to the combined peak hour analysis of the three utilities.

Finally, each utility provided energy delivered on each feeder by customer type (Residential, Commercial, Industrial, and Agricultural). This information is used to characterize the distribution system peak by the predominant type of customers that the distribution system serves.

Measured Impact

Given the data provided, the SGIP output at the time of the distribution system peak was directly measured. Hourly generation for the 2005 and 2006 summer seasons was calculated from the 15-minute interval data for each metered SGIP facility. Then, the data on the peak day and hour for each feeder/substation were used to determine the output of each SGIP generator coincident with the local distribution system peak. An example determination of distribution coincident peak generation for one of the SGIP generators is illustrated in Figure B-10.

Figure B-10: Example Feeder Peak Hour Generation for PV system



In this example the feeder has a load shape typical of residential loads, peaking at HE 16. The SGIP generator is a 31 kW PV system with peak generation of 21 kW at HE 13. During the feeder peak at HE16 the PV system is producing 13.8 kW. The 13.8 kW of generation at HE 16 is used in this analysis of distribution impacts. To summarize across SGIP installations, the distribution peak load reduction is calculated as a percentage of nameplate capacity. In this case, the PV system has a distribution coincidence factor of 44.5 percent of nameplate capacity (13.8kW / 31kW).

Generators with no meter data throughout the study period were excluded from the analysis. In addition, some generators were removed because peak day and hour data for the feeder or substation were unavailable. Overall, 313 metered SGIP generators had sufficient data available for the analysis and were included in the study. The breakdown of metered SGIP facilities by utility, technology and fuel type is shown in Table B-3.

Table B-3: Distribution Coincident Peak Observations Included In Analysis – 2005 & 2006

	PV	ICE		MT		FC		Total
	--	N	R	N	R	N	R	
PG&E	42	10		1		1		54
SCE	30	67	4	38	2		3	144
SDG&E	66	27		15	6	1		115
Total	138	104	4	54	8	2	3	313

System Planning Impact

To analyze the potential impact of SGIP generation on distribution system planning, the analysis of the metered data is further broken out by utility, climate zone, and feeder type. Groups of climate zones and feeder types were developed to provide a sufficient number of observations in each category to provide meaningful results.

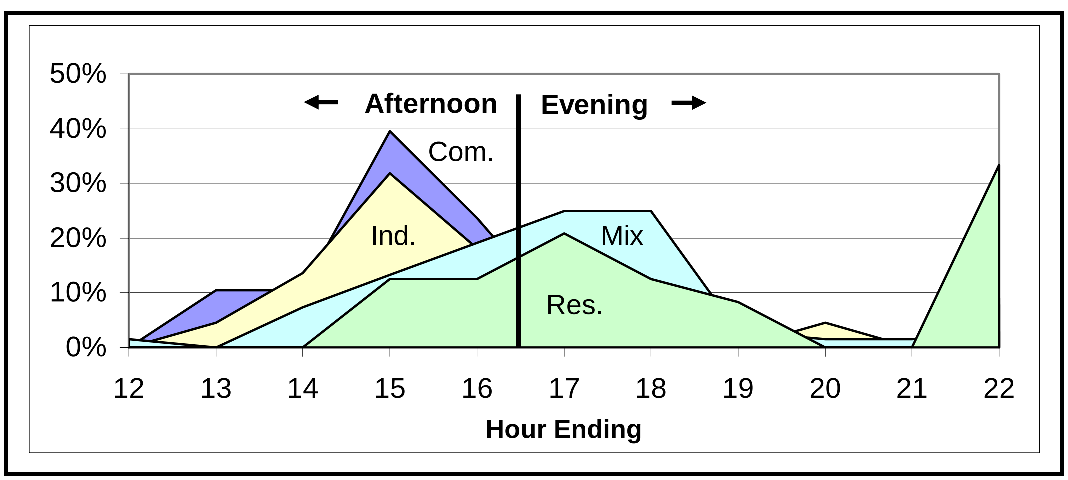
SGIP distributed generators were categorized into one of four Climate Zone/ Utility Groups, shown in Table B-4. The PG&E Coast group includes 31 generators in climate zones 2-5. The SCE Coast group includes 128 generators in climate zones 6-10 while the SDG&E Coast group includes 112 generators in the same zones. Due to a limited number of generators, it was not possible to separate the inland climate zones by utility. The Inland group includes a total of 42 generators in climate zones 11-15. Since we do not expect significant differences by utility in the central valley we do not expect this to affect the robustness of the analysis.

Table B-4: Number of Complete Observations in each Climate Zone/Utility Group – 2005 and 2006

	Climate Zone	PG&E	SCE	SDG&E	Total
North Coast	2	6			6
	3	22			22
	4	2			2
	5	1			1
	Sub Total	*31*			*31*
South Coast	6		23		23
	7			90	90
	8		42	1	43
	9		33		33
	10		30	21	51
	Sub Total		*128*	*112*	*240*
Inland	11	8			8
	12	15			15
	13		12		12
	14		4	1	5
	15			2	2
	Sub Total	*23*	*16*	*3*	*42*
	Total	31	128	112	313

In addition to climate zone, the analysis initially grouped installations by the type of customers served by the distribution system. However, even with a threshold as low as 50 percent of energy sales to a specific class, a large number of feeders in the system can only be categorized as mixed. The distribution of the feeder peak hours by feeder type across all of the utilities is shown in Figure B-11. The commercial and industrial feeders tend to peak earlier in the day, with HE 13 being the most common peak hour. Residential and mixed feeders tended to peak in the evening (HE 17 & 18) or at night (HE 22).

Figure B-11: Distribution of Feeder Peak Hour by Customer Types Served



Since there were not enough observations by customer mix, grouping the feeders according to the hour in which they peak rather than by load type proved to be more useful. The timing of the peak is also more likely to be available to distribution system planners than customer mix. The distribution of peak hours in Figure B-11 suggests a division between HE 16 and HE 17. Accordingly, the feeders are divided into two distinct groups: feeders that peak in the afternoon (HE 12-16) and feeders that peek in evening (HE 17-22).

Table B-5: Feeder Observations by Feeder Category and Utility – 2005 and 2006

	PG&E	SCE	SDG&E	Total
Afternoon	22	73	94	189
Evening	32	71	21	124
Grand Total	54	144	115	313

The observations by Technology, Climate Zone and Feeder Type are shown in Table B-5. There is a limited number of observations for fuel cells as well as for internal combustion engines (ICE) and microturbines (MT) using renewable fuel (R). There is a larger number of non-renewable (N) fuelled internal combustion engines and microturbines, though observations in specific categories are limited. Photovoltaic technology provides the largest number of observations, though again observations in some categories are limited.

Table B-6: Number of Complete Observations by Category and Utility – 2005 and 2006

		PV	ICE		MT		FC		Total
		--	N	R	N	R	N	R	
PG&E Coast	Afternoon	14	4		1				19
	Evening	10	2						12
SCE Coast	Afternoon	17	33		14			1	65
	Evening	8	27	4	22	2			63
SDG&E Coa	Afternoon	50	26		11	4			91
	Evening	13	1		4	2	1		21
Inland	Afternoon	7	5					2	14
	Evening	19	6		2		1		28
Total by Technology/Fuel		138	104	4	54	8	2	3	313
Total by Technology		138	108		62		5		

Cost Savings

This final step in the analysis process is to estimate the distribution system savings associated with SGIP. Given the available data for the analysis, the potential cost savings are divided into two major categories of benefits on the distribution system; (1) distribution capacity savings and (2) reduced distribution system losses.

To evaluate the capacity savings, the amount of distribution peak load reduction observed on each feeder is summarized as a percentage of the feeder peak load. If significant peak load reductions are observed, there is greater potential for distribution capacity savings. The percentage of feeder peak load offset by the SGIP program is calculated as the total distribution peak load reduction of all SGIP installations on a particular feeder or substation divided by the feeder or substation peak load.

To evaluate the distribution system loss reductions, the annual energy generated by each metered SGIP installation is tabulated from the interval-metered SGIP output. The total energy for metered SGIP installations by utility is then extrapolated to non-metered SGIP installations to provide a total by utility, shown in Table B-7.

Table B-7: Total SGIP Energy Generated by Utility

Year	Utility	SGIP Generation (MWh)
2005	PG&E	432,451
	SCE	625,546
	SDG&E	249,062
2006	PG&E	460,797
	SCE	478,397
	SDG&E	247,761

To calculate the value of the loss savings, the total amount of SGIP energy generated is multiplied by a distribution loss factor for each utility to estimate energy saved, and then by the average on-peak wholesale value of electricity based on market data. The distribution loss factor and wholesale electricity value assumptions are shown in Table B-8. The distribution loss factors measure the average change in energy lost from the distribution substation to the customer meter for a change in consumption (marginal loss factors). For example, a reduction in 1 kWh of energy delivered results in a savings of 0.035 kWh on average in the PG&E distribution system. Both input assumptions are from the 5/23/06 update to the energy efficiency avoided costs (CPUC Avoided Cost Proceeding R0404025).

Table B-8: Distribution System Loss Factors and Energy Value Assumptions by Utility

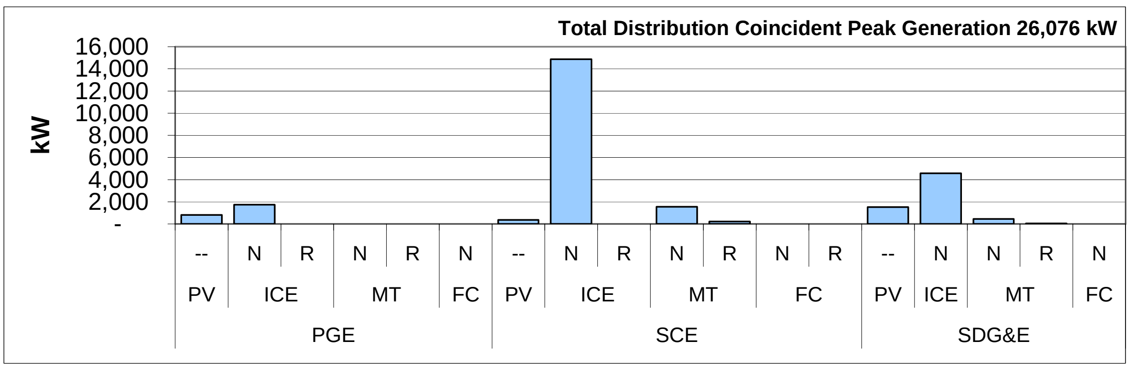
Utility	Distribution Loss Factor	Wholesale Energy Value ($/MWh)
PG&E	3.5%	$57.62
SCE	2.4%	$58.58
SDG&E	4.3%	$58.58

Results

Measured Impacts

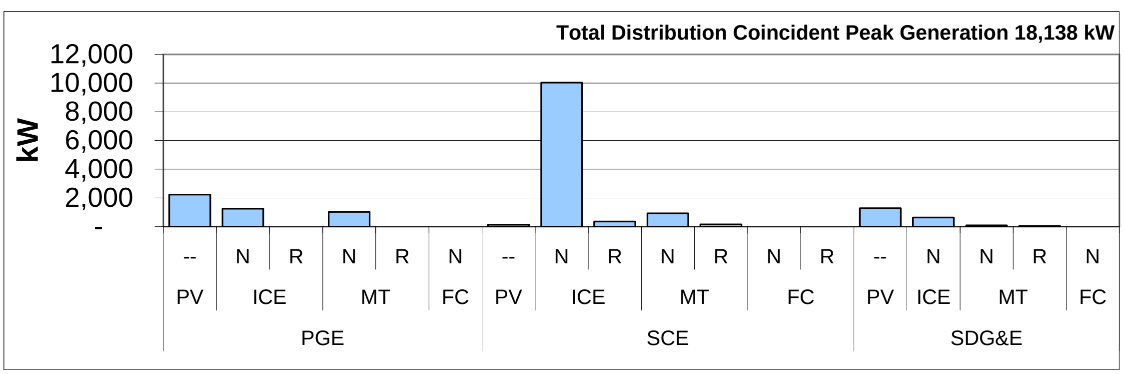
In 2005, 111 of 170 SGIP metered generators were operating during the distribution system peak hour, producing 26 MW of distribution coincident peak load reduction (Figure B-12). In 2006, 115 of 140 metered generators were operational during the distribution system peak, producing 18 MW of load reduction (Figure B-13). Internal combustion engines provide by far the largest contribution, with 21 installations of 1 MW or more.

Figure B-12: Metered Distribution Coincident Peak Load Reduction - 2005



	PGE						SCE							SDG&E				
	PV --	ICE N	ICE R	MT N	MT R	FC N	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R	PV --	ICE N	MT N	MT R	FC N
Operational % kW	99%	88%					92%	89%	0%	93%	100%		0%	72%	81%	96%	21%	
Generation % kW	39%	79%					41%	65%	0%	61%	50%		0%	37%	69%	61%	6%	
Operational #	14	3					14	27	0	14	1		0	25	9	7	1	
Total #	15	6	0	0	0	0	16	31	1	17	1	0	2	28	12	8	3	0

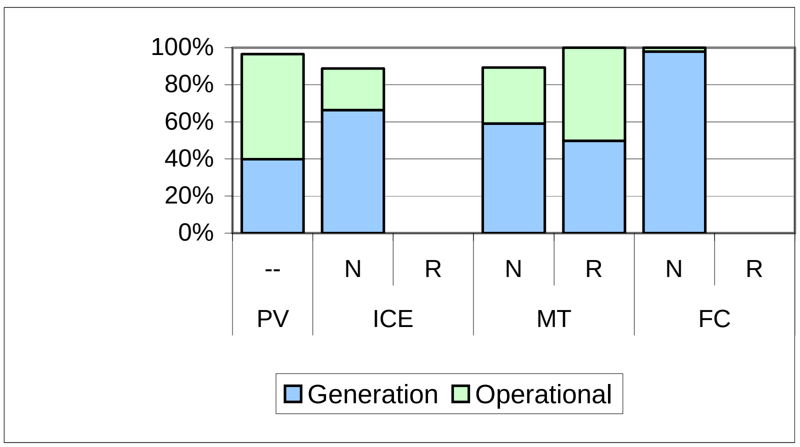
Figure B-13: Metered Distribution Coincident Peak Load Reduction – 2006



	PGE						SCE							SDG&E				
	PV --	ICE N	ICE R	MT N	MT R	FC N	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R	PV --	ICE N	MT N	MT R	FC N
Operational % kW	94%	96%		100%			73%	74%	35%	57%	100%		0%	73%	12%	21%	21%	0%
Generation % kW	42%	86%		74%			22%	41%	18%	32%	39%		0%	25%	7%	15%	7%	0%
Operational #	23	3		1			10	25	1	11	1	0	0	30	3	2	1	0
Total #	27	4	0	1	0	0	14	36	3	21	1	0	1	37	15	6	3	1

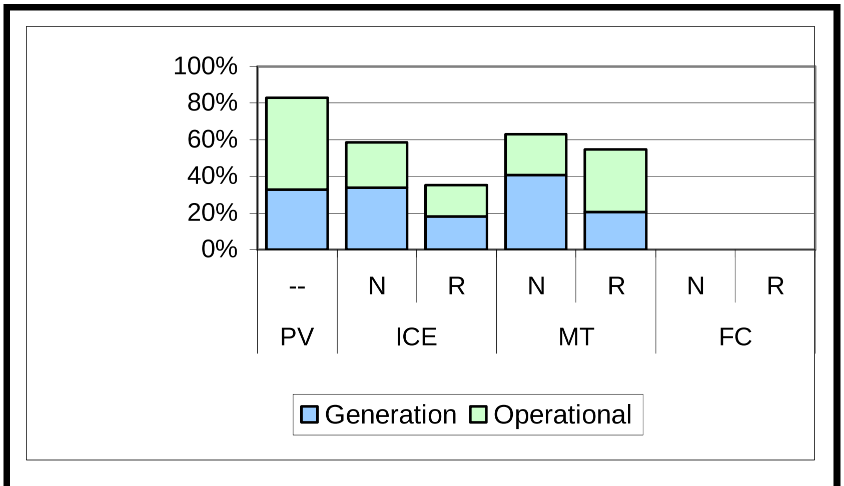
Figure B-14 shows the percentage of each technology/fuel type combination that was operational during the feeder peak hour in 2005. For example, 28 of 31 metered PV systems were producing energy during their respective distribution peak hour. The total nameplate capacity of those 28 operational systems was 2.8 MW, representing 97 percent of 2.9 MW of installed PV capacity. The 28 operational PV systems produced a total of 1.2 MW during their respective distribution peak hours, or 40 percent of the installed PV capacity. Similar figures for 2006 are shown in Figure B-15.

Figure B-14: Operating Capacity and Distribution Coincident Peak Generation as percentage of Total Metered Capacity – 2005



	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
Operational % kW	97%	89%	0%	89%	100%	100%	0%
Generation % kW	40%	66%	0%	59%	50%	98%	0%
Operational #	28	30	0	14	1	1	0
Total #	31	37	1	18	1	1	2

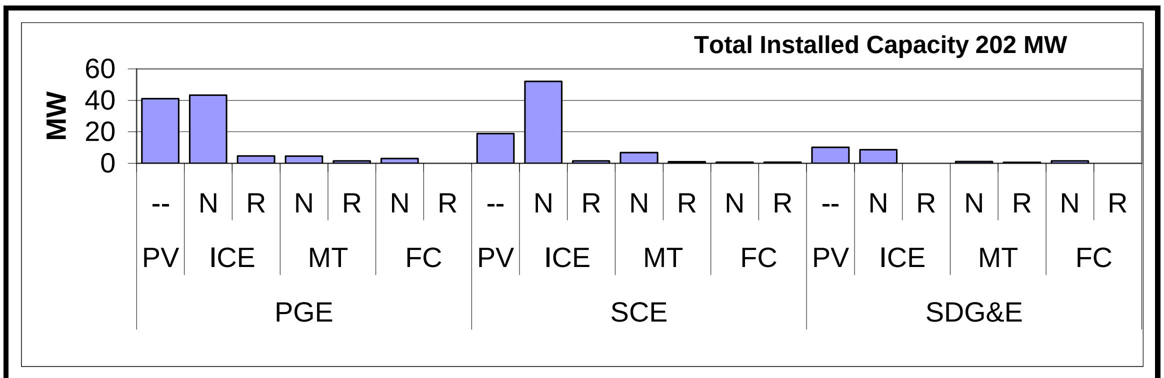
Figure B-15: Operating Capacity and Distribution Coincident Peak Generation as percentage of Total Metered Capacity – 2006



	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
Operational % kW	83%	58%	35%	63%	55%	0%	0%
Generation % kW	33%	34%	18%	41%	21%	0%	0%
Operational #	63	31	1	14	2	0	0
Total #	78	56	3	31	4	1	1

The total installed SGIP capacity was 202 MW in 2006 (Figure B-16). The data provided by the utilities show very little difference in installed capacity between 2005 and 2006.[2] The installed capacity is predominately PV and ICE.

Figure B-16: SGIP Installed Capacity – California 2006



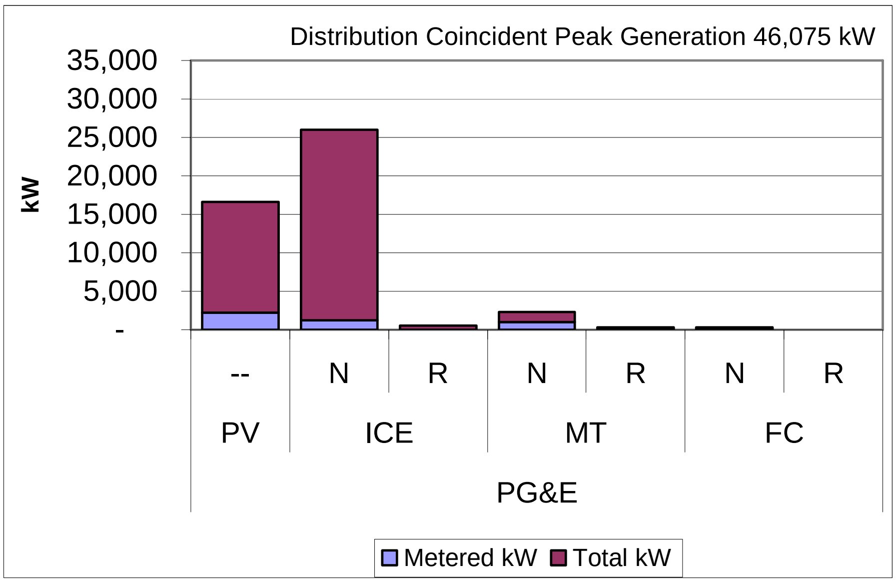
	PGE PV --	PGE ICE N	PGE ICE R	PGE MT N	PGE MT R	PGE FC N	PGE FC R	SCE PV --	SCE ICE N	SCE ICE R	SCE MT N	SCE MT R	SCE FC N	SCE FC R	SDG&E PV --	SDG&E ICE N	SDG&E ICE R	SDG&E MT N	SDG&E MT R	SDG&E FC N	SDG&E FC R
Installed MW	41.1	43.2	4.7	4.6	1.4	3.1		18.9	52.0	1.5	6.8	1.0	0.7	0.8	10.1	8.6		1.1	0.6	1.5	
Total #	303	71	7	30	9	5	0	181	77	2	39	4	2	2	85	17	0	12	3	2	0

An estimate of total SGIP generation is made by applying the percent of distribution coincident peak generation to the total SGIP metered capacity. The distribution coincident peak load reduction as a percentage of installed SGIP capacity is calculated using the 2005

[2] The data provided by the utilities shows only 9 additional generators for 2006 (SGIP Program Year 6) totaling 1.4 MW.

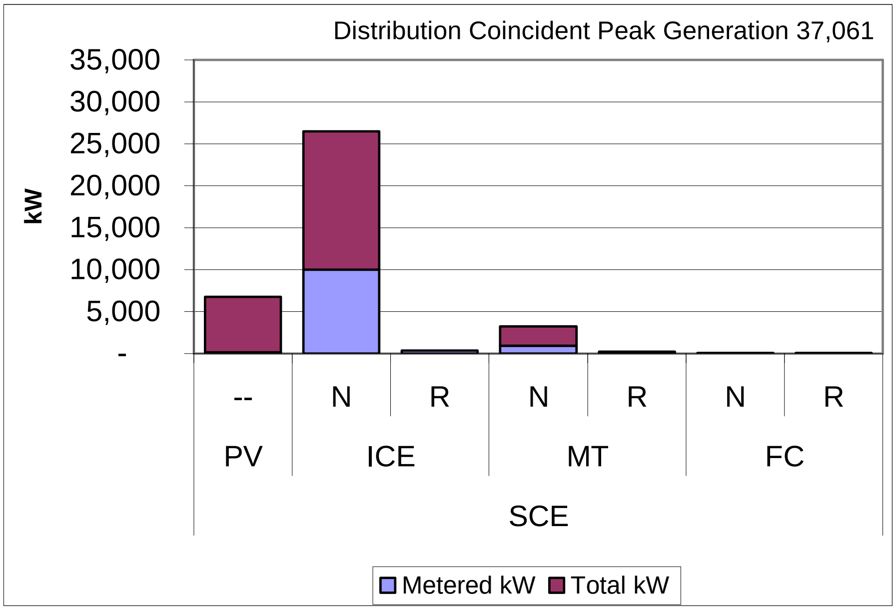
and 2006 data combined. The more detailed calculation of the percentages—broken out by technology, fuel type, climate zone—is calculated in the next section. Those percentages are applied to the installed capacity shown in Figure B-16. Both the metered and extrapolated total distribution coincident peak load reduction for each utility are shown in Figure B-17, Figure B-18, and Figure B-19. PV provided 29 percent of the total distribution coincident peak load reduction for all three utilities combined. Non-renewable fueled ICE was the largest contributor of distribution coincident peak load reduction at 62 percent of the total.

Figure B-17: Metered and Estimated Total Generation – PG&E



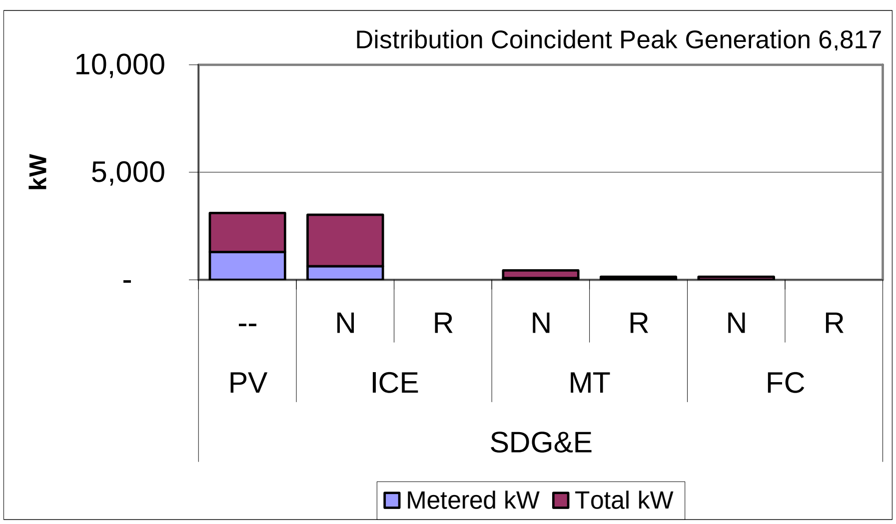
Metered kW	2,224	1,248	-	1,020	-	-	-
Total kW	16,639	26,009	564	2,276	323	272	-
Metered #	27	4	0	1	0	0	0
Total #	303	71	7	30	9	5	0

Figure B-18: Metered and Estimated Total Generation – SCE



Metered kW	133	10,034	360	920	163	0	0
Total kW	6,774	26,475	180	3,267	237	62	67
Metered #	14	36	3	21	1	0	1
Total #	181	77	2	39	4	2	2

Figure B-19: Metered and Estimated Total Generation – SDG&E



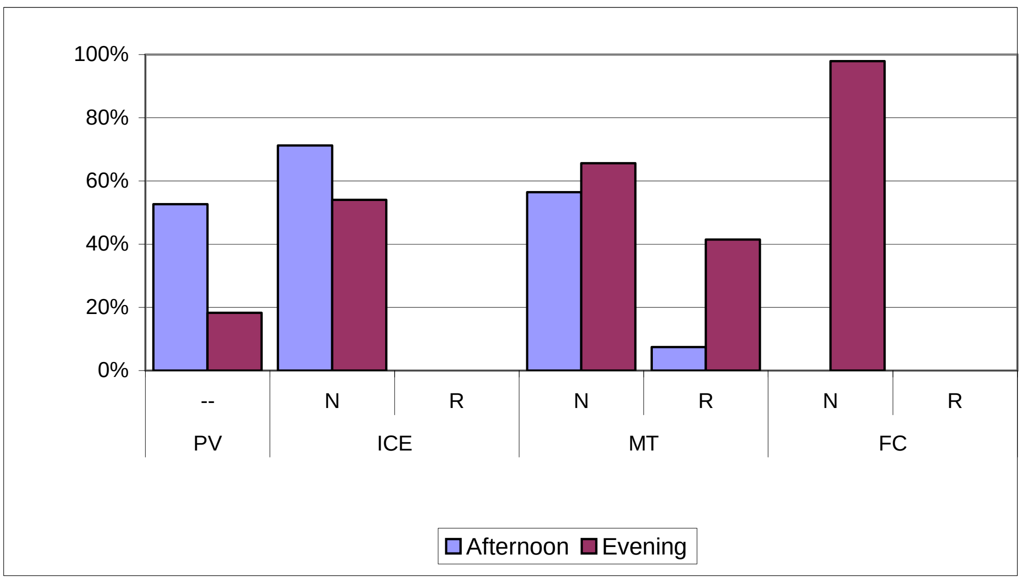
Metered kW	1,279	633	0	84	40	0	0
Total kW	3,103	3,031	0	432	128	134	0
Metered #	37	15	0	6	3	1	0
Total #	85	17	0	12	3	2	0

System Planning Impacts

SGIP Generation by Feeder Type

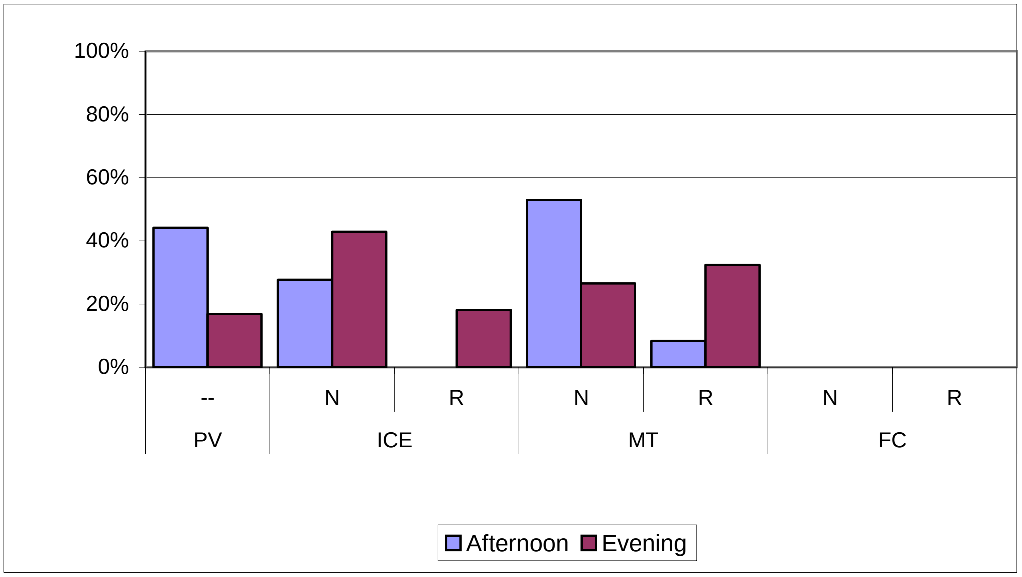
In this section distribution coincident peak generation is compared across the afternoon peaking and evening peaking feeder types. Figure B-20 and Figure B-21 show the percent of each technology/fuel type that was operational during the distribution system peak hour in 2005 and 2006, respectively. Note that outside the PV and non-renewable fuel ICE and MT categories, the number of observations is quite small.

Figure B-20: Percent of Capacity Operational During Distribution Peak Hour by Feeder Type - 2005



Afternoon	53%	82%		63%	30%		0%
Evening	31%	62%	0%	68%	50%	98%	
Afternoon #	40	29		10	1		0
Evening #	13	10	0	11	1	1	

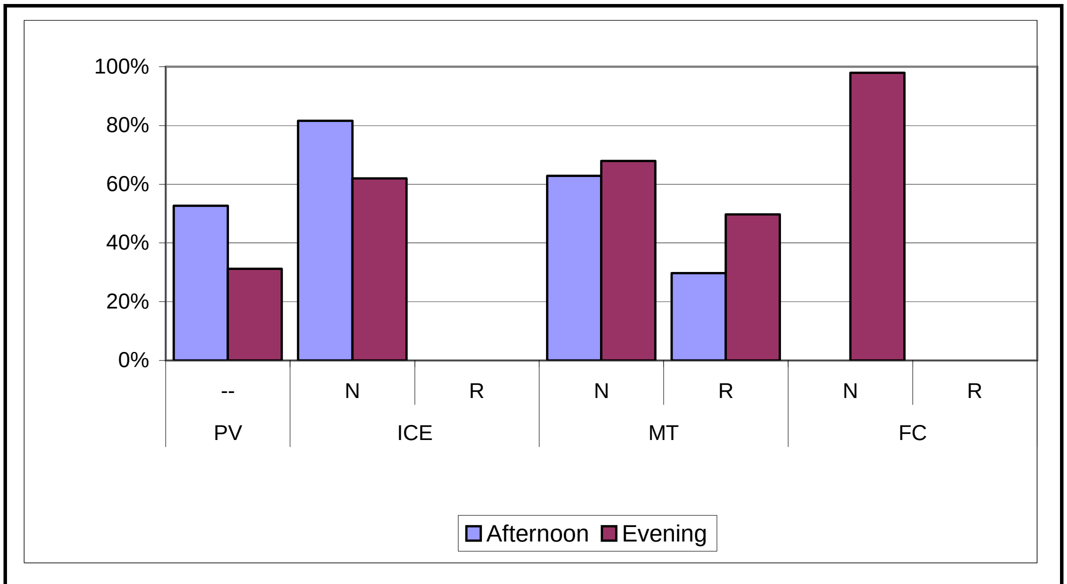
Figure B-21: Percent of Capacity Operational During Distribution Peak Hour by Feeder - 2006



Afternoon	45%	54%		66%	33%		0%
Evening	28%	62%	0%	62%	39%		
Afternoon #	46	18		7	1		0
Evening #	17	13	1	7	1	0	

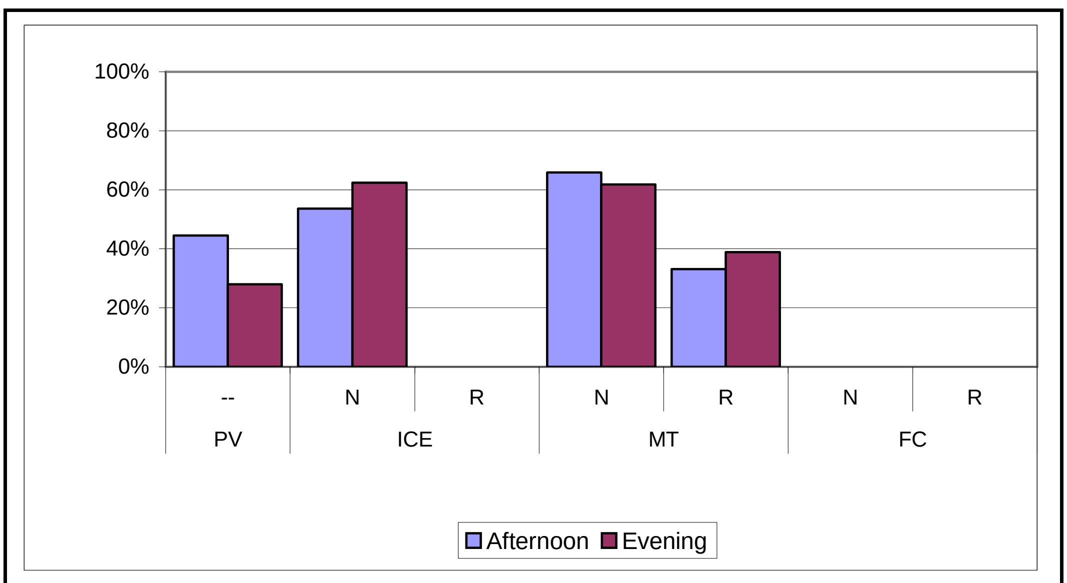
The capacity factor of operational generators at the distribution coincident peak hour is shown in Figure B-22 and Figure B-23. Not surprisingly, the capacity factor for PV is higher for afternoon peaking feeders. For non-renewable fueled ICE, the capacity factor is higher for afternoon peaking feeders in 2005 but lower in 2006. The capacity factor for microturbines is similar for both types of feeders in 2005 and 2006.

Figure B-22: Generation as a Percent of Operational Capacity by Feeder Type - 2005



Afternoon	53%	71%		57%	7%		0%
Evening	18%	54%	0%	66%	41%	98%	
Afternoon #	40	29		10	1		0
Evening #	13	10	0	11	1	1	

Figure B-23: Generation as a Percent of Operational Capacity by Feeder Type - 2006



Afternoon	44%	28%		53%	8%		0%
Evening	17%	43%	18%	27%	32%	0%	
Afternoon #	46	18		7	1		0
Evening #	17	13	1	7	1	0	

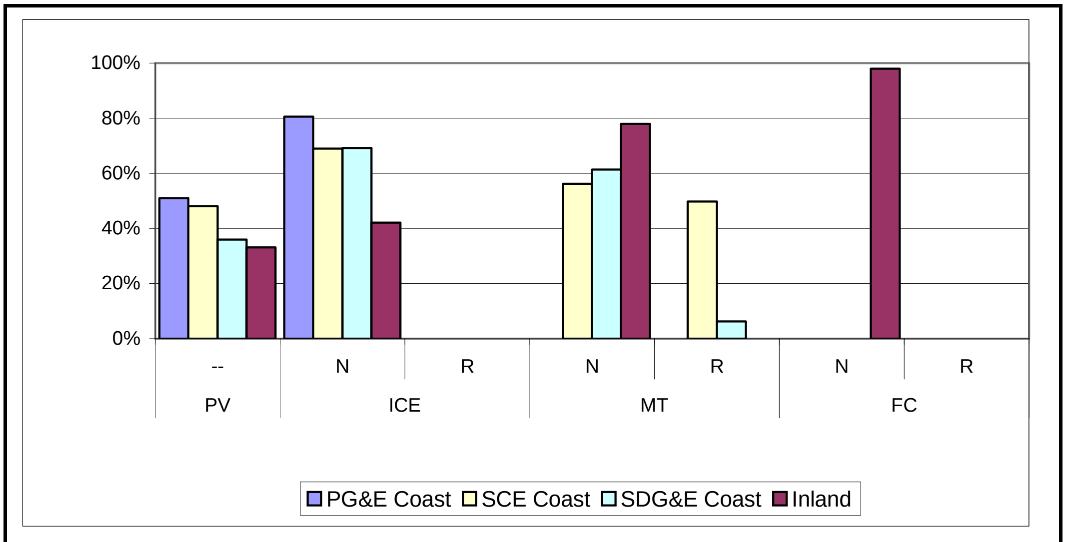
SGIP Generation by Climate Zone

In this section, distribution coincident peak generation is compared across four climate zone groups; PG&E Coast, SCE Coast, SDG&E Coast, and Inland. Due to a limited number of observations in many categories, care should be taken in comparing the results.

Around 40 percent of PV generation was operational during the distribution peak in the PG&E Coast zones in both 2005 and 2006 (Figure B-24 and Figure B-25). For SCE and SDG&E Coast zones the percent of capacity operational was significantly higher in 2005 than 2006. Percent of capacity operational in the Inland zones was fairly constant between 2005 and 2006 at between 35-38 percent.

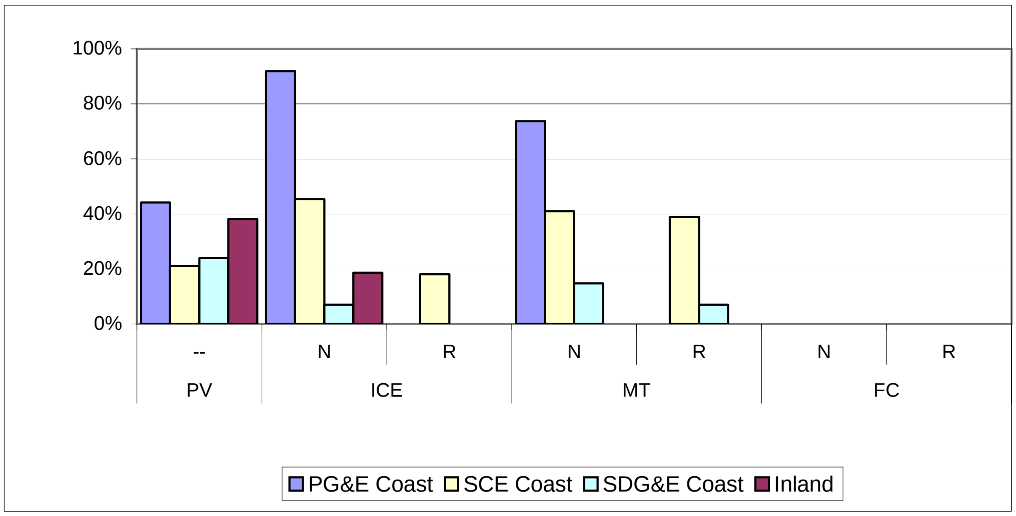
The largest number of non-renewable ICE generators is located in the SCE Coast zones, with 85 and 62 percent of capacity operational in 2005 and 2006, respectively. The SCE Coast zones also have the largest number of non-renewable MT with 62 and 57 percent of capacity operational in 2005 and 2006, respectively.

Figure B-24: Percentage of Capacity Operational By Climate Zone - 2005



PG&E Coast	53%	91%					
SCE Coast	51%	79%		62%	50%		
SDG&E Coast	51%	85%		64%	30%		
Inland	34%	43%		78%		98%	
PG&E Coast #	7	2					
SCE Coast #	12	24	0	13	1		0
SDG&E Coast #	24	9		7	1		
Inland #	10	4		1		1	0

Figure B-25: Percentage of Capacity Operational By Climate Zone - 2006

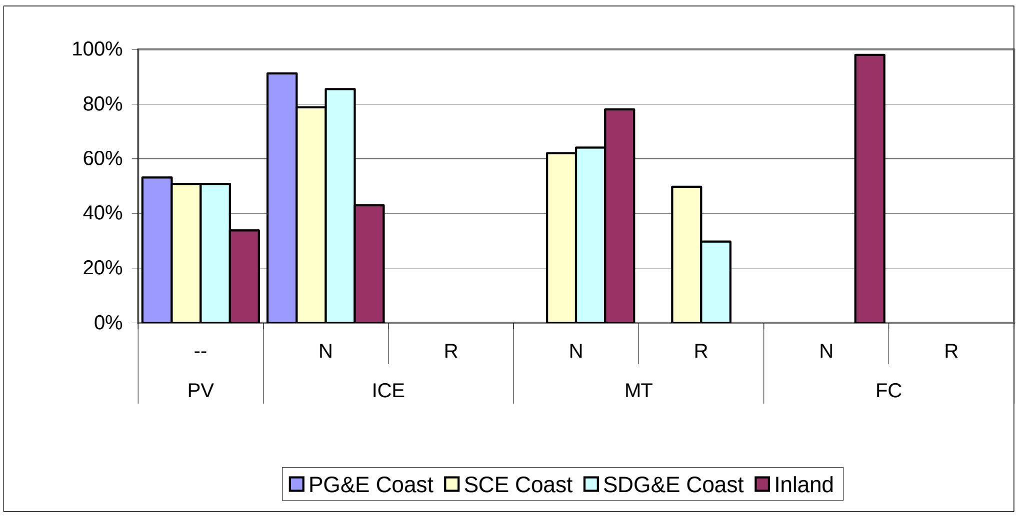


	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
PG&E Coast	50%	92%		74%			
SCE Coast	30%	62%	51%	57%	39%		
SDG&E Coast	34%	60%		70%	33%		
Inland	38%	25%					
PG&E Coast #	12	2		1			
SCE Coast #	8	23	1	11	1		
SDG&E Coast #	28	3		2	1	0	
Inland #	15	3		0			0

The capacity factor of SGIP generators operating during the distribution peak are shown for 2005 and 2006 in Figure B-26 and Figure B-27. PV shows a higher capacity factor for the Coast zones than the Inland zones in 2005, though the results are more mixed for 2006. The Coast zones also appear to show a higher capacity factor than the Inland zones for ICE, but the number of observations for the Inland zones is quite small (less than four).

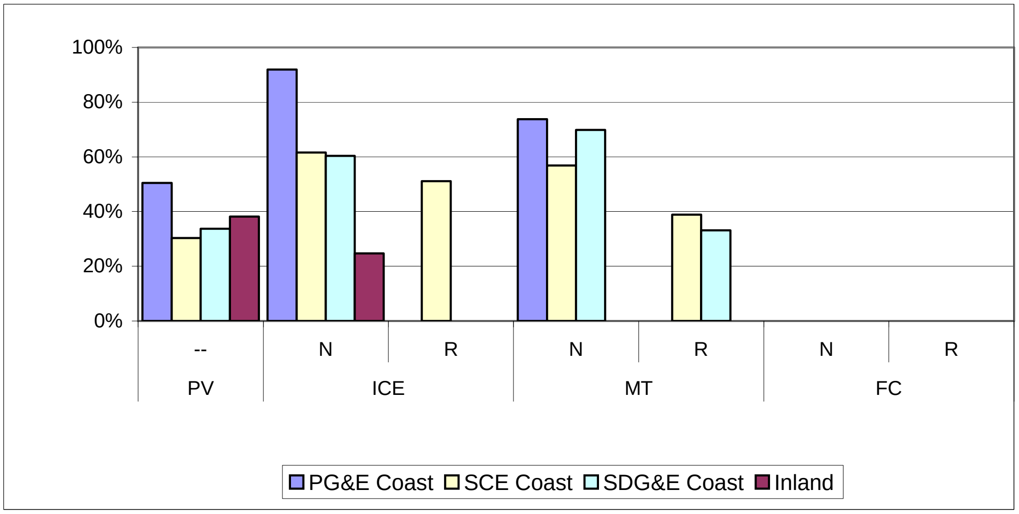
For other technologies, the limited number of observations makes comparisons highly uncertain.

Figure B-26: Generation as a Percent of Operational Capacity by Climate Zone – 2005



	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
PG&E Coast	51%	81%					
SCE Coast	48%	69%	0%	56%	50%		0%
SDG&E Coast	36%	69%		61%	6%		
Inland	33%	42%		78%		98%	0%
PG&E Coast #	7	2					
SCE Coast #	12	24	0	13	1		0
SDG&E Coast #	24	9		7	1		
Inland #	10	4		1		1	0

Figure B-27: Generation as a Percent of Operational Capacity by Climate Zone – 2006

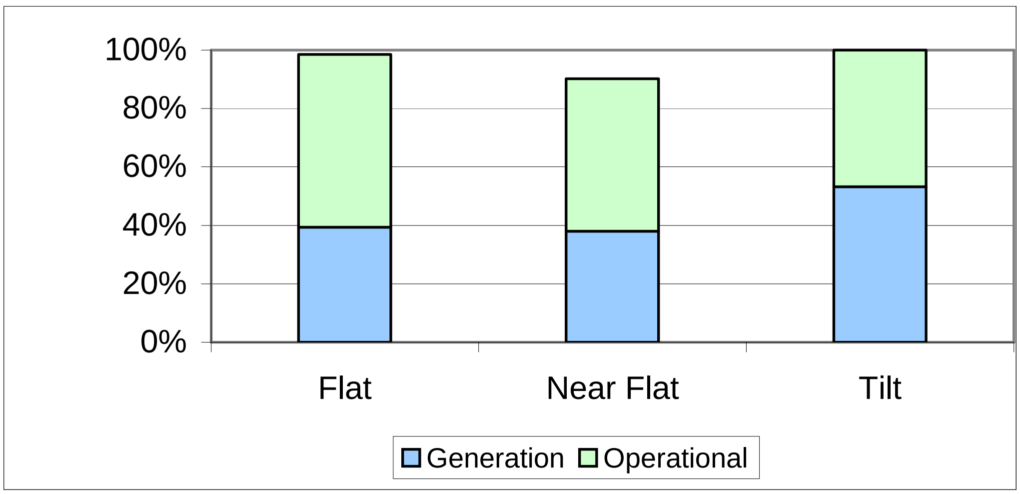


	PV --	ICE N	ICE R	MT N	MT R	FC N	FC R
PG&E Coast	44%	92%		74%			
SCE Coast	21%	45%	18%	41%	39%		
SDG&E Coast	24%	7%		15%	7%	0%	
Inland	38%	19%		0%			0%
PG&E Coast #	12	2		1			
SCE Coast #	8	23	1	11	1		
SDG&E Coast #	28	3		2	1	0	
Inland #	15	3		0			0

PV Generation

Because PV may be particularly sensitive to orientation and climate zone, further investigation of PV SGIP installations is performed in this section. The SGIP data contained information on the orientation and tilt of some PV systems, though the number of generators with specific information (i.e., the degree of tilt) was quite limited. A simple comparison of PV systems labeled as flat, near flat, and tilt is shown in Figure B-28. The operational capacity as a percent of installed nameplate is fairly consistent. However, as one would expect, the PV systems with some degree of tilt show a higher level of generation during the distribution system peak.

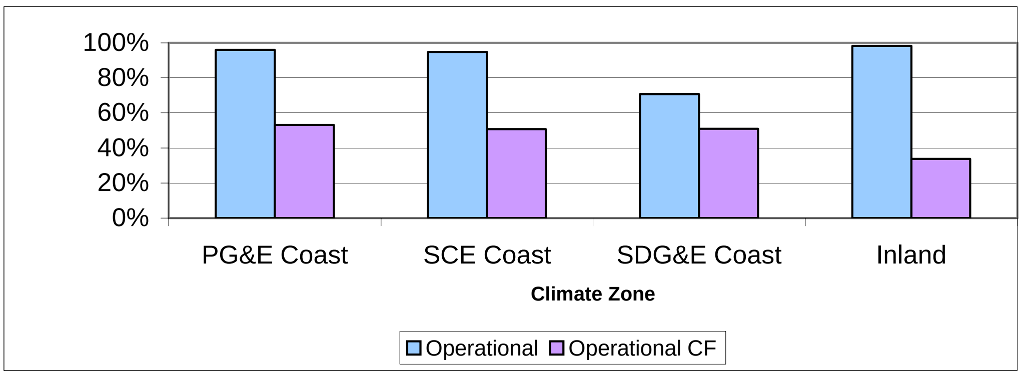
Figure B-28: PV System Generation by Tilt



Operational % kW	99%	90%	100%
Generation % kW	39%	38%	53%
Operational #	14	9	5
Total #	15	11	5

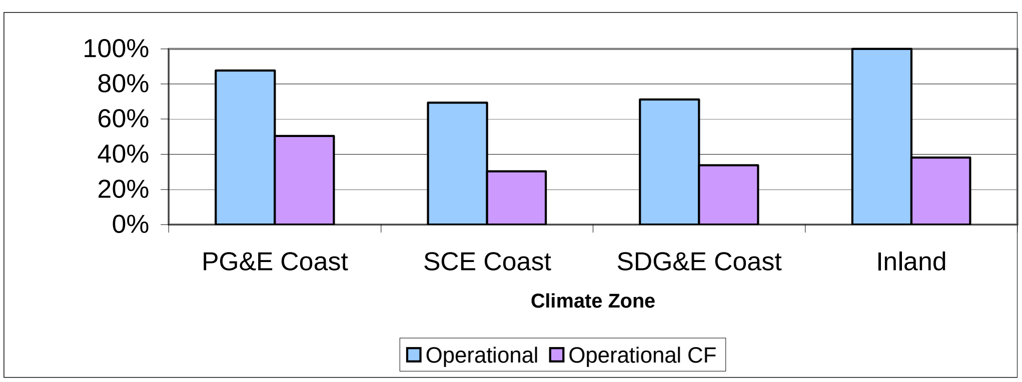
PG&E data show the highest capacity factor for PV generators operational during the distribution peak in both 2005 and 2006 (Figure B-29 and Figure B-30). One might expect the warmer, sunny inland zones to have a higher capacity factor for PV systems operational during the system peak, but Figure B-29 shows that the opposite is in fact true for 2005. In 2006 the Inland zones have a higher capacity factor than the SCE and SDG&E Coast zones, but not the PG&E Coast zones.

