January 2005 • NREL/SR-560-36951

Subcontractor Report

Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System

Final Report

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Operated for the U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy
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List of Acronyms

ADA-DER	Advanced Distribution Automation for Distributed Energy Resources
BCAP	Biennial Cost Allocation Proceeding
CAISO	California Independent System Operator
CaIS Reports	California Interconnection Status Reports
CHP	combined heat and power
CPUC	California Public Utilities Commission
CRS	cost recovery surcharge
CT	current transformer
CTC	competition transition charge
DCHP	CHP information design hierarchy
DER	distributed energy resources
DFCL	fuel cell
DG	distributed generation
DIES	diesel engine
DWR	Department of Water Resources
DWRBC	Department of Water Resources bond charges
FERC	Federal Energy Regulatory Commission
FSC	fixed services charge
GPC	generator power control
GSP	gas service provider
GRC	General Rate Case
HTML	hypertext markup language
ICCP	inter-control center communications protocol
ICE	internal combustion engine
IDL	interface definition language
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
ISO	independent system operator
LDC	local distribution company
LN	logical node
MMS	manufacturing message specification
NDC	nuclear decommissioning charge
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
OASIS	Open Access Same-Time Information Systems, Organization for Advancement of Structured Information Systems
PCC	point of common coupling
PDF	portable document format
PG&E	Pacific Gas and Electric
PON	program opportunity notice
PPPC	public purpose programs charge
PUC	Public Utilities Code

PV	photovoltaics
PY	program year
RE