Figure B-29: PV System Percent Operational and Generation as Percent of Operating Capacity by Climate Zone - 2005



	PG&E Coast	SCE Coast	SDG&E Coast	Inland
Operational % kW	96%	95%	71%	98%
Operational CF	53%	51%	51%	34%
Operational #	7	12	24	10
Total #	8	13	27	11

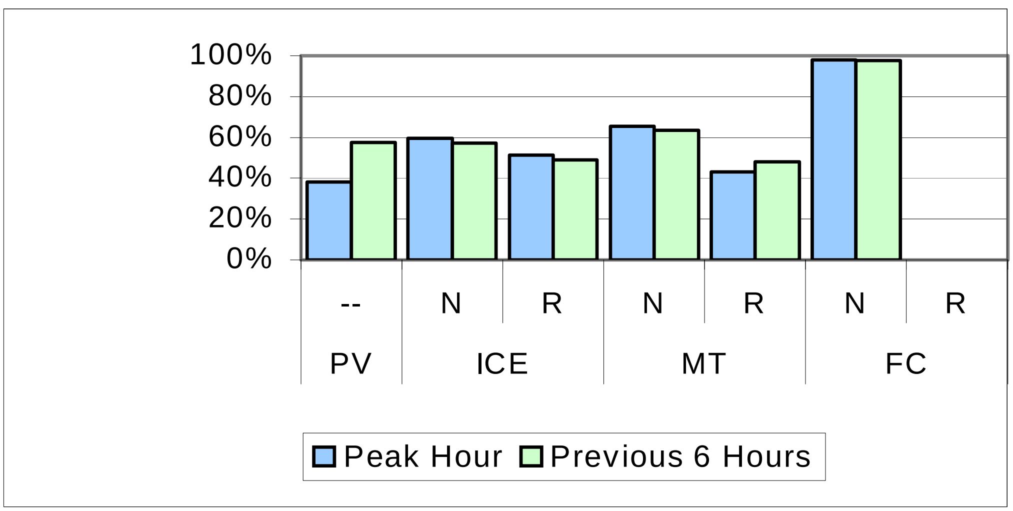
Figure B-30: PV System Percent Operational and Generation as Percent of Operating Capacity by Climate Zone - 2006



	PG&E Coast	SCE Coast	SDG&E Coast	Inland
Operational % kW	88%	69%	71%	100%
Operational CF	50%	30%	34%	38%
Operational #	12	8	28	15
Total #	16	12	35	15

PV system generation tends to peak around HE 13, prior to the peak on most distribution feeders. The potential for PV and other technologies to reduce loads on substation equipment prior to the distribution peak was examined. Reducing loads prior to the system peak may allow substation equipment to operate within allowable temperature ranges during the peak when they might not otherwise have been able to do so. The capacity factor of SGIP generation for the six hours prior to the distribution system peak is shown in Figure B-31. Not surprisingly, PV shows a significantly higher capacity factor of 57 percent for the six hours prior as compared to 38 percent on the actual distribution peak. The capacity factor for other technologies is fairly consistent across the six previous hours and the actual distribution system peak.

Figure B-31: Capacity Factor for Peak Hour vs. Previous Six Hours by Technology and Fuel Type



Peak Hour CF	38%	60%	51%	65%	43%	98%	
Pre. 6 Hour CF	57%	57%	49%	63%	48%	97%	
Operational	91	56	1	28	3	1	0

Lookup Table

The results shown above are compiled in a lookup table below, showing generation as a percent of nameplate capacity for each technology, by climate zone group and feeder type. The number of observations in each group of categories is shown in Table B-9. As noted above, several technology/zone/feeder type combinations have a limited number of observations.

Table B-9: Number of Generators – 2005 & 2006

		PV	ICE		MT		FC		Total
		--	N	R	N	R	N	R	
PG&E Coast	Afternoon	14	4		1				19
	Evening	10	2						12
SCE Coast	Afternoon	17	33		14			1	65
	Evening	8	27	4	22	2			63
SDG&E Coast	Afternoon	50	26		11	4			91
	Evening	13	1		4	2	1		21
Inland	Afternoon	7	5					2	14
	Evening	19	6		2		1		28
Total by Technology/Fuel		138	104	4	54	8	2	3	313
Total by Technology		138	108		62		5		

The generation as percent of installed nameplate capacity is shown in Table B-10. Percentages are shown only for those combinations with a sufficient number of observations to report meaningful results. For example, in the PG&E Coast zones, there are only four afternoon peaking feeders and two evening peaking feeders in the data. The percentages are not shown separately for each feeder type but instead together for the PG&E Coast zones as a whole.

Table B-10: Generation as Percent of Nameplate Capacity – 2005 & 2006

		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon	56%	85%					
	Evening	30%						
SCE Coast	Afternoon	46%	34%		48%			
	Evening	6%	0%					
SDG&E Coast	Afternoon	42%	33%		40%			
	Evening	1%						
Inland	Afternoon	63%	29%					
	Evening	26%						
Total by Technology/Fuel		35%	50%	12%	50%	23%	16%	0%
Total by Technology		35%	48%		44%		9%	

The standard error of the above percentages is shown in Table B-11. Note the results for technologies with limited observations (such as FC) show a relatively high standard error relative to the percentages reported.

Table B-11: Standard Error of Observed Generation as Percentage of Nameplate

		PV	ICE		MT		FC	
		--	N	R	N	R	N	R
PG&E Coast	Afternoon	3.3%	15.7%					
	Evening	5.4%						
SCE Coast	Afternoon	3.1%	2.7%		1.2%			
	Evening	1.0%	1.8%					
SDG&E Coast	Afternoon	1.1%	2.7%		2.7%			
	Evening	0.2%						
Inland	Afternoon	10.3%	2.9%					
	Evening	1.4%						
Total by Technology/Fuel		0.4%	0.7%	6.0%	1.9%	4.2%	11.5%	0.0%
Total by Technology		0.4%	0.6%		1.6%		7.3%	

Additional analysis on the appropriate reporting of certainty is underway. In addition we hope to present a methodology for showing a high level of certainty for estimated load reduction on feeders with multiple generators.

Probability of Achieving Distribution Load Impacts

The lookup table provides *average* values for different SGIP output coincident with the local distribution peak. The project team has also developed probability distributions of output expressed as a function of rebated capacity. These distributions are based on the different output levels measured across the metered SGIP installations.

Table B-12 and Table B-13 show the likelihood of the SGIP generator having an output at least as great as a given percentage of the rebated capacity. Table B-12 shows the probability distributions for feeders which peak on Hour Ending 16 or earlier, Table B-13 shows the probability distribution for feeders which peak after Hour Ending 16. For example, there is a 71% probability of having an output at least as great as 40% of the rebated capacity of a PV system in the SCE Coastal zones on a feeder that peaks on or before 4pm (example highlighted).

Table B-12: Probability Distribution of Output from SGIP for Feeder Peak <=HE 16

Technology	PV	PV	PV	PV	PV	ICE	MT	FC
Percent of Rebated Capacity	PG&E Coast	SCE Coast	SDG&E Coast	Inland	All Zones	All Zones	All Zones	All Zones
0%	100%	100%	100%	100%	100%	100%	100%	100%
5%	100%	94%	100%	100%	99%	65%	64%	20%
10%	100%	94%	98%	100%	98%	65%	64%	20%
15%	100%	94%	92%	100%	94%	65%	64%	20%
20%	100%	94%	86%	100%	91%	61%	64%	20%
25%	100%	88%	82%	100%	87%	60%	64%	20%
30%	100%	88%	80%	86%	85%	57%	64%	20%
35%	100%	88%	80%	86%	85%	57%	62%	20%
40%	93%	71%	73%	86%	77%	57%	61%	20%
45%	86%	65%	69%	86%	72%	54%	52%	20%
50%	86%	35%	55%	86%	59%	51%	52%	20%
55%	79%	29%	45%	71%	49%	50%	51%	20%
60%	79%	18%	31%	43%	37%	48%	41%	20%
65%	50%	18%	12%	14%	20%	41%	36%	20%
70%	29%	12%	12%	14%	15%	35%	30%	20%
75%	29%	0%	6%	14%	9%	30%	25%	20%
80%	7%	0%	6%	14%	6%	20%	11%	20%
85%	0%	0%	2%	14%	2%	14%	0%	20%
90%	0%	0%	0%	14%	1%	9%	0%	20%
95%	0%	0%	0%	14%	1%	7%	0%	20%
100%	0%	0%	0%	0%	0%	4%	0%	20%
Number of Observations	24	25	62	26	87	108	61	5

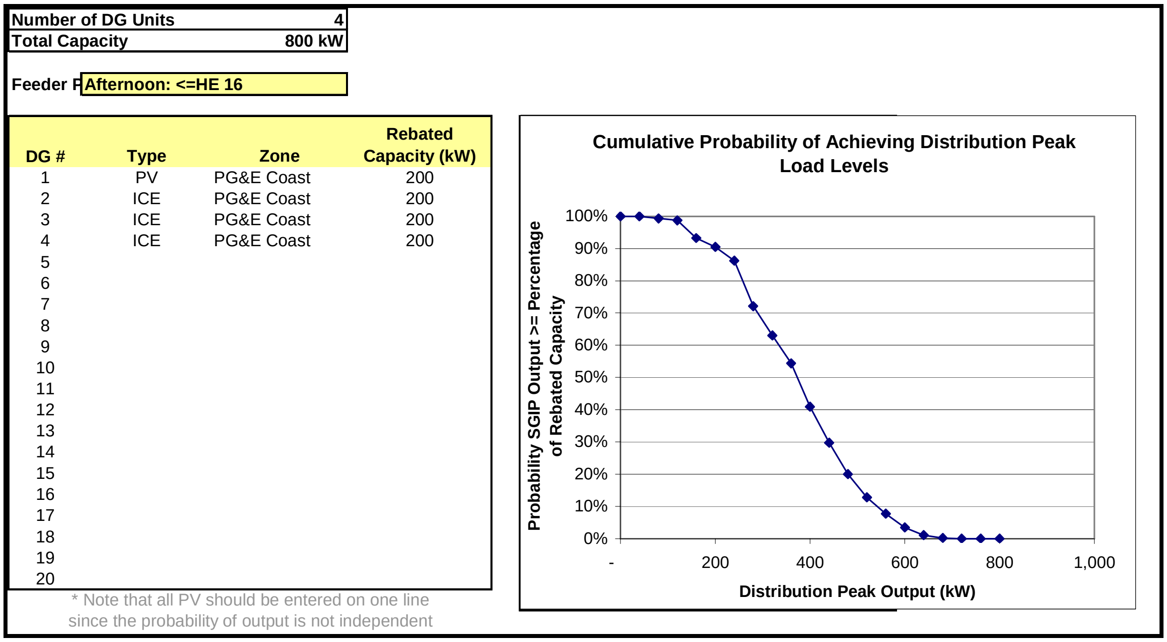
Table B-13: Probability Distribution of Output from SGIP for Feeder Peak >HE 16

Technology	PV	PV	PV	PV	PV	ICE	MT	FC
Percent of Rebated Capacity	PG&E Coast	SCE Coast	SDG&E Coast	Inland	All Zones	All Zones	All Zones	All Zones
0%	100%	100%	100%	100%	100%	100%	100%	100%
5%	50%	38%	23%	95%	58%	65%	64%	20%
10%	40%	38%	23%	89%	54%	65%	64%	20%
15%	40%	38%	23%	84%	52%	65%	64%	20%
20%	40%	25%	15%	68%	42%	61%	64%	20%
25%	40%	0%	15%	58%	34%	60%	64%	20%
30%	30%	0%	15%	53%	30%	57%	64%	20%
35%	30%	0%	15%	26%	20%	57%	62%	20%
40%	20%	0%	15%	11%	12%	57%	61%	20%
45%	10%	0%	0%	5%	4%	54%	52%	20%
50%	10%	0%	0%	5%	4%	51%	52%	20%
55%	10%	0%	0%	0%	2%	50%	51%	20%
60%	0%	0%	0%	0%	0%	48%	41%	20%
65%	0%	0%	0%	0%	0%	41%	36%	20%
70%	0%	0%	0%	0%	0%	35%	30%	20%
75%	0%	0%	0%	0%	0%	30%	25%	20%
80%	0%	0%	0%	0%	0%	20%	11%	20%
85%	0%	0%	0%	0%	0%	14%	0%	20%
90%	0%	0%	0%	0%	0%	9%	0%	20%
95%	0%	0%	0%	0%	0%	7%	0%	20%
100%	0%	0%	0%	0%	0%	4%	0%	20%
Number of Observations	24	25	62	26	50	108	61	5

The probability distributions above provide the probability achieving a given level of output for a single SGIP installation. However, as penetration of SGIP generators increases on the system, it is possible to have multiple generators on the same feeder. Therefore, the project team has developed a spreadsheet tool to compute the combined probability of achieving a given level of output in the case of multiple generators. The spreadsheet combines the cumulative probability distributions to compute a single distribution that can be used in the distribution planning assessment.

Figure B-32 provides a 'screen shot' of the spreadsheet tool to illustrate the use of the analysis tool. To use the tool, the user selects the feeder peak period (either <=HE 16 or >HE16), the climate zone, the technology type, and the rebated capacity of each generator. The analyst then pushes the 'Calculate' button and the spreadsheet computes the combined probability distribution. The algorithm works by computing the probability of each combination of generator output based on the individual probability distributions, and then summing the probability of all the combinations that result at a total combined output for each output level.

Figure B-32: Screenshot from Spreadsheet Tool for Multiple SGIP Units



DG #	Type	Zone	Rebated Capacity (kW)
1	PV	PG&E Coast	200
2	ICE	PG&E Coast	200
3	ICE	PG&E Coast	200
4	ICE	PG&E Coast	200
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			

Cost Savings

Major Categories of Benefits

The May 18, 2006 ruling characterizes transmission and distribution system benefits have in three categories: (1) performance improvement, (2) reliability improvement, and (3) operations improvement. In developing the M&E approach in this study, each of these categories was considered individually and those that could be quantified with available data were evaluated.

Performance improvement benefits include reduction in losses, improvement in voltage profile, and improvement of power quality. In this category, the value of reduced losses was evaluated based on SGIP generation, distribution loss factors for each utility, and an estimate of the wholesale value of energy. Improvements in voltage profile and power quality were not evaluated because this information is not readily available.

Reliability improvement was estimated as the reduced capital investment necessary to meet the distribution planning criteria at each utility with SGIP distributed generation operating in the system. This approach evaluates the ability of distribution system planners to incorporate the peak load reduction in their planning. To the extent peak load reductions are achieved and distribution planning methods can defer necessary capital upgrades, there are savings associated with the SGIP installations.

For reliability improvement assessment, the analysis approach does not try to estimate the reduced number of outages associated with SGIP, or the value of lost load to customers. This type of analysis would be highly speculative and difficult.

Operations improvement includes reduced crew time and maintenance costs. Information necessary to estimate any reductions or increases in crew time and maintenance associated with SGIP is not readily available and are likely to be small. Therefore, this category of benefits has not been evaluated.

Quantification of Benefits

<u>Distribution System Loss Reductions</u>

The value of distribution loss savings from SGIP is on the order of $2.2M to $2.4M per year statewide in California, shown in Table B-14. The value is similar for 2005 and 2006, with a slight decrease in 2006 due to less generation identified overall in 2006 than 2005. While we are not certain, this reduction is likely due to higher natural gas prices for natural gas-powered CHP units. The calculation is simply the energy generated times the distribution loss factor for each utility times the estimated wholesale value of energy. Input assumptions are provided in the Methodology section.

Table B-14: Estimated Value of Distribution System Loss Savings

Year	Utility	SGIP Generation (MWh)	Distribution Loss Savings (MWh)	Loss Savings ($/year)	Total Savings ($/year)
2005	PG&E	432,451	15,003	$864,512	
	SCE	625,546	14,707	$861,491	
	SDG&E	249,062	10,669	$624,948	$2,350,951
2006	PG&E	460,797	15,986	$921,177	
	SCE	478,397	11,247	$658,840	
	SDG&E	247,761	10,613	$621,682	$2,201,699

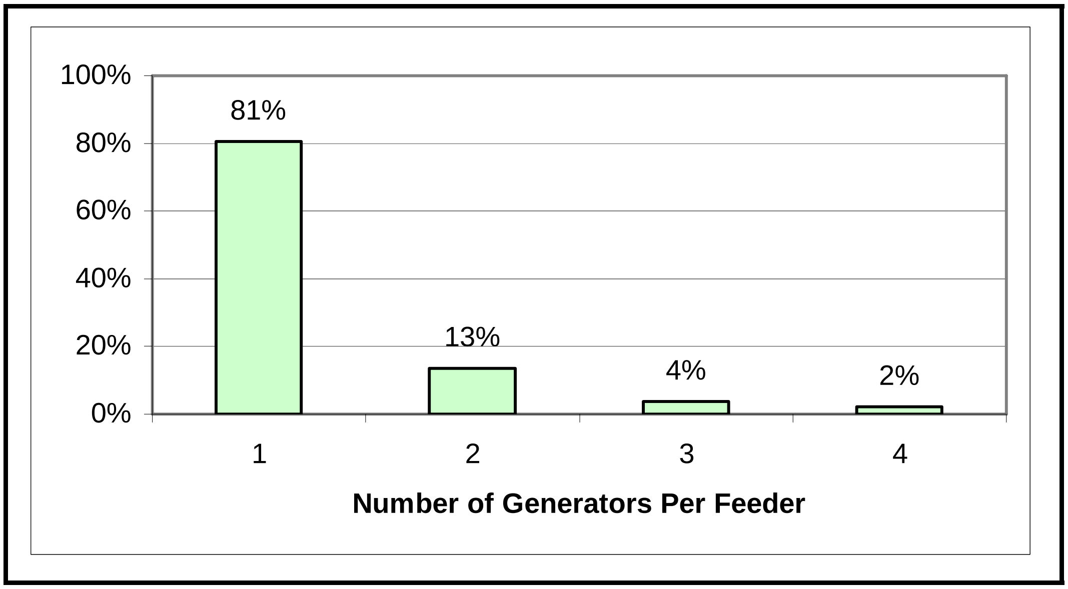
There are a number of sources of error in estimating the distribution system losses. The approach uses an annual average methodology which is conservative. The total generation, distribution losses factors, and wholesale energy costs are all computed on an annual average. Therefore, distributed generation that consistently operates on peak will have a higher level of total loss savings. A high estimate can be developed assuming wholesale energy costs and distribution loss factors twice the annual average. With these assumptions, the value of distribution losses could be as high as $8M annually.

<u>Distribution Peak Capacity Reduction</u>
A potentially larger benefit is the distribution capacity value associated with the SGIP installations. A key driver for providing distribution capacity value is achieving sufficient peak load reductions to defer planned capital additions without exceeding the N-1 peak load ratings on distribution system equipment. This requires enough distribution coincident peak load reduction to defer investments.

To evaluate the potential for capital investment deferrals, the project team tabulated the penetration of SGIP installations per feeder, and then the total amount of measured load reduction. The percentage of feeders serving SGIP installations that have one or more SGIP installations is shown in Figure B-33. Based on available data, 81 percent of distribution feeders serving a customer with a SGIP generator have a single SGIP installation. Approximately 2 percent of feeders serving an SGIP generator have four SGIP generators. Also note that SCE submitted data for substations rather than feeders and that some of the substations with multiple SGIP generators will likely have numerous feeders. Therefore, even if there are four distributed generators, they may not be connected to the same feeder or substation transformer.

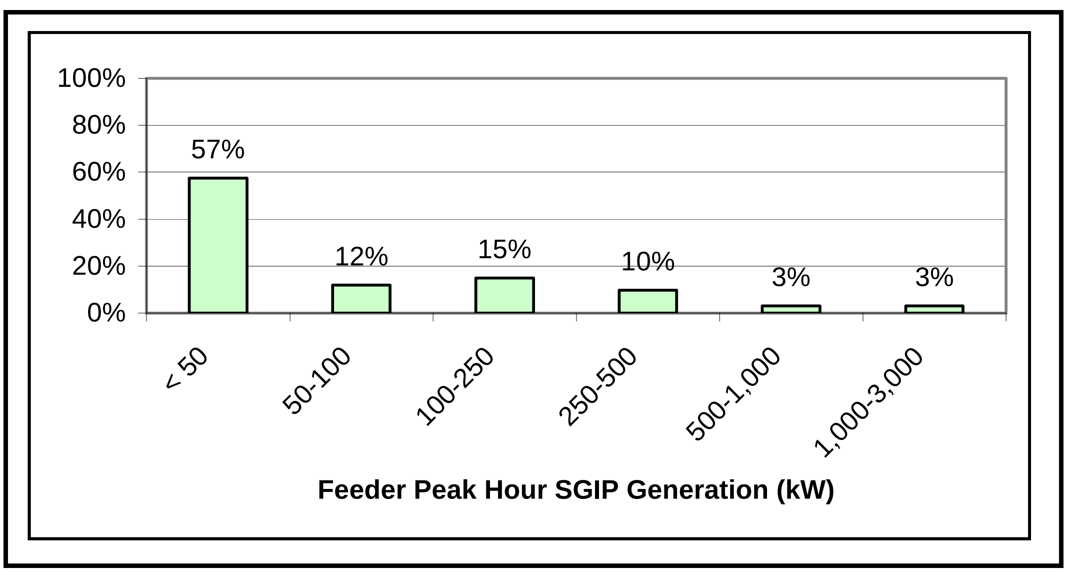
The number of SGIP generators per substation is related to the amount of SGIP peak load reduction, but also indicates the diversity of peak load reduction. If there are multiple generators per substation, then peak load reduction can still be achieved even if a single generator were to fail. This effect is explored in more detail in the certainty analysis of the "look-up" table.

Figure B-33: Number of SGIP Generators per Feeder - 2006



The amount of peak load reduction per substation or feeder is also critical for evaluating the potential for distribution capacity savings. The percentage of substations or feeders with varying amounts of observed distribution peak load reduction is shown in Figure B-34. Of the feeders evaluated, 57 percent of those with SGIP installations had a peak load reduction of less than 50 kW. Only 3 percent of substations or feeders had load reductions from 1 MW to 3 MW.

Figure B-34: Feeder Peak Hour Generation (kW) per Feeder - 2006



The amount of distribution load reduction achieved with SGIP reduction can also be expressed as the percentage of feeders that have achieved 'significant' peak load reductions.

The frequency of different levels of peak load reduction achieved in 2005 and 2006 is shown in Figure B-35 and Figure B-36, below. In 2005, 8 percent of the feeders or substations had greater than 5 percent peak load reduction, while 57 percent showed less than 0.5 percent peak load reduction. In 2006, no feeder or substation had a measured peak load reduction of greater than 5 percent. The results from 2006 are due to the fact that the SGIP generators observed operating during the peak in 2005 were not running during the distribution peak hour in 2006. The reason for the generation was not running is not known, but could be due to high natural gas prices, a forced outage, or something else.

Figure B-35: Distribution of SGIP Generation as Percent of Feeder Peak - 2005

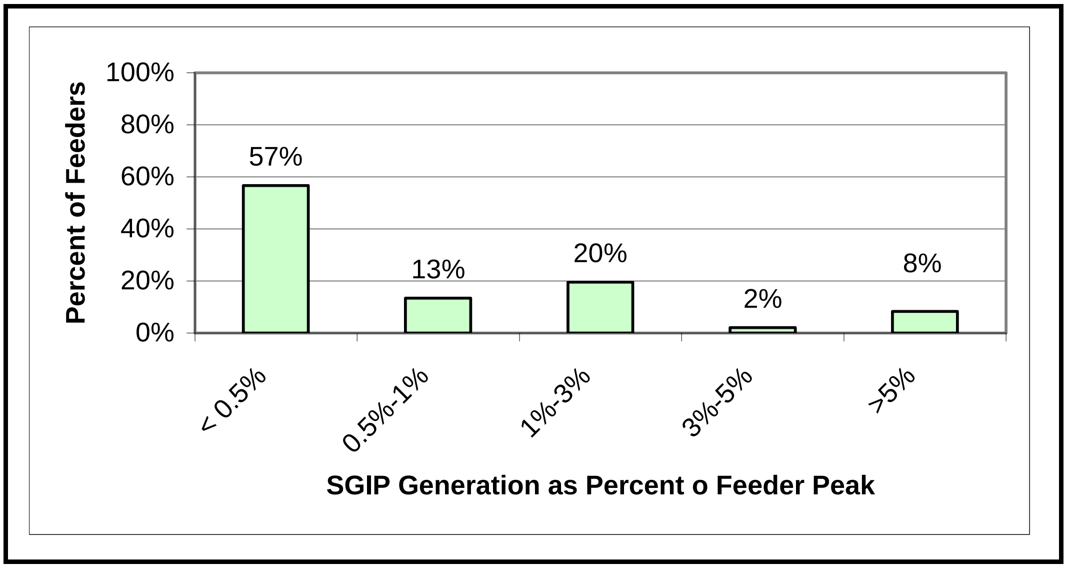
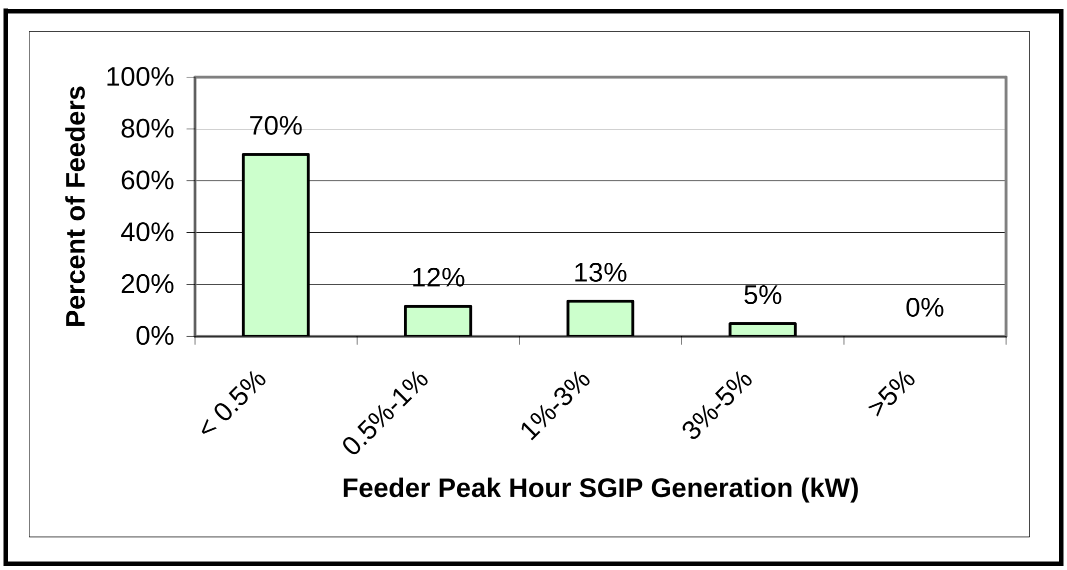


Figure B-36: Distribution of SGIP Generation as Percent of Feeder Peak – 2006



Taken together, the results of the distribution capacity evaluation indicate that there is not a sufficient penetration of SGIP distributed generators to provide distribution capacity value. With greater penetration overall, or targeted penetration on a specific distribution system in danger of an overload, it would be possible to capture distribution capacity savings.

In addition to penetration of SGIP, a number of other factors contribute to a lack of distribution capital savings. One of these is that the SGIP generators operate independently of the distribution system. Therefore, the SGIP owner does not know when the distribution peak is, nor do they have any incentive to operate during the peak even if they did know. In fact, the current SGIP rules prohibit an additional incentive to operate during the local capacity peak. Similarly, the distribution utility planners do not necessarily know which SGIP generators are being served by overloaded equipment, likely because the penetration of SGIP generators is not currently high enough to warrant close attention for capacity planning at the distribution level. In addition, SGIP owners choose where to install their systems, not the utility; therefore they are not a concentrated number of installations in a single area of need that could provide significant load relief on a particular overloaded feeder or substation.

Appendix C

Greenhouse Gas Emissions Reduction Methodology

This appendix provides information regarding the methodology used to estimate the net reduction in specific greenhouse gas (GHG) emissions from the operation of SGIP systems on-line during PY06. The GHG emissions considered in this analysis are carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants whose emissions are potentially affected by the operation of SGIP systems. Specifically, the operation of photovoltaic projects, wind turbines, and non-renewable microturbines, gas turbines, and internal combustion engines directly affect CO_2 emissions, while renewable microturbines, gas turbines, and internal combustion engines directly affect both CH_4 and CO_2 emissions.

C.1 Net GHG Emission Reductions

Net emission reductions of methane and carbon dioxide are quantified in this analysis by examining the change in emissions that occur during the following processes:

- When in operation, power generated by SGIP systems directly displaces grid electricity that would have been generated from central station power plants.[1] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The CO_2 emissions from these conventional power plants are estimated on an hour-by-hour basis over all 8760 hours of the 2006 year[2]. The CO_2 estimates are based on a methodology developed by Energy and Environmental Economics, Inc. (E3) and made publicly available on its website as part of its avoided cost calculator.[3]
- The operation of specific renewable and non-renewable fueled cogeneration systems such as microturbines (MT), fuel cells (FC), gas turbines (GT), and

[1] In this analysis, we compare GHG emissions from SGIP facilities only to GHG emissions from utility power generation that could be subject to economic dispatch (i.e., central station natural gas-fired combined cycle facilities and simple cycle gas turbine peaking plants). We assume that operation of SGIP facilities have no impact on electricity generated from utility facilities not subject to economic dispatch. Consequently, comparison of SGIP facilities to nuclear or hydroelectric facilities is not made as neither of these facilities is subject to dispatch.

[2] Consequently, during those hours when a SGIP facility is not in operation, displacement of CO_2 emissions from central station power plants is equal to zero.

[3] Energy and Environmental Economics for the California Public Utilities Commission, "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," October 25, 2004.

reciprocating internal combustion engines (ICE) emit CO_2. While CO_2 emissions from central power plants are avoided when SGIP systems are in operation, the SGIP cogeneration plants are responsible for the generation of CO_2 emissions as well. Emissions of CO_2 from SGIP facilities are estimated based on the hour-by-hour electricity generated from SGIP facilities over all 8760 hours of the 2006 year.

- Waste heat recovered from the operation of cogeneration systems displaces natural gas that would have been used to fuel boilers responsible for producing process heating at the customer host site. This displaces accompanying CO_2 emissions from the boilers, which are taken into account by calculating the CO_2 emissions avoided from using natural gas to fuel boilers. Since virtually all fuel carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in the estimated reduction in GHG from SGIP systems.
- For those facilities that contain both absorption and electric chillers, recovered waste heat can also displace electricity (and its accompanying CO_2 emissions) that would have been used to operate electric chillers. In this case, electricity is displaced only when recovered waste heat is used as a heat source for the absorption chiller and it is used instead of the electric chiller. Estimates of avoided CO_2 emissions are based on the hour-by-hour electricity savings from reduced reliance on central station facilities.
- Renewable fuel use facilities with a capacity less than 400 kW, such as dairies, small landfill sites, and wastewater treatment plants, are assumed to capture CH_4 that typically would have been vented and instead use it for energy purposes. The avoided CH_4 emissions represent a direct reduction of greenhouse gases. For biogas generated from wastewater treatment facilities and landfill gas recovery operations that are used in SGIP facilities equal to or greater than 400 kW in rebated capacity, it was assumed this biogas would have been flared if not used at a SGIP renewable fuel use facility. Flaring was assumed to have essentially the same degree of combustion completion as SGIP renewable fuel use facilities. Consequently, for renewable fuel use facilities equal to or larger than 400 kW, there is no net CH_4 benefit.

Section C.2 presents an overview of the estimation technique used to calculate reductions in CH_4 emissions from renewable fuel use facilities and, therefore, focuses on quantifying the avoided CH_4 emissions from renewable fuel use facilities with a capacity less than 400 kW. Section C.3 presents the methodology for the estimation of net reductions in CO_2 emissions. Since SGIP systems emit CO_2 while generating electricity, the release of these emissions must be accounted for in addition to the reduction in CO_2 resulting from the reliance on recovered waste heat and reduced use of electricity generated by conventional power plants.

C.2 Methodology for the Calculation of Methane Emission Reductions

Calculation of CH_4 emission reductions from cogeneration facilities was carried out for the subset of 20 renewable fuel use facilities in the SGIP system. These facilities used exclusively or predominately biogas as the generation fuel source. These included the following facility types:

- Renewable-Powered Fuel Cells;
- Renewable-Fueled Microturbines;
- Renewable-Fueled Internal Combustion Engines; and
- Renewable-Fueled Small Gas Turbines.

The baseline treatment of biogas is important for assessing the methane emission impacts of renewable fuel facilities. Baseline treatment refers to the typical fate of the biogas in lieu of being used for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared). There are three common sources of biogas: landfills, wastewater treatment facilities, and dairies. For dairy digesters, the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2000 dairies in California, conventional manure management practice for flush dairies[4] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into carbon dioxide and water. Because these lagoons are typically uncovered, all of the methane generated in the lagoon escapes into the atmosphere. Currently, there are no requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for control of volatile organic compounds. Consequently, the baseline used in this report for dairy digesters is venting of the methane to the atmosphere.

For wastewater treatment facilities, the baseline is not as straightforward. There are approximately 250 wastewater treatment plants (WWTPs) in California and fewer than 30 of those conduct energy recovery. The larger facilities (i.e., those that could generate 1 MW or more of electricity) tend to install energy recovery systems. However, the vast majority of the remaining WWTPs do not recover energy, and most flare the gas on an infrequent basis. Consequently, for smaller facilities (i.e., those generating less than 400 kW in capacity), venting of the biogas (i.e., venting of the methane) is used as the baseline.

[4] Most dairies manage their wastes via flush, scrape, or some mixture of the two processes. While manure management practices for any of these processes will result in methane being vented to the atmosphere, flush dairies are the most likely candidates for installing anaerobic digesters (i.e., dairy biogas systems).

Landfill gas recovery operations present the biggest challenge in defining the methane treatment baseline. A study conducted by the California Energy Commission in 2001[5] showed that landfills with biogas capacities less than 500 kW, would tend to vent rather than flare the generated landfill gas by a margin of over three to one. Consequently, for this impact evaluation, the baseline for those landfill gas facilities less than 400 kW is to vent the methane to the atmosphere. For landfill gas facilities equal to or greater than 400 kW, the baseline is to flare the biogas. In situations where flaring occurs, the net methane impact is zero. In essence, combustion of methane in a flare or in a SGIP facility results in zero emissions of methane to the atmosphere.

Methane captured and used at renewable fuel use facilities where the baseline is venting represents CH_4 emissions that are no longer emitted to the atmosphere. Biogas consumption is not metered at SGIP facilities. However, electricity generated from SGIP facilities is metered on an hour–by-hour basis and can therefore be used in conjunction with the electrical efficiency of the SGIP facility to estimate methane emissions. Nearly all SGIP renewable use facilities in 2006 used IC engines or microturbines as the prime mover. Methane emission factors were calculated for each renewable fuel technology type as follows: An electrical efficiency of 29 percent was assumed for IC Engines, 21 percent for microturbines, and 42 percent for fuel cells. Substituting these electrical efficiencies into the methane emissions factor equation gives us the following results:

IC Engine equation: uses electrical efficiency of 29%

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.29}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$
$$\cong 237\ \frac{grams}{kWhr}$$

MT Engine equation: uses electrical efficiency of 21%

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.21}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$
$$\cong 327.8\ \frac{grams}{kWhr}$$

[5] California Energy Commission, "Landfill Gas to Energy Potential in California," 500-02-041V1, September 2002

Fuel Cell equation: uses electrical efficiency of 42%

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.42}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$

$$\cong 163.9\ \frac{grams}{kWhr}$$

The derived emission factors (*CH_4EF*) are multiplied by the total electricity generated from the SGIP renewable fuel use sites (depending upon technology) to estimate the annual avoided CH_4 emissions. Since GHG emissions are often reported in terms of tons of CO_2 equivalent[6], each facility's avoided CH_4 emissions were converted first from grams to pounds and then pounds to metric tons. The equation used to calculate the reduction in CH_4 emissions for site *j*, is equal to:

Avoided CH_4 emissions in 2006 by site j (in tons of CH_4 reduced)	=	*CH_4EF_j grams/kWh * electricity generated in 2006 by site j * 0.002204 lbs/grams ÷ 2,205 lbs/metric ton*

The avoided tons of CH_4 emissions were then converted to tons of CO_2 equivalent by multiplying the avoided methane emissions by 21 CO_2 equivalent, which represents the Global Warming Potential (GWP) of methane (relative to carbon dioxide) over a 100-year time horizon. Based on the methodology described above, the methane reduction from SGIP systems in PY06 amounted to 60,283 in CO_2 equivalent, as shown in Table 5-21 in Section 5 of this report.

6 Carbon dioxide equivalent is a metric measure used to compare the emissions of various greenhouse gases based upon their global warming potential (GWP). The carbon dioxide equivalent for a gas is derived by multiplying the tons of the gas by the associated GWP. OECD Glossary of Statistical Terms, http://stats.oecd.org/glossary/detail.asp?ID=285

C.3 Methodology for the Calculation of Carbon Dioxide Emission Reductions

This section describes the methodology used to calculate the net reduction of carbon dioxide emissions from SGIP facilities during PY06. The methodological approach used for this analysis relies upon the multiplication of emission factors (in pounds of CO_2 per kWh of electricity generated) that are technology, location, and hour-specific by the total kWh generated by SGIP cogeneration sites during 2006. The different fuel/technology combinations that are accounted for include renewable and nonrenewable; fuel cells, internal combustion engines, microturbines, and gas turbines. The location or service territory of a cogeneration site is also considered in the development of emission factors by accounting for whether the facility is located in PG&E's territory (northern California) or in SCE/SDG&E's territory (southern California). The geographic location naturally has an effect on the demand and use of electricity due to differences in climate and electricity market conditions. This in turn affects the emission factors used to estimate the avoided CO_2 released by conventional power plants. Lastly, the date and time that electricity is generated affects the emission factors because the mix of high and low efficiency plants used differ throughout the day. The larger the proportion of low efficiency plants that would have been used to generate electricity, the greater the avoided CO_2 emissions.

Underlying Assumption of CO_2 Emissions Factors

As described above, there are a number of elements that can affect the emission factors used to calculate the overall net emission reductions of CO_2 for SGIP facilities. The basic methodology used to formulate emission factors for this analysis relies upon certain assumptions made by E3 in their emission factor development and avoided cost calculation workbook.[7] These are as follows:

- The emissions of CO_2 released from a conventional power plant depends upon its heat rate, which in turn is dictated by the power plant's efficiency, and
- The mix of high and low efficiency plants in operation is determined by the price and demand for electricity at that time.

Hourly carbon dioxide emission factors used in this study were based upon a methodology initially developed by E3. E3 provided CO_2 emission factors and the basis for those factors in a workbook available for download on their website. The premise for hourly CO_2 emission factors calculated in E3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the market demand conditions for electricity; as demand for electricity increases, all else equal, the price

[7] The filename of the workbook that contains the data used to generate hour-specific emission factors for CO_2 is called cpucAvoided26.xls and can be downloaded from www.ethree.com/CPUC.

of natural gas will rise. To meet the higher demand for natural gas, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission factor for CO_2. In other words, one can expect an emission factor representing the release of CO_2 from the central grid to be higher during peak hours than during off-peak hours.

The E3 workbook mentioned above includes the price of natural gas for each hour over the year 1999 presented as the percentage of the annual average price of natural gas for 1999. Two streams of hourly natural gas prices exist: one for northern California and another for southern California. These "price shape" data streams dictate the mix of high and low efficiency power plants used by the conventional power grid to meet demand. During the hours where the price of natural gas is high (e.g., weekday, on-peak versus weekend or holiday, off-peak), the demand for electricity is met using high efficiency as well as low efficiency peaking power plants ("peakers"). The price of natural gas is used to calculate an implied heat rate, which is dependent on the mix of low and high efficiency power plants. This implied heat rate is used to calculate the tons of CO_2 per kWh emission factors for each hour of the year. The greater the demand during these times (as indicated by a higher hourly price for natural gas), the higher the percentage of electricity generated by peakers and the greater the benefit of relying upon SGIP systems.

Base CO_2 Emission Factors

Two streams of 8760 hourly emission factors for 1999 are included in the E3 workbook; one is for PG&E (hereafter these factors will be referred to as the northern California CO_2 emission factors) and the other is for SCE and SDG&E (hereafter referred to as the southern California CO_2 emission factors). Inputs to develop the hourly emission factors are geographically dependent due to different weather conditions, different central station plant heat rates, and different natural gas market conditions.

The basic hourly CO_2 emission factor (EF) equation (represented in tons per MWh) is described below:

$$BaseCO_2\ EF_{it} = \text{high efficiency plant } CO_2\ EF + (\text{implied heat rate}_{it} - \text{high efficiency plant heat rate})*[(\text{low efficiency plant } CO_2\ EF - \text{high efficiency plant } CO_2\ EF)/(\text{low efficiency plant heat rate} - \text{high efficiency plant heat rate})]$$

where i =NC for northern California and SC for southern California
t = hour, 1 to 8760 in year 1999

This equation shows that for a given time *t*, the emission factor is dependent upon how the implied heat rate of the average power plant differs from the average heat rate of a high efficiency power plant. The higher the heat rate (which indicates a heavier reliance on lower efficiency plants, such as during times of high electricity demand), the greater the emission factor. To calculate the base hourly emission factor values, we rely upon the parameters and "price shape" data or percentage mix representing low and high efficiency plants in operation that E3 presents in its workbook. These are as follows:

high efficiency plant CO_2 EF (tons per MWh) = 0.3650

low efficiency plant CO_2 EF (tons per MWh) = 0.8190

high efficiency plant heat rate = 6,240

low efficiency plant heat rate = 14,000

*implied heat rate$_{it}$ = current price of natural gas$_{it}$/annual average price of natural gas$_{it}$ * avg heat rate$_i$*

where i= NC, SC
t = hours 1 to 8760 in year 1999

avg heat rate$_{NC}$ =9,160 for NC
avg heat rate$_{SC}$ = 9,590 for SC

If implied heat rate$_t$ < 6,240, then implied heat rate$_t$ = 6,240
If implied heat rate$_t$ > 14,000 then implied heat rate$_t$ = 14,000
(implied heat rate is bounded by low and high efficiency plant heat rates)

The base hourly emission factor values, as calculated here, are presented in tons per MWh. We converted these factors into lbs. per kWh by multiplying the factors by the conversion rate of 2,205 lbs. /metric ton and then dividing by 1,000 kWh for ease of application and consistency across the emission factors calculated for CH_4.

Since we required CO_2 emissions avoided for every hour of the year 2006 to be able to calculate the net emission reductions of this primary component of greenhouse gases, simply lining up the hourly emission factors from 1999 to the hourly totals of electricity generated from power plants in 2006 would not work due to the possible differences in days of the week. Upon examination of these two years, we determined that January 1, 1999 fell on a Friday while January 1, 2006 fell on a Sunday. To properly align the emission factors for the correct day type, the emission factor values for 1/1/1999 and 1/2/1999 were removed from both the northern and southern California price streams and moved up. This adjustment was made so that the emission factor value calculated for Sunday, January 3, 1999 could be multiplied by the electricity supplied by the conventional grid on Sunday, January 1, 2006.

This realignment allowed us to maintain the proper days of the week over the year for the emissions factor values. However, this adjustment left two missing days at the end of the year, a Saturday and a Sunday. To correct for this, the emission factor values for the last non-holiday Saturday and Sunday of the month of December, 12/18/1999 and 12/19/1999, were used for the last two days of 2006.

Technology-Specific Adjustments to CO_2 Emission Factors

The above location- and hour-specific emission factors, when multiplied by the quantity of electricity generated each hour estimate the *hourly emissions avoided when electricity from SGIP sites is used in lieu of electricity from the grid*. Earlier in this appendix, it was noted that SGIP sites are also responsible for emitting CO_2; this must also be taken into account when calculating the net emission reductions of CO_2 for SGIP facilities. The following assumptions were made regarding the emissions generated per kWh of electricity generated for the various cogeneration technologies:

$$\begin{aligned} SGIPCO_2\ EF_a \text{ (in lbs. per kWh)} \quad &= 1.99 \text{ when } a = \text{Gas Turbine} \\ &= 1.99 \text{ when } a = \text{Microturbine} \\ &= 1.44 \text{ when } a = \text{IC Engine} \\ &= 0.99 \text{ when } a = \text{Fuel Cell} \end{aligned}$$

The equations used to derive the technology-specific component of the emission factors are as follows:

Microturbine and Gas Turbine equation: uses electrical efficiency of 21%

$$(CO_2)_{MT} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.21}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right) \cong \frac{1.99\ lbs\ of\ CO_2}{kWhr}$$

IC Engine equation: uses electrical efficiency of 29%

$$(CO_2)_{ICE} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.29}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right) \cong \frac{1.44\ lbs\ of\ CO_2}{kWhr}$$

Fuel Cell equation: uses electrical efficiency of 42%

$$(CO_2)_{FC} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.42}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.99\ lbs\ of\ CO_2}{kWhr}$$

The technology-specific emission factors were calculated to account for CO_2 emissions released from SGIP sites and, therefore, when multiplied by the electricity generated from cogeneration sites, represent an increase in CO_2 emissions.

Waste Heat Recovery Adjustment to CO_2 Emission Factors

The third bullet presented in Section C.1 of this appendix described additional GHG reduction benefits derived from cogeneration. These benefits come in the form of waste heat recovered from SGIP facilities that is then used for energy purposes, and hence avoids additional reliance on electricity from conventional power plants. The application of these emission factors was dependent upon the presence of a natural gas boiler and whether or not recovered waste heat is used to fuel the boiler (this was indicated through a *boilerflag* dummy variable).

The emission factor adjustment made to account for the recovery of waste heat is technology dependent, just as the CO_2 emissions released from cogeneration facilities was technology dependent as well. The following heat recovery factors (HRFs) were applied for those facilities that are able to recover waste heat for use in boilers:

$$
\begin{aligned}
HRF_a \text{ (in lbs. per kWh)} \quad &= 0.49 \text{ when } a = \text{Gas Turbine} \\
&= 0.35 \text{ when } a = \text{Microturbine} \\
&= 0.29 \text{ when } a = \text{IC Engine} \\
&= 0.29 \text{ when } a = \text{Fuel Cell}
\end{aligned}
$$

These HRFs were calculated based upon technology-specific average heat recovery rates from the SGIP projects active in 2006, with the exception of the heat recovery rate used for gas turbines. Because of the dearth of gas turbine projects operating in 2006, the highest technology-specific heat recovery rate was used. This was equal to 4.0 kBtu/kW which was calculated for petroleum-fueled IC engines. In the Fifth Year CPUC SGIP Impacts Report, general, or default, heat recovery rates were used to calculate the technology-specific heat recovery factors. For this impacts report, we were able to use both metered and estimated data to calculate average heat recovery rates by technology.

The equations used to derive these components of the emission factors are as follows:

Gas Turbine equation: uses heat recovery rate of 4.0 kBtu/kWh

$$(CO_2)_{GTWH} \cong \left(\frac{4.0\ kBtu}{kWh}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$
$$\cong \frac{0.49\ lbs\ of\ CO2}{kWh}$$

Microturbine equation: uses heat recovery rate of 2.9 kBtu/kWh

$$(CO_2)_{MTWH} \cong \left(\frac{2.9\ kBtu}{kWh}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$
$$\cong \frac{0.35\ lbs\ of\ CO2}{kWh}$$

IC Engine equation: uses heat recovery rate of 2.4 kBtu/kWh

$$(CO_2)_{ICEWHE} \cong \left(\frac{2.4\ kBtu}{kWh}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$
$$\cong \frac{0.29\ lbs\ of\ CO2}{kWh}$$

Fuel Cell equation: uses heat recovery rate of 2.4 kBtu/kWh

$$(CO_2)_{FCWH} \cong \left(\frac{2.4\ kBtu}{kWh}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$
$$\cong \frac{0.29\ lbs\ of\ CO2}{kWh}$$

These emission factors are based on the ability of waste heat to be recovered and used in lieu of energy from the conventional power grid and are therefore calculated as a reduction in CO_2 emissions (an environmental benefit).

Absorption Chiller Adjustment to CO_2 Emission Factors

The fourth bullet presented in Section C.1 of this appendix described one additional GHG reduction benefit derived from the presence of absorption chillers present in cogeneration facilities. Since absorption chillers can replace the use of standard efficiency centrifugal electric chillers that operate using electricity from the central power plant, there are avoided CO_2 emissions that translate to a reduction in GHG emissions.

Actual heat recovery rates and typical absorption and centrifugal chiller efficiencies were incorporated into an algorithm to estimate the avoided electricity that would have been serving the centrifugal chiller in the absence of the cogeneration system. This component of the emission factors are also technology-specific:

CHF_a *(in lbs. per kWh)* = 0.15 when a = Gas Turbine

= 0.11 when a = Microturbine

= 0.09 when a = IC Engine

= 0.09 when a = Fuel Cell

Just as was the case with HRFs, the CHFs were calculated based upon technology-specific average heat recovery rates calculated from data collected from SGIP projects active in 2006, with the exception of the heat recovery rate used for gas turbines (due to the extremely small number of gas turbine projects operating in 2006).

The equations used to derive this component of the emission factors are as follows:

Gas Turbine equation: uses heat recovery factor of 4.0 kBtu/kWh

$$(CO_2)_{GTC} \cong \left(\frac{7.9\,kBtu}{kWh_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\,kWh_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\,kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWh_{elecin}}\right)$$

$$\cong \frac{0.15\,lbs\ of\ CO_2}{kWh_{electin}}$$

Microturbine equation: uses heat recovery factor of 2.9 kBtu/kWh

$$(CO_2)_{MTC} \cong \left(\frac{4.0\,kBtu}{kWh_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\,kWh_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\,kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWh_{elecin}}\right)$$

$$\cong \frac{0.11\,lbs\ of\ CO_2}{kWh_{electin}}$$

IC Engine equation: uses heat recovery factor of 2.4 kBtu/kWh

$$(CO_2)_{ICEC} \cong \left(\frac{2.8\,kBtu}{kWh_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\,kWh_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\,kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWh_{elecin}}\right)$$

$$\cong \frac{0.09\,lbs\ of\ CO_2}{kWh_{electin}}$$

Fuel Cell equation: uses heat recovery factor of 2.4 kBtu/kWh

$$(CO_2)_{FCC} \cong \left(\frac{1.7\ kBtu}{kWh_{ENGO}}\right)\left(\frac{0.7 Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\ kWh_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\ kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWh_{elecin}}\right)$$
$$\cong \frac{0.09\ lbs\ of\ CO_2}{kWh_{electin}}$$

Fully Adjusted CO_2 Emission Factors

The fully adjusted emission factor, when multiplied by the electricity generated at cogeneration sites, represents the net change in GHG emissions due to the existence of the SGIP program. The equation for the adjusted emission factor is:

$$Fully\ adjusted\ CO_2\ EF = (BaseCO_2\ EF_{it} - SGIPCO_2\ EF_a + HRF_a + CHFa)*electricity_j$$

where:

i = NC or SC
t = hour
a = technology type
j = facility

Appendix D

Data Analysis

The data sources for the evaluation impact report were described in Section 4. Program impact estimates and the uncertainty in those estimates were presented in Section 5. This appendix discusses data availability by PA and the data analysis methodology, including the bases of the impact estimates uncertainty characterizations.

D.1 Data Availability

Data availability charts for 2003 through 2006 by PA, technology, and fuel are presented in Attachment 1.

D.2 Data Processing Methods

This section discusses the ENGO, HEAT, and FUEL data processing and validation methodology for PV, fuel cells, and engines/turbines operating on nonrenewable or renewable fuel.

ENGO Data Processing

PV data is processed differently from the fuel cell, engine and turbine data.

For PV, a code template has been developed which reads, processes and validates data, and outputs suspect data. When necessary, the code adjusts for daylight savings time, accounts for inverter losses, corrects a data stream which contains more than one site, as well as many other site-specific and data-provider specific issues. Validation of PV data utilizes irradiance, temperature, and rainfall data downloaded from the California Irrigation Management Information System (CIMIS). Each PV site is assigned a nearby CIMIS site. Data is flagged as suspect when there is low daily output, low hourly output, high daily output, or high hourly output compared to the available irradiation. The suspect data is reviewed internally and either validated or invalidated. An example of a suspect case that can be validated internally is a bad weather event which results in low daily output. An example of a suspect case that can be invalidated internally is consistently high daily output which greatly exceeds the system capacity. When the data validity cannot be determined internally the data provider is contacted. Data providers are most often contacted if a site has an outage for more than two days in order to determine if the outage was a PV system failure (indicates valid data) or a data acquisition system failure (indicates invalid data). Invalid data is excluded from the analysis.

For fuel cells, engines and turbines, ENGO data refers to a measure of system output that excludes electric parasitic loads (e.g., onsite controls, pumps, fans, compressors, generators and heat recovery systems.) In some cases it is not possible to measure ENGO directly with a single meter. In those cases ENGO is calculated by subtracting the electrical parasitic loads from the gross generator output. Due to wide variety of formats in which raw data is received, conversion of raw data to a common format is essential in order to ensure that all data received are treated consistently. After converting the data to a common format, all data files are reviewed to identify suspicious data (low or high capacity factors). Data providers are contacted when data validity cannot be determined internally. In cases where anomalous behavior cannot be explained, the metered data are excluded from the analysis.

HEAT data processing

Thermal data is stored in 15-min intervals, in units of kBtu, in permanent SAS datasets. Main source of thermal data are applicants and Itron installed heat meters. If the data comes from Itron data loggers, processing time is minimal because the raw data is already stored in 15-minute intervals. However, if the raw data comes from applicants, then the data should be converted to the standard format. When data are received from an applicant, host, or some other party, certain validation steps must be passed before the data are incorporated into the analysis. These steps include calculation of range of heat recovery rate and comparing waste heat recovered with net generator output.

FUEL data processing

Two main sources of fuel data for non-renewable projects are natural gas utilities and Itron metering. If the data comes from Itron data loggers, processing time is minimal because the raw data is already stored in 15-minute intervals. However, if the raw data comes from gas utility, data is typically reported in monthly or billing cycle intervals. Monthly electrical conversion efficiencies are calculated to validate the monthly fuel data. Validated monthly data is transformed into 15-minute data based on the monthly electrical efficiencies and 15-minute ENGO data. Since the fuel data are a ratio using other metered data (ENGO), a flag in the permanent dataset is set to “R”.

D.3 Estimating Impacts of Unmetered Systems

Data from metered systems were used to estimate impacts for unmetered systems of the same technology and fuel. In most cases, the metered data was for the exact same hour of the year and from systems of same technology, fuel, and PA. For PV systems, the metered data were further limited to systems with additional similarities to those of the unmetered systems.

By limiting the metered data used to those with the same PA, factors that can influence operational performance were better matched between the metered and unmetered systems. These PA-related factors include local economic climate, available tariffs, and to some degree the local meteorological climate. Likewise in the case of PV, additional system similarities included technology details that can influence power output. These PV details included an output capacity class of large versus small (small defined as less than 300 kW), a locale category (coastal or inland), and a module configuration category (flat, tilted, tracking, or mixed).

All estimated hourly impacts were based on no fewer than five metered observations of the same technology and fuel type. For some unmetered systems there were hours with fewer than five metered observations with like technology, fuel, and PA. To estimate impacts for these metered data from one or more of the other PAs was included until there were at least five metered observations for the same hour. For example, metered data from SCE could be used to estimate impacts for similar systems at the same hour for SCG unmetered systems when too few metered observations existed from SCG systems alone. If there still were fewer than five metered observations, then data from CCSE were allowed to be used. If inclusion of CCSE did not provide enough metered observations, then data from PG&E were allowed.

The inclusion of metered data from other PAs did not always satisfy the minimum requirement of five metered observations for the same hour of the year and same technology and fuel. In these cases the metered data were restricted again to the same PA but the time component of the metered data was allowed to include same hours of the day from like weekday types (weekday or weekend) from the same month. For example, an hourly estimate for 3-4 pm on Monday, July 24, for a renewable ICE system administered by SCE might be based on metered observations from renewable ICE systems administered by SCE from all July weekday hours of 3-4pm.

In fewer than 3 percent of the system hours needing to be estimated the relaxation of the metered data time component did not satisfy the minimum requirement of five metered observations. Estimates for these system hours thus were allowed to be based on metered observations during like weekday hours of the same month and from other PAs.

A ratio representing average power output per unit of rebated system capacity was calculated using at least five metered observations for each system hour needing an impact estimate. The product of this ratio and the system's rebated capacity was the system's estimated hourly average power output. Estimates of power output were calculated as:

$$EN\hat{G}O_{psdh} = \left(S_{ps}\right)_{Unmetered} \times \left(\frac{\sum ENGO_{psdh}}{\sum S_{ps}}\right)_{Metered}$$

Where:

$EN\hat{G}O_{psdh}$ = Predicted net generator output for project *p* in strata[1] *s* on date *d* during hour *h*

Units: kWh
Source: Calculated

S_{ps} = System size for project *p* in strata *s*

Units: kW
Source: SGIP Tracking Database

$ENGO_{psdh}$ = Metered net generator output for project *p* in strata *s* on date *d* during hour *h*

Units: kWh
Source: Net Generator Output Meters

D.4 Assessing Uncertainty of Impacts Estimates

Program impacts covered in Section 5 include those on electricity and fuel, as well as those on GHG emissions. The principal factors contributing to uncertainty in those reported results are quite different for these two types of program impacts. The treatment of those factors is described below for each of the two types of impacts.

Electricity and Fuel Impacts

Electricity and fuel impact estimates reported in Section 5 are affected by at least two sources of error that introduce uncertainty into the estimates. The two sources of error are measurement error and sampling error. Measurement error refers to the differences between actual values (e.g., actual electricity production) and measured values (i.e., electricity production values recorded by metering and data collection systems).

Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average

[1] Strata are always defined by like technology and fuel and like hour of like weekday in like month. As described in text, however, strata may be more specific by additional like technology details, like PA or like group of PAs, and by exact hour of the year.

performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

The actual performance of unmetered systems is not known, and will never be known. It is therefore not possible to directly assess the validity of the assumption regarding identical central tendencies. However, it is possible to examine this issue indirectly by incorporating information about the performance *variability* characteristics of the systems.

Theoretical and empirical approaches exist to assess uncertainty effects attributable to both measurement and sampling error. Propagation of error equations are a representative example of theoretical approaches. Empirical approaches to quantification of impact estimate uncertainty are not grounded on equations derived from theory. Instead, information about factors contributing to uncertainty is used to create large numbers of possible sets of actual values for unmetered systems. Characteristics of the sets of simulated actual values are analyzed. Inferences about the uncertainty in impact estimates are based on results of this analysis.

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact estimates uncertainty. The term MCS refers to "the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[2]

A principle advantage of this approach is that it readily accommodates complex analytic questions. This is an important advantage for this project because numerous factors contribute to variability in impact estimates, and the availability of metered data upon which to base impact estimates is variable. For example, metered electricity production and heat recovery data are both available for some cogeneration systems, whereas other systems may also include metered fuel usage, while still others might have other combinations of data available.

GHG Emission Impacts

Electricity and fuel impact estimates represent the starting point for the analysis of GHG emission impacts. Uncertainty in those electricity and fuel impact estimates therefore flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impacts analysis. GHG emissions impact estimates are therefore subject to greater levels of uncertainty than are electricity and fuel

[2] Webster's dictionary

impact estimates. The two most important additional sources of uncertainty in GHG emissions impacts are summarized below.

Baseline Central Station Powerplant GHG Emissions. Estimation of net GHG emissions impacts of each SGIP system involves comparing emissions of the SGIP system with emissions that would have occurred in the absence of the program. The latter quantity depends on the central station powerplant generation technology (e.g., natural gas combined cycle, natural gas gas turbine) that would have met the participant's electric load if the SGIP system had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and hence GHG emissions factors) were obtained from E3. Quantitative assessment of uncertainty in E3's avoided GHG emissions database is outside the scope of this SGIP impacts evaluation.

Baseline Biogas Project GHG Emissions. Biomass material (e.g., trash in landfills, manure at dairies) would typically have existed and decomposed (releasing methane) even in the absence of the program. While the program does not influence the existence or decomposition of the biomass material, it may impact whether or not the methane is released directly into the atmosphere or not. This is critical because methane is a much more active GHG than are the products of its combustion (e.g., CO2).

For this GHG impacts evaluation we used the methane disposition baseline assumptions summarized in Table D-1. Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, in the future additional site-specific information about methane disposition baselines will be collected and incorporated into the analysis. Modification of installation verification inspection forms will be recommended, and information available from air permitting and other information sources will be compiled.

Table D-1: Methane Disposition Baseline Assumptions for Biogas Projects

SGIP System Size (Rebated kW)	Methane Disposition Baseline Assumption
<400 kW	Venting
≥400 kW	Combustion

Data Sources

The usefulness of MCS results rests on the degree to which the factors underlying the simulations of actual performance of unmetered systems resemble factors known to influence those SGIP systems for which impact estimates are being reported. Several key sources of data for these factors are described briefly below.

SGIP Project Information

Basic project identifiers include Program Administrator, project status, project location, system type, and system size. This information is obtained from project lists that Program Administrators update monthly for the CPUC. More detailed project information (e.g., PV system configuration) is obtained from Verification Inspection Reports developed by Program Administrators just prior to issuance of incentive checks.

Metered Data for SGIP DG Systems

Collection and analysis of metered performance data collected from SGIP DG systems is a central focus of the overall program evaluation effort. In the MCS study the metered performance data are used for three principal purposes:

1. Metered data are used to estimate the actual performance of metered systems. The metered data are not used directly for this purpose. Rather, information about measurement error is applied to metered values to estimate actual values.
2. The central tendencies of groups of metered data are used to estimate the actual performance of unmetered systems.
3. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study to explore the likelihood that actual performance of unmetered systems deviates by certain amounts from estimates of their performance.

Manufacturer's Technical Specifications

Metering systems are subject to measurement error. The values recorded by metering systems represent very close approximations to actual performance; they are not necessarily identical to actual performance. Technical specifications available for metering systems provide information necessary to characterize the difference between measured values and actual performance.

Analytic Methodology

The analytic methodology used for this MCS study is described in this section. The discussion is broken down into the five steps listed below:

- Ask Question
- Design Study
- Generate Sample Data
- Calculate the Quantities of Interest for Each Sample
- Analyze Accumulated Quantities of Interest

Ask Question

The first step in the MCS study is to clearly describe the question(s) that the MCS study is being designed to answer. In this instance that question is: How confident can one be that *actual* program total impact deviates from *reported* program total impact by less than certain amounts? The scope of the MCS study includes the following program total impacts:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC216.6 (b) Cogeneration System Efficiency

Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility and accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the systems came on-line during 2006 and therefore contributed to energy impacts for only a portion of the year. Some of the systems for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2006. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came on-line during 2006 and therefore contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more labor- and processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the system is metered or not. However, for many of the SGIP systems metered data are available for a portion—but not all—of 2006. This complicates any analysis that requires classification of systems as either "metered" or "not metered".

It would be possible to design an MCS study that accommodated the project status and data availability details described above. However, such a study would require considerable resources and would not be likely to yield results that would differ substantially from those yielded by a simpler design. Therefore, two important simplifying assumptions are included in the MCS study design.

1. Each data archive (e.g., electricity, fuel, heat) for each project is classified as being either ‘metered’ (at least 75 percent of reported impacts are based on metered data) or ‘unmetered’ (less than 75 percent of reported impacts are based on metered data) for MCS purposes.
2. Only full years of data for unmetered systems are included in the MCS analysis. Projects on-line for fewer than six months are excluded from the analysis. Projects on-line for at least six months are treated as if they were on-line during the entire year.

Generate Sample Data

Actual values for each of the program impact estimates identified above (“Ask Question”) are generated for each sample (i.e., “run”, or simulation). If metered data are available for the system then the actual values are created by applying a measurement error to the metered values. If metered data are not available for the system then the actual values are created using distributions that reflect performance variability assumptions. **A total of 10,000 simulation runs were used to generate sample data.**

Metered Data Available – Generating Sample Data that Include Measurement Error

The assumed characteristics of random measurement-error variables are summarized in Table D-2. The ranges are based on typical accuracy specifications from manufacturers of metering equipment (e.g., specified accuracy of +/- 2%). A uniform distribution with mean equal to zero is assumed for all three measurement types. This distribution implies that any error value within the stated range has an identical probability of occurring in any measurement. This distribution is more conservative than some other commonly assumed distributions (e.g., normal “bell shaped” curve) because the outlying values are just as likely to occur as the central values.

Table D-2: Summary of Random Measurement-Error Variables

Measurement	Range	Mean	Distribution
Electricity	-0.5% to 0.5%	0%	Uniform
Natural gas	-2% to 2%		
Heat recovered	-5% to 5%		

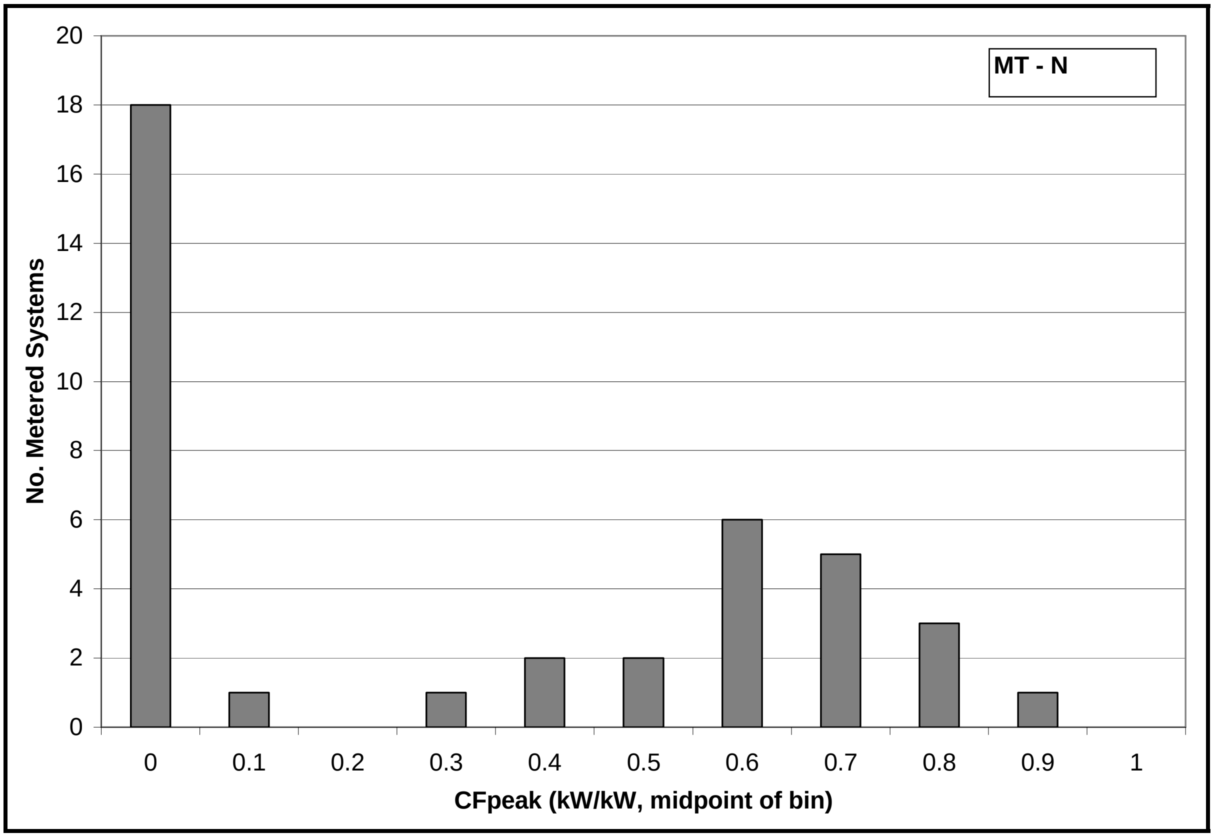
Metered Data Unavailable – Generating Sample Data from Performance Distributions

In the case of unmetered sites, the sample data are generated by random assignment from distributions of performance values assumed representative of entire groups of unmetered sites. Because measured performance data are not available for any of these sites the natural place to look first for performance values is similar metered systems.

Specification of performance distributions for the MCS study involves a degree of judgment in at least two areas: first, in deciding whether or not metered data available for a stratum are sufficient to provide a realistic indication of the distribution of values likely for the unmetered systems; second, when metered data available for a stratum are not sufficient, in deciding when and how to incorporate the metered data available for other strata into a performance distribution for the data-insufficient stratum.

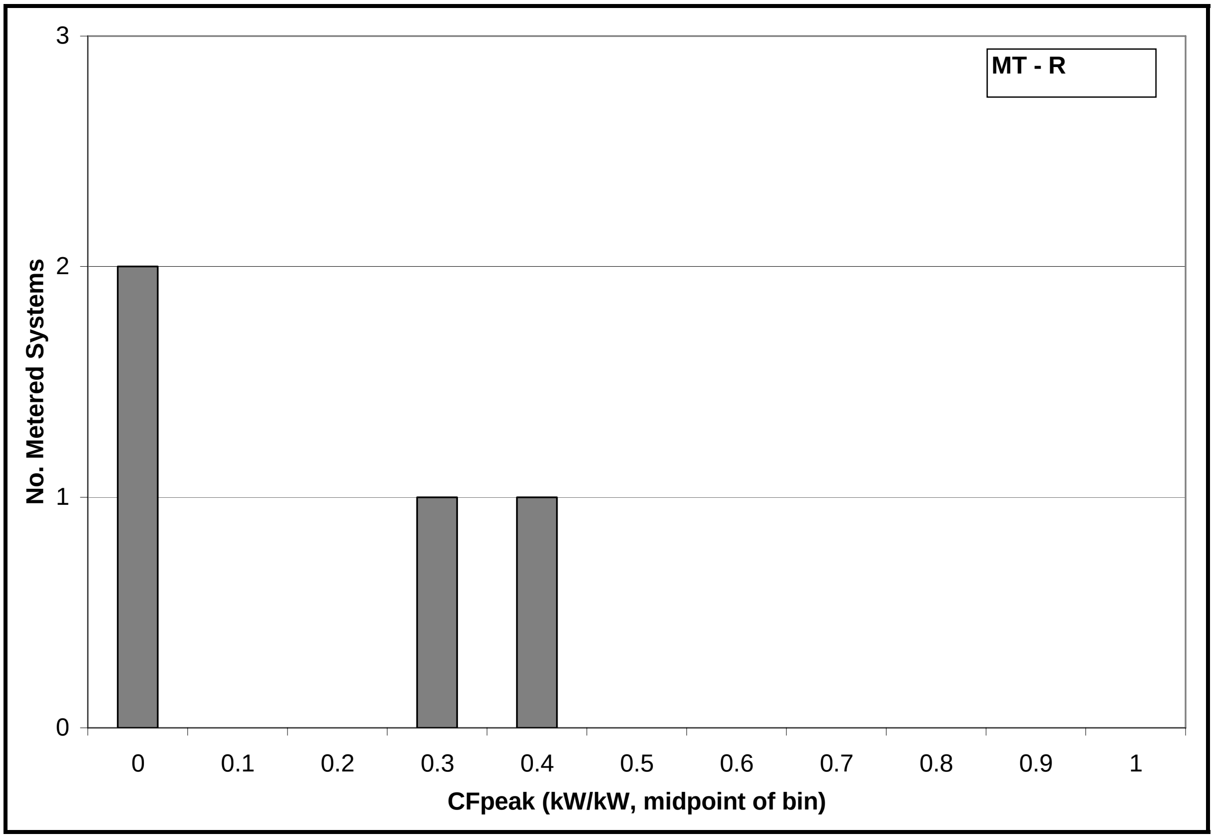
The assessment of the suitability of available metered data for use in MCS performance distributions is illustrated below with an example. The output of a group of nonrenewable-fueled microturbines during the hour when CAISO system load reached its annual peak value is illustrated in Figure D-1. In this figure microturbine system output is expressed as metered power output per unit of system rebated capacity (CFpeak). Metered data were available for 39 systems. There were 50 systems for which metered data were not available for this hour. For each MCS run the actual performance of each of these systems must be assigned from an MCS performance distribution. The metered data available for this group of systems appear to provide a good general indication of the distribution of values likely for unmetered systems.

Figure D-1: Nonrenewable-Fueled Microturbine Measured Coincident Peak Output



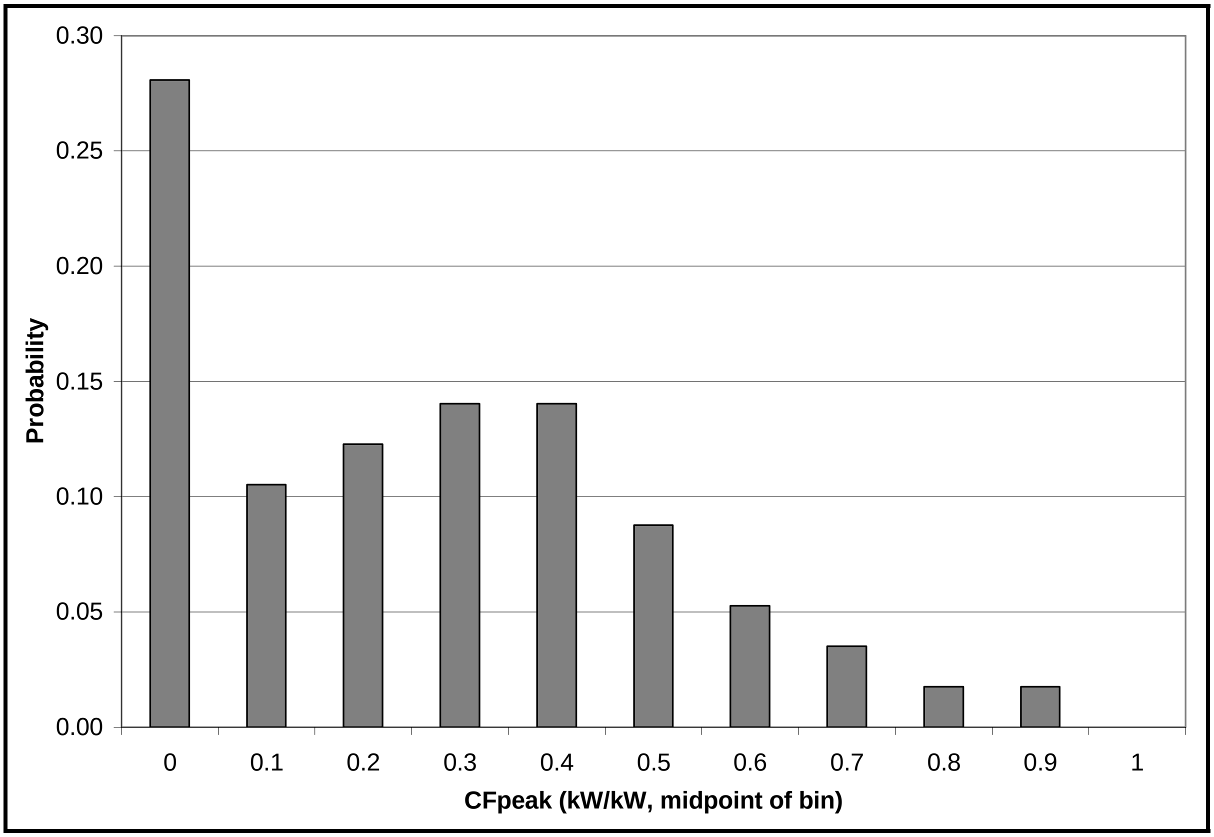
There are other sample design strata for which the quantity of metered data available is insufficient to provide a good indication of the distribution of values likely for unmetered projects. For example, there were only four metered nonrenewable-fueled microturbines during the CAISO peak hour. The measured performance of these four systems is summarized in Figure D-2.

Figure D-2: Renewable-Fueled Microturbine Measured Coincident Peak Output



If 10, 24, or 31 systems were metered it is unlikely that all of them would fall in this exact same distribution. Instead you would expect to see some systems have a CF of 0.1 and 0.2, and other systems could have been running at full capacity (CF = 1). The metered data available for this group of systems do not appear to provide a good general indication of the distribution of values likely for unmetered systems. Figure D-3 shows the distribution used in the MCS for renewable-fueled microturbines at the CAISO peak hour.

Figure D-3: CFpeak Distribution used in MCS for Renewable-Fueled Microturbines



Use of a simplified distribution shown in Figure D-3 emphasizes the fact that the performance of the unmetered systems is not known, and that in the MCS the assumed distribution of CFpeak values is based on judgment. Lastly, the modification introduces a small measure of additional conservatism into MCS results.

Review of metered data availability for all technology and fuel sample design strata revealed numerous instances such as that described above. Consequently, in some instances simplifying assumptions were made. Fuel cell, engine and turbine technologies were not separated by PA and renewable-fueled systems were assumed to follow a similar distribution to nonrenewable-fueled systems within the same technology group. Engineering judgment was used for the wind turbine distribution to determine the maximum output possible for the wind speed at that day and hour. For PV, SCE and SCG systems were grouped together and PV groups were further broken down by configuration and location (coastal or inland). Lastly, the heat recovery distribution from 2005 for nonrenewable engines/turbines was used for the 2006 analysis because there was more heat data available in 2005 than in 2006.

Table D-3 shows the groups used to estimate the uncertainty in the CAISO peak hour impact.

Table D-3: Technology and Fuel Groupings for the CAISO peak hour MCS Analysis

Technology	Fuel	PA[3]	PV Configuration	Coastal/Inland
PV	n/a	PGE, CCSE, SCE & SCG	Near Flat, Other[4], Tracking[5]	Coastal, Inland
Wind	n/a	SCE[6]	n/a	n/a
IC Engine	Nonrenewable, Renewable	All	n/a	n/a
Microturbine	Nonrenewable, Renewable	All	n/a	n/a
Gas Turbine	Nonrenewable[7]			
Fuel Cell	Nonrenewable, Renewable	All	n/a	n/a

[3] PV projects are grouped by PA while engines are not because PV output is dependent on location.

[4] Near Flat systems are those systems with a tilt of 20° or less. Other systems are those systems with a tilt greater than 20°.

[5] Tracking systems are those systems with automatically adjusting tilts which allow the PV system to follow the sun. All tracking systems in SGIP are one-axis tracking systems. Tracking systems were not broken out by coastal/inland.

[6] As of December 31, 2006 there are two completed wind turbine projects in the SGIP and both are within SCE's service territory.

[7] There are no renewable-fueled gas turbines in the program as of December 31, 2006.

Table D-4 shows the groups used to estimate the uncertainty in the yearly energy production. Yearly capacity factors for PV throughout California are less variable than for the CAISO peak hour, therefore all fixed (near flat and other) PV systems are grouped together for the uncertainty analysis of the annual energy production, Tracking systems are kept separate because these systems are designed to have higher daily output than a fixed system. Internal combustion engines, gas turbines, and microturbines are grouped together for the uncertainty analysis of the annual energy production because of the small number of systems within each technology group for which data was available for 75 percent of the year and because a significant difference was not seen between the annual capacity factors of these systems.

Table D-4: Technology and Fuel Groupings for the 2006 Annual Energy Production MCS Analysis

Technology	Fuel	PV Configuration
PV	n/a	Fixed, Tracking
Wind	n/a	n/a
Engine/Turbine	Nonrenewable, Renewable	n/a
Fuel Cell	All	n/a

Performance distributions were developed for each of the groups in the tables based on metered data and engineering judgment. In the MCS, a capacity factor is randomly assigned from the performance distribution and sample values are calculated as the product of CFpeak and system size. All of these performance distributions are included as attachment to this appendix.

Bias. Performance data collected from metered sites were used to estimate program impacts attributable to unmetered sites. If the metered sites are not representative of the unmetered sites then those estimates will include systematic error called bias. Potential sources of bias of principle concern for this study include:

Planned data collection disproportionally favors dissimilar groups. For example, no new HEAT metering has been installed in the last 12 months. During this period 48 new projects have been completed and have entered commercial operations. If the actual heat recovery performance of the newer systems differs systematically from the older, metered systems then estimates calculated for the newer systems will be biased. A similar situation can occur when actual performance differs substantially from performance assumptions underlying data collection plans.

Actual data collection allocations deviate from planned data collection allocations. In program impacts evaluation studies actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated for unmetered systems may be biased. For example, no new ENGO metering of PV systems has been installed by Itron in the last 18 months. In some areas the result is a metered dataset containing a disproportionate quantity of data received from program participants who operate their own metering. This metered dataset is used to calculate impacts for unmetered sites. If the actual performance of the unmetered systems differs systematically from that of the systems metered by participants then estimates calculated for the unmetered systems will be biased. One example of this is if a participant metered system's output decreases unexpectedly the participant will know almost immediately and steps can be taken to get the system running normally again. However, a similar situation with an unmetered system could go unnoticed for months.

Actual data collection quantities deviate from planned data collection quantities. For example, plans called for collection of ENGO data from all RFU systems; however data actually were collected only from a small proportion of completed RFU systems.

In the MCS analysis bias is accounted for during development of performance distributions assumed for unmetered systems. If the metered sample is thought to be biased then engineering judgment dictates specification of a relatively 'more spread out' performance distribution. Bias is accounted for, but the accounting does not involve adjustment of point estimates of program impacts. If engineering judgment dictates an accounting for bias then the performance distribution assumed for the MCS analysis has a higher standard deviation. The result is a larger confidence interval about the reported point estimate. If there is good reason to believe that bias could be substantial then the confidence interval reported for the point estimate will be larger than it otherwise would be.

To this point the discussion of bias has been limited to sampling bias. More generally, bias can also be the result of instrumentation yielding measurements that are not representative of the actual parameters being monitored. Due to the wide variety of instrumentation types and data providers involved with this project it is not possible to say one way or the other whether or not instrumentation bias contributes to error in impacts reported for either metered or unmetered sites. Due to the relative magnitudes involved, instrumentation error – if it exists – accounts for an insignificant portion or total bias contained in point estimates.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered sites. The relative importance of this varies with metering rate. For example, where the metering rate is 90 percent, a 20 percent sampling bias will yield an error of only 2 percent in total (metered + unmetered) program impacts. All else equal, higher metering rates reduce the impact of sampling bias on estimates of total program impacts.

Calculate the Quantities of Interest for Each Sample

After each simulation run the resulting sample data for individual sites are summed to the program level and the result is saved. The quantities of interest were defined previously:

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC216.6 (b) Cogeneration System Efficiency

Cogeneration system efficiency is a calculated value that is based on sample data for electricity production, fuel consumption, and heat recovery. The efficiency values for each simulation run were calculated as:

$$PUC218.5b_r = \frac{\left(\sum ELEC_{rs} \times \text{KWH2KBTU}\right) + \left(\sum \text{C1} \times HEAT_{rs}\right)}{\sum FUEL_{rs}} \times \frac{100\%}{1}$$

Where:

PUC216.6b

$PUC216.6b_r$	is program total PUC216.6 (b) cogeneration system efficiency for run r Units: %
$ELEC_{rs}$	is total electricity production for run r and system s Units: kWh
KWH2KBTU	is a conversion factor Value: 0.2931 (i.e., 1/3.412) Units: kWh/kBtu
C1	is a constant Value: 0.5 Units: none Basis: Cogeneration system efficiency definition of CPUC
$HEAT_{rs}$	is total useful waste heat recovery for run r and system s Units: kBtu
$FUEL_{rs}$	is total fuel consumption for run r and system s Units: kBtu Basis: Lower Heating Value of fuel

Analyze Accumulated Quantities of Interest

The pools of accumulated MCS analysis results are analyzed to yield summary information about their central tendency and variability. Mean values are calculated and the variability exhibited by the values for the many runs is examined to determine confidence levels (under the constraint of constant relative precision), or to determine confidence intervals (under the constraint of constant confidence level).

Results

The confidence levels in the energy impacts, demand impacts, and PUC 216.6 compliance results have been presented along with those results. This section will present the precision and confidence intervals associated with those confidence levels in more detail. Three bins were used for Confidence Levels: 90/10 or better, 70/30 or better (but worse than 90/10), and worse than 70/30.

Table D-5: Uncertainty Analysis Results for Annual Energy Impact Results by Technology and Basis

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	**70%**	**±24.6%**	**0.538 to 0.890**
Metered	< 70%	±36.4%	0.414 to 0.890
Estimated	70%	±23.1%	0.500 to 0.800
Gas Turbine	**< 70%**	**±50.9%**	**0.287 to 0.881**
Metered	90%	±0.5%	0.875 to 0.884
Estimated	< 70%	±61.7%	0.153 to 0.647
IC Engine	**70%**	**±27.0%**	**0.233 to 0.406**
Metered	< 70%	±30.0%	0.221 to 0.411
Estimated	< 70%	±36.8%	0.215 to 0.466
Microturbine	**< 70%**	**±55.9%**	**0.126 to 0.445**
Metered	< 70%	±76.8%	0.077 to 0.585
Estimated	< 70%	±39.1%	0.213 to 0.486
Photovoltaics	**90%**	**±7.3%**	**0.177 to 0.205**
Metered	70%	±16.2%	0.147 to 0.204
Estimated	90%	±7.5%	0.191 to 0.207
Wind	**70%**	**±24.0%**	**0.140 to 0.230**
Metered	90%	±0.3%	0.157 to 0.158
Estimated	<70%	±60%	0.100 to 0.400

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table D-6: Uncertainty Analysis Results for Annual Energy Impact Results by Technology, Fuel, and Basis

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell - Nonrenewable	**70%**	**±15.9%**	**0.646 to 0.891**
Metered	70%	±9.9%	0.730 to 0.891
Estimated	70%	±18.9%	0.526 to 0.771
Fuel Cell - Renewable	**70%**	**±29.1%**	**0.405 to 0.738**
Metered	90%	±0.45%	0.413 to 0.416
Estimated	< 70%	±38.5%	0.400 to 0.900
Gas Turbine - Nonrenewable	**< 70%**	**±50.9%**	**0.287 to 0.881**
Metered	90%	±0.5%	0.875 to 0.884
Estimated	< 70%	±61.7%	0.153 to 0.647
IC Engine – Nonrenewable	**70%**	**±11.1%**	**0.331 to 0.413**
Metered	70%	±24.5%	0.250 to 0.412
Estimated	70%	±18.9	0.323 to 0.474
IC Engine – Renewable	**< 70%**	**±34.2%**	**0.170 to 0.347**
Metered	90%	±0.3%	0.220 to 0.222
Estimated	< 70%	±56.5%	0.122 to 0.437
Microturbine – Nonrenewable	**70%**	**±18.5%**	**0.312 to 0.453**
Metered	70%	±16.5	0.312 to 0.436
Estimated	70%	±28.4%	0.287 to 0.515
Microturbine – Renewable	**< 70%**	**±69.4%**	**0.076 to 0.423**
Metered	< 70%	±77.0%	0.076 to 0.588
Estimated	< 70%	±47.0%	0.145 to 0.402

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table D-7: Uncertainty Analysis Results for PG&E Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	**70%**	**±11.0%**	**0.606 to 0.756**
Estimated	70%	±18.9%	0.526 to 0.771
Metered	90%	±0.45%	0.728 to 0.735
Gas Turbine	**< 70%**	**±11.0%**	**0.153 to 0.647**
Estimated	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
Metered			
IC Engine	**< 70%**	**±61.7%**	**0.205 to 0.438**
Estimated	< 70%	±36.85%	0.205 to 0.444
Metered	90%	±0.15%	0.411 to 0.412
Microturbine	**< 70%**	**±36.3%**	**0.221 to 0.428**
Estimated	< 70%	±34.90%	0.218 to 0.452
Metered	90%	±0.26%	0.318 to 0.319
Photovoltaics	**90%**	**±50.6%**	**0.190 to 0.203**
Estimated	90%	±3.82%	0.193 to 0.177
Metered	90%	±0.12%	0.176 to 1.000

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table D-8: Uncertainty Analysis Results for SCE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	**70%**	**±29.1%**	**0.405 to 0.738**
Estimated	< 70%	±38.5%	0.400 to 0.900
Metered	90%	±0.4%	0.413 to 0.416
IC Engine	**70%**	**±27.0%**	**0.206 to 0.358**
Estimated	< 70%	±47.3%	0.174 to 0.487
Metered	90%	±6.3%	0.220 to 0.250
Microturbine	**70%**	**±16.5%**	**0.337 to 0.470**
Estimated	< 70%	±50.4%	0.168 to 0.508
Metered	70%	±17.8%	0.410 to 0.588
Photovoltaics	**90%**	**±29.4%**	**0.187 to 0.204**
Estimated	90%	±4.5%	0.189 to 0.207
Metered	90%	±0.2%	0.147 to 0.147
Wind	**70%**	**±24.0%**	**0.140 to 0.230**
Estimated	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
Metered			

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table D-9: Uncertainty Analysis Results for SCG Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
Estimated			
Metered			
Gas Turbine	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
Estimated			
Metered			
IC Engine	**70%**	**±8.4%**	**0.352 to 0.416**
Estimated	70%	±19.7%	0.319 to 0.476
Metered	90%	±0.1%	0.374 to 0.375
Microturbine	**70%**	**±21.4%**	**0.322 to 0.497**
Estimated	70%	±27.1%	0.294 to 0.512
Metered	90%	±0.3%	0.435 to 0.437
Photovoltaics	**< 70%**	**±2.8%**	**0.193 to 0.205**
Estimated	90%	±5.4%	0.187 to 0.208
Metered	90%	±0.4%	0.203 to 0.205

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table D-10: Uncertainty Analysis Results for CCSE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	**90%**	**±0.5%**	**0.885 to 0.893**
Estimated			
Metered	90%	±0.5%	0.885 to 0.893
Gas Turbine	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		
Estimated			
Metered			
IC Engine	**90%**	**±0.2%**	**0.344 to 0.345**
Estimated			
Metered	90%	±0.2%	0.344 to 0.345
Microturbine	**< 70%**	**±60.7%**	**0.076 to 0.312**
Estimated			
Metered	< 70%	±60.7%	0.076 to 0.312
Photovoltaics	**90%**	**±2.3%**	**0.174 to 0.182**
Estimated	70%	±8.6%	0.181 to 0.215
Metered	90%	±0.1%	0.175 to 0.176

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table D-11: Uncertainty Analysis Results for Peak Demand Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	**< 70%**	**±33.4%**	**0.467 to 0.935**
Metered	< 70%	±100.0%	0.000 to 0.868
Estimated	70%	±28.6%	0.500 to 0.900
Gas Turbine	**70%**	**±15.7%**	**0.625 to 0.859**
Metered	90%	±0.37%	0.826 to 0.832
Estimated	< 70%	±45.5%	0.300 to 0.800
IC Engine	**< 70%**	**±42.7%**	**0.215 to 0.536**
Metered	< 70%	±100.0%	0.000 to 0.437
Estimated	70%	±21.4%	0.351 to 0.542
Microturbine	**< 70%**	**±54.4%**	**0.112 to 0.379**
Metered	70%	±18.1%	0.215 to 0.310
Estimated	70%	±28.4%	0.206 to 0.369
Photovoltaics	**< 70%**	**±46.8%**	**0.216 to 0.597**
Metered	< 70%	±54.3%	0.178 to 0.602
Estimated	70%	±29.1%	0.352 to 0.641
Wind	**90%**	**±0.47%**	**0.032 to 0.032**
Metered	90%	±0.47%	0.032 to 0.032
Estimated	< 70%	±54.3%	0.178 to 0.602

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

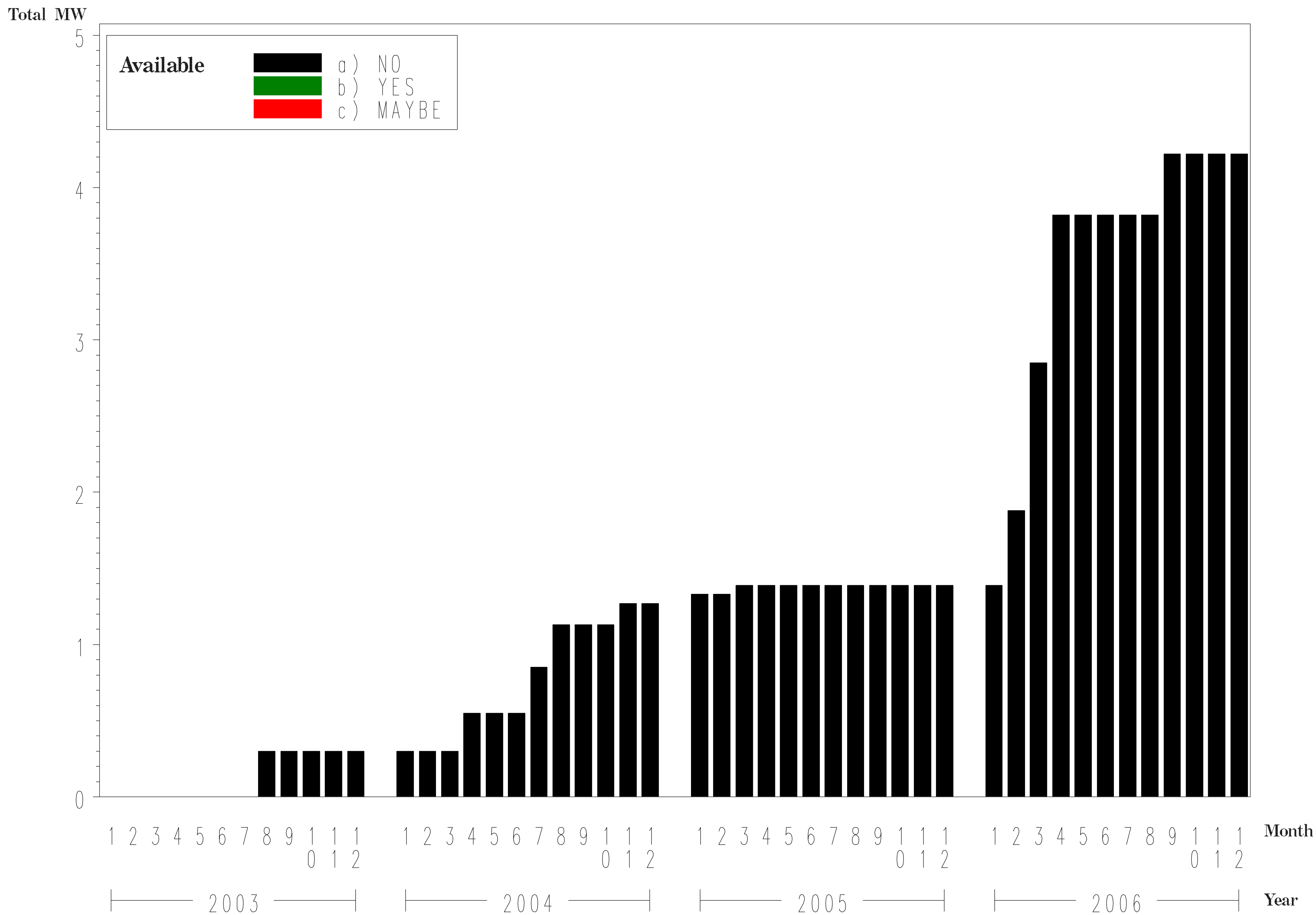
Table D-12: Uncertainty Analysis Results for Annual PUC 216.6(b)

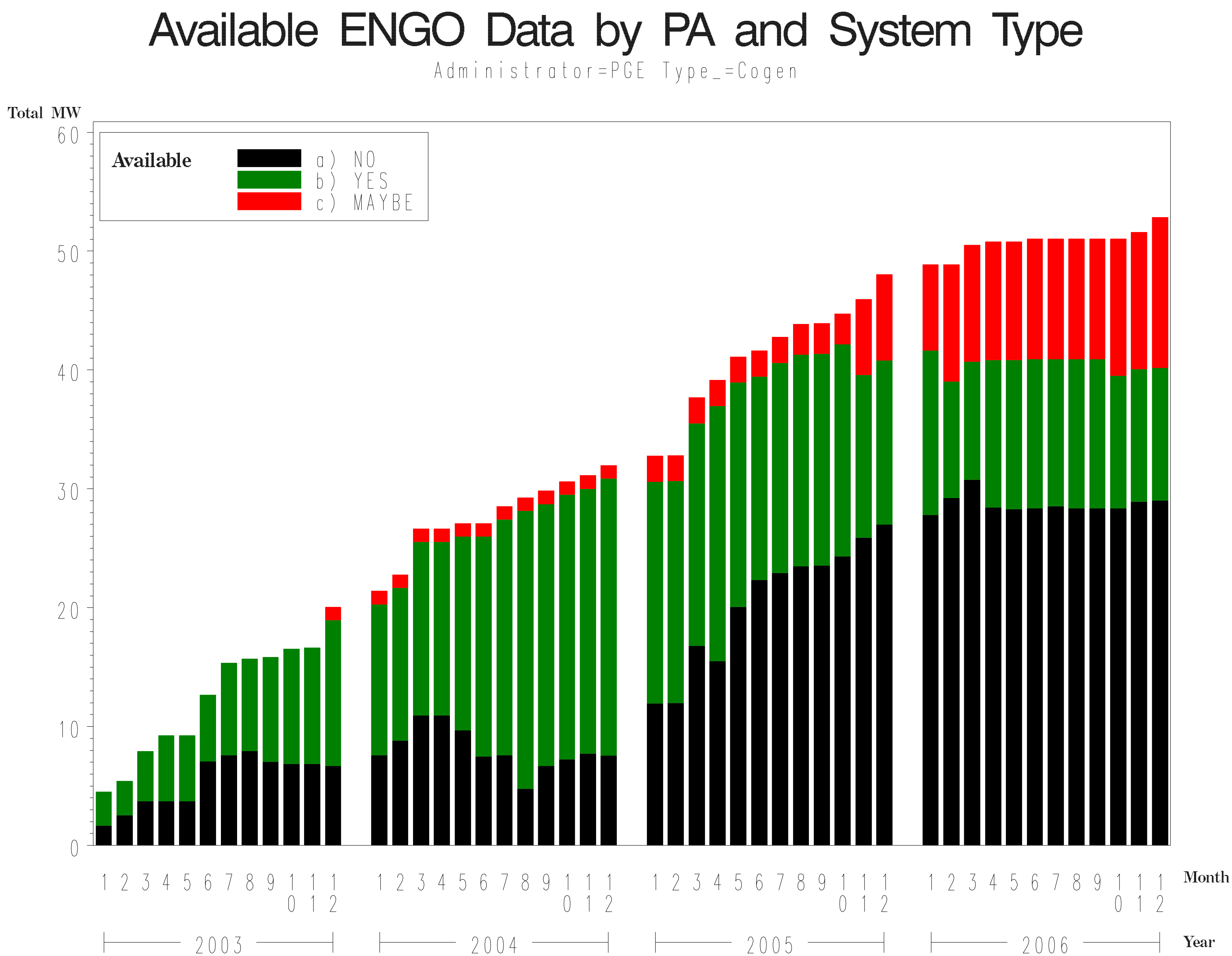
Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	**90%**	**±9.86%**	**52.2 to 63.6**
Metered	-	-	-
Estimated	90%	±9.86%	52.2 to 63.6
Gas Turbine	**70%**	**±20.1%**	**30.2 to 45.3**
Metered	-	-	-
Estimated	70%	±20.1%	30.2 to 45.3
IC Engine	**90%**	**±4.59%**	**39.0 to 42.7**
Metered	90%	±8.65%	32.7 to 38.9
Estimated	90%	±4.75%	39.1 to 43.0
Microturbine	**70%**	**±6.2%**	**27.8 to 31.5**
Metered	70%	±13.5%	24.6 to 32.2
Estimated	70%	±6.6%	27.8 to 31.8

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Available ENGO Data by PA and System Type

Administrator=PGE Type_=Biogas

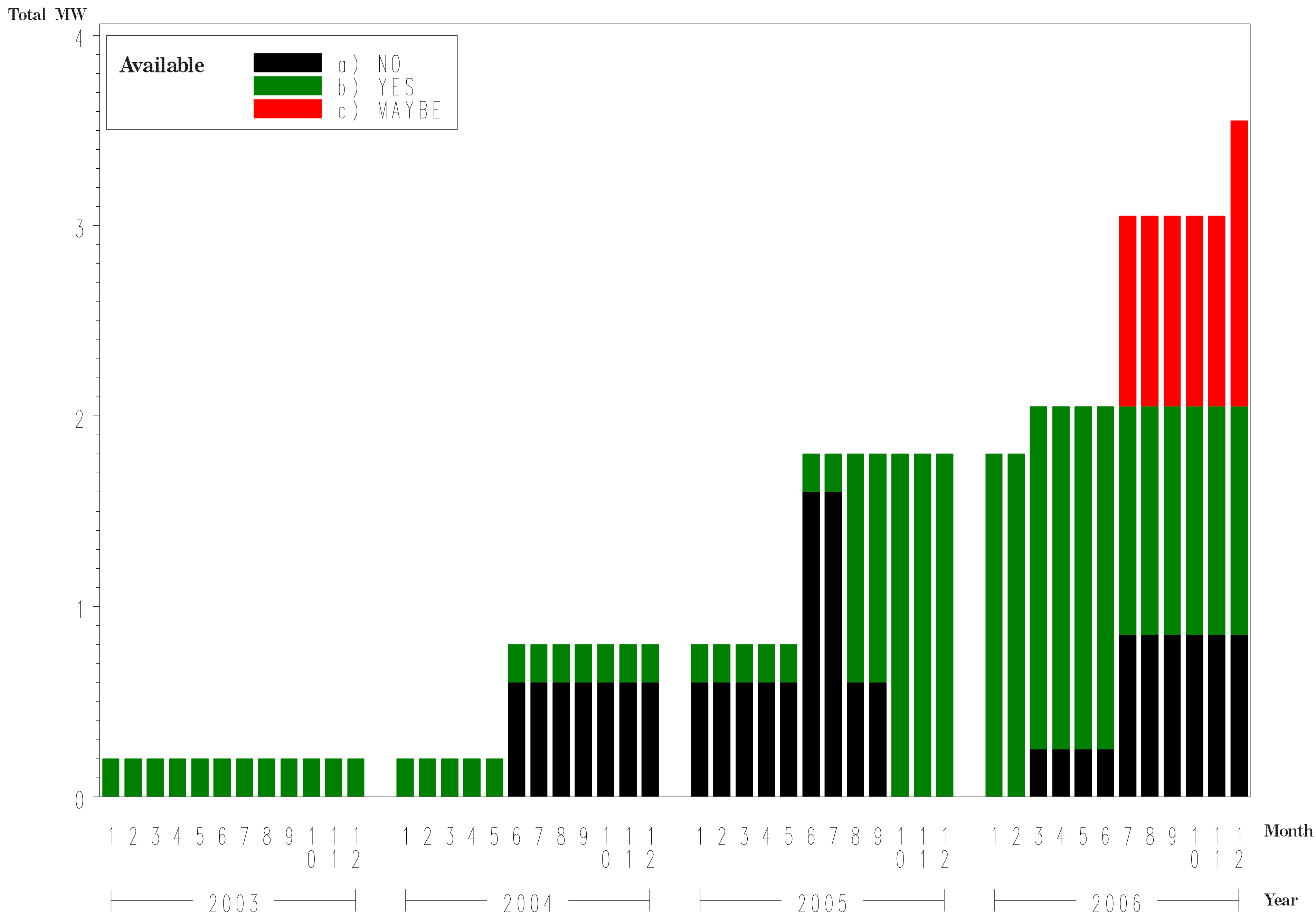


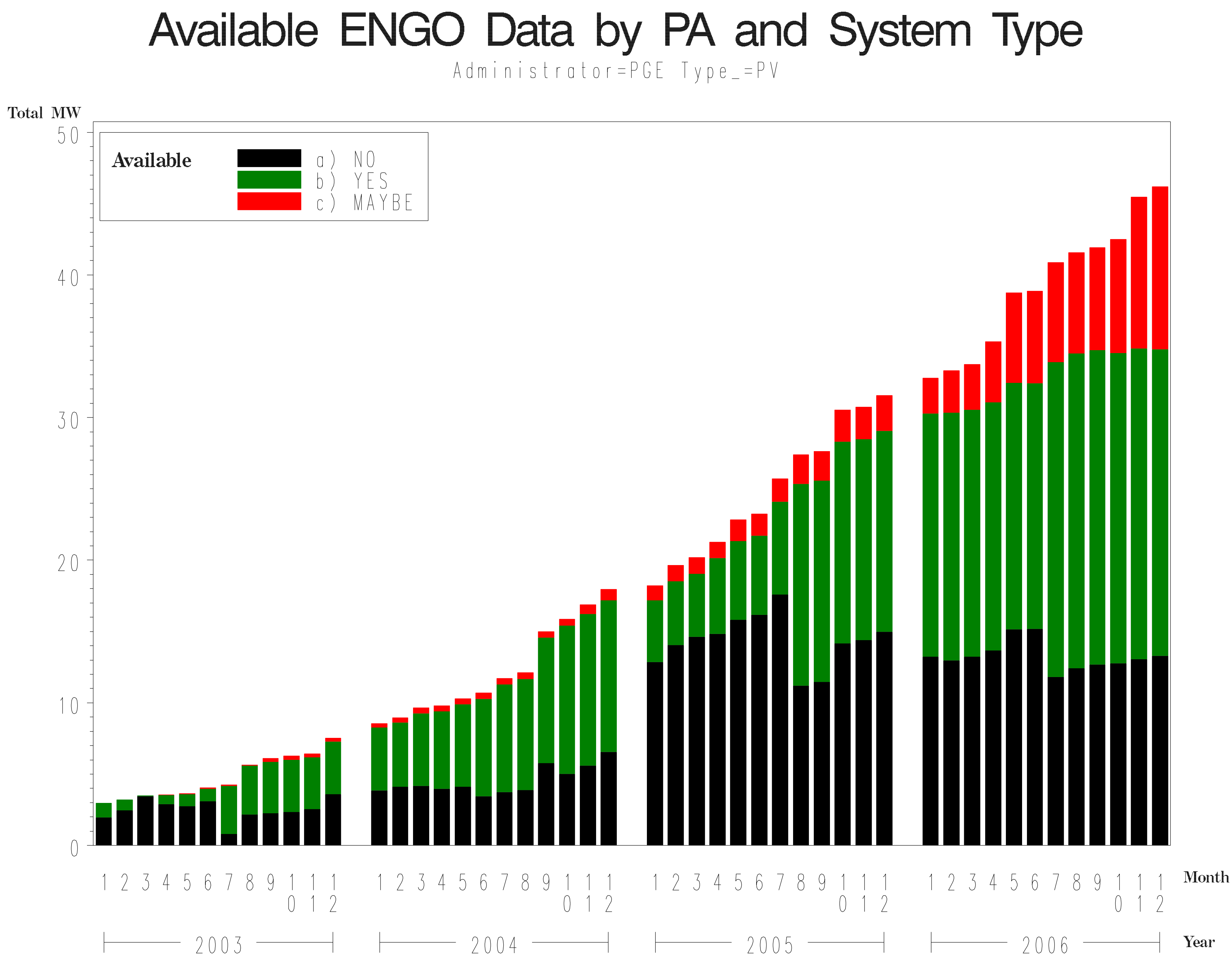


Available ENGO Data by PA and System Type
Administrator=PGE Type_=Cogen
Total MW
Available
a) NO
b) YES
c) MAYBE
0
10
20
30
40
50
60
Month
Year
2003
2004
2005
2006

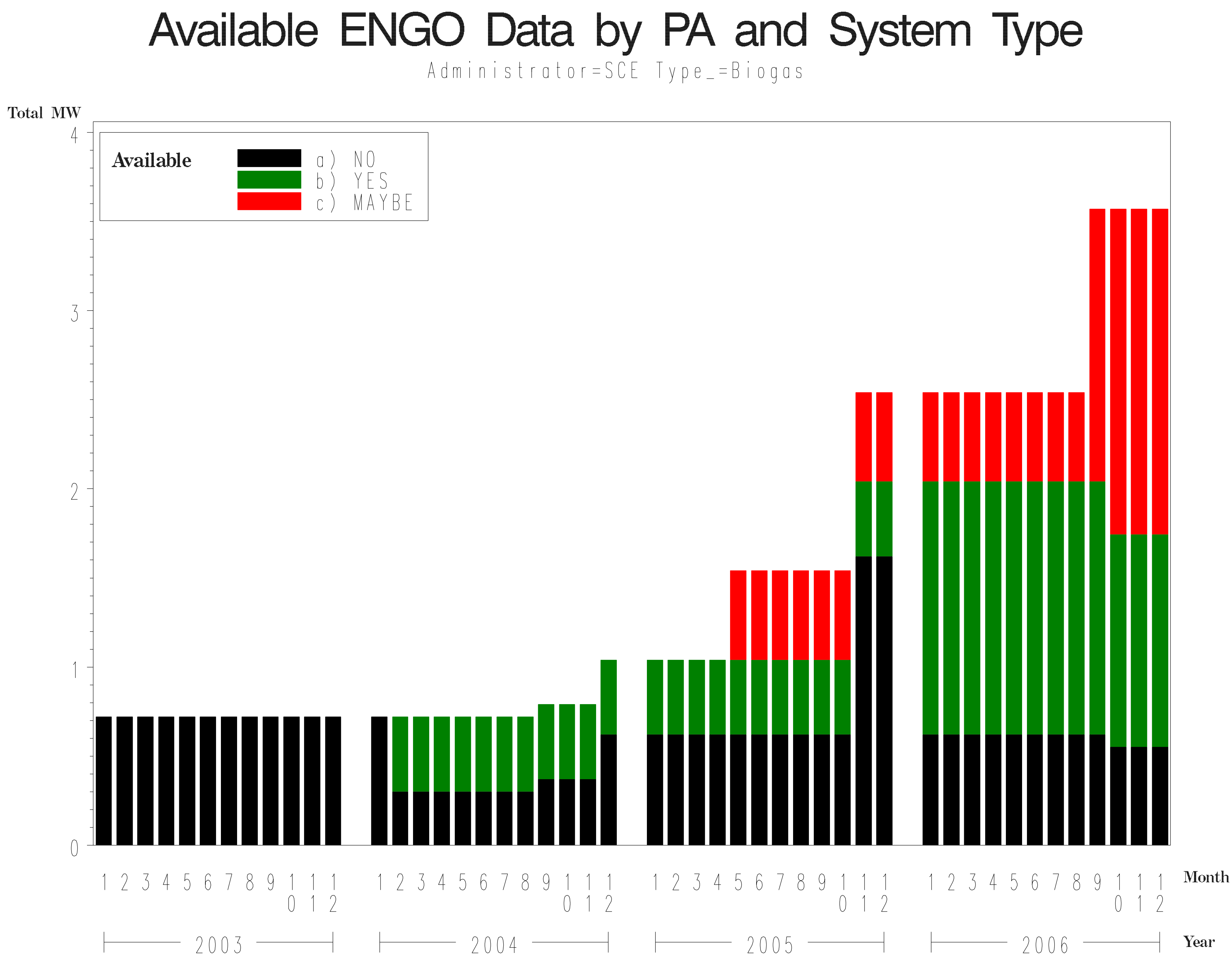
Available ENGO Data by PA and System Type

Administrator=PGE Type_=FC





Available ENGO Data by PA and System Type
Administrator=PGE Type_=PV
Total MW
0
10
20
30
40
50
Available
a) NO
b) YES
c) MAYBE
1 2 3 4 5 6 7 8 9 10 11 12
Month
2003
2004
2005
2006
Year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Total MW
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1
2
3
4
Available
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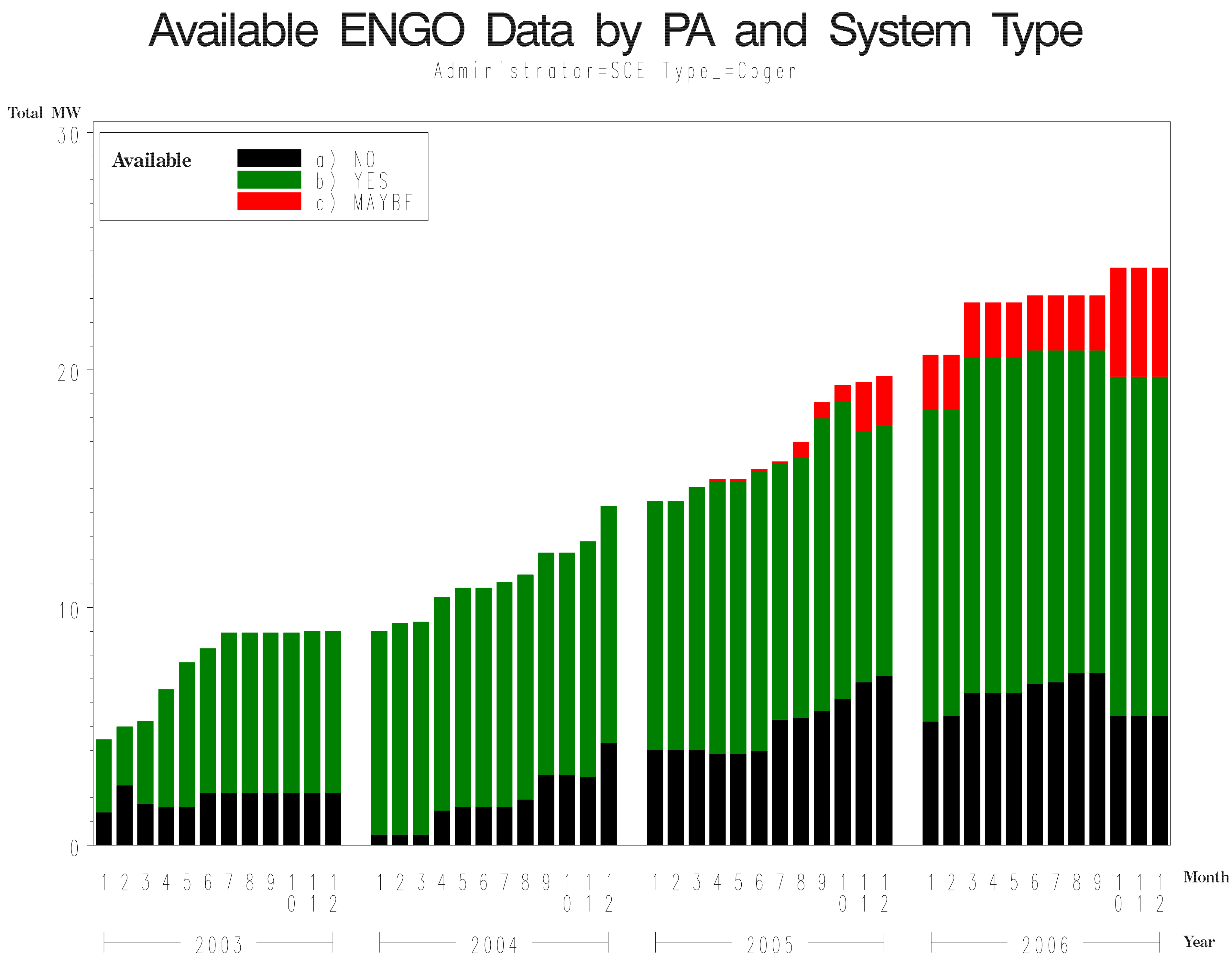
b) YES
c) MAYBE
Month
Year
2003
2004
2005
2006



Available ENGO Data by PA and System Type
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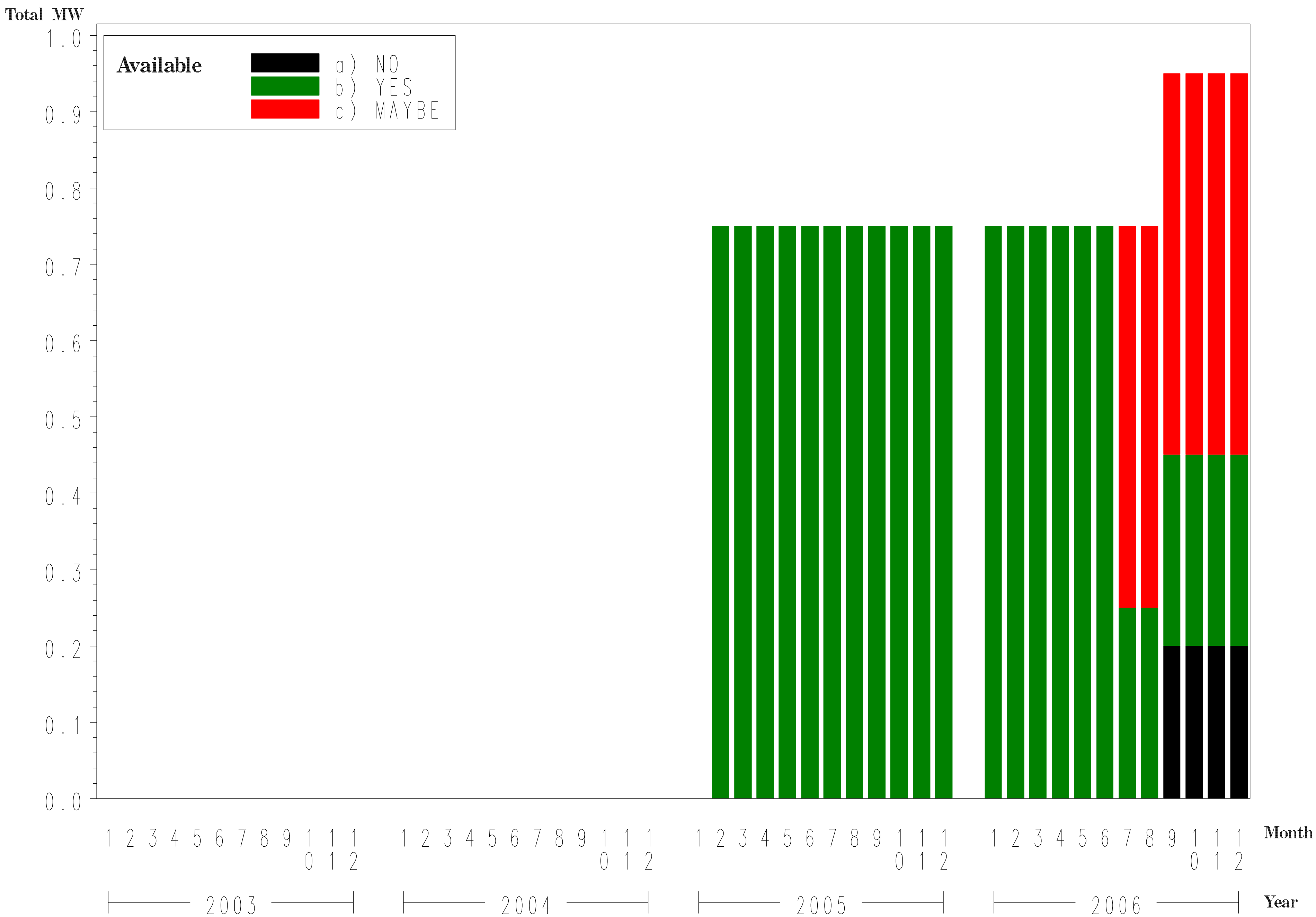
Total MW
30
20
10
0
Available
a) NO
b) YES
c) MAYBE
Month
1 2 3 4 5 6 7 8 9 10 11 12
Year
2003
2004
2005
2006

Available ENGO Data by PA and System Type

Administrator=SCE Type_=FC



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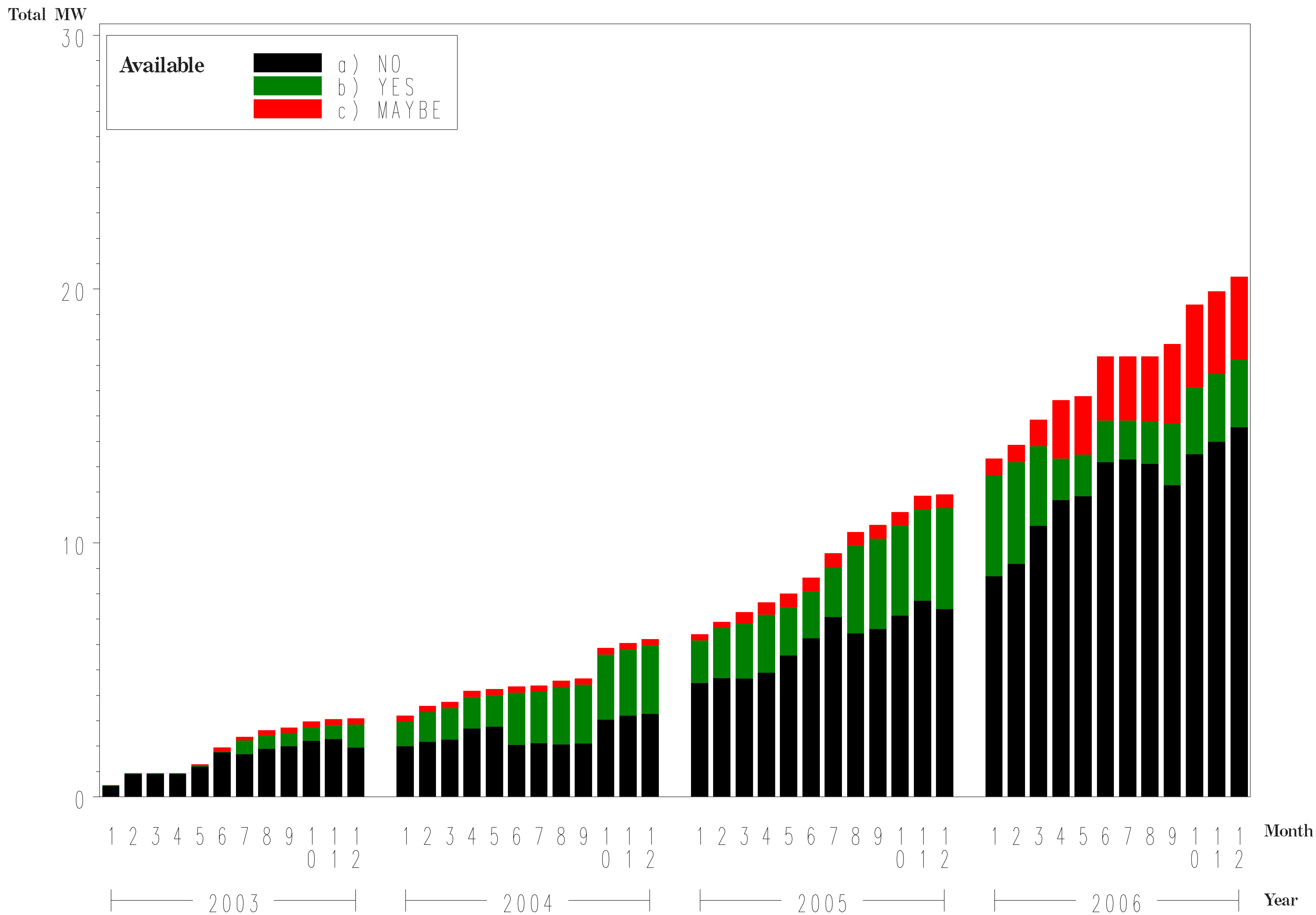

Available ENGO Data by PA and System Type

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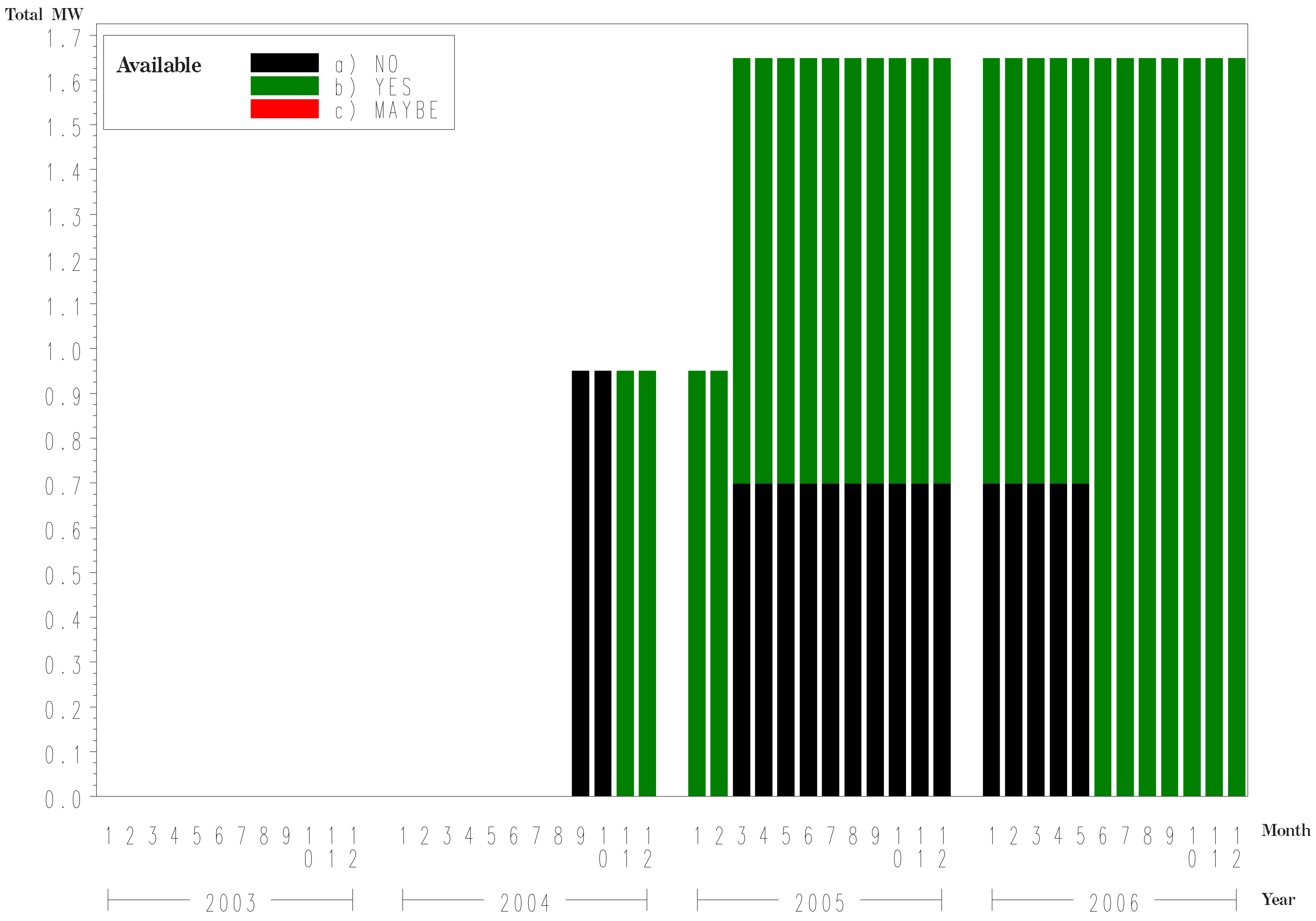

Available ENGO Data by PA and System Type

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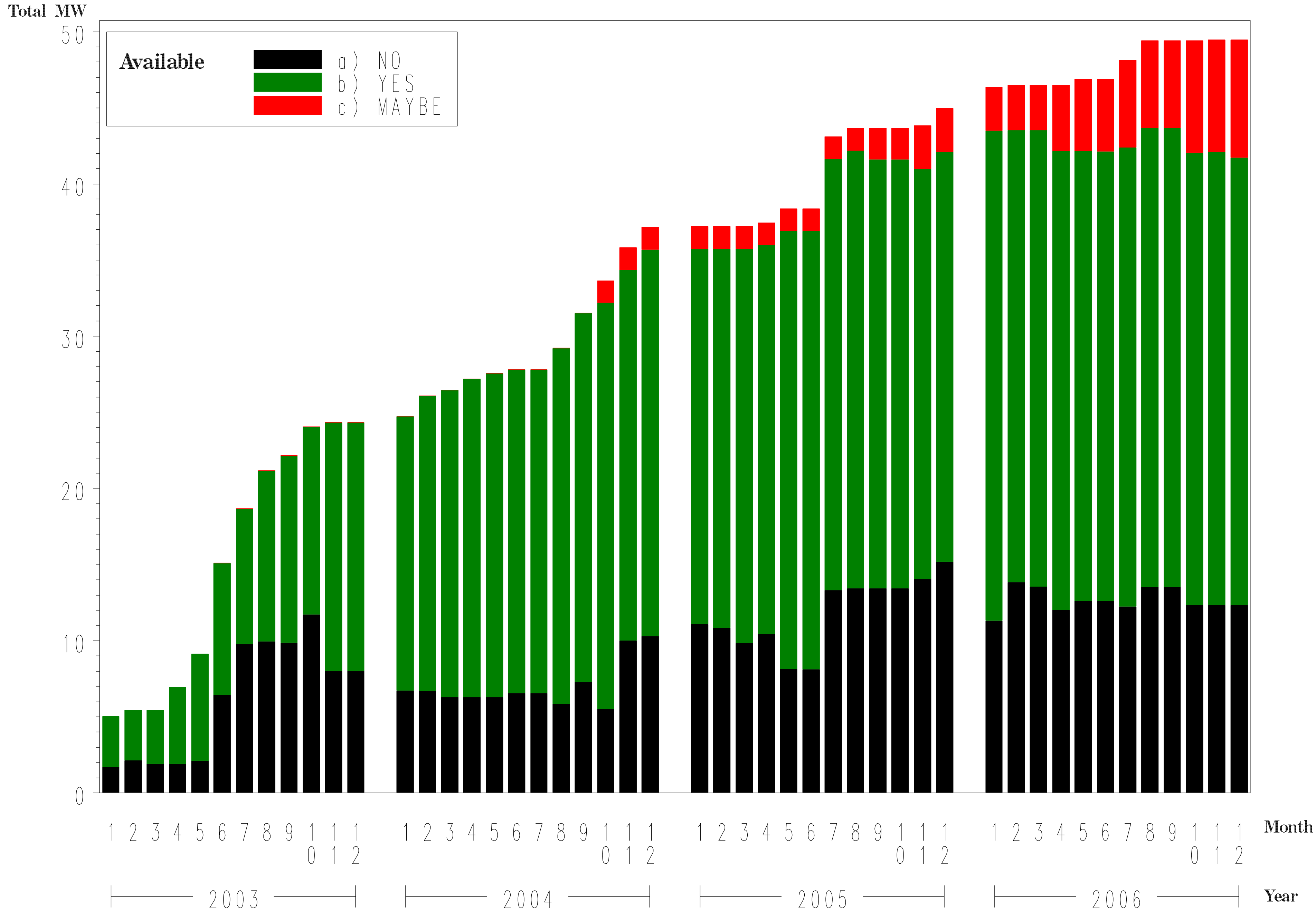
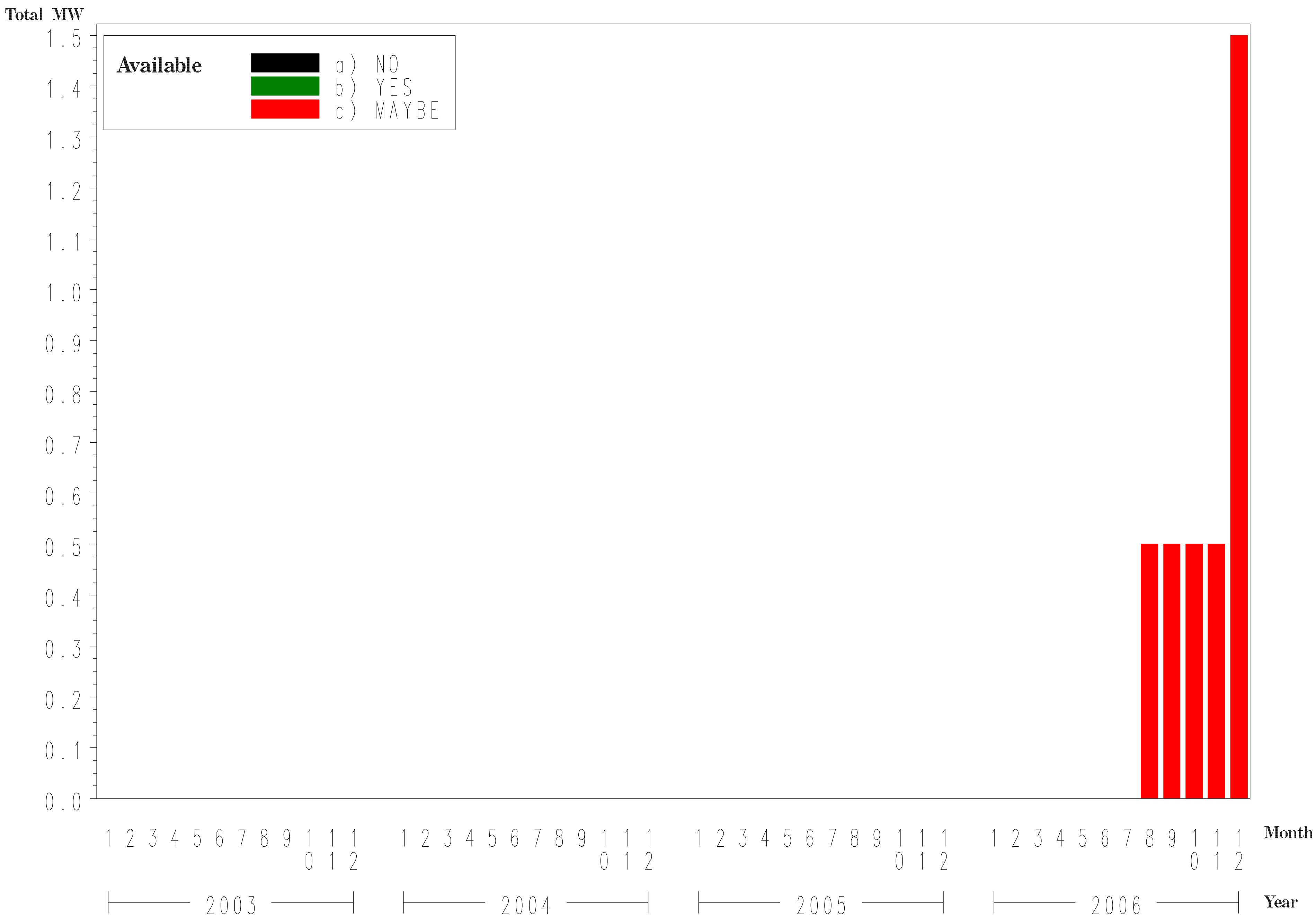


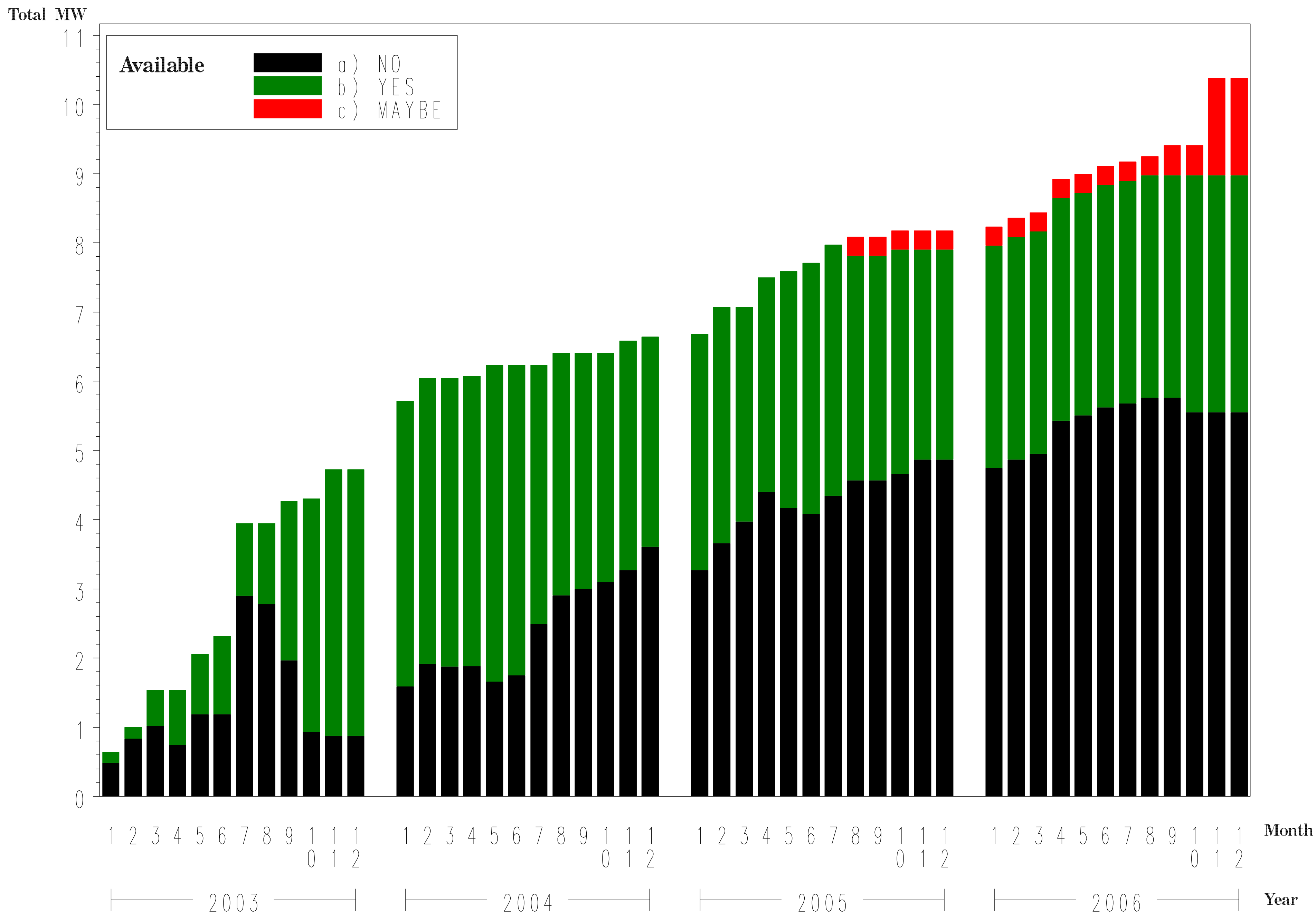
Available ENGO Data by PA and System Type

Administrator=SCG Type_=FC



Available ENGO Data by PA and System Type

Administrator=SCG Type_=PV



Available ENGO Data by PA and System Type

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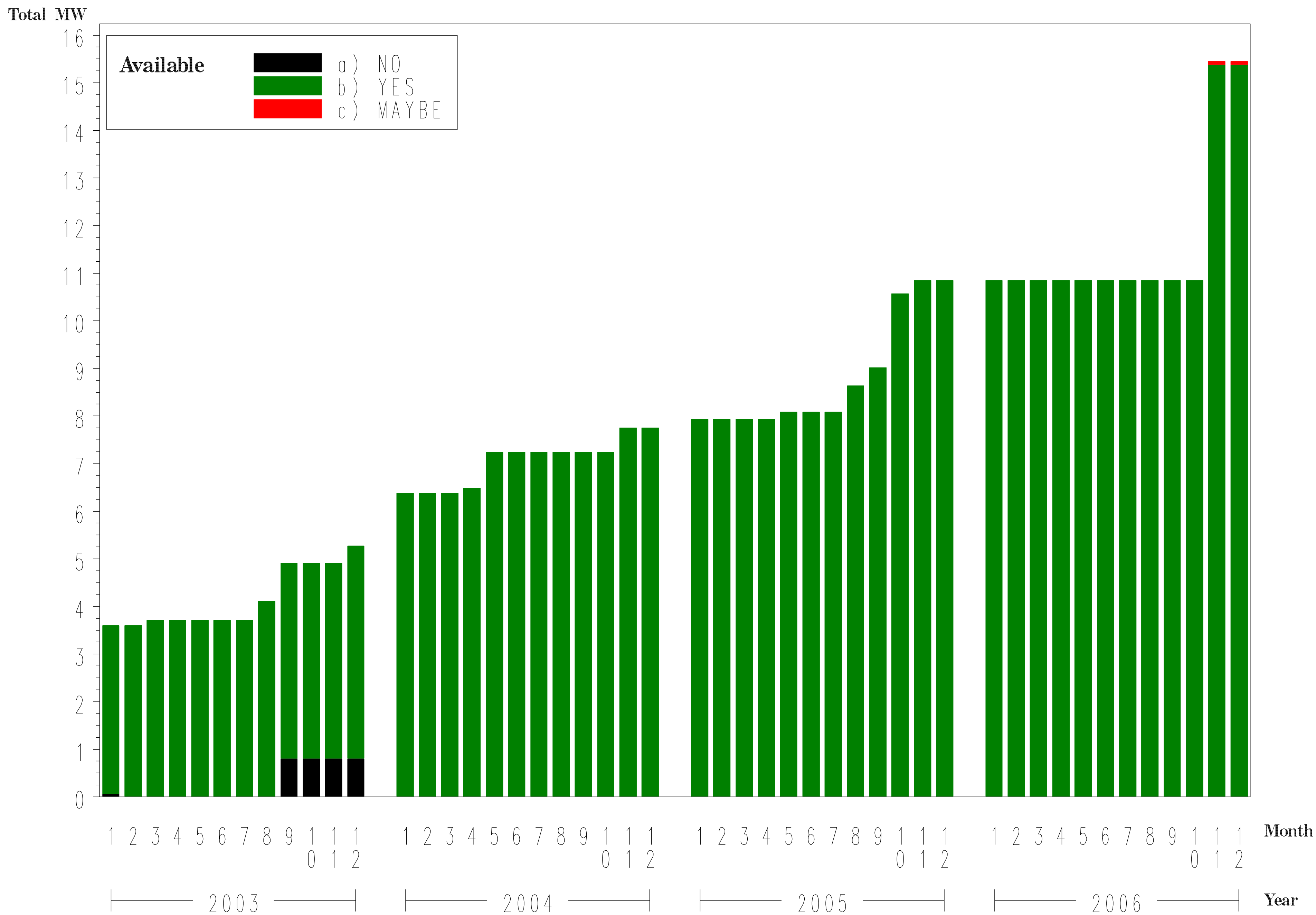

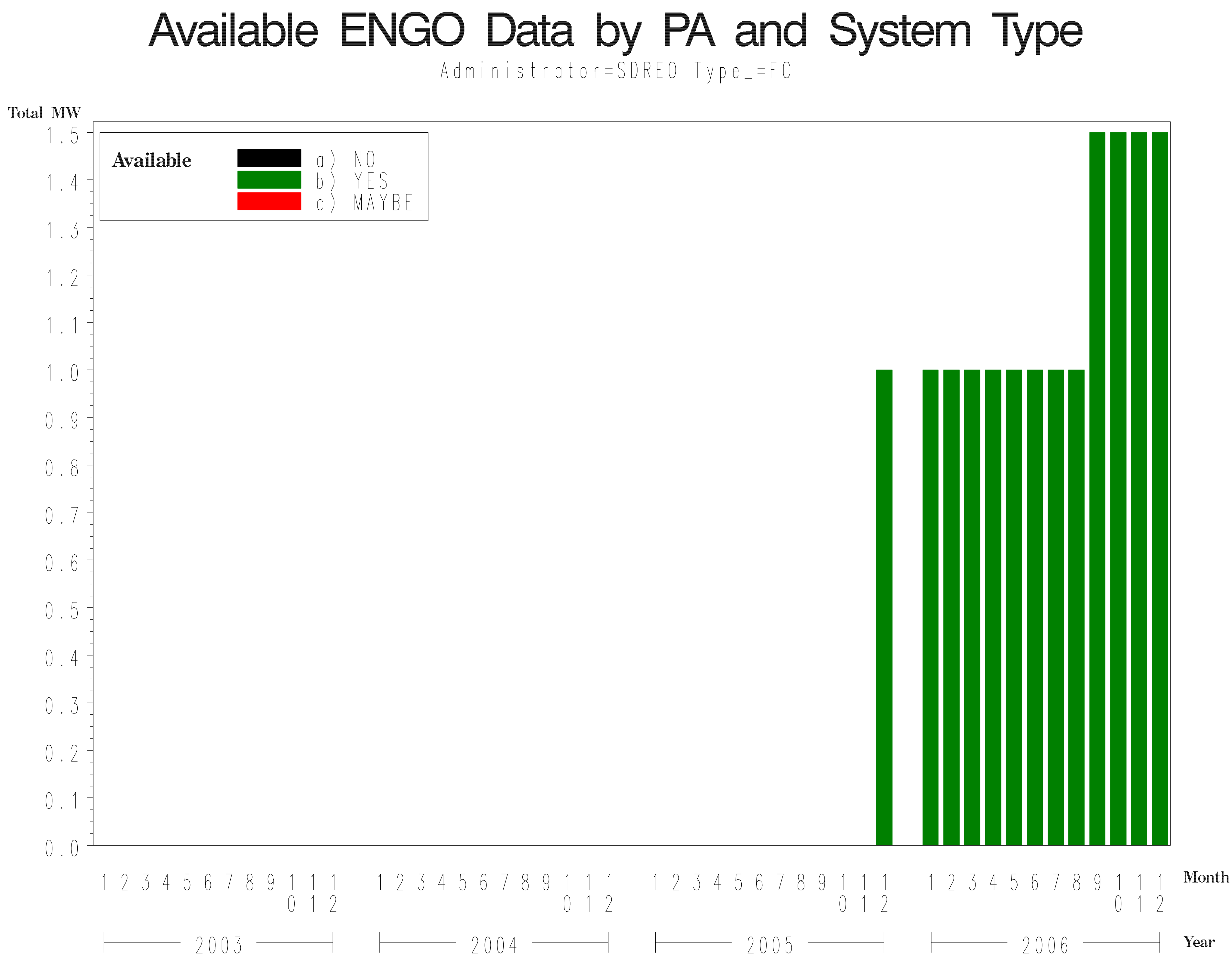

Available ENGO Data by PA and System Type
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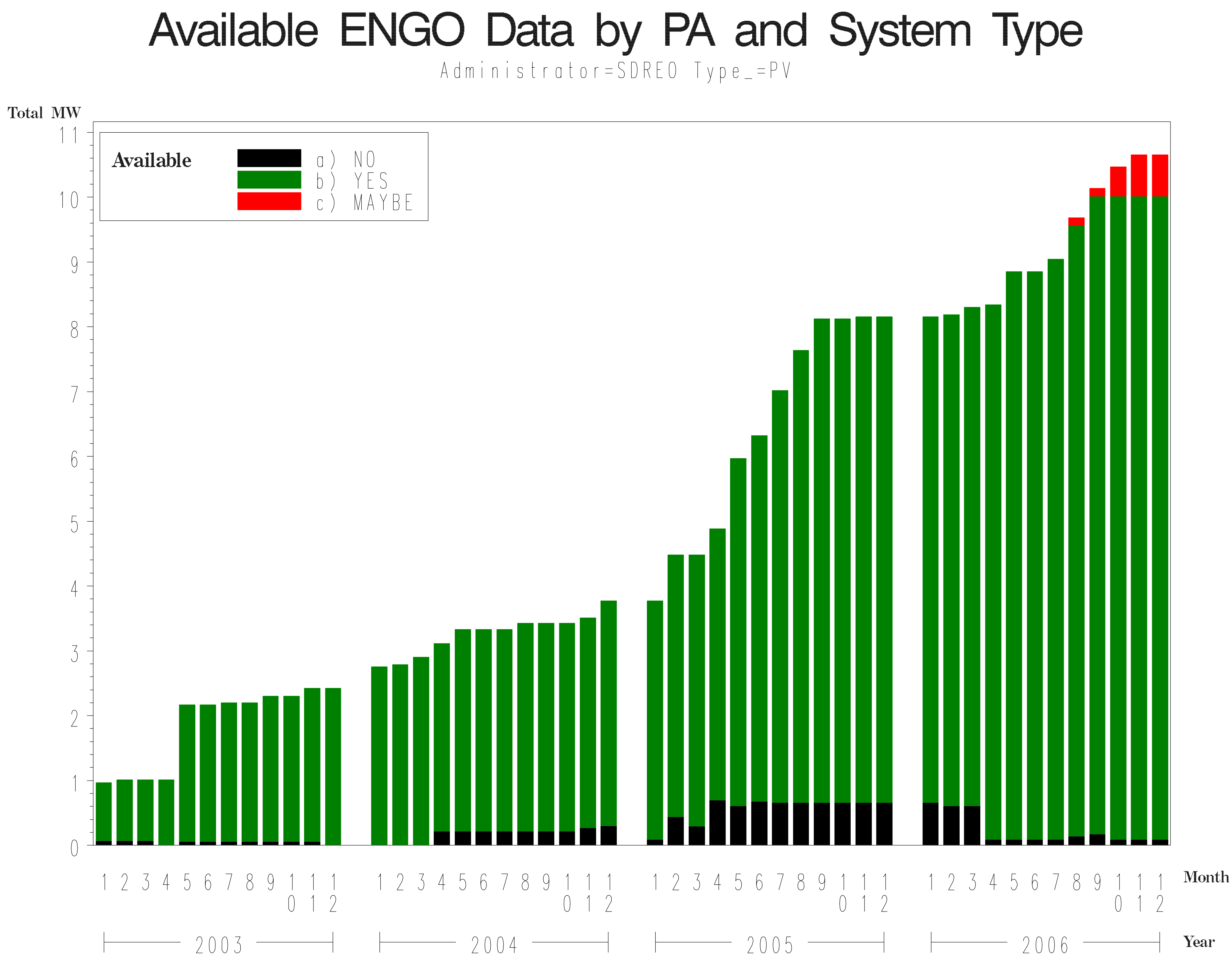
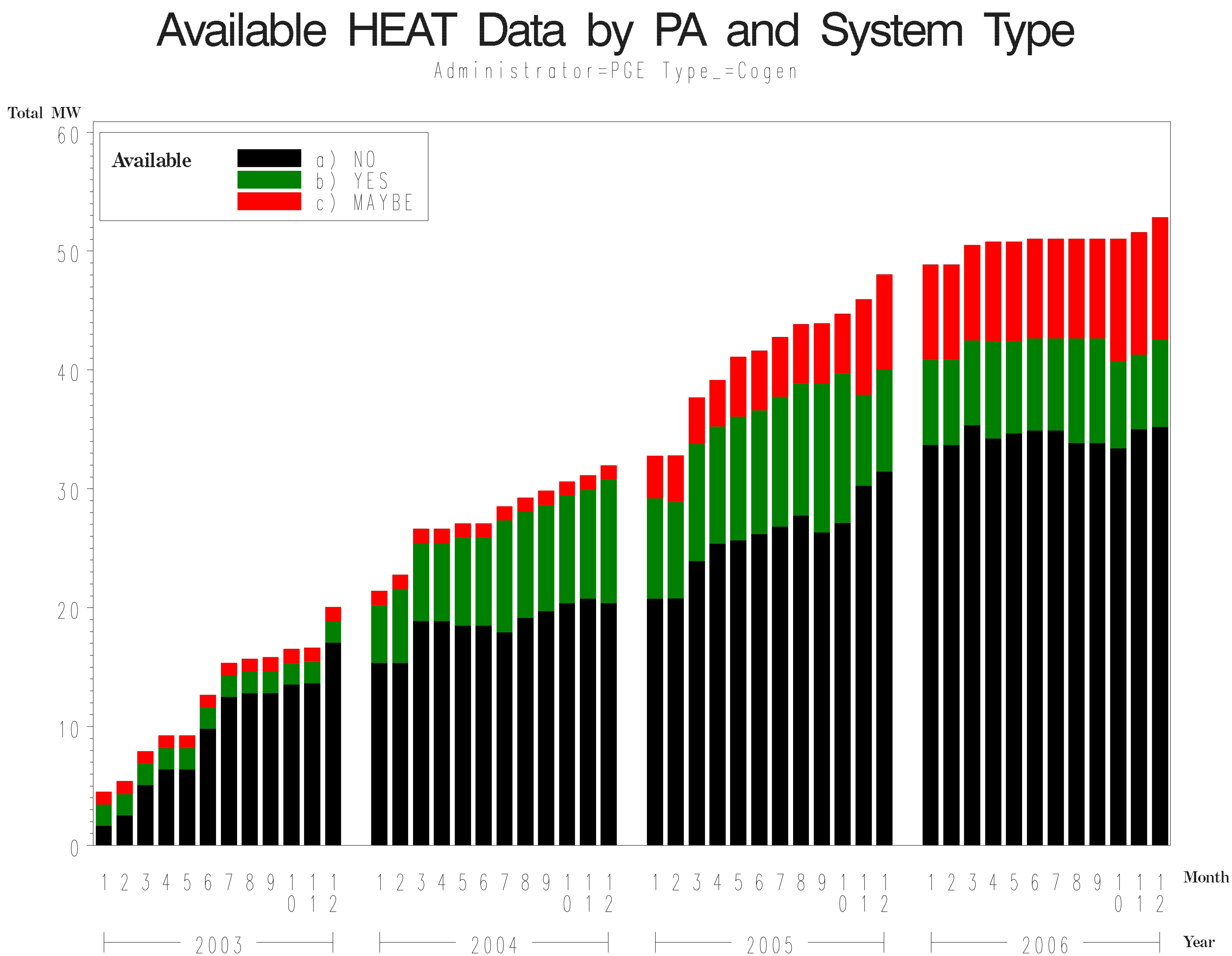
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Available
a) NO
b) YES
c) MAYBE
1 2 3 4 5 6 7 8 9 10 11 12
Month
2003
2004
2005
2006
Year


Available ENGO Data by PA and System Type
Administrator=SDREO Type_=PV
Total MW
Available
a) NO
b) YES
c) MAYBE
0
1
2
3
4
5
6
7
8
9
10
11
Month
Year
2003
2004
2005
2006


Available HEAT Data by PA and System Type
Administrator=PGE Type_=Cogen
Total MW
Available
a) NO
b) YES
c) MAYBE
0
10
20
30
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Month
Year
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2004
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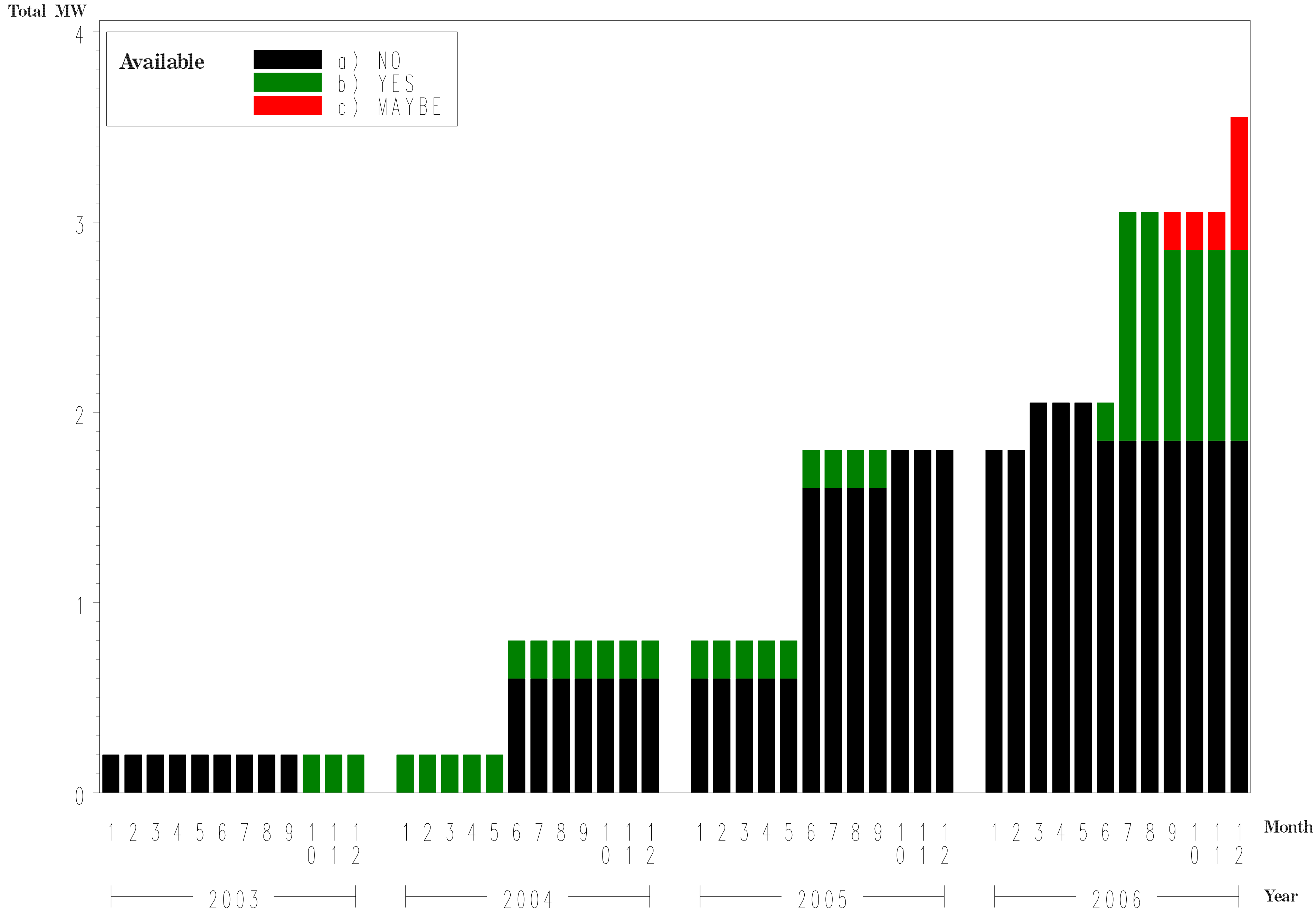
2006

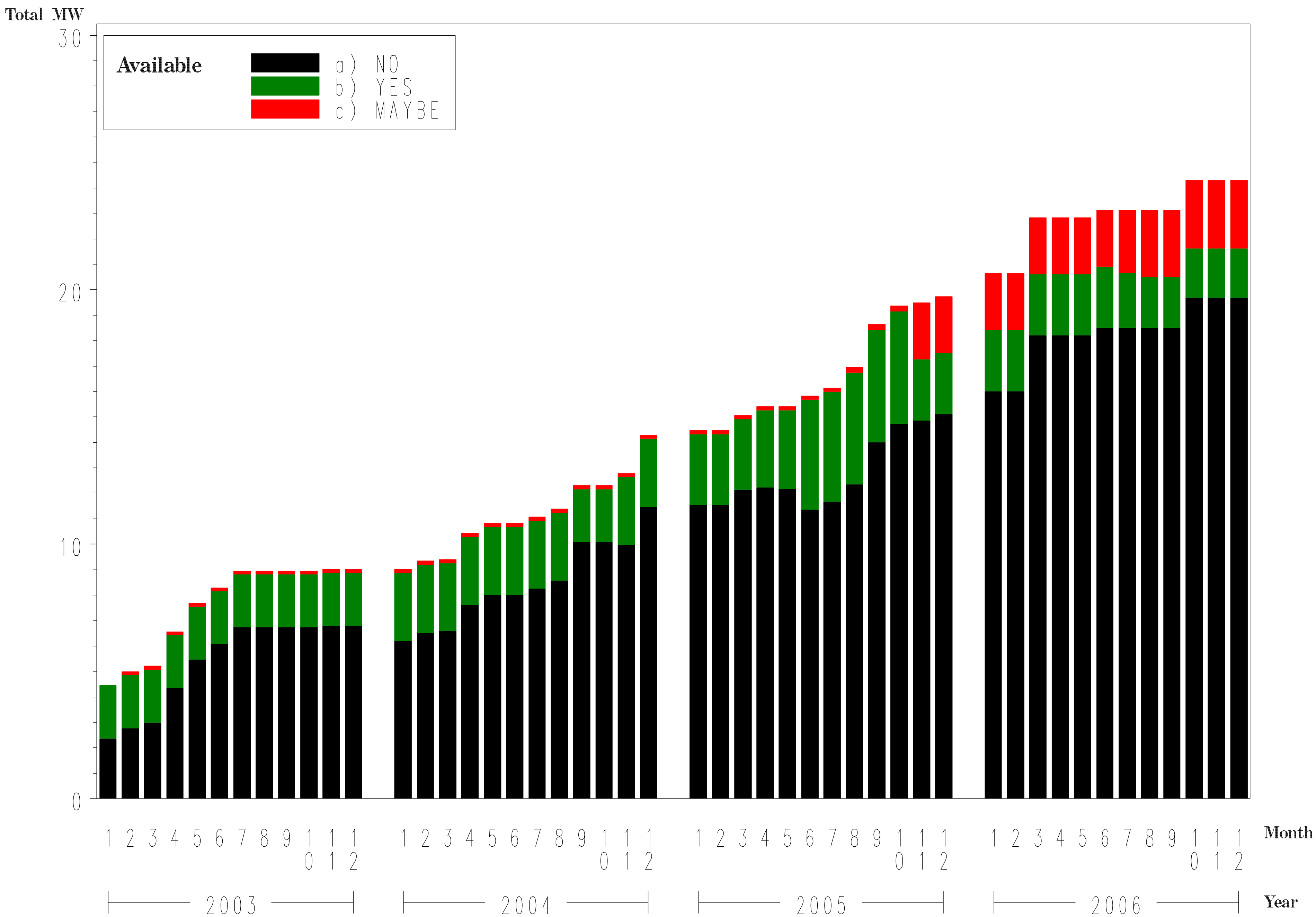
Available HEAT Data by PA and System Type

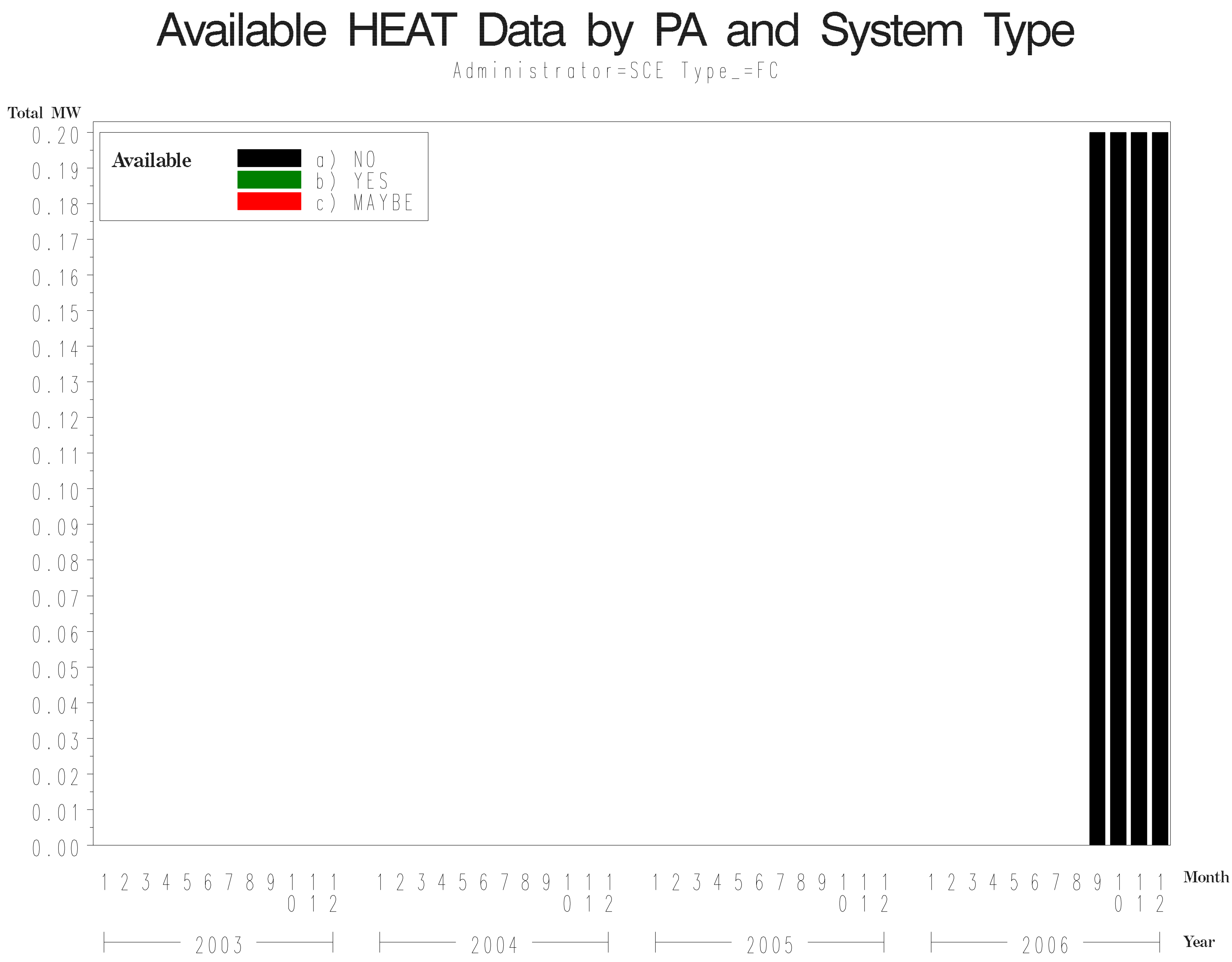
Administrator=PGE Type_=FC



Available HEAT Data by PA and System Type

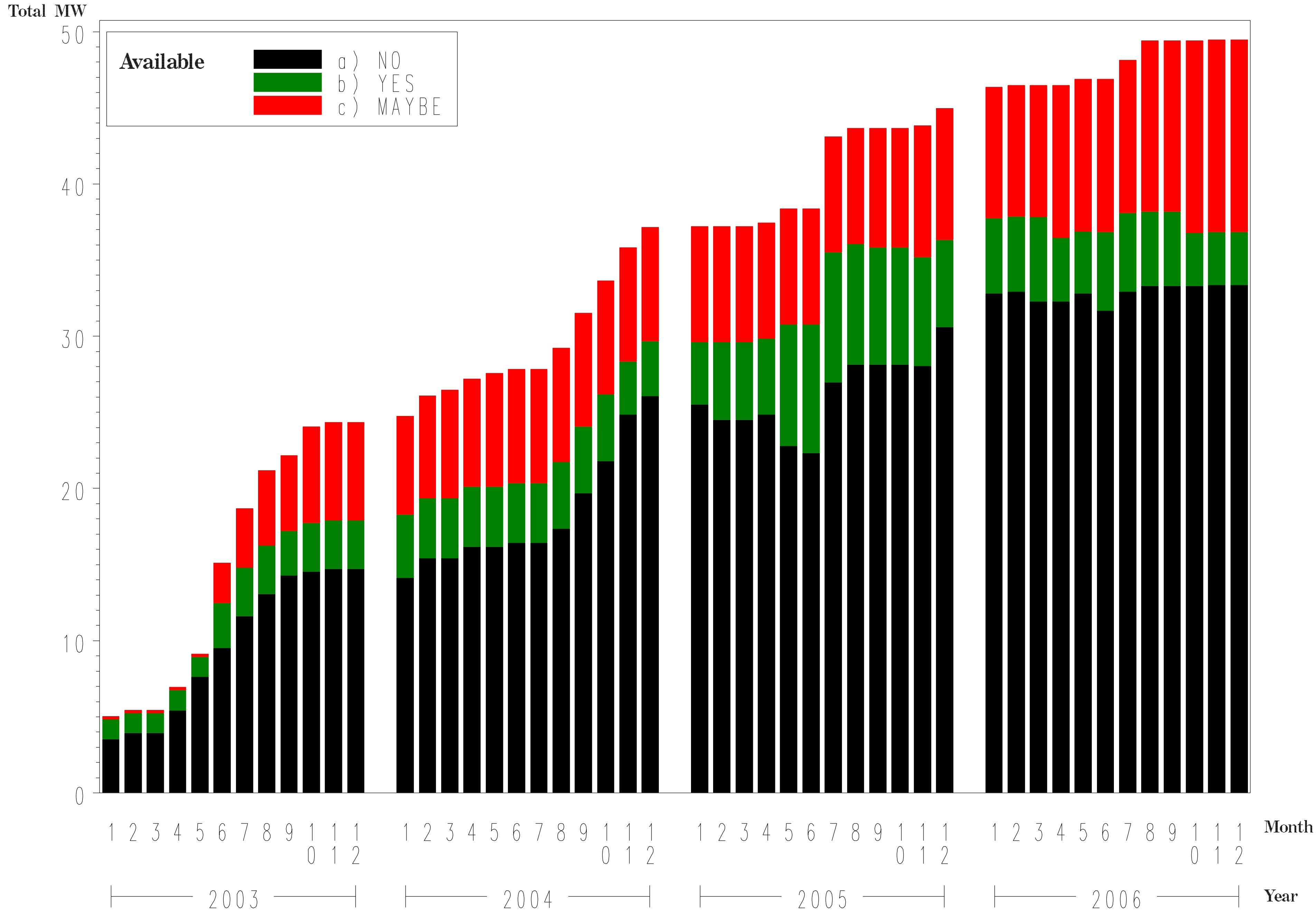
Administrator=SCE Type_=Cogen




Available HEAT Data by PA and System Type
Administrator=SCE Type_=FC
Total MW
0.20
0.19
0.18
0.17
0.16
0.15
0.14
0.13
0.12
0.11
0.10
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
Available
a) NO
b) YES
c) MAYBE
1 2 3 4 5 6 7 8 9 10 11 12
Month
2003
2004
2005
2006
Year

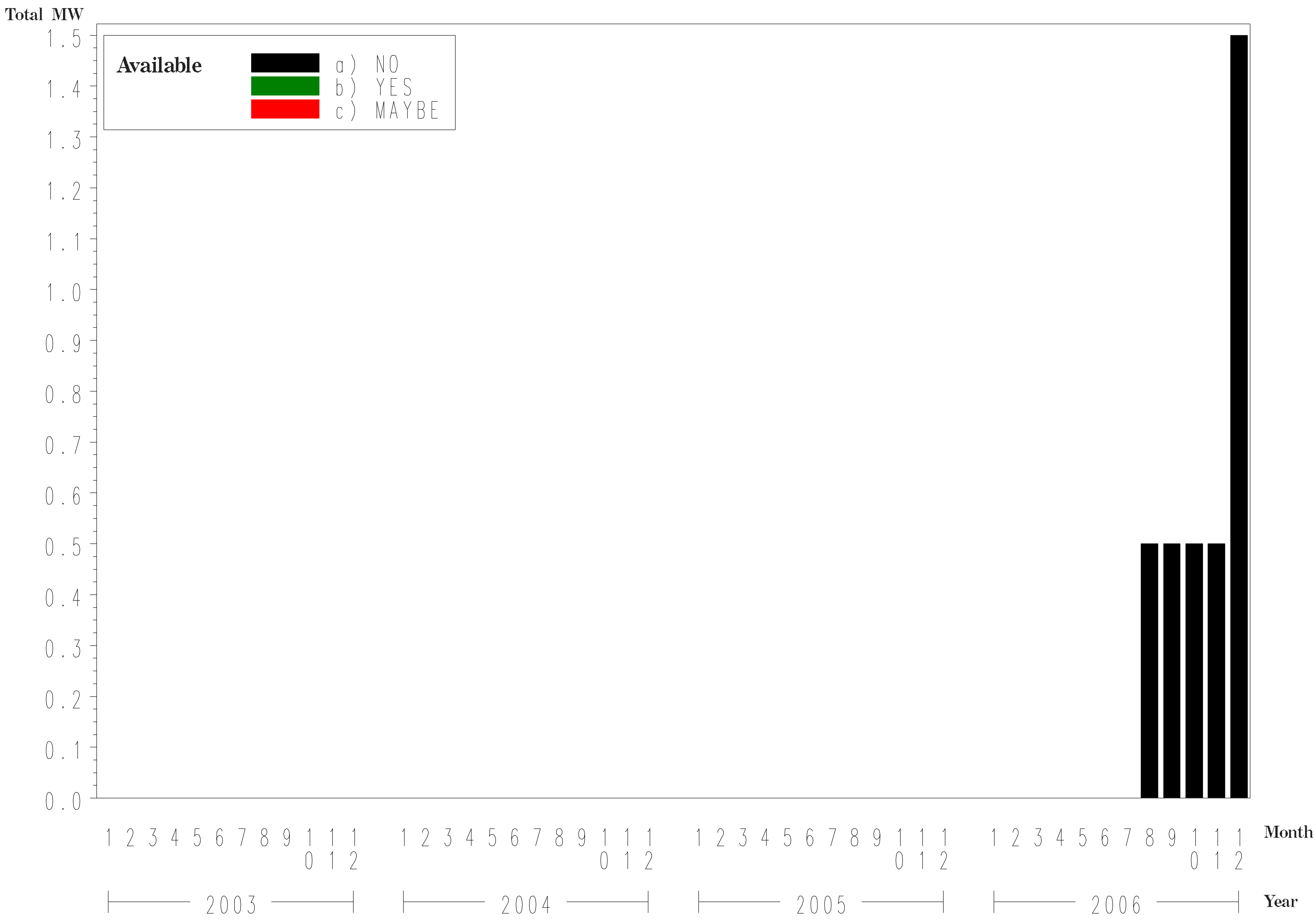
Available HEAT Data by PA and System Type

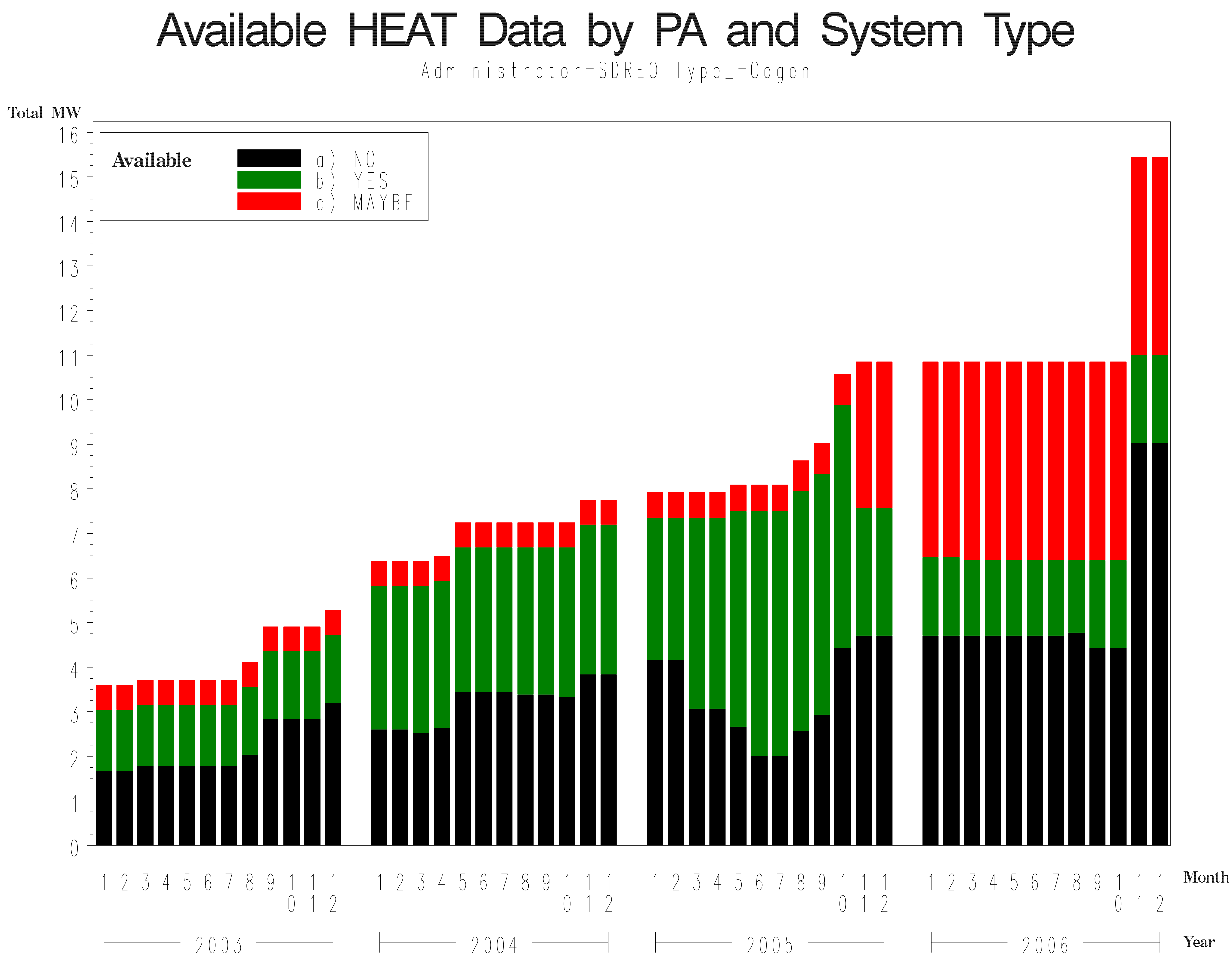
Administrator=SCG Type_=Cogen

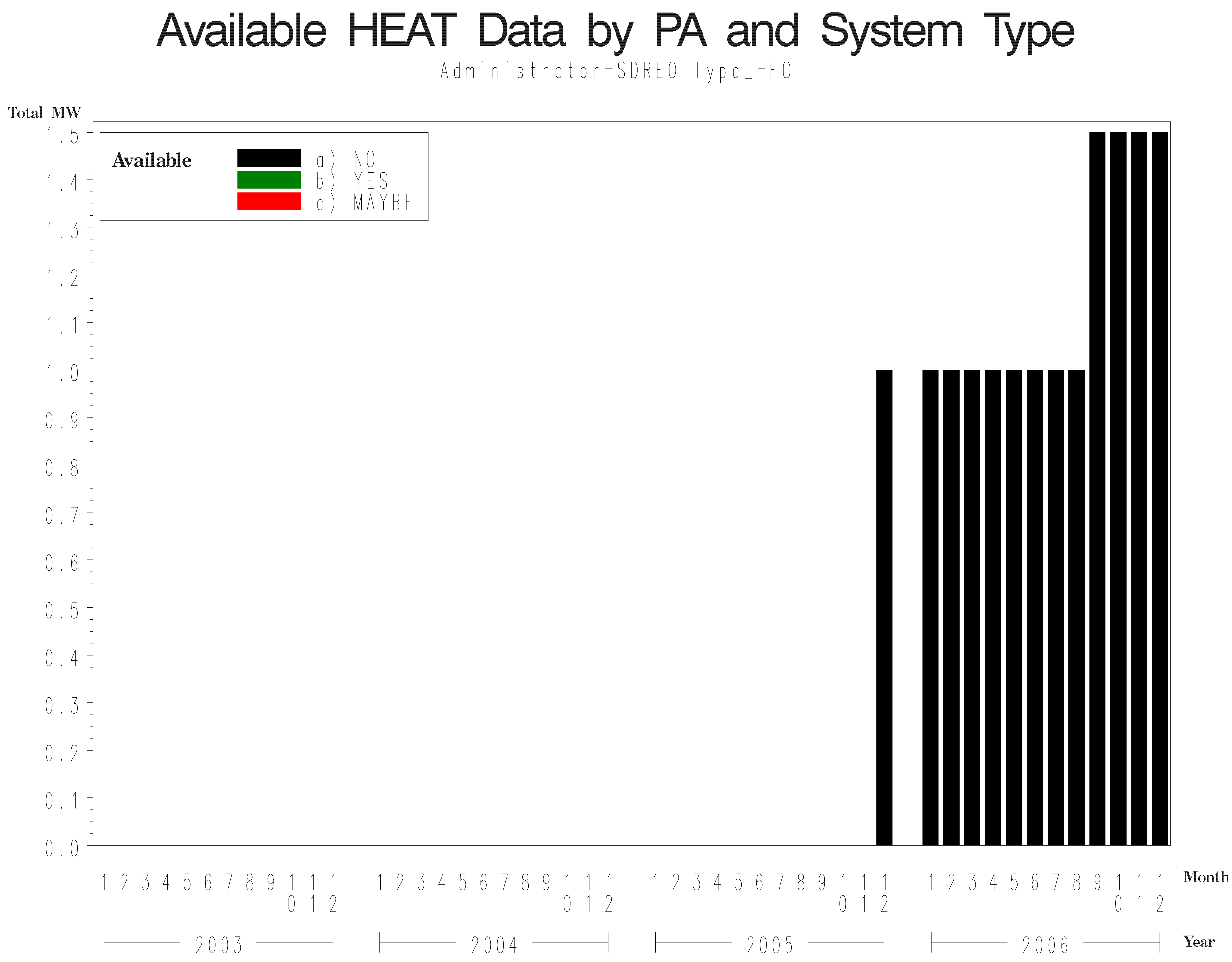


Available HEAT Data by PA and System Type

Administrator=SCG Type_=FC




Available HEAT Data by PA and System Type
Administrator=SDREO Type_=Cogen
Total MW
Available
a) NO
b) YES
c) MAYBE
Month
Year
2003
2004
2005
2006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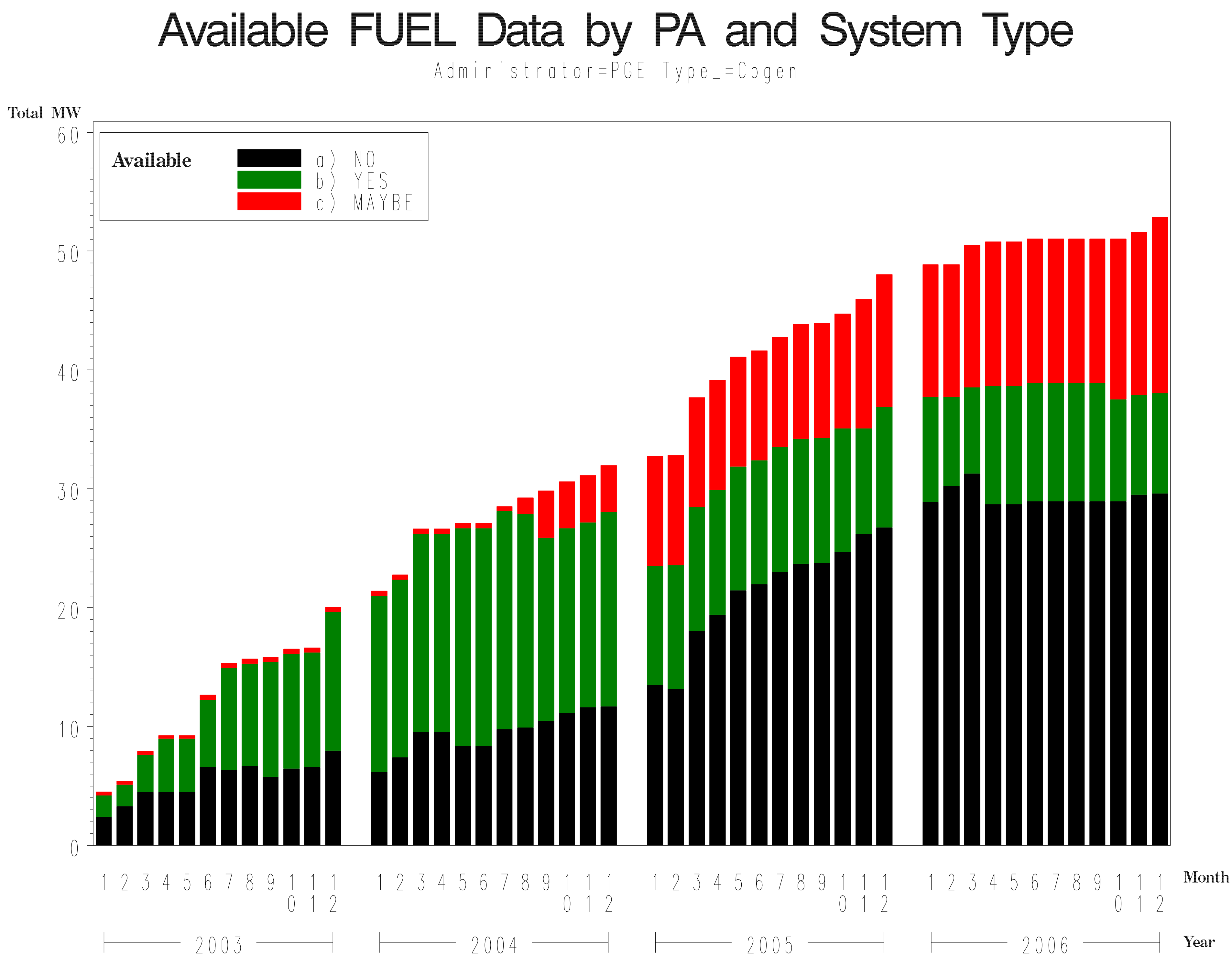
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Available
a) NO
b) YES
c) MAYBE
1 2 3 4 5 6 7 8 9 10 11 12
Month
2003
2004
2005
2006
Year


Available FUEL Data by PA and System Type
Administrator=PGE Type_=Cogen
Total MW
Available
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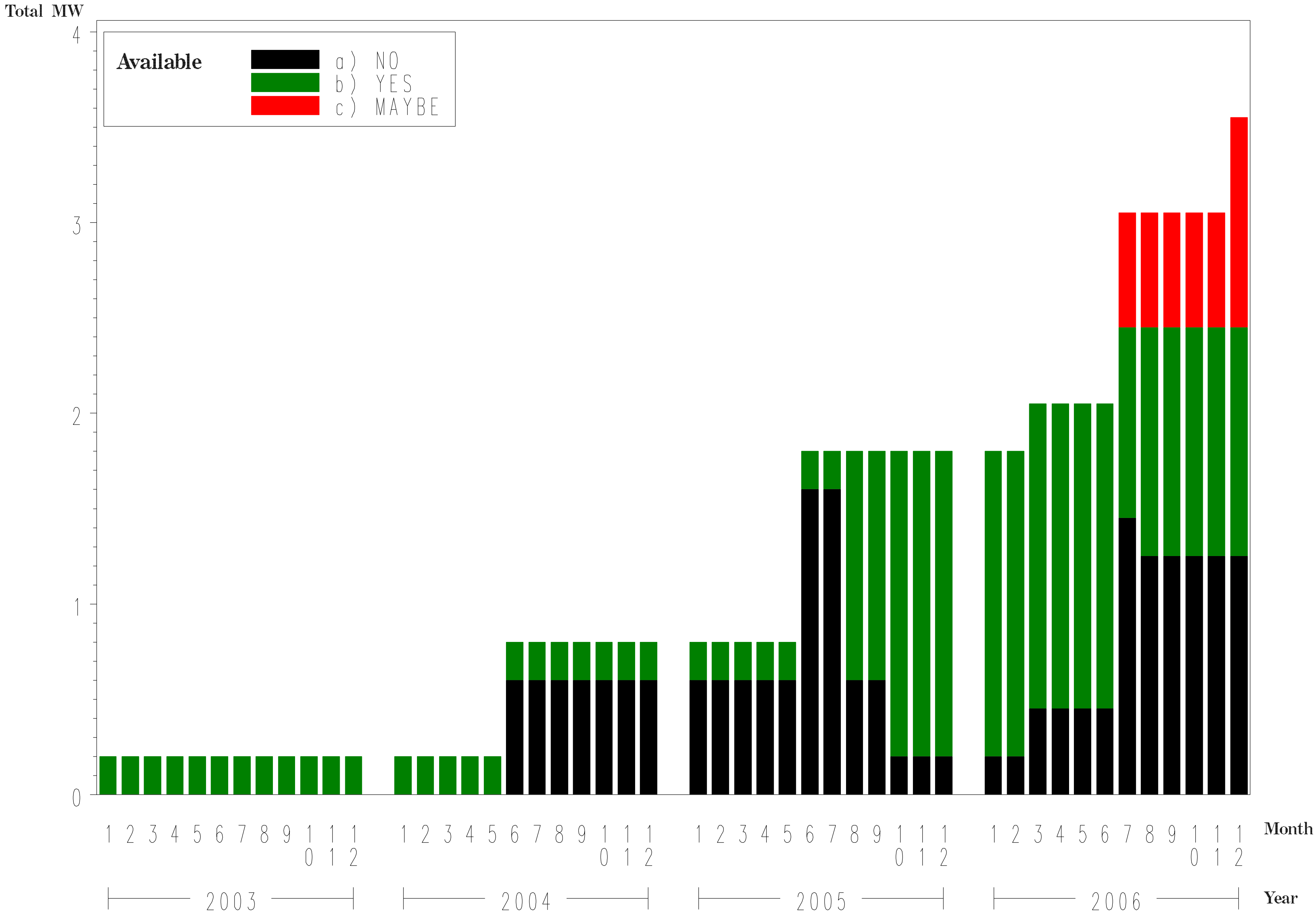
b) YES
c) MAYBE
0
10
20
30
40
50
60
Month
Year
2003
2004
2005
2006

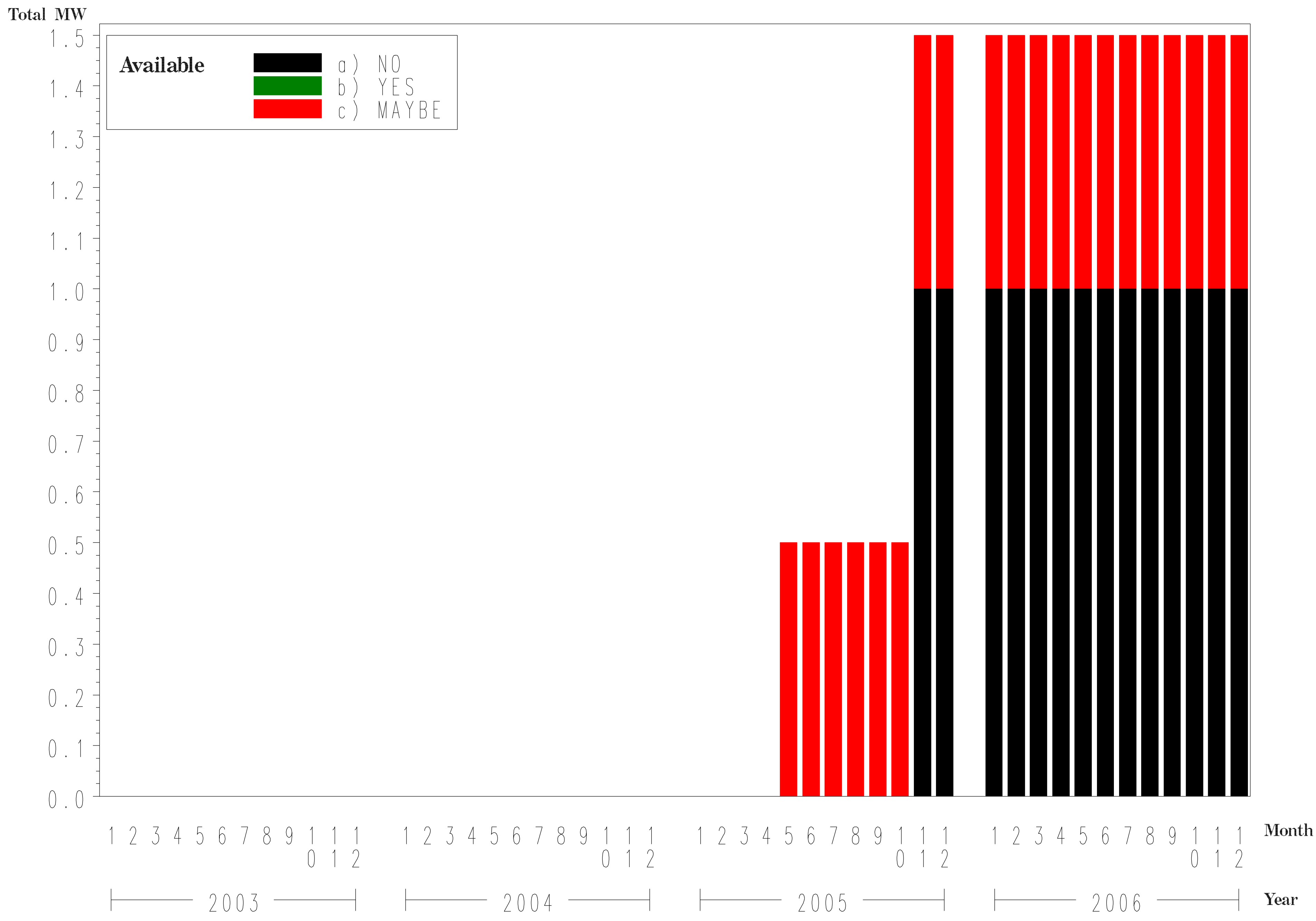
Available FUEL Data by PA and System Type

Administrator=PGE Type_=FC



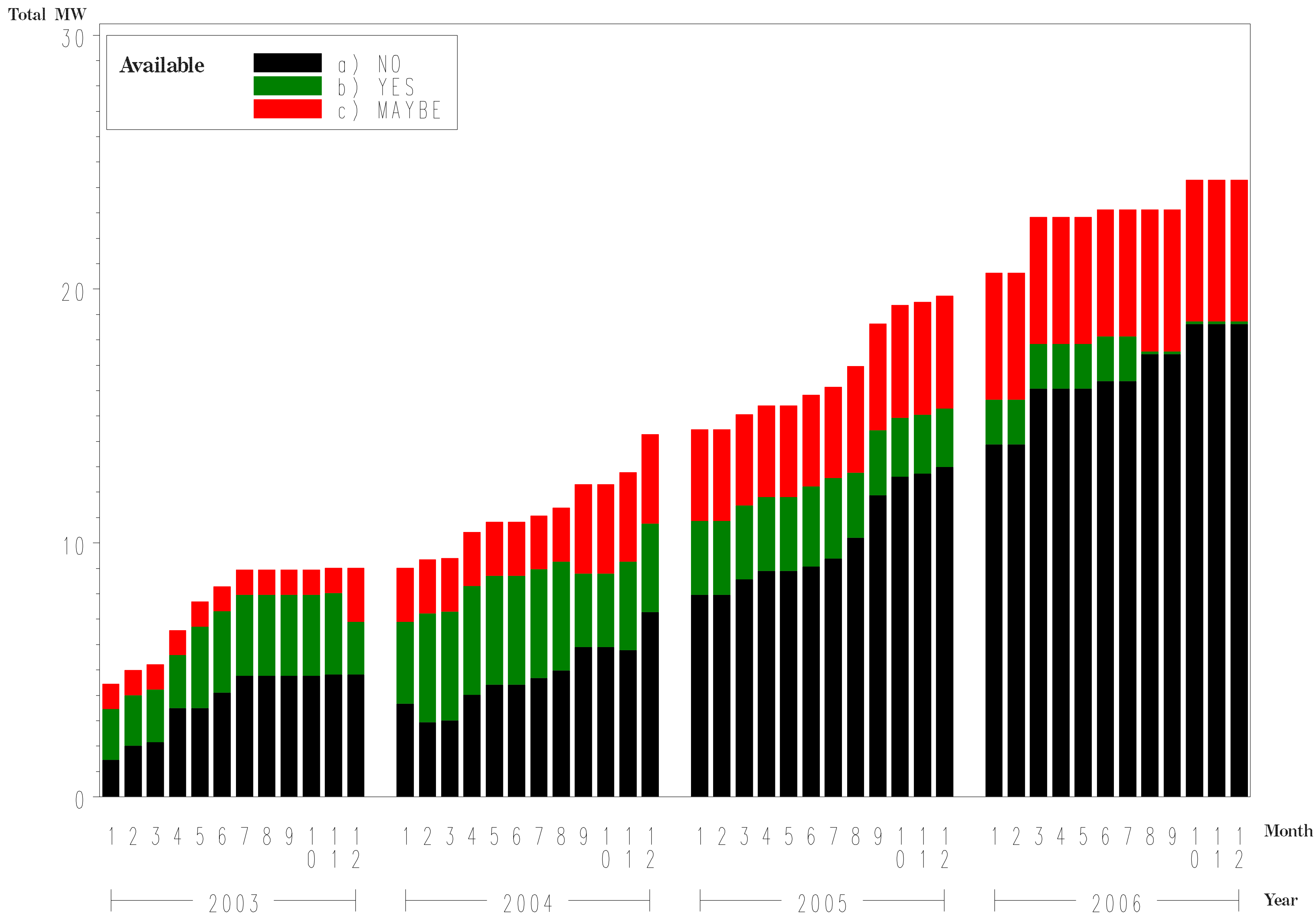
Available FUEL Data by PA and System Type

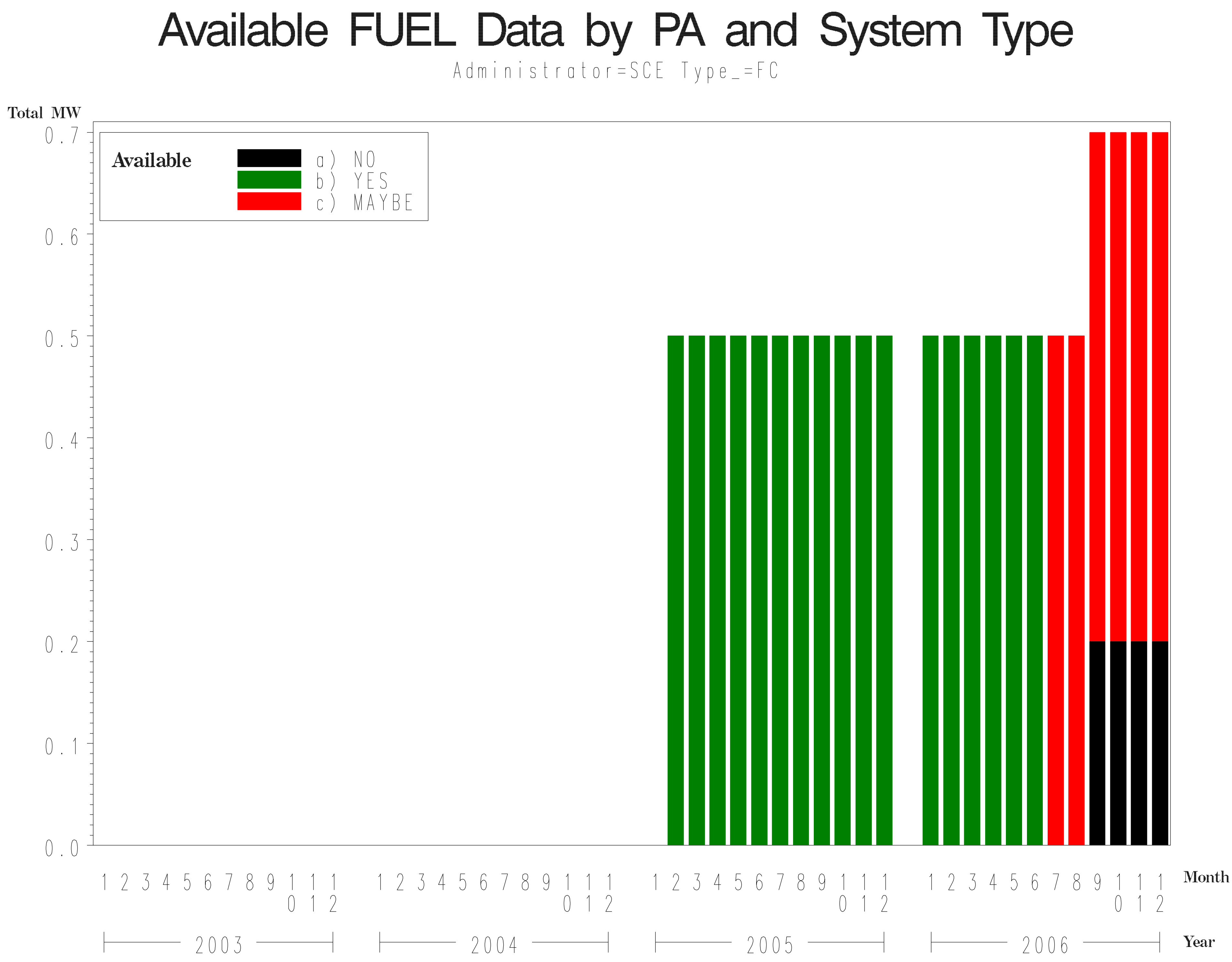
Administrator=SCE Type_=Biogas



Available FUEL Data by PA and System Type

Administrator=SCE Type_=Cogen




Available FUEL Data by PA and System Type
Administrator=SCE Type_=FC
Total MW
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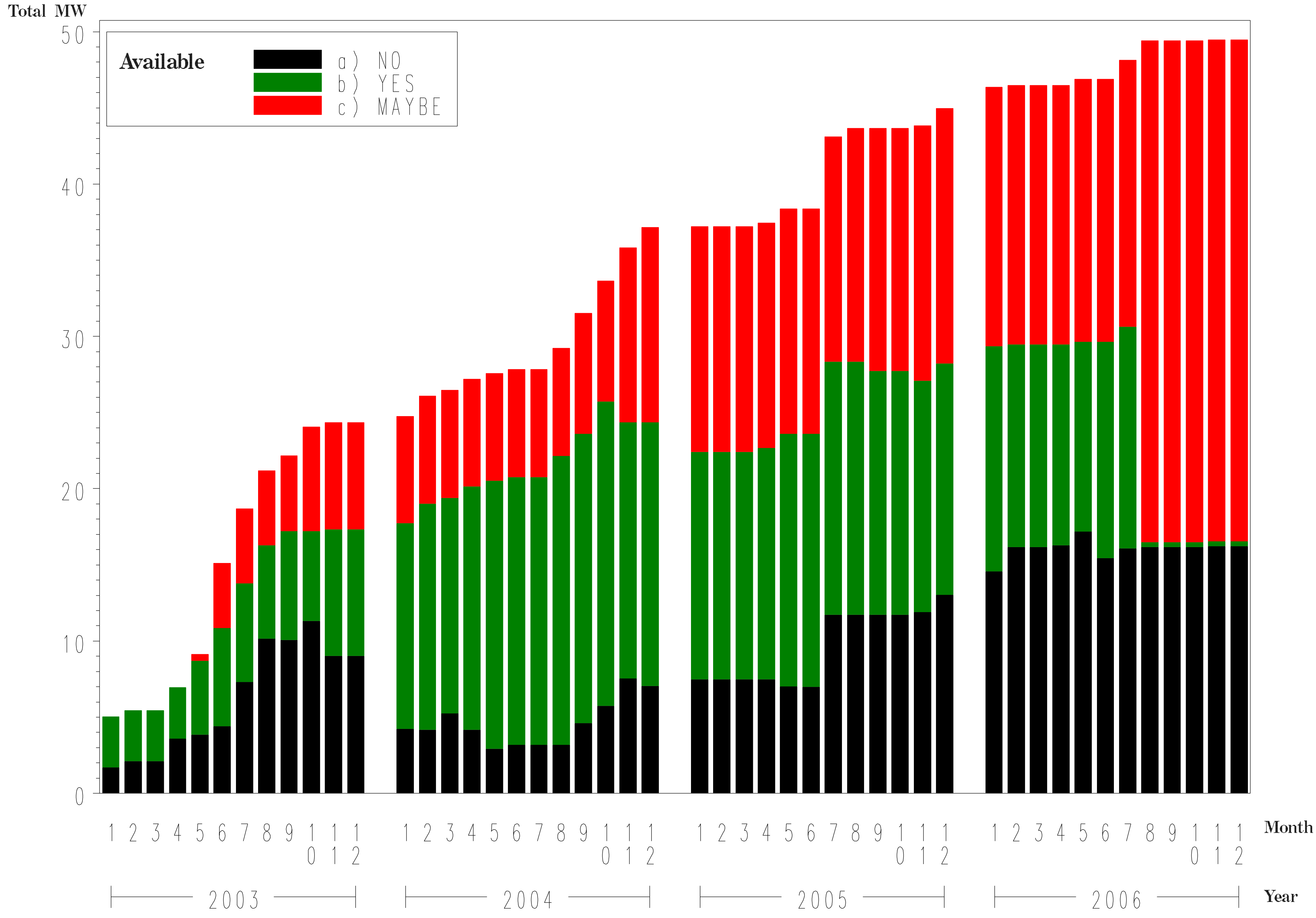
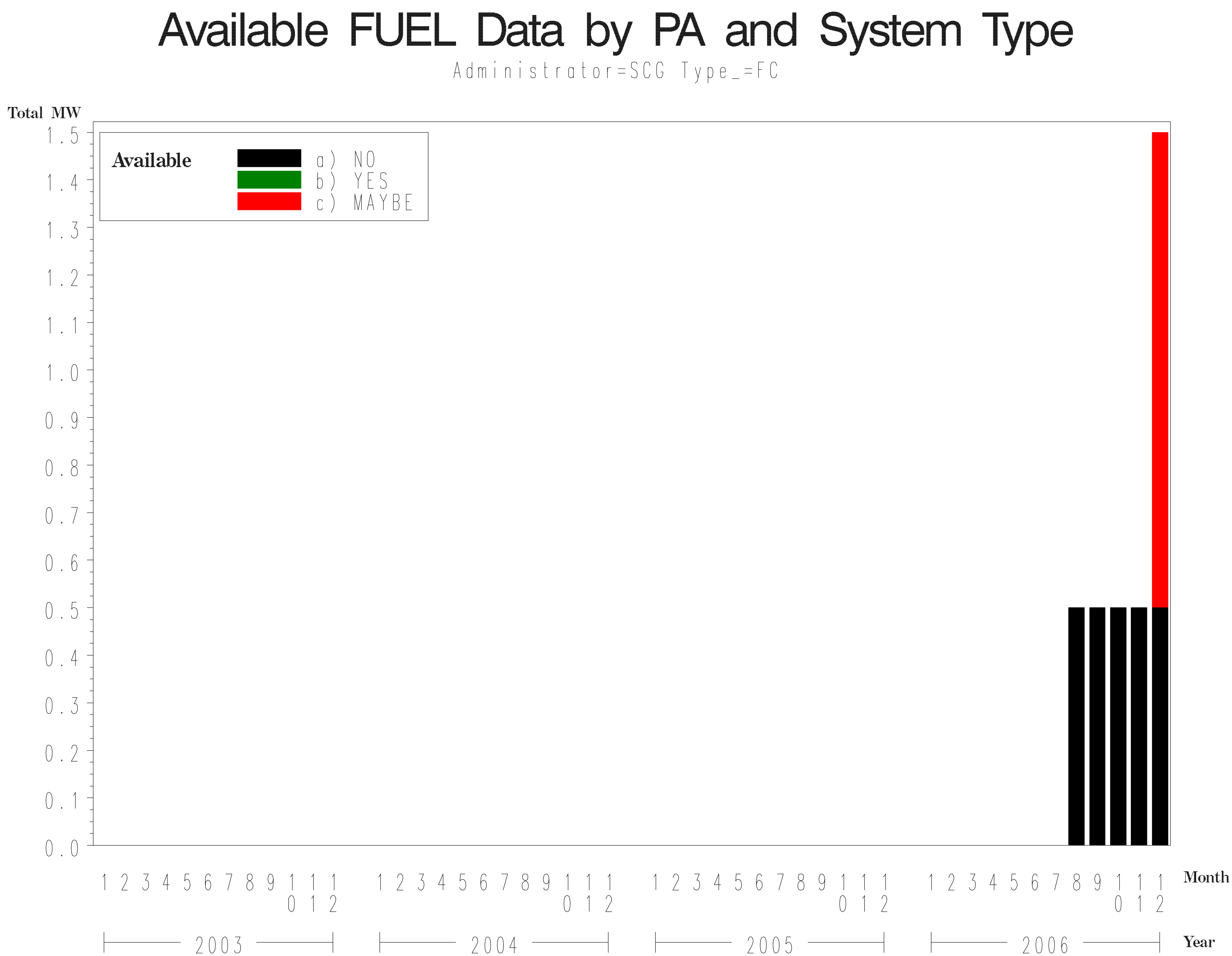
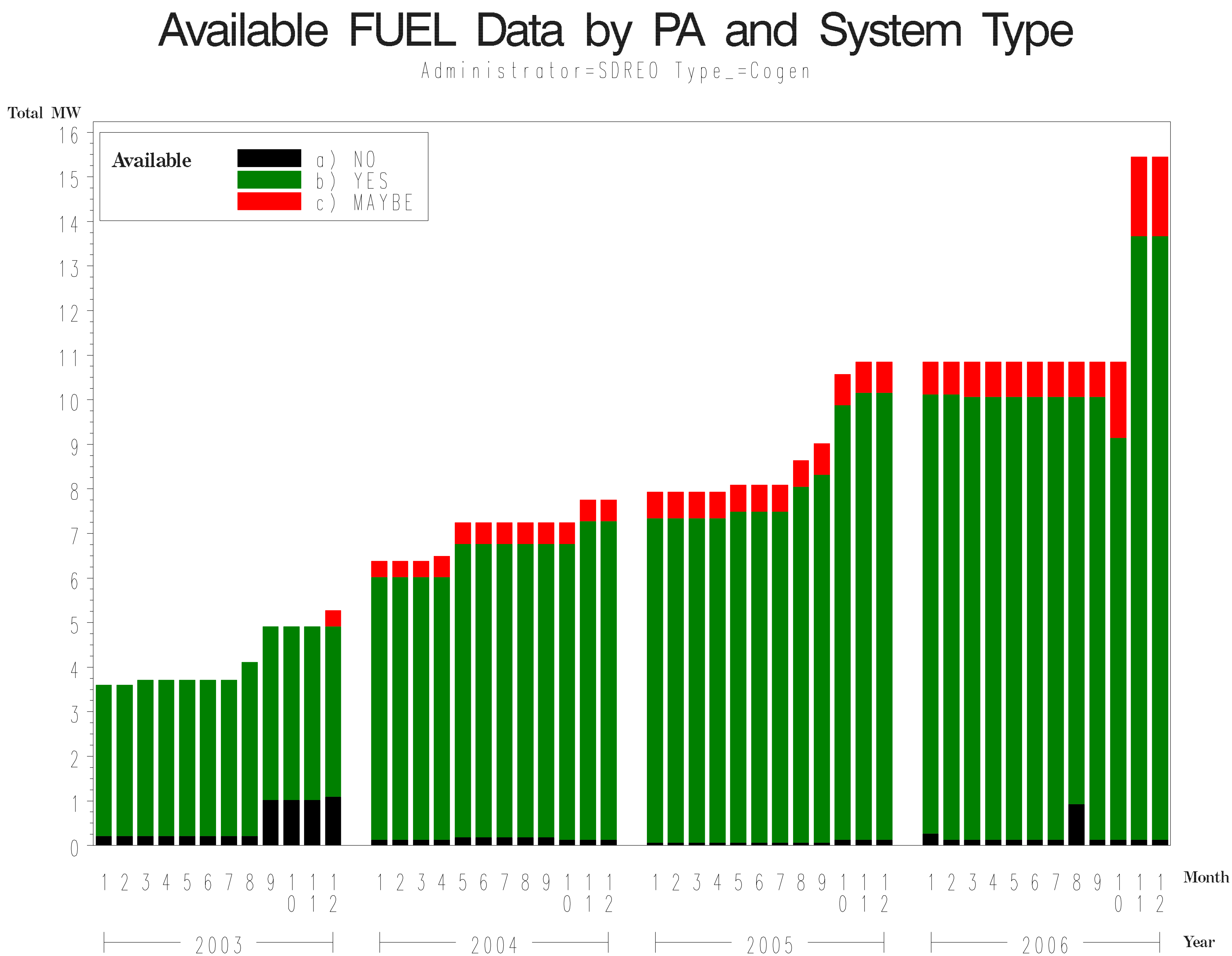
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Available
a) NO
b) YES
c) MAYBE
1 2 3 4 5 6 7 8 9 10 11 12
Month
2003
2004
2005
2006
Year

Available FUEL Data by PA and System Type

Administrator=SCG Type_=Cogen




Available FUEL Data by PA and System Type
Administrator=SCG Type_=FC
Total MW
1.5
1.4
1.3
1.2
1.1
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Available
a) NO
b) YES
c) MAYBE
Month
1 2 3 4 5 6 7 8 9 10 11 12
Year
2003
2004
2005
2006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Administrator=SDREO Type_=Cogen
Total MW
Available
a) NO
b) YES
c) MAYBE
0
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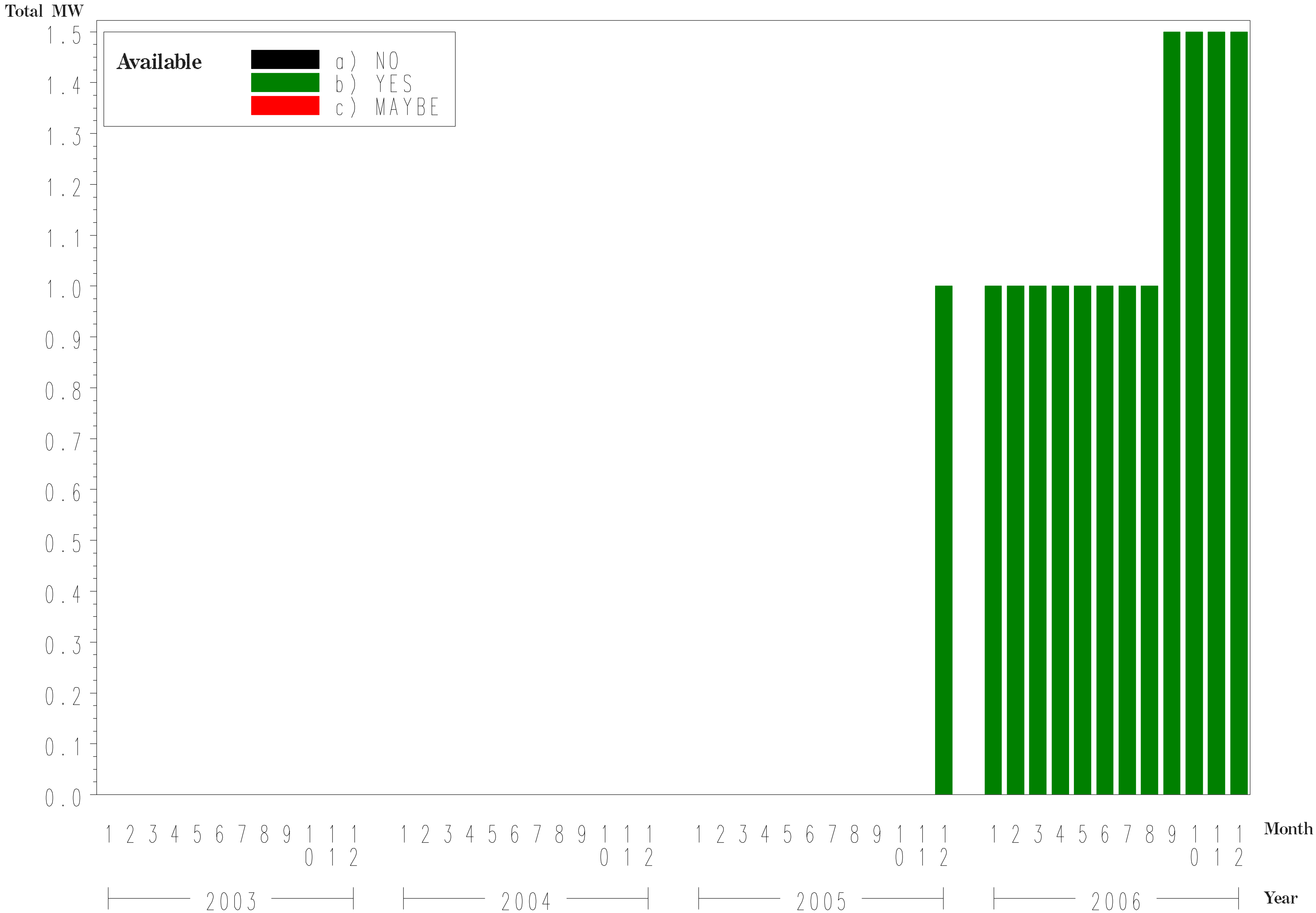
3
4
5
6
7
8
9
10
11
12
13
14
15
16
Month
1 2 3 4 5 6 7 8 9 10 11 12
Year
2003
2004
2005
2006

Available FUEL Data by PA and System Type

Administrator=SDREO Type_=FC



Appendix D

Attachment 2: Uncertainty Analysis for Impacts Estimates

Assumed performance distributions used in the Monte Carlo Simulation uncertainty analysis for unmetered systems are included under this cover along with summaries of performance observed for groups of metered projects.

D.1 Performance Distributions for Coincident Peak Demand Impacts

Figure D-1: PG&E PV Measured Coincident Peak Output (Coastal, Near Flat)

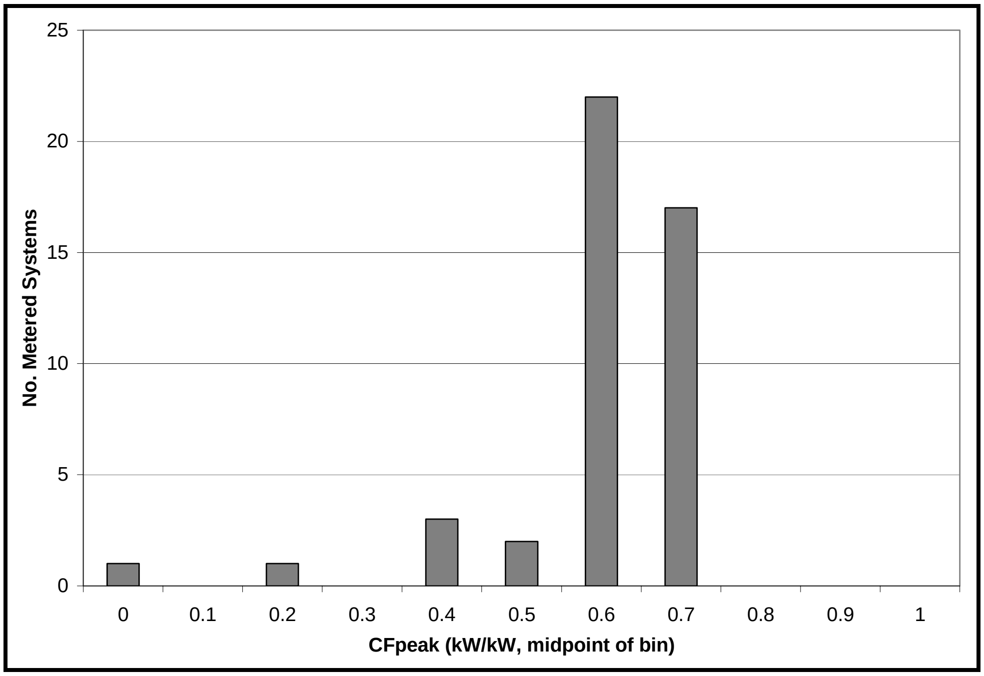


Figure D-2: MCS Distribution - PG&E PV Coincident Peak Output (Coastal, Near Flat)

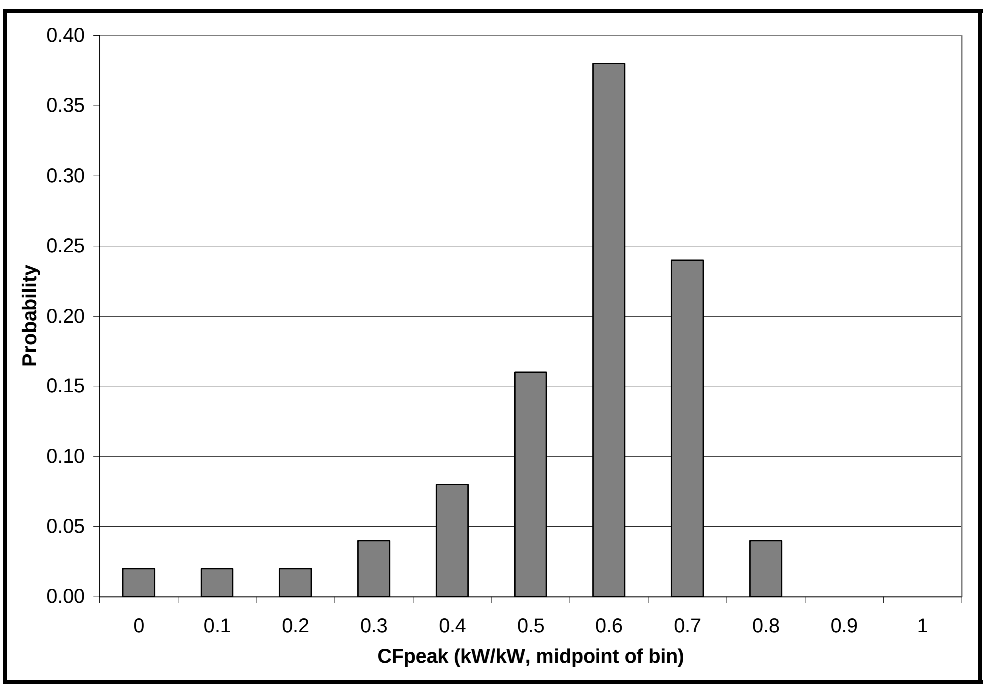


Figure D-3: PG&E PV Measured Coincident Peak Output (Coastal, Other)

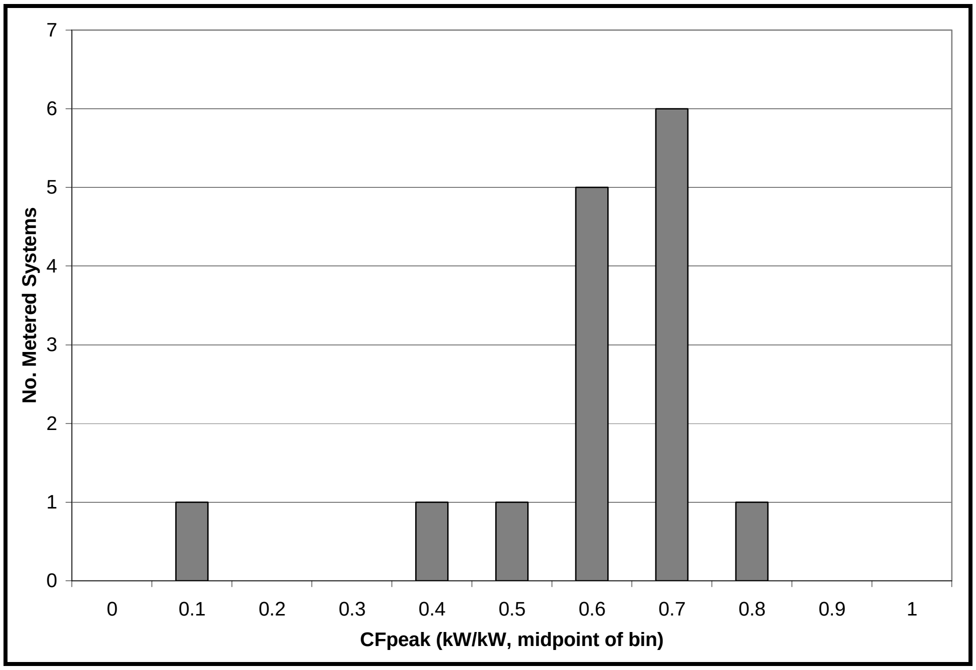


Figure D-4: MCS Distribution - PG&E PV Coincident Peak Output (Coastal, Other)

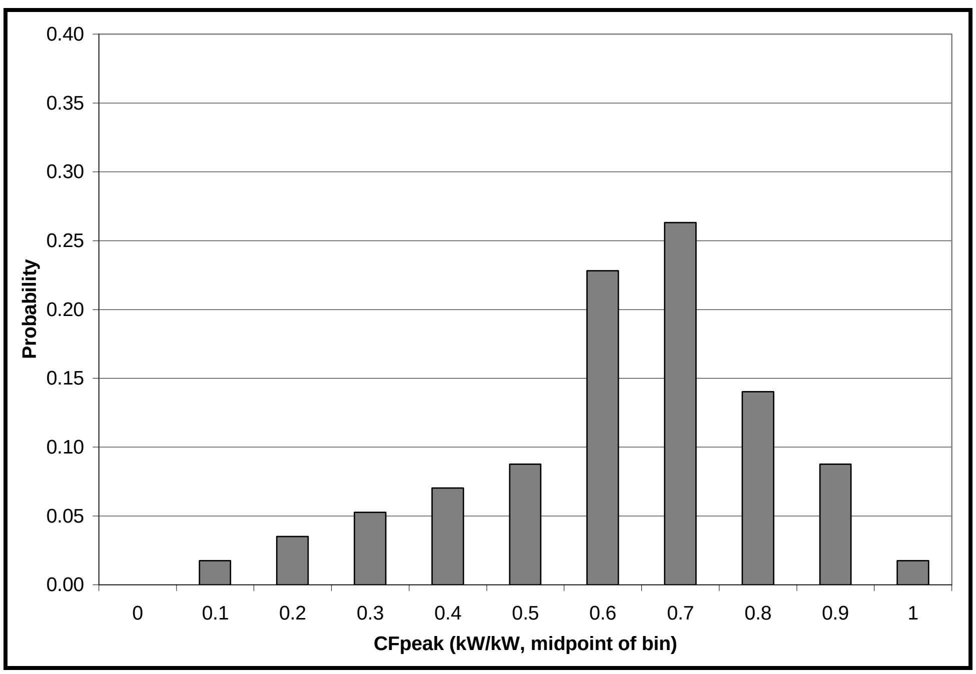


Figure D-5: PG&E PV Measured Coincident Peak Output (Inland, Near Flat)

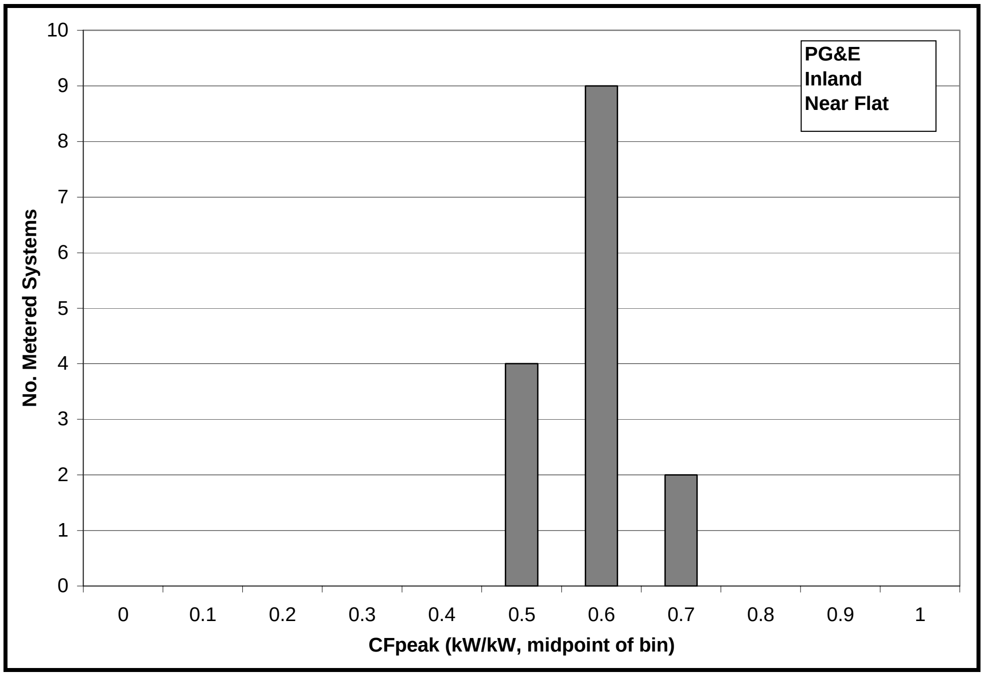


Figure D-6: MCS Distribution - PG&E PV Coincident Peak Output (Inland, Near Flat)

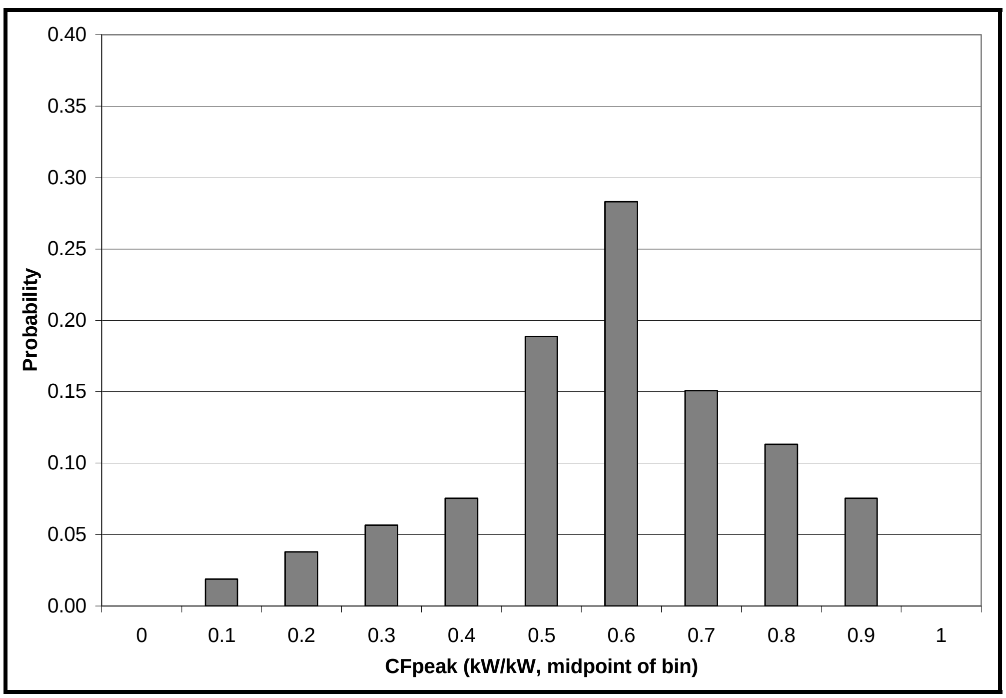


Figure D-7: PG&E PV Measured Coincident Peak Output (Inland, Other)

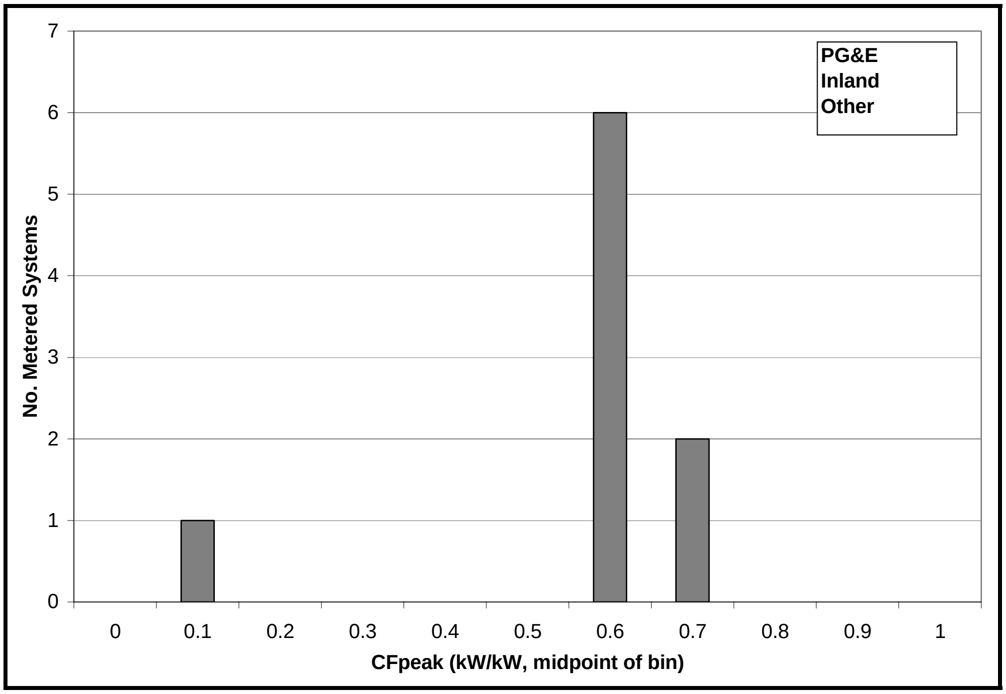


Figure D-8: MCS Distribution - PG&E PV Coincident Peak Output (Inland, Other)

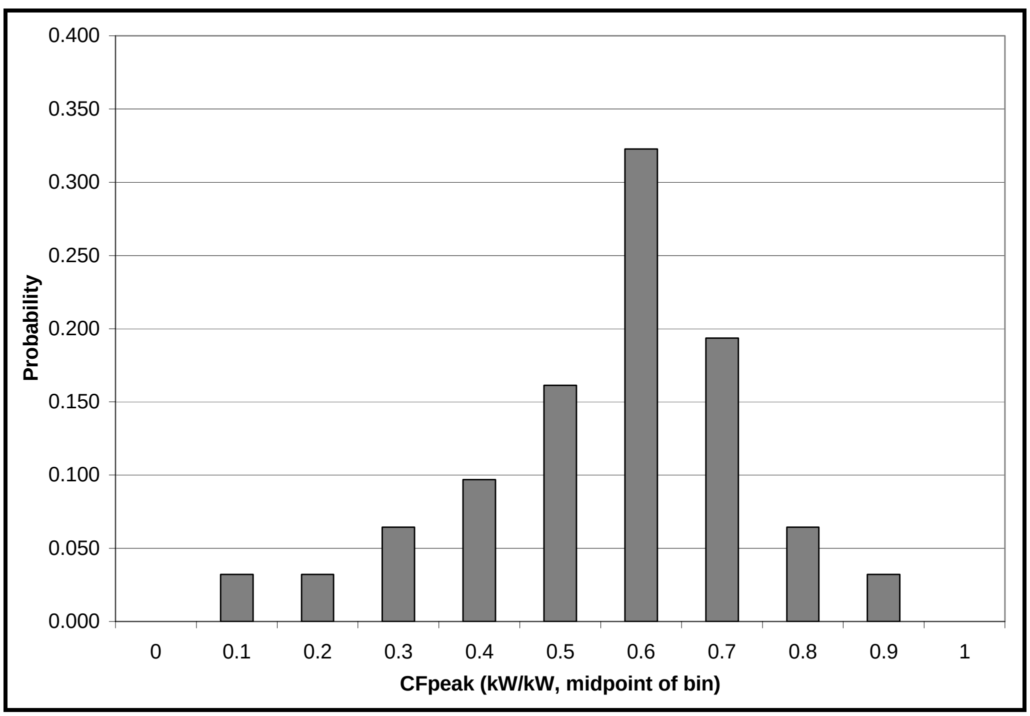


Figure D-9: PG&E PV Measured Coincident Peak Output (Tracking)

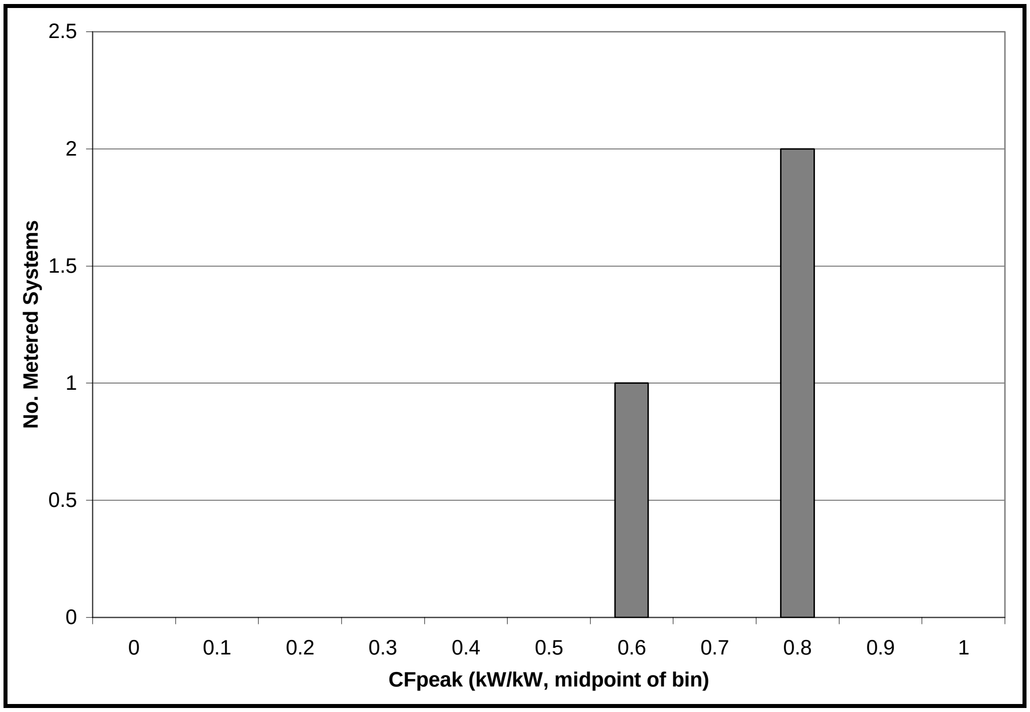


Figure D-10: MCS Distribution - PG&E PV Coincident Peak Output (Tracking)

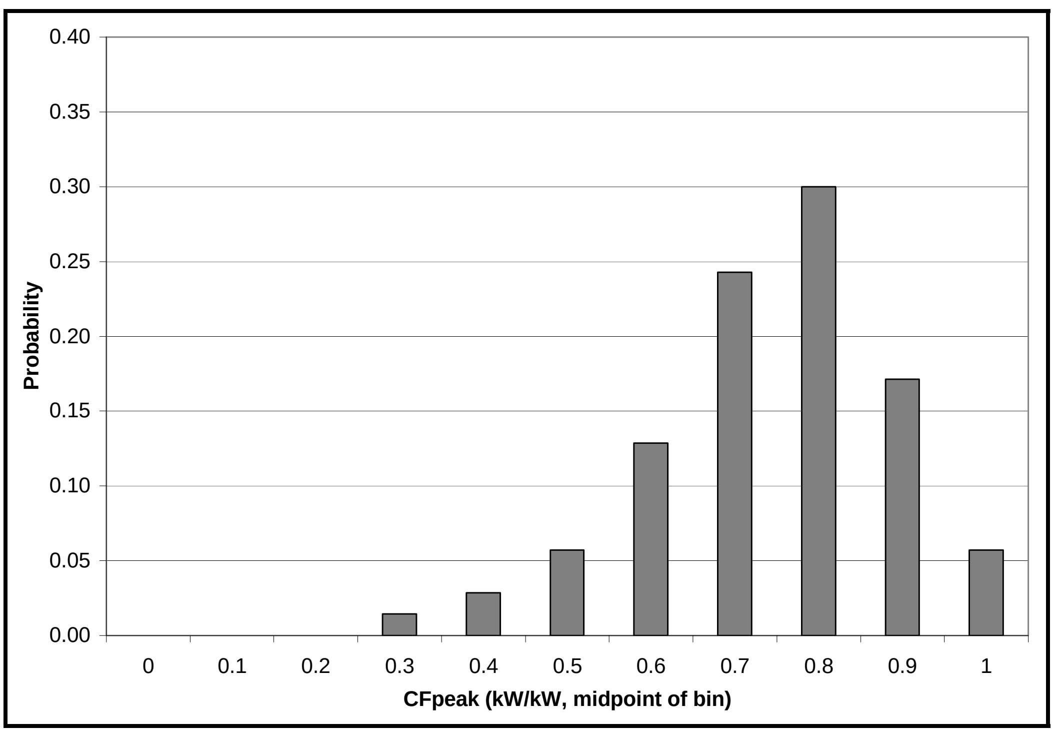


Figure D-11: LA (SCE & SCG) PV Measured Coincident Peak Output (Coastal, Near Flat)

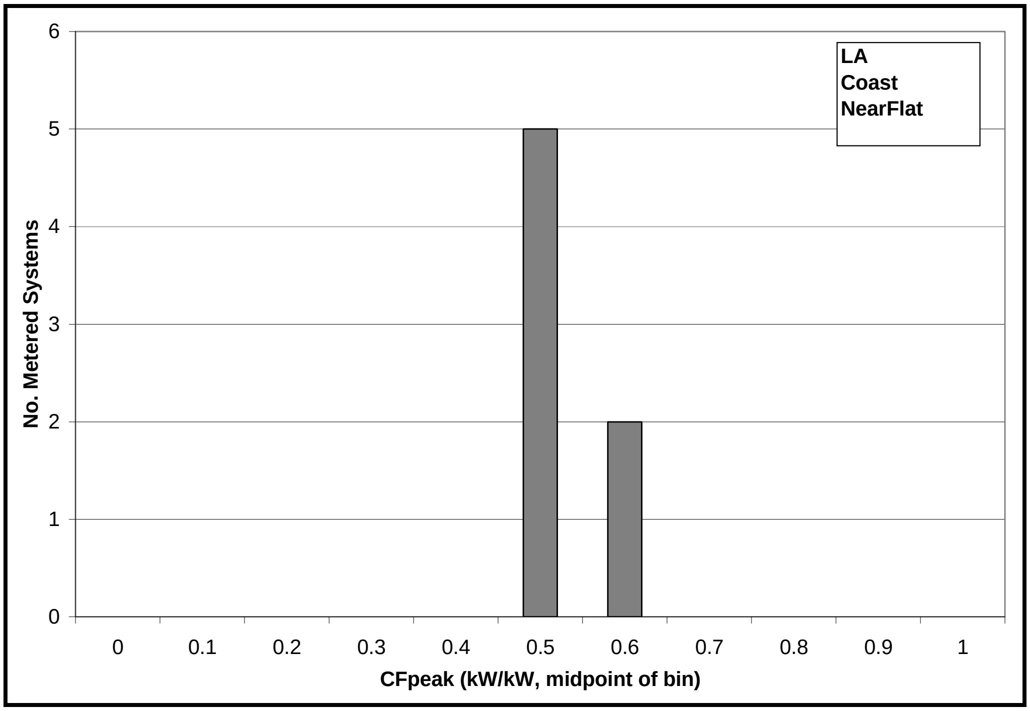


Figure D-12: MCS Distribution - LA (SCE & SCG) PV Coincident Peak Output (Coastal, Near Flat)

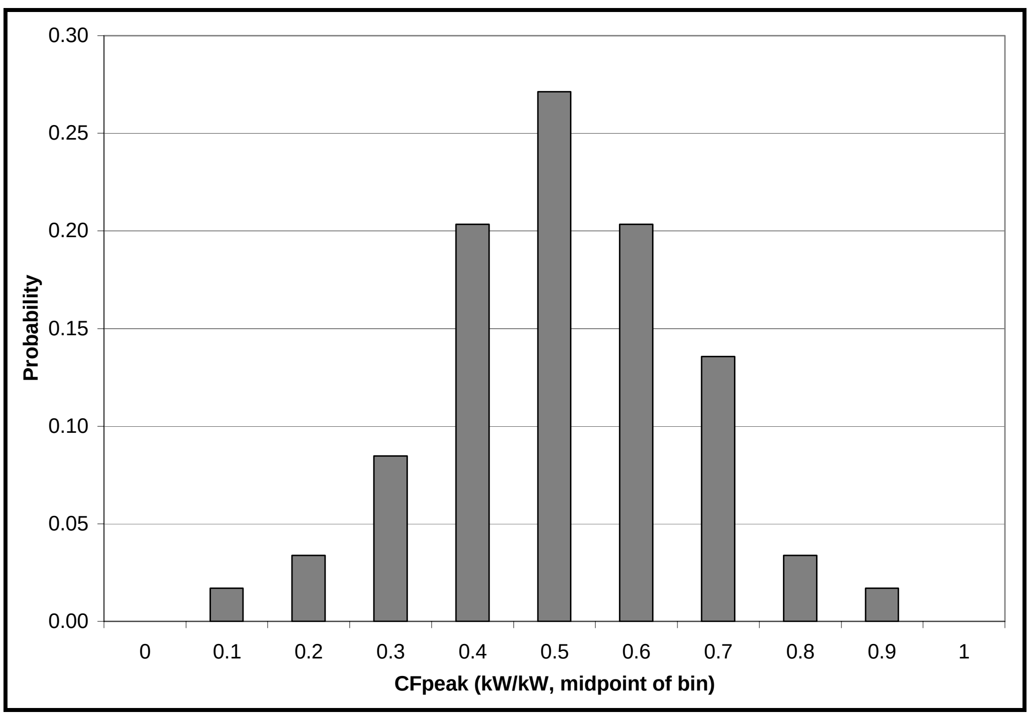


Figure D-13: LA (SCE & SCG) PV Measured Coincident Peak Output (Coastal, Other)

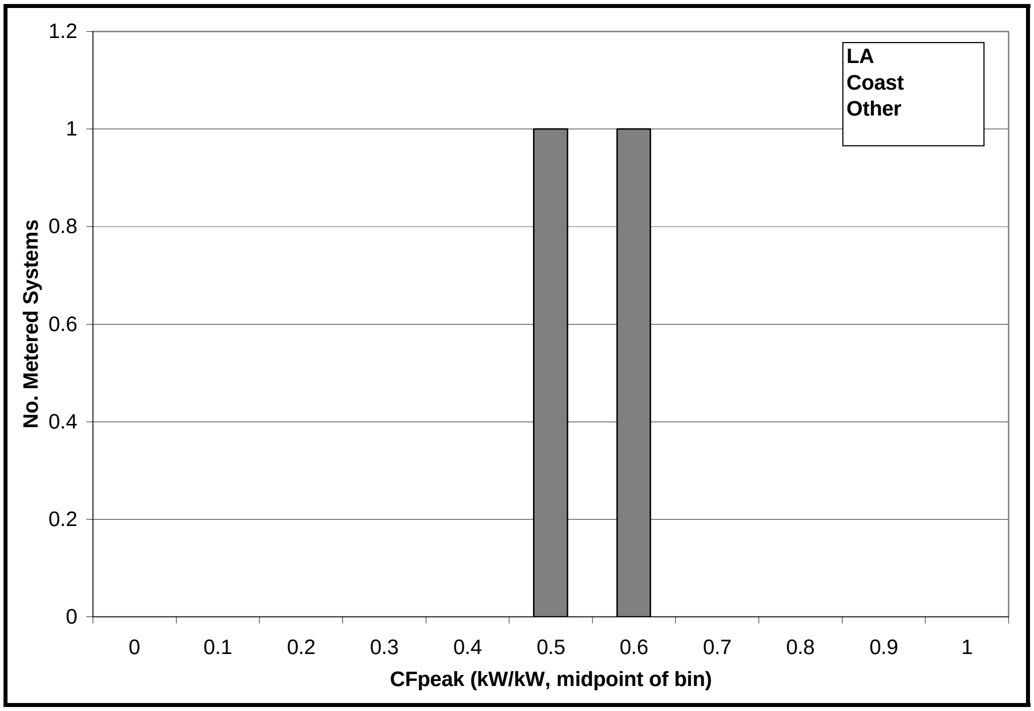


Figure D-14: MCS Distribution - LA (SCE & SCG) PV Coincident Peak Output (Coastal, Other)

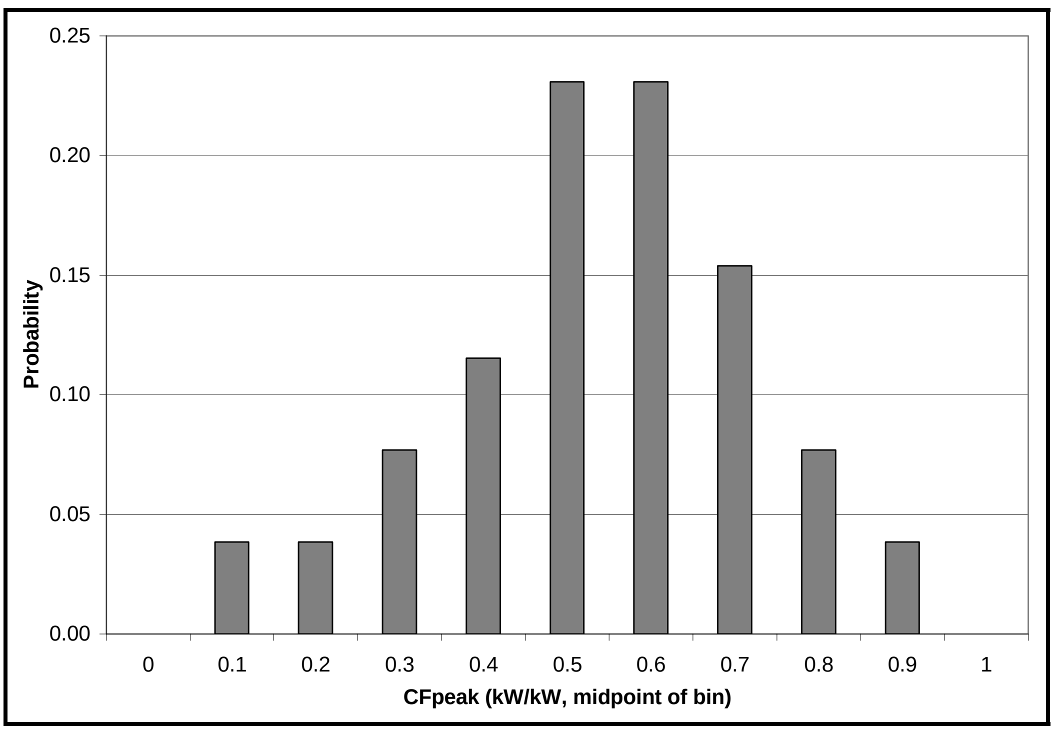


Figure D-15: LA (SCE & SCG) PV Measured Coincident Peak Output (Inland, Near Flat)

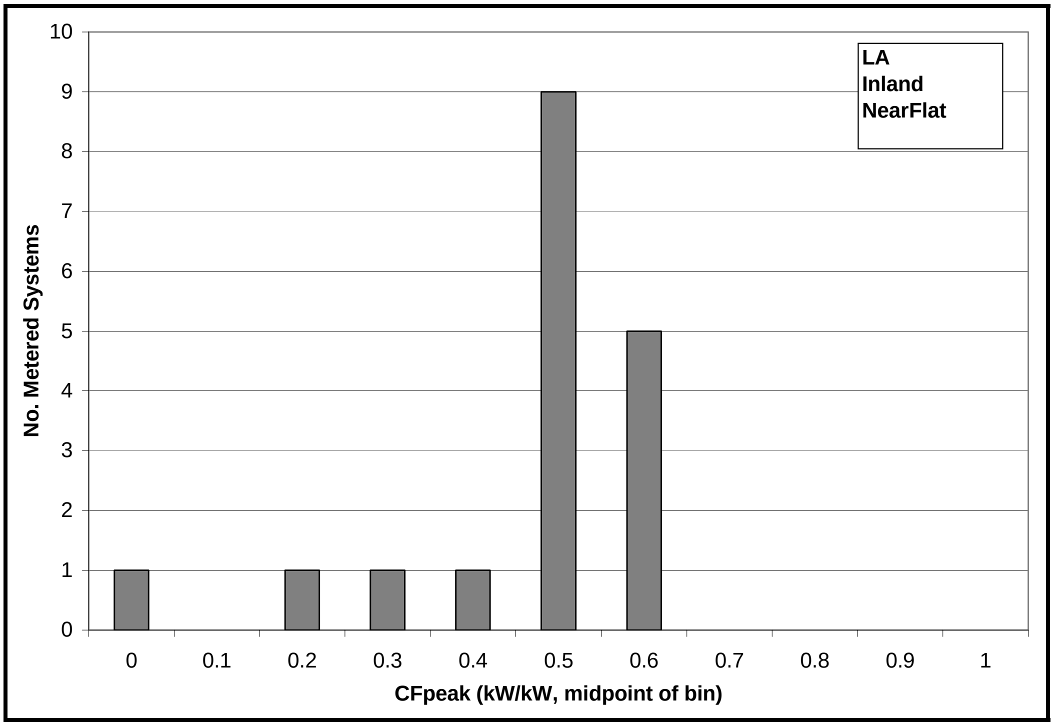


Figure D-16: MCS Distribution - LA (SCE & SCG) PV Coincident Peak Output (Inland, Near Flat)

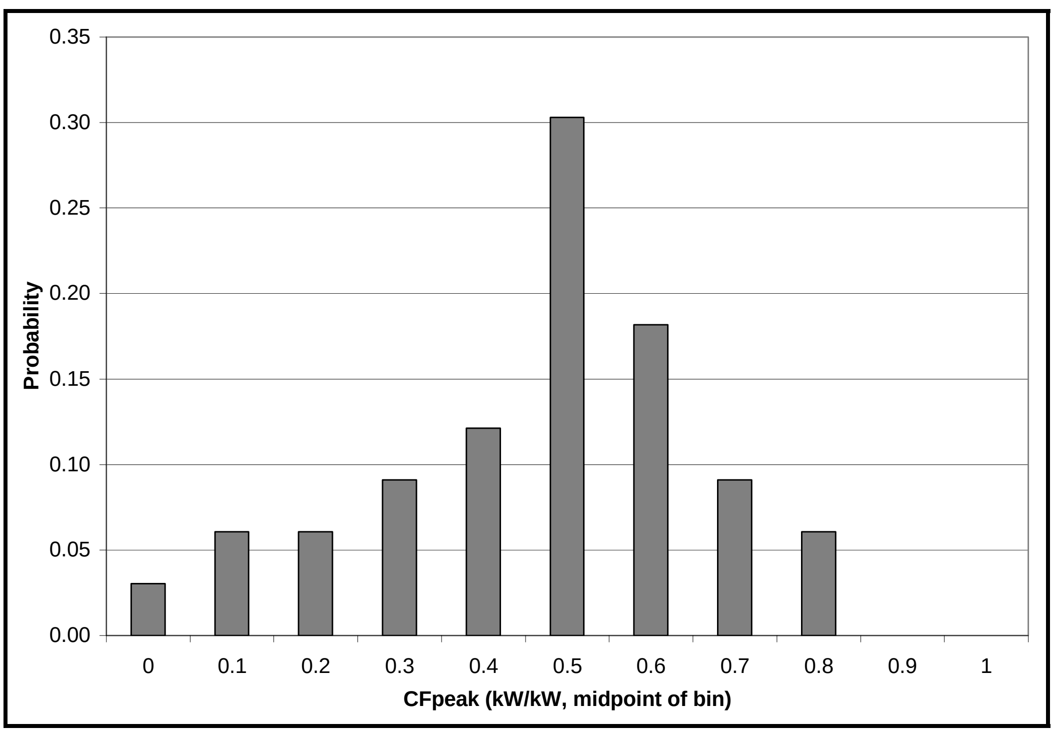


Figure D-17: LA (SCE & SCG) PV Measured Coincident Peak Output (Inland, Other)

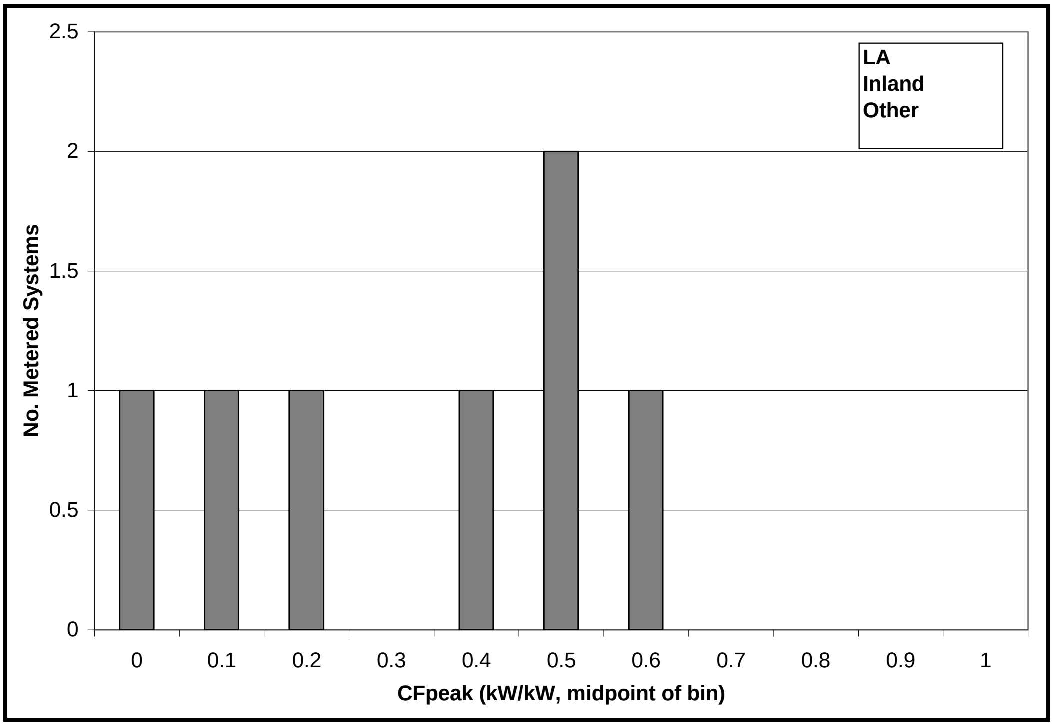


Figure D-18: MCS Distribution - LA (SCE & SCG) PV Coincident Peak Output (Inland, Other)

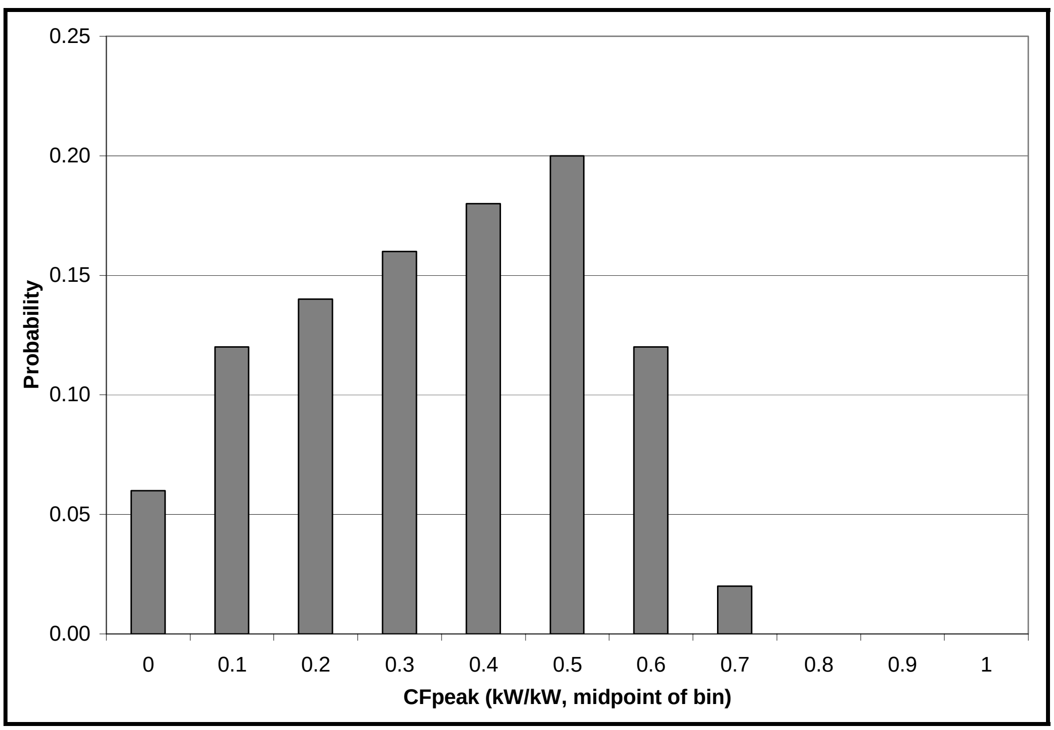


Figure D-19: LA (SCE & SCG) PV Measured Coincident Peak Output (Tracking)

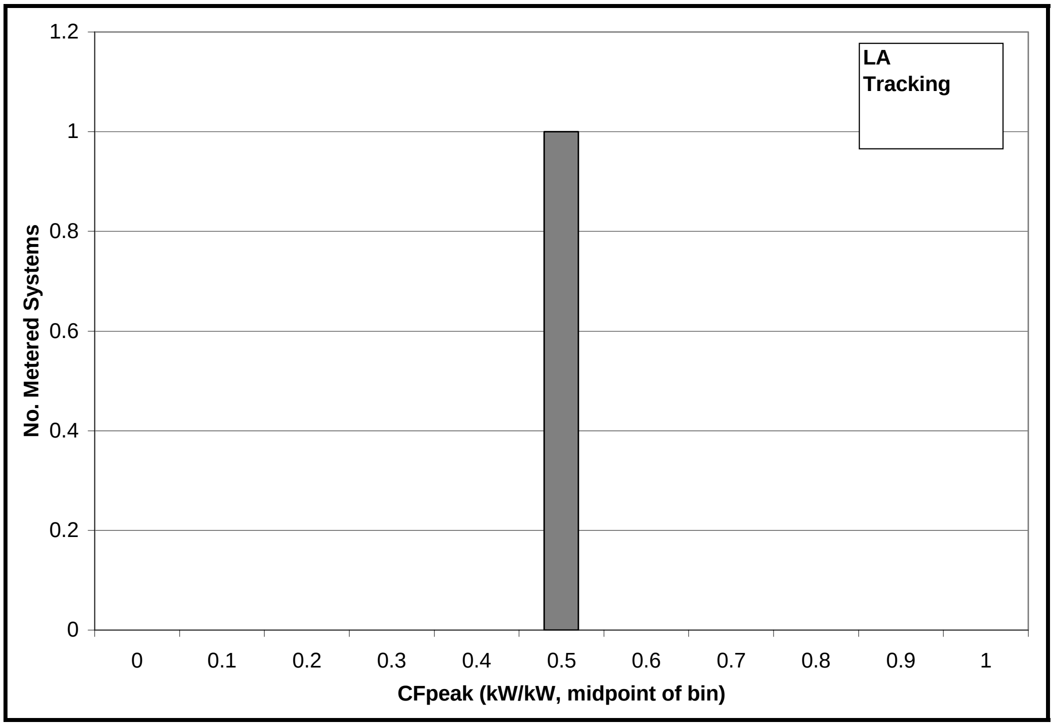


Figure D-20: MCS Distribution - LA (SCE & SCG) PV Coincident Peak Output (Tracking)

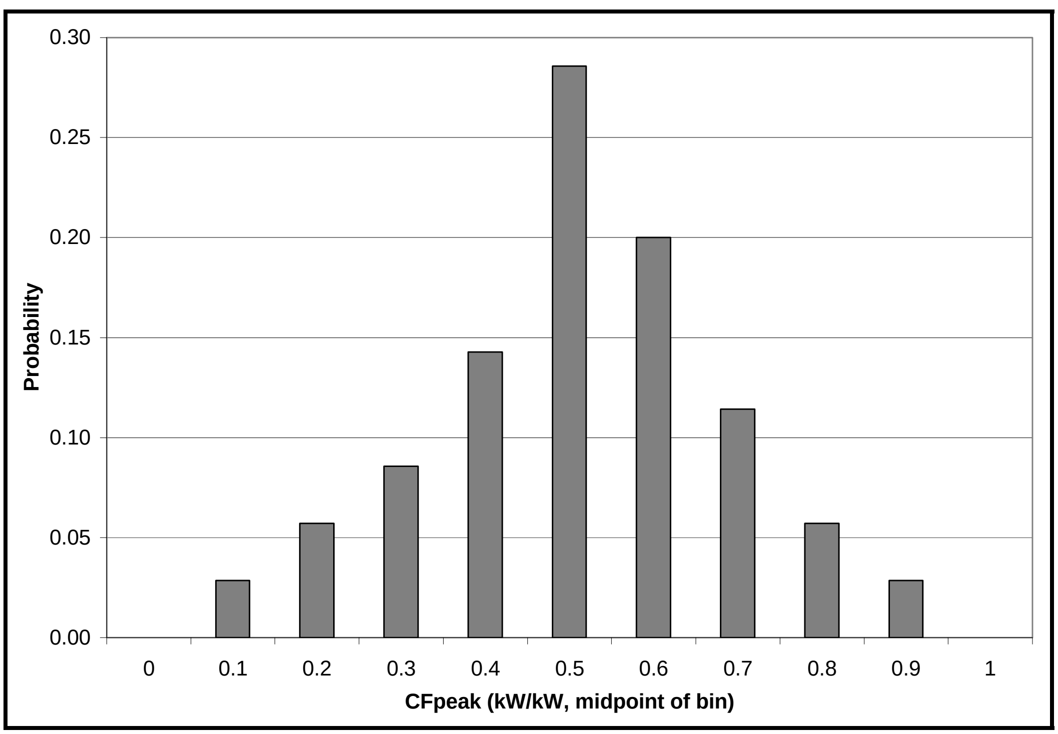


Figure D-21: SDREO PV Measured Coincident Peak Output (Coastal, Near Flat)

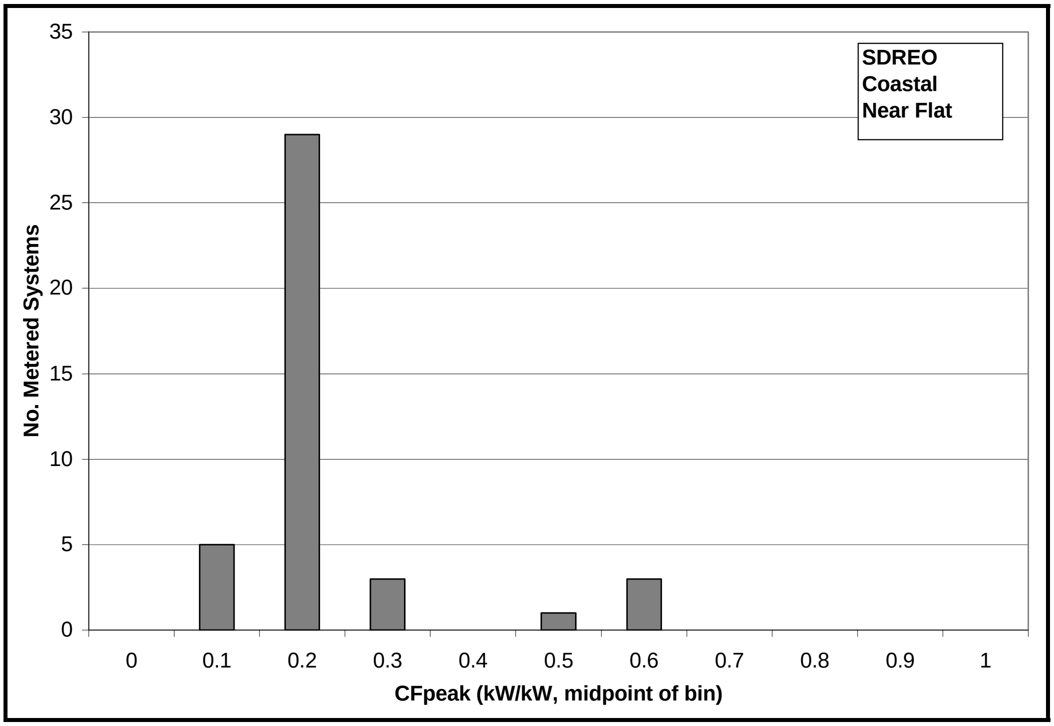


Figure D-22: MCS Distribution - SDREO PV Coincident Peak Output (Coastal, Near Flat)

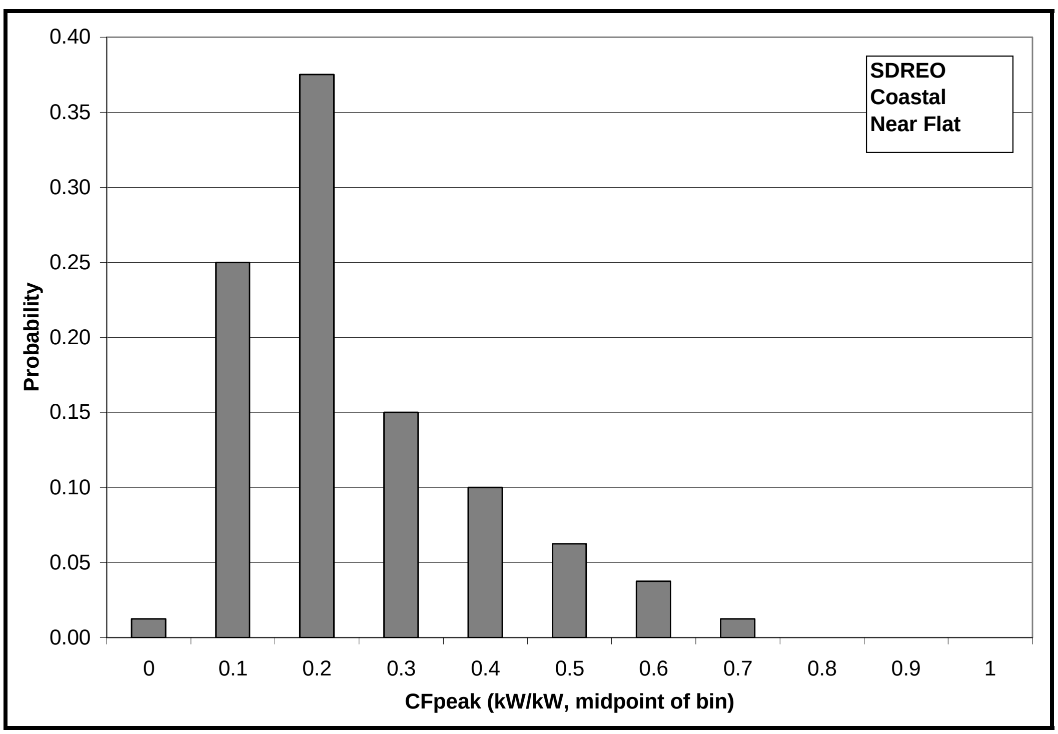


Figure D-23: Fuel Cell Measured Coincident Peak Output (Nonrenewable Fuel)

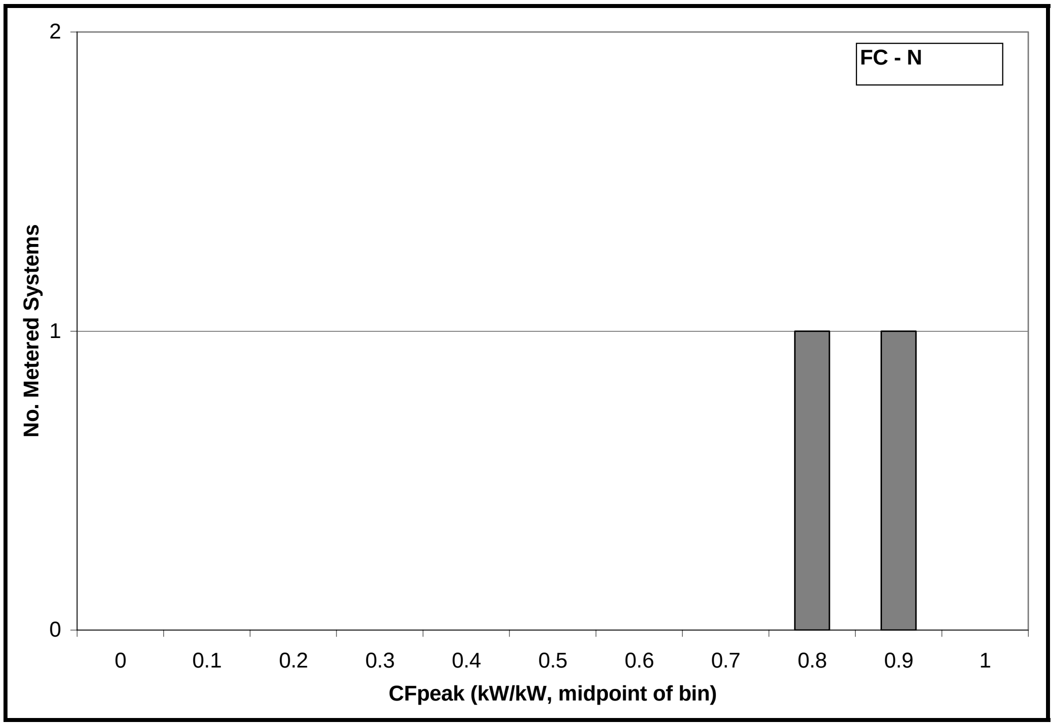


Figure D-24: MCS Distribution –Fuel Cell Coincident Peak Output (Nonrenewable Fuel)

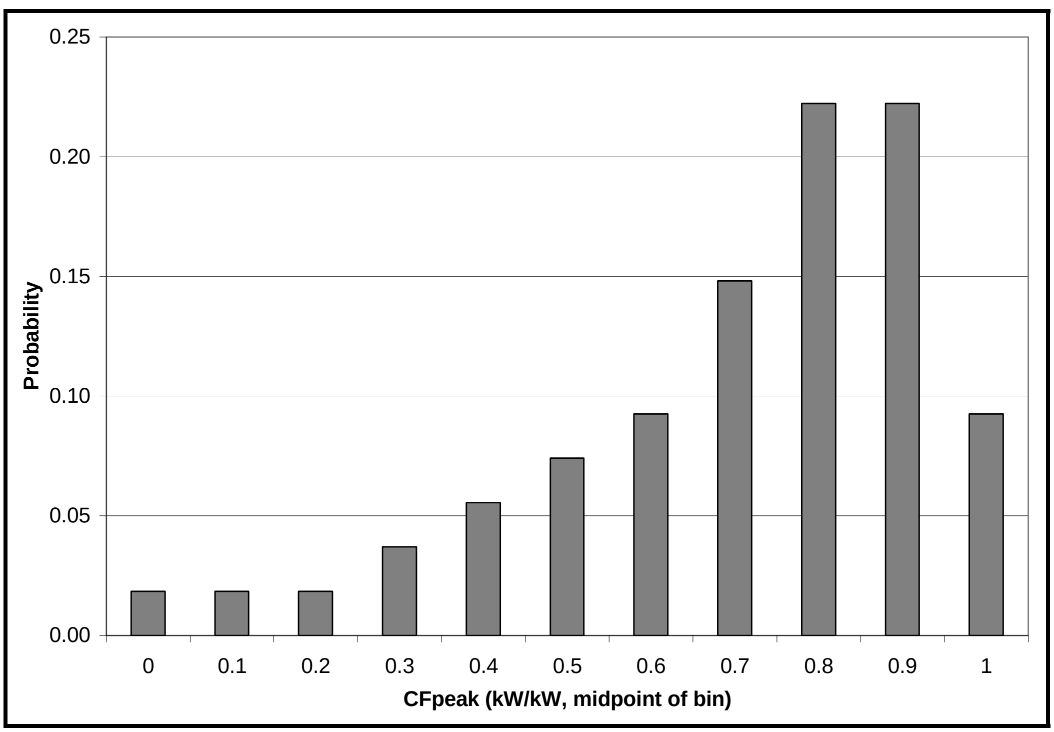


Figure D-25: Fuel Cell Measured Coincident Peak Output (Renewable Fuel)

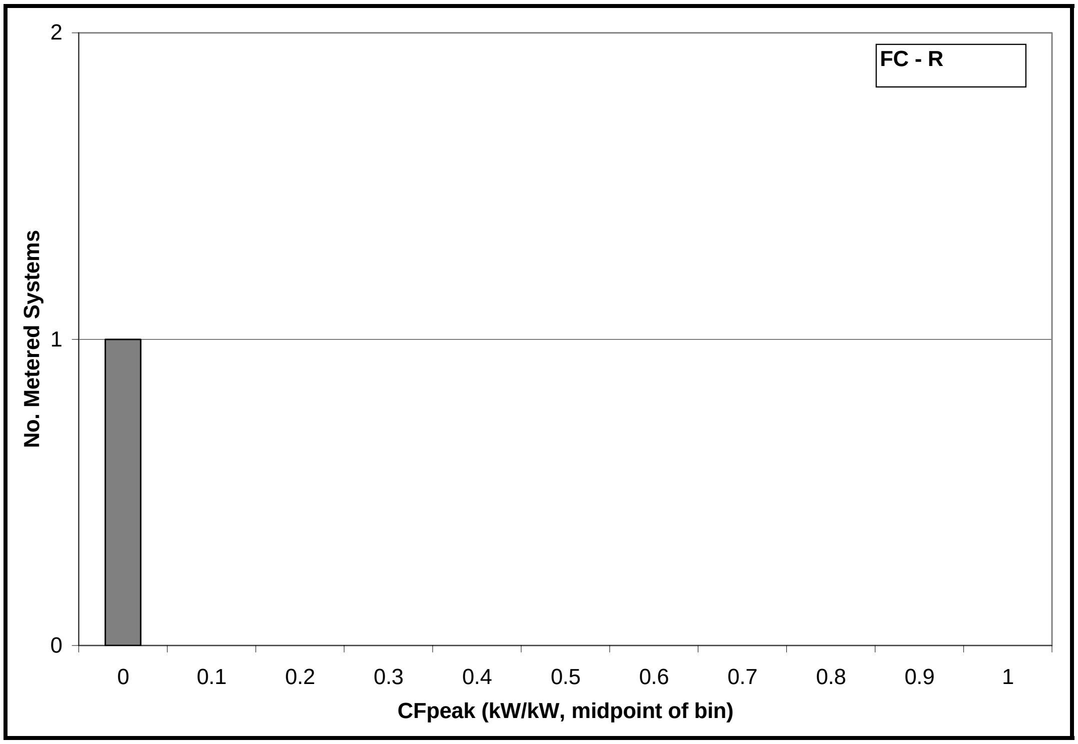


Figure D-26: MCS Distribution –Fuel Cell Coincident Peak Output (Renewable Fuel)

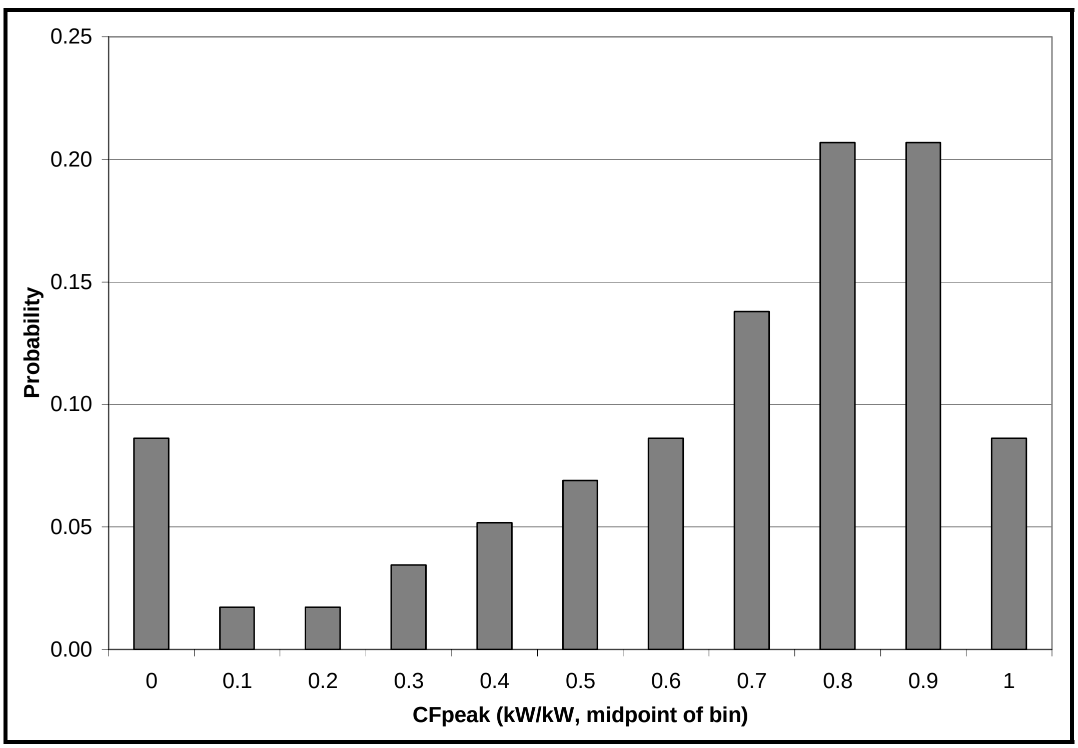


Figure D-27: IC Engine Measured Coincident Peak Output (Nonrenewable Fuel)

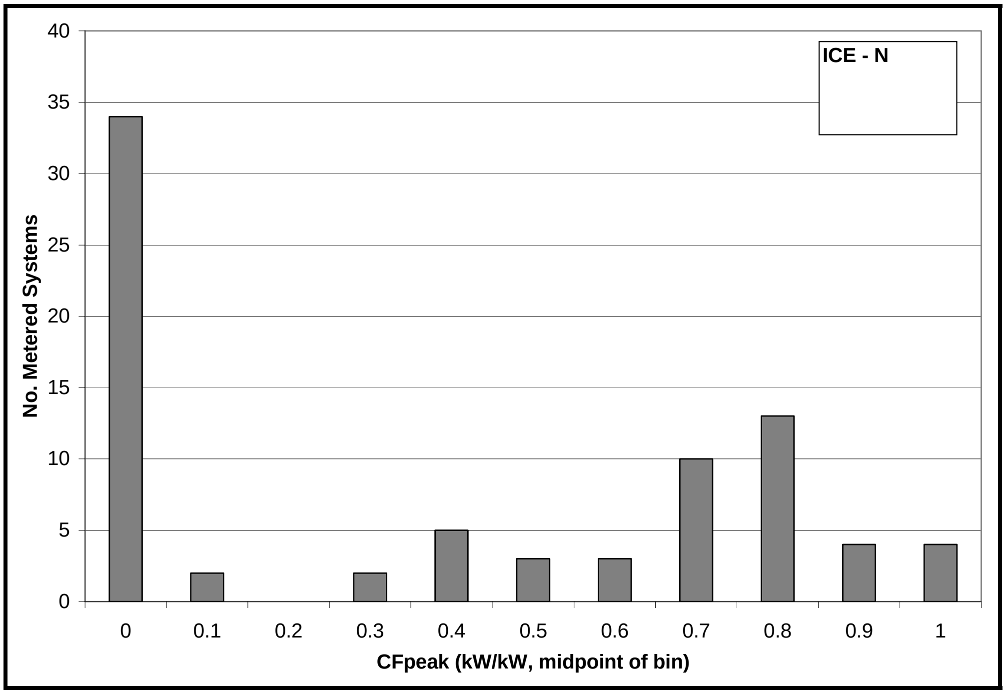


Figure D-28: MCS Distribution – IC Engine Coincident Peak Output (Nonrenewable Fuel)

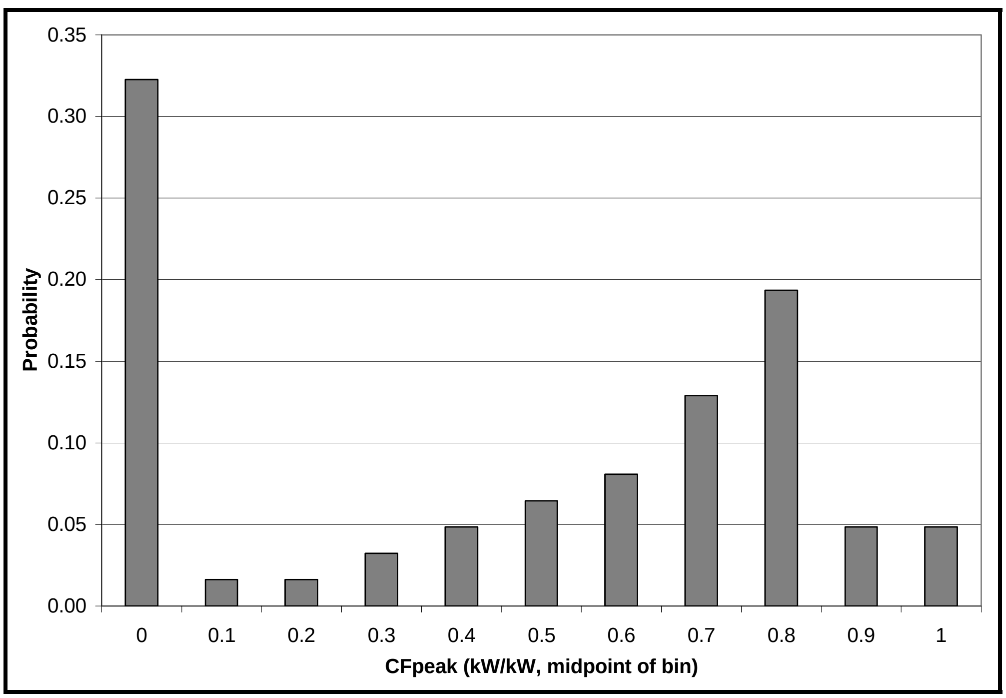


Figure D-29: IC Engine Measured Coincident Peak Output (Renewable Fuel)

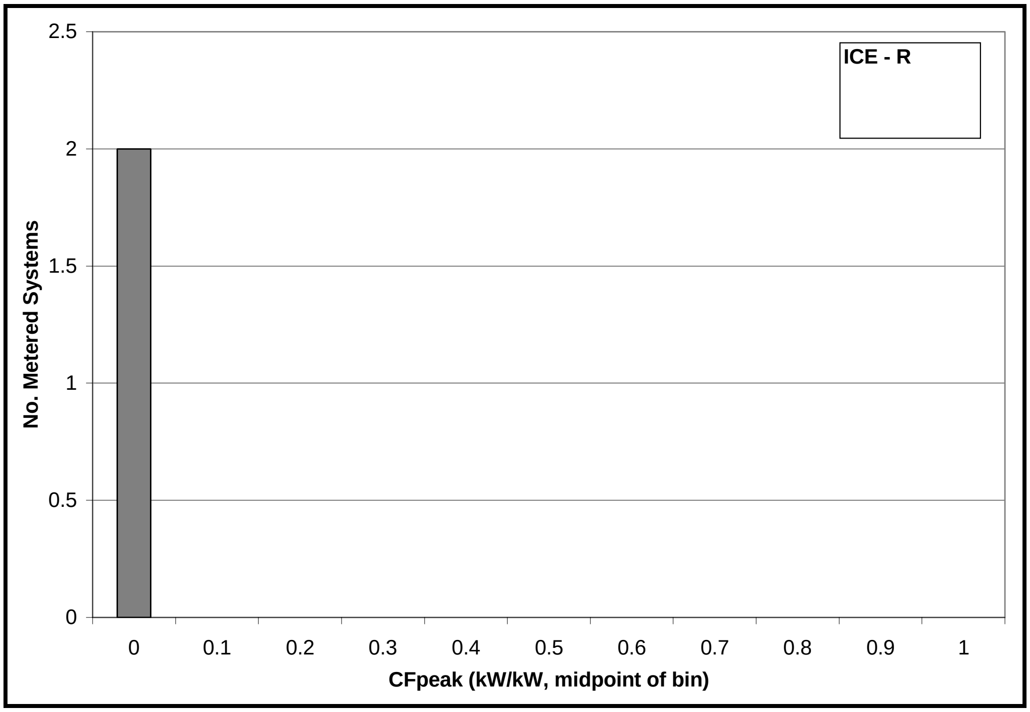


Figure D-30: MCS Distribution – IC Engine Coincident Peak Output (Renewable Fuel)

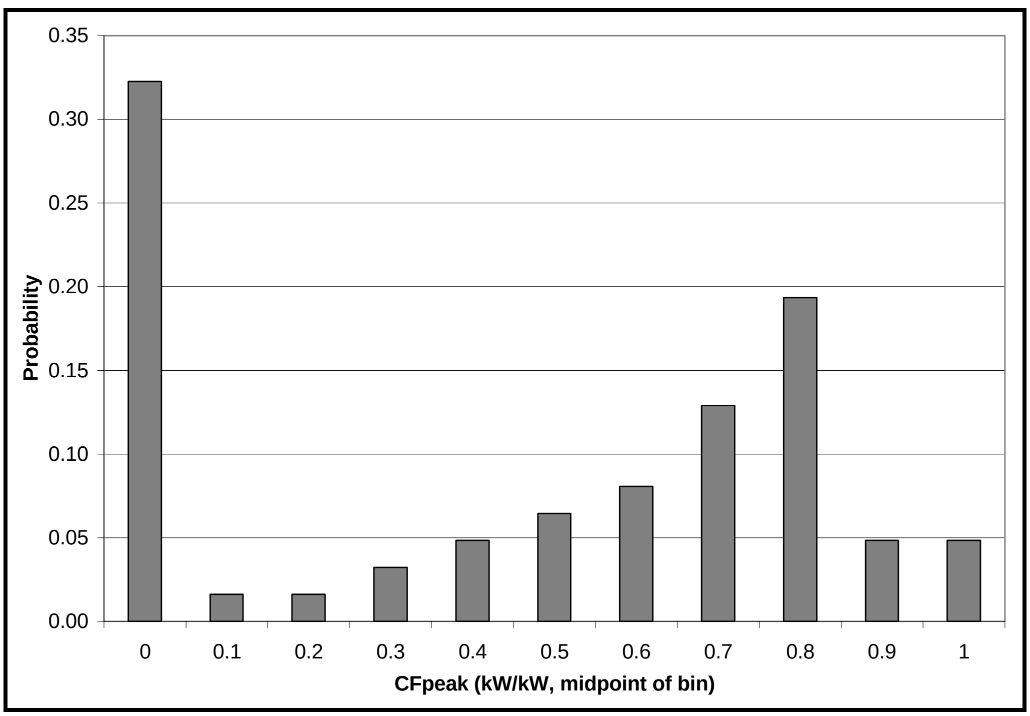


Figure D-31: Gas Turbine Measured Coincident Peak Output (Nonrenewable Fuel)

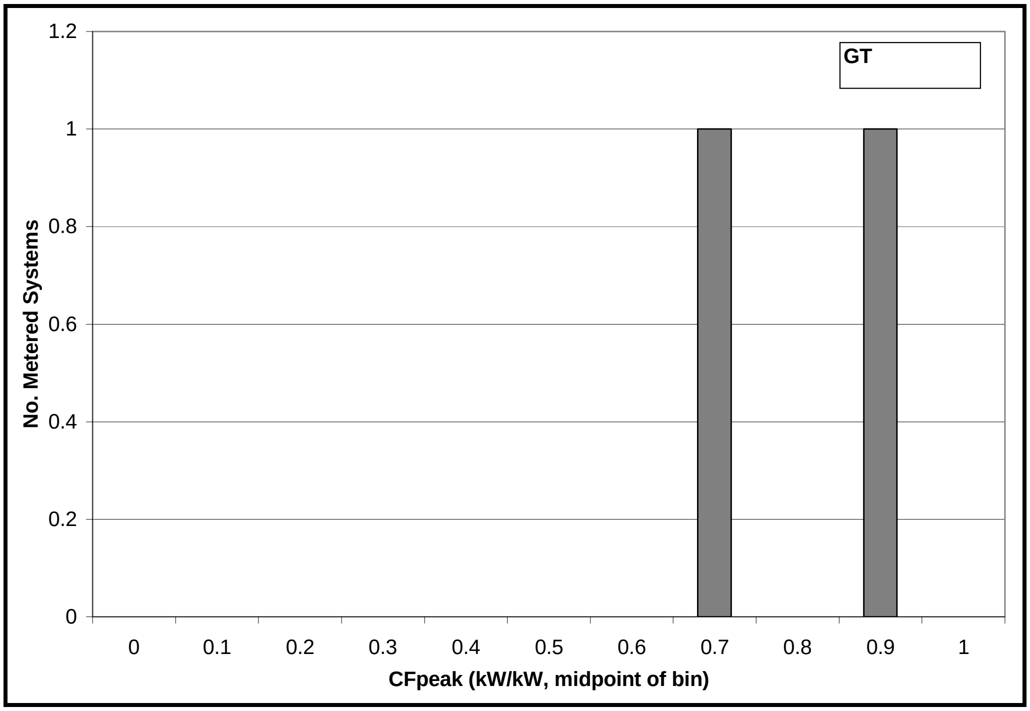


Figure D-32: MCS Distribution – Gas Turbine Coincident Peak Output (Nonrenewable Fuel)

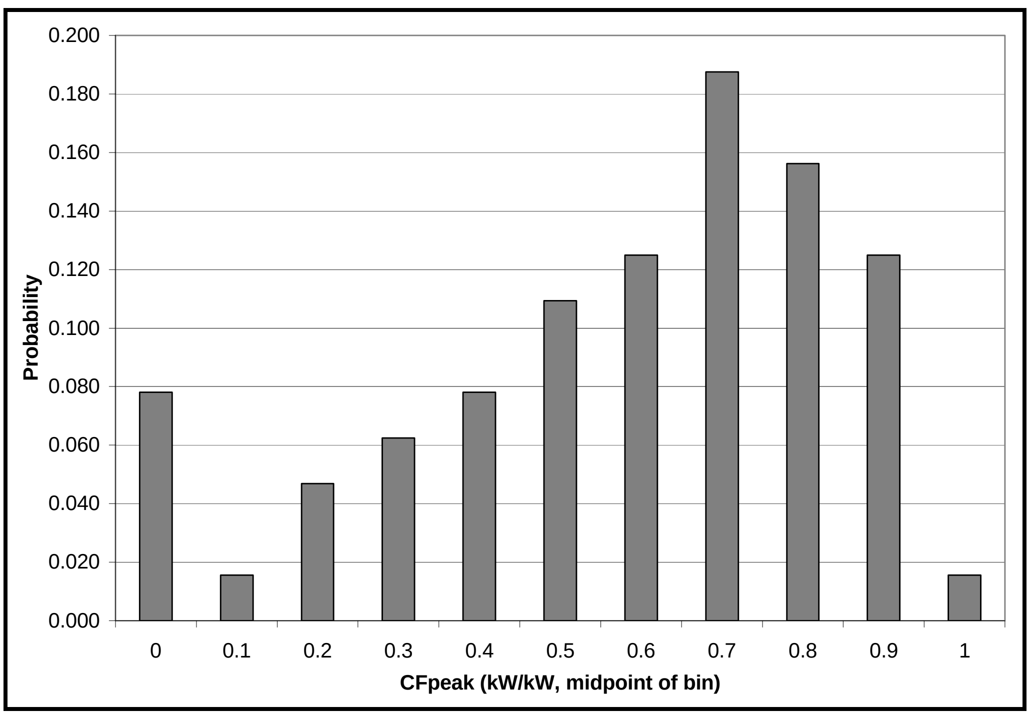


Figure D-33: Microturbine Measured Coincident Peak Output (Nonrenewable Fuel)

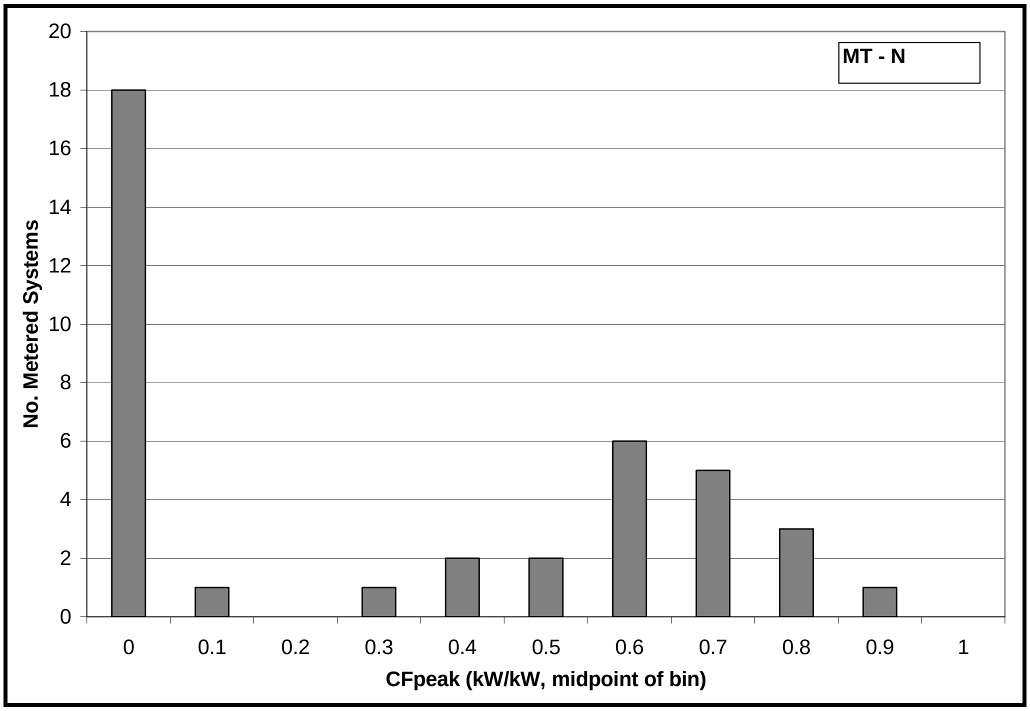


Figure D-34: MCS Distribution – Microturbine Coincident Peak Output (Nonrenewable Fuel)

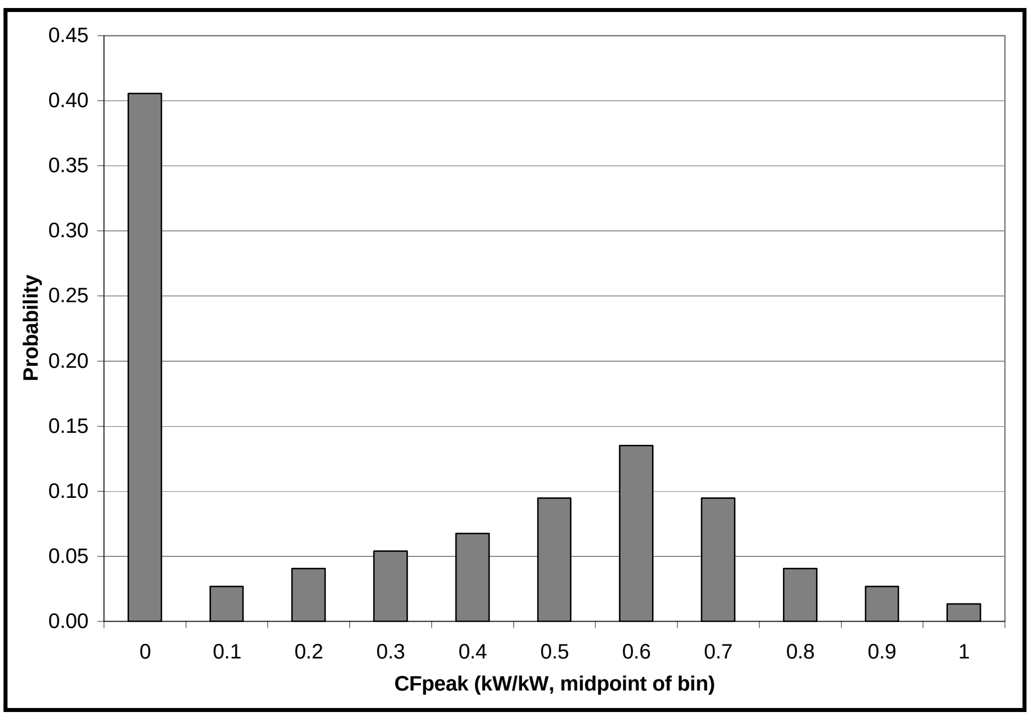


Figure D-35: Microturbine Measured Coincident Peak Output (Renewable Fuel)

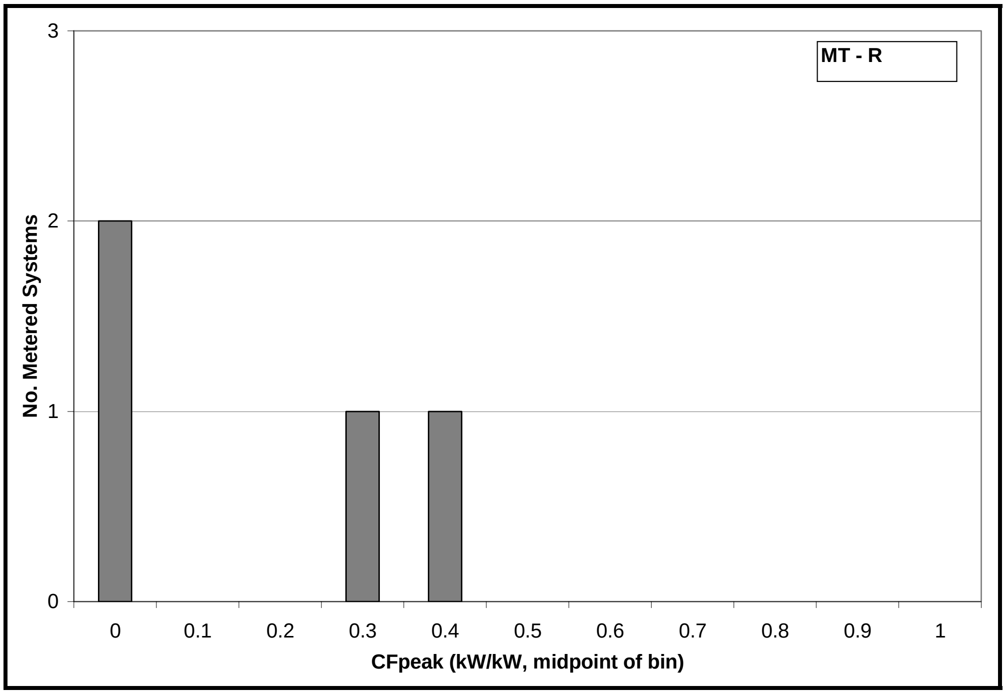
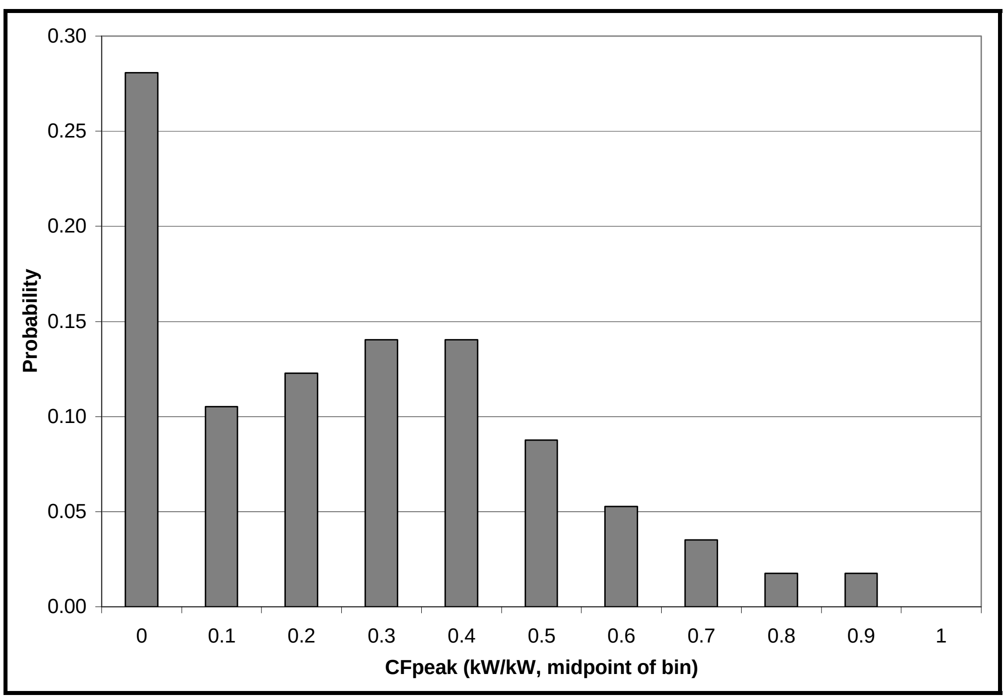


Figure D-36: MCS Distribution – Microturbine Coincident Peak Output (Renewable Fuel)



D.2 Performance Distributions for Energy Impacts

Figure D-37: PV (Non-tracking) Measured Energy Production (Capacity Factor)

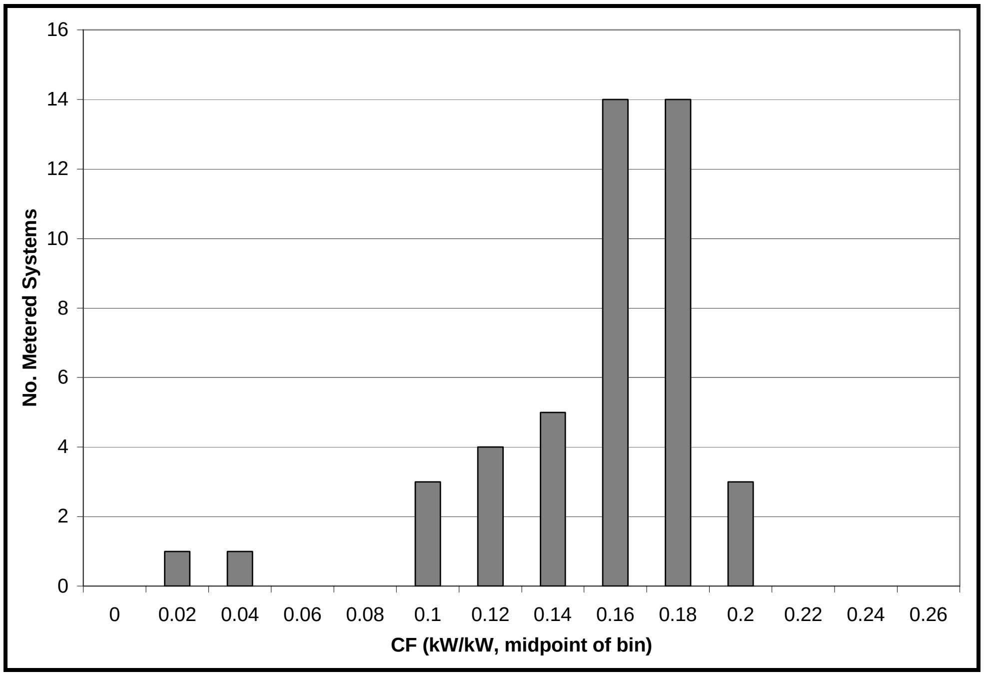


Figure D-38: MCS Distribution – PV (Non-tracking) Energy Production (Capacity Factor)

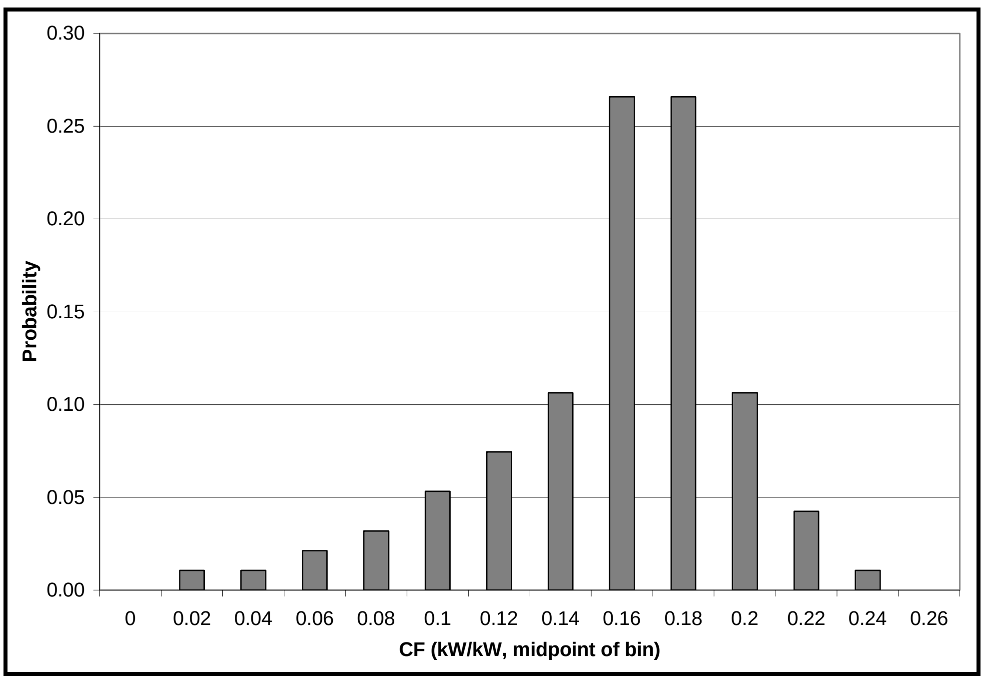


Figure D-39: PV (Tracking) Measured Energy Production (Capacity Factor)

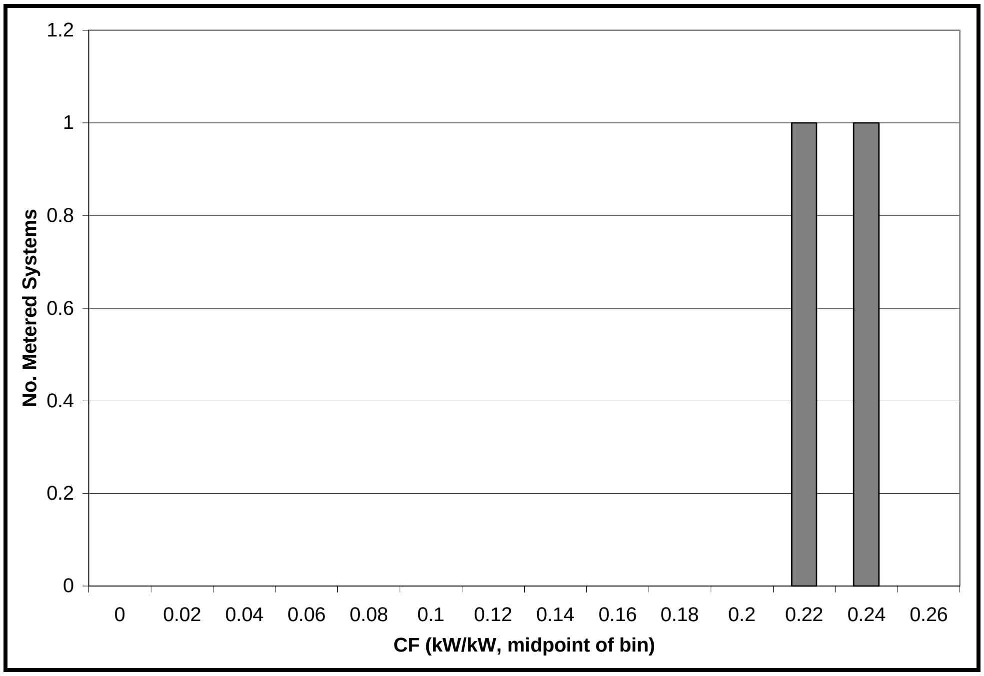


Figure D-40: MCS Distribution – PV (Tracking) Energy Production (Capacity Factor)

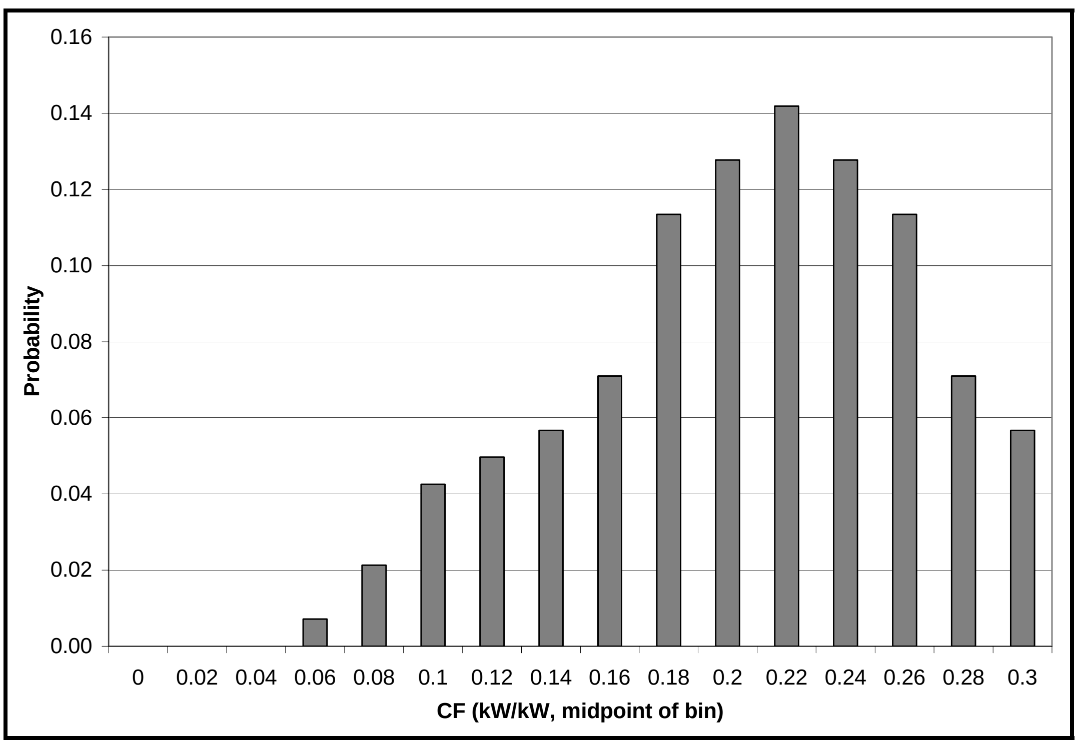


Figure D-41: Wind Turbine Measured Energy Production (Capacity Factor)

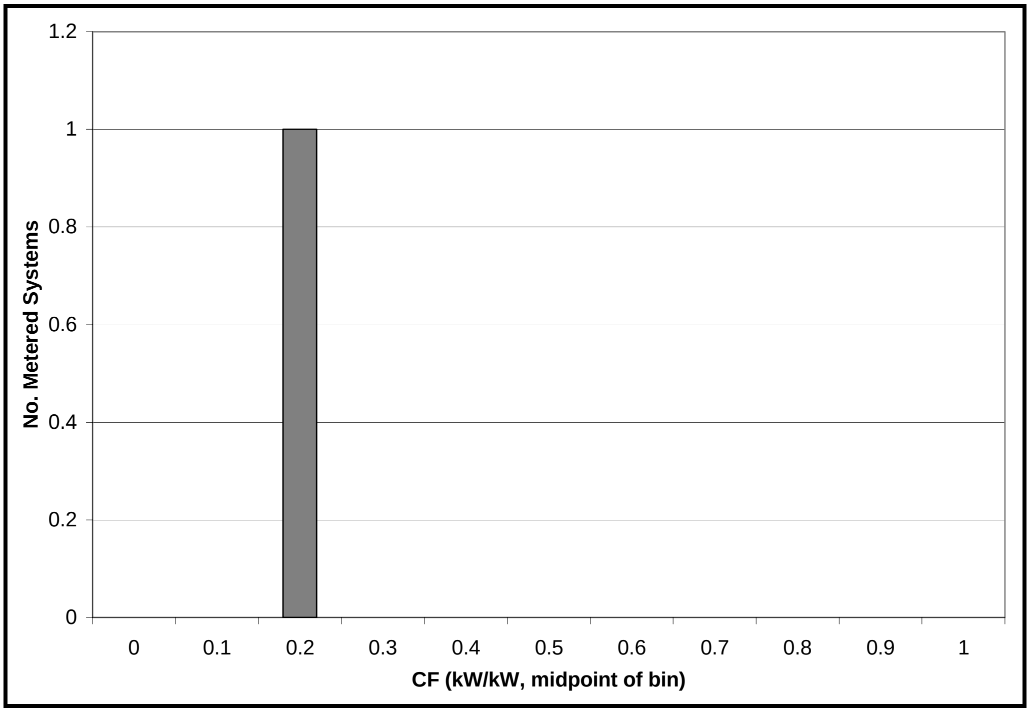


Figure D-42: MCS Distribution – Wind Turbine Energy Production (Capacity Factor)

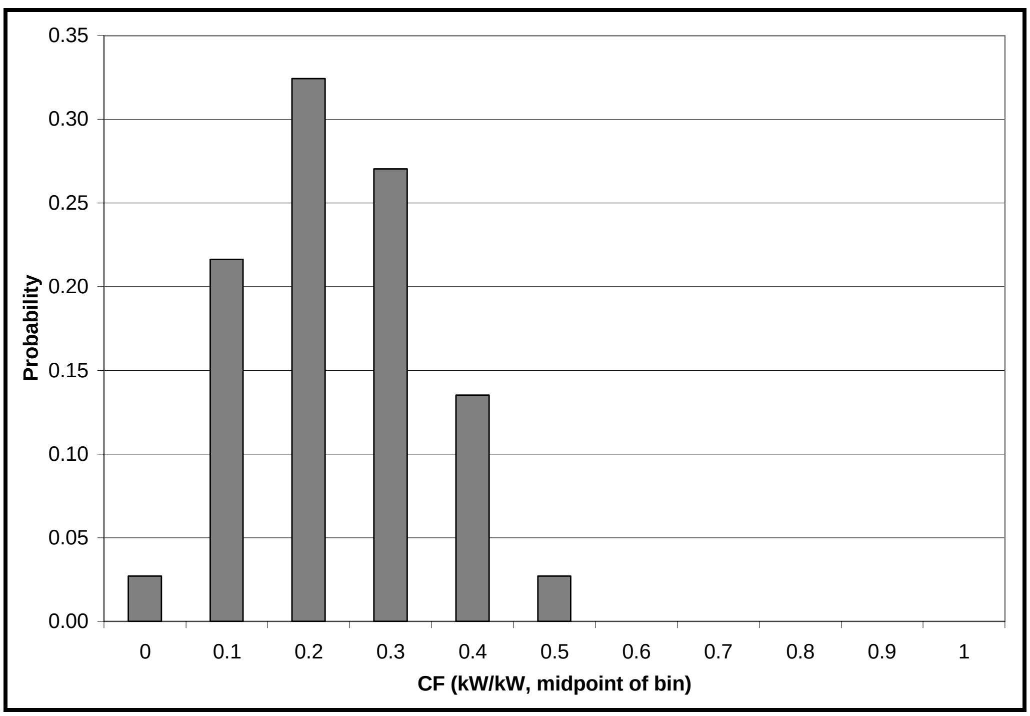


Figure D-43: Fuel Cell Measured Energy Production (Capacity Factor)

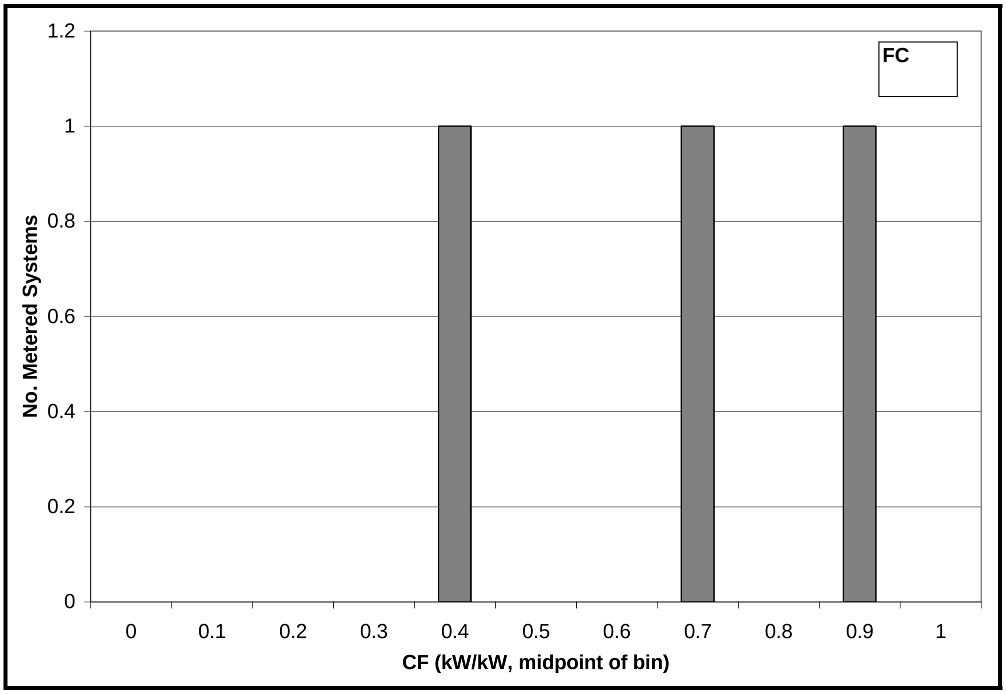


Figure D-44: MCS Distribution – Fuel Cell Energy Production (Capacity Factor)

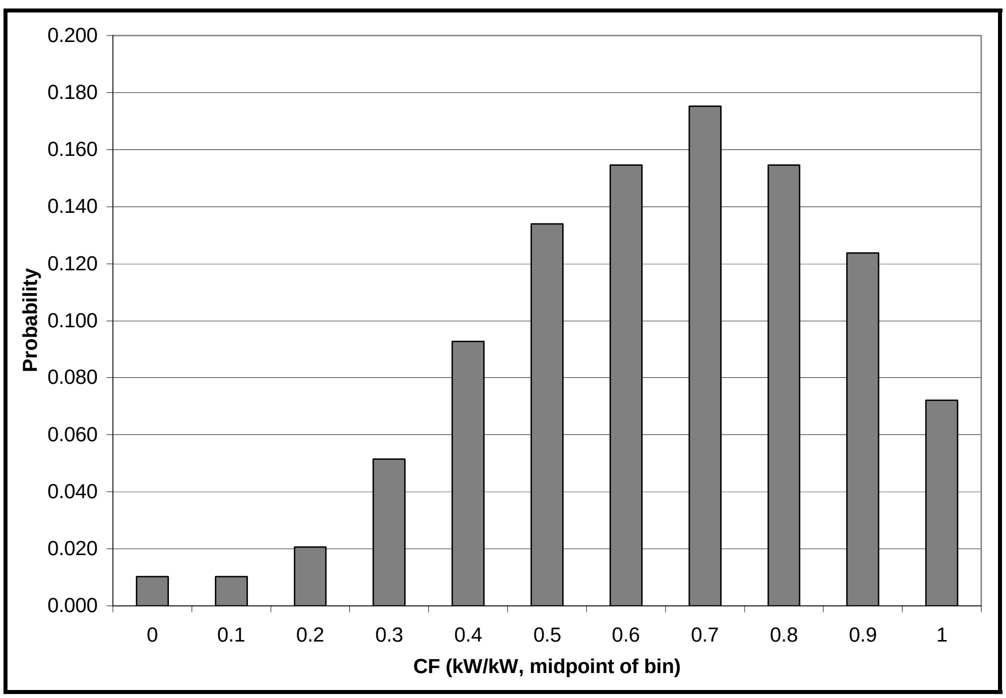


Figure D-45: Engine/Turbine (Nonrenewable) Measured Electricity Production (Capacity Factor)

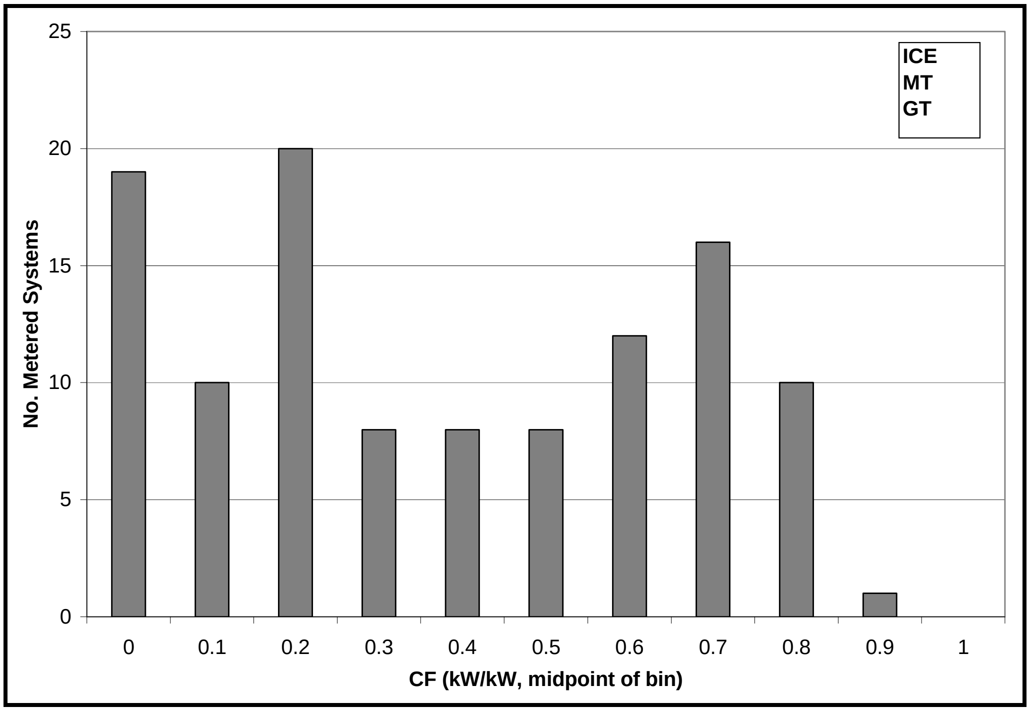


Figure D-46: MCS Distribution – Engine/Turbine (Nonrenewable) Electricity Production (Capacity Factor)

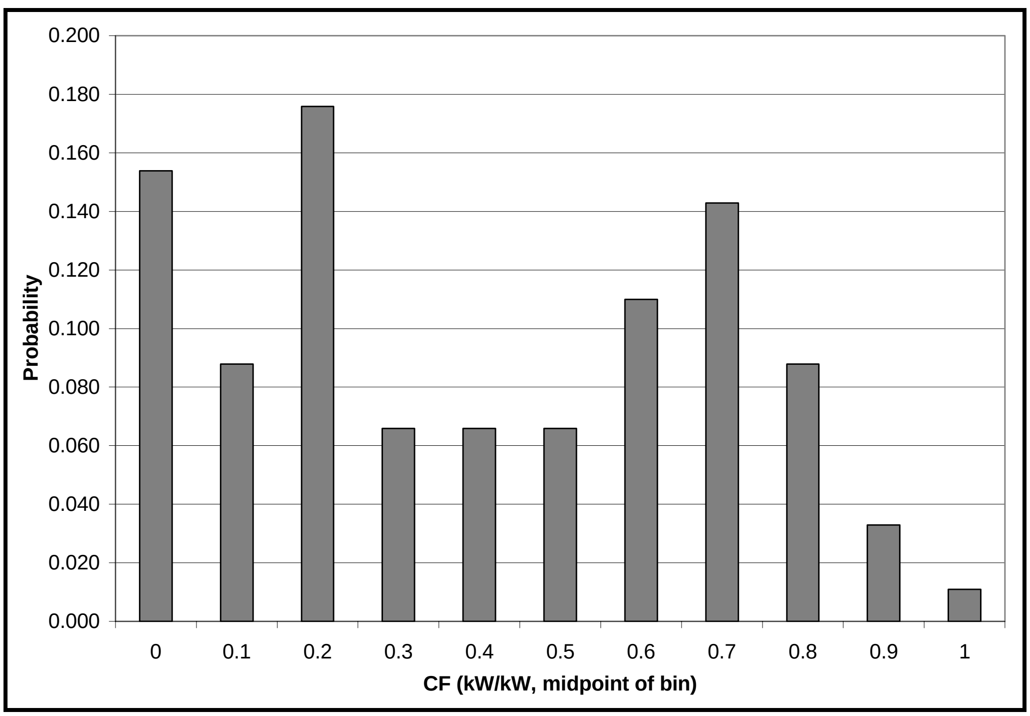


Figure D-47: Engine/Turbine (Renewable) Measured Electricity Production (Capacity Factor)

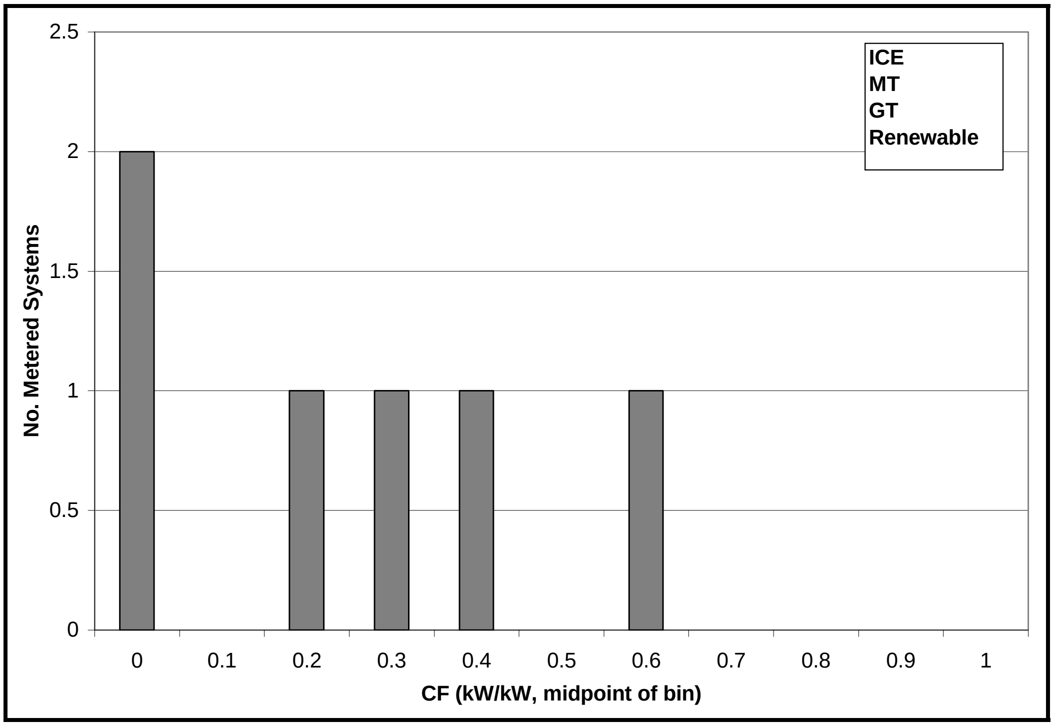


Figure D-48: MCS Distribution – Engine/Turbine (Renewable) Electricity Production (Capacity Factor)

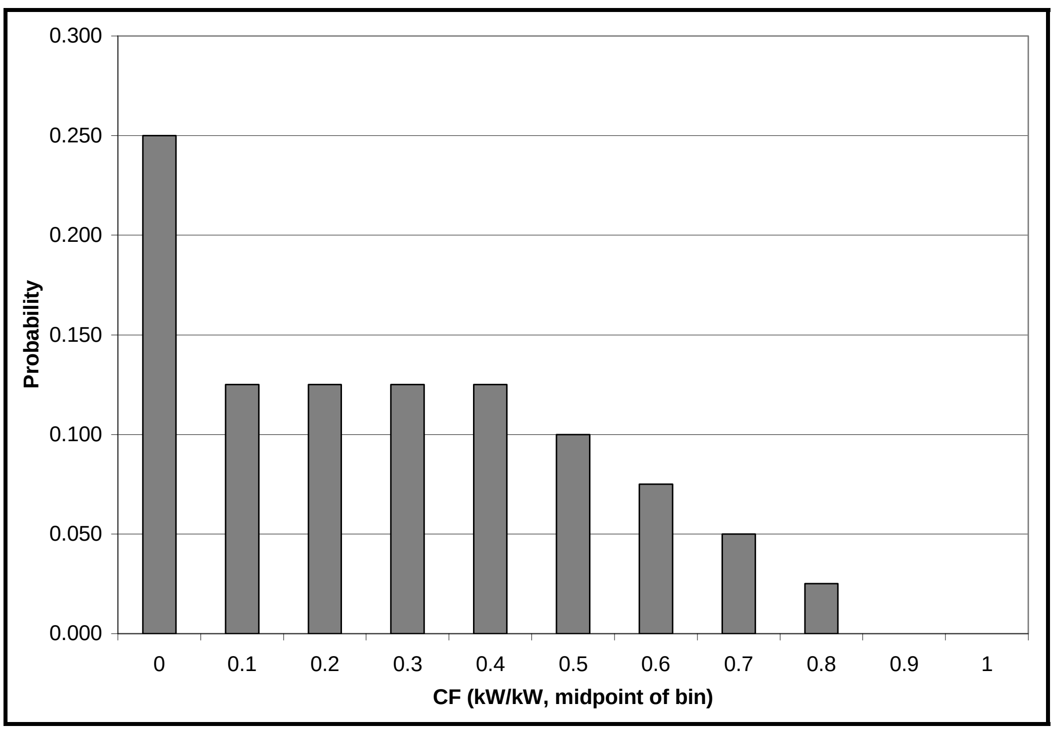


Figure D-49: Fuel Cell (Nonrenewable) Measured Heat Recovery Rate

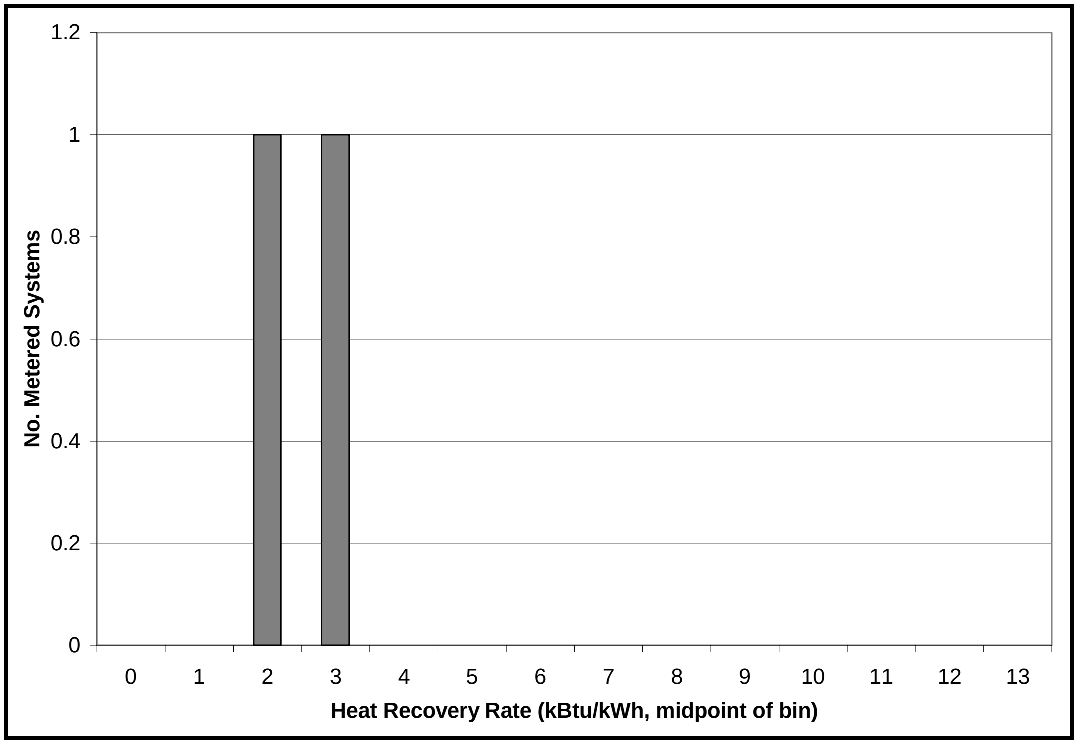


Figure D-50: MCS Distribution – Fuel Cell (Nonrenewable) Heat Recovery Rate

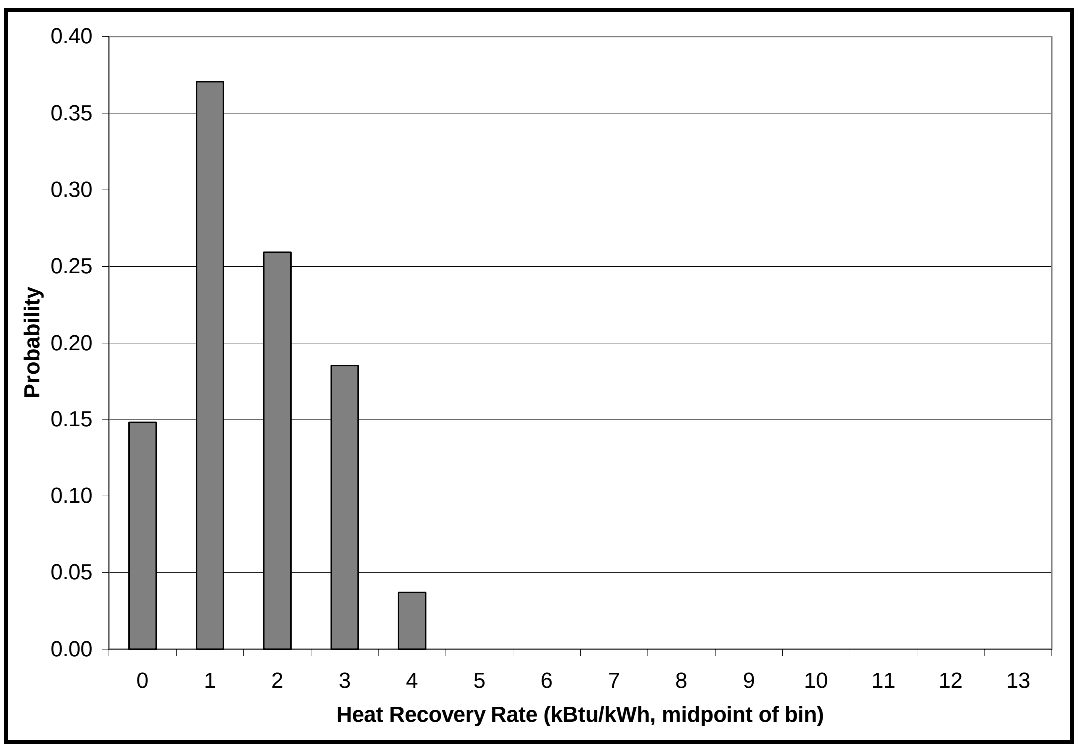


Figure D-51: Engine/Turbine Measured Heat Recovery Rate

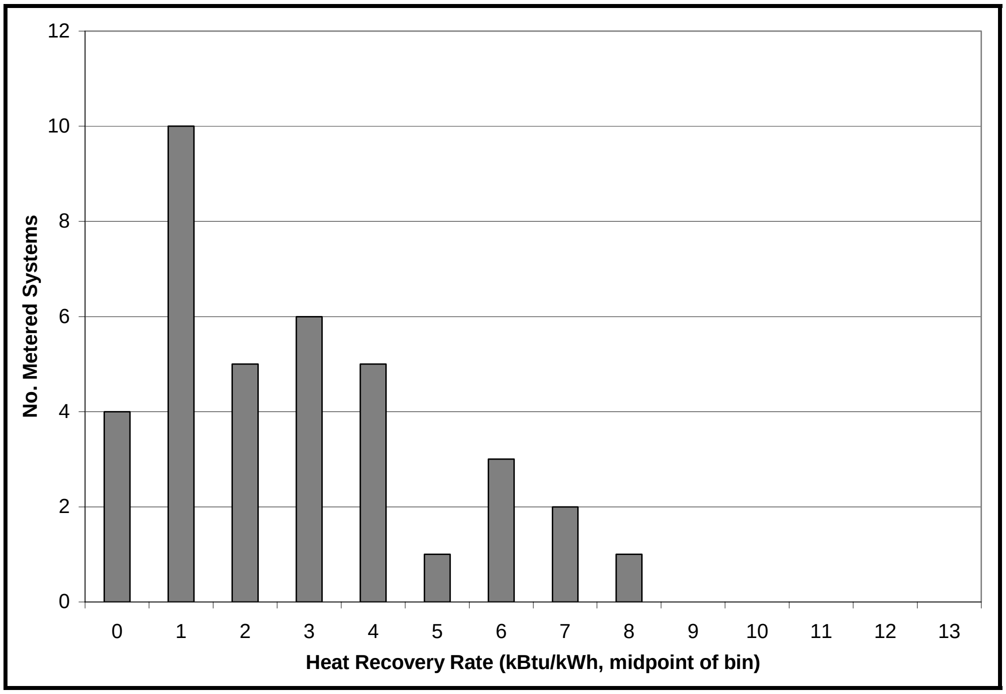
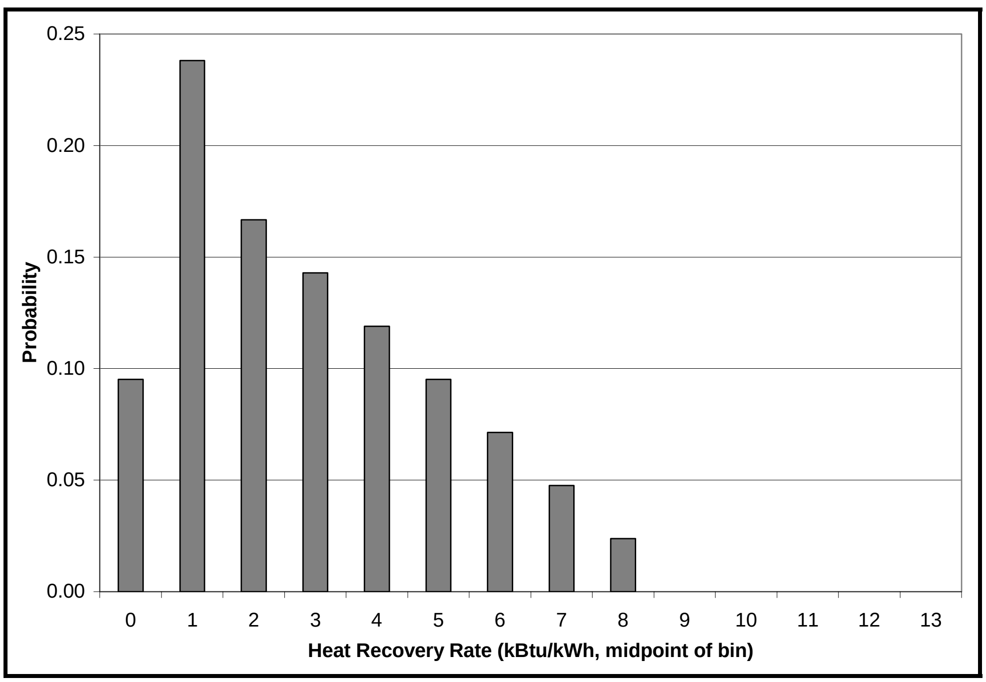


Figure D-52: MCS Distribution – Engine/Turbine Heat Recovery Rate



Appendix E

Metering Systems

As a part of the Measurement & Evaluation (M&E) of the SGIP, Itron installs metering equipment at HOST facilities. The exact metering required varies by incentive level but may include electric, fuel, and/or heat metering. Many considerations inform the metering decision process including the presence of existing metering equipment, the quality or quantity of data from existing metering sources, and the relative difficulty, and therefore expense, of installing new metering equipment.

E.1 Electric Generation Metering Equipment

Metering equipment installed by Itron for the purpose of obtaining electric net generation output (ENGO) falls under two distinct categories: systems where ENGO is the only metering required such as PV, and cogeneration systems with HEAT metering in addition to ENGO metering. Each of these two systems seeks to achieve the same goal through slightly different approaches.

Systems without HEAT Metering

Metering of these systems for ENGO involves the installation of current transducers (CTs), a meter, a socket, a panel, communications equipment, and associated wire and conduit. The exact equipment required varies based upon the equipment found on-site. For example, a panel may be installed that has ample room for the M&E meter. For the purposes of this description the assumption is made that there is no existing that facilitates ENGO meter installation.

Itron's installation subcontractors install an electrical panel to house the wiring and meter. All wiring is run through conduit at least at the protective level as found on-site. Typical installation practices involve rigid conduit (EMT) but may involve flexible conduit if necessary or appropriate. A meter socket is installed on this panel that varies depending upon the electrical characteristics of the system such as 1-phase versus 3-phase and maximum amperage. Current transducers (CTs) are installed on each phase of power and wired to the electrical meter. The meter used is a revenue-grade electrical meter equipped with a land-based modem for communications. A telephone line is activated at the property and a telephone line is installed from the Minimum Point of Entry to the meter.

Systems with HEAT Metering

ENGO metering of cogeneration systems varies from the above description in order to minimize the expense of installing metering equipment. Because a data logger is installed for HEAT metering, the ENGO can be stored on the data logger as well. In these cases, power transducers with a pulse output are installed on each phase of power and wired to the data logger's pulse input channel. Similar to the ENGO-only description, all wire is run through conduit at least to the level found at the facility.

E.2 Fuel Consumption Metering Equipment

Fuel meters are installed in very few cases for M&E purposes. These include renewable-fueled systems that are piped to also use utility-supplied natural gas and in some fossil-fueled cogeneration systems lacking a dedicated fuel meter. Fuel meters are invasive and require a licensed contractor to complete the work and typically require the plant operator to shut down the cogeneration system. Gas meter technology varies based on the operating pressure of the system. Low pressure and low capacity systems use diaphragm meters while higher pressure or capacity systems will use rotary or turbine meters. Table E-1 below provides some guidelines that are used for meter selection.

Table E-1: Gas Meter Selection Criteria

Gas Meter Type	Maximum Pressure (psig)	Maximum Flow (SCFH)
Diaphragm	100	1,000
Rotary	175	141,000
Turbine	1,440	18,000,000

Electronic volume correctors may also be specified to correct for ambient conditions. Finally, gas meters are specified with a pulse output that is stored in a data logger. Data logger characteristics, including power and transmission of data to the evaluation contractor, use the method described below for metering of heat recovery.

E.3 Heat Recovery Metering Equipment

Heat recovery applies to nonrenewable-fueled cogeneration systems. 2006 represents a transitional year as early systems utilized invasive equipment and later systems utilized noninvasive equipment. This discussion will focus on the latter. Conceptually, measurement of heat typically involves measurement of a fluid flow and the temperature of that fluid on both sides of a heat exchanger[1]. The fluid may be liquid (water, glycol mixture, oil, etc.) or gas (steam or exhaust air) and temperatures range from 32°F to 500°F. The heat exchanger may be a simple plate-and-frame heat exchanger or as complex as an absorption chiller.

Flow is measured using an ultrasonic flow meter with clamp-on transducers. The evaluation contractor researched all commercially available products and chose a product that is highly calibrated and has a much better low flow reading capability than other ultrasonic flow meters. Accuracy and precision are similar to that of insertion flow meters used in the past.

Temperature is measured using clamp-on thermocouples. These thermocouples are accurate and precise but suffer from a delay in temperature changes as it takes some time for the fluid temperature to migrate to the pipe surface. This delay is partially offset by utilizing a differential temperature, where the delay is seen on both measurements and is assumed to cancel out. As these temperature sensors are relatively inexpensive and not as accurate as desired, redundant sensors are used (two on the hot side and two on the cold side). This allows for the average of each of the two sensors to be used in the differential temperature calculations as long as they are within a certain range. Should one sensor fall out of range the calculation of heat may still be completed without requiring a service call.

Data are stored in a data logger capable of reading digital and analog inputs. Memory is sufficient to store data for at least one month should communications fail. Proprietary software is used to program the data logger and to communicate with the data logger in a server/client configuration for downloading data.

Communications are handled by a cellular-based modem using an IP connection. Static IP addresses are currently used and the capability of using dynamic IP addresses is being explored. Data are downloaded daily and copied to a web-accessible server.

Power is supplied to the data logger, flow meter, and modem via an external battery. This battery is connected to facility power and, in the event of a power outage, is capable of operating the metering equipment for approximately two days.

[1] There are some instances where exhaust air is used directly in a process without the use of a heat exchanger. As these systems do not represent a significant portion of the metering effort they will not be specifically discussed here. However, they are conceptually similar to heat exchanger based systems.

All equipment is housed in a NEMA weatherproof enclosure which is mounted to a wall near the thermal metering location. NE MA specification is typically 4x but varies based on conditions found at the facility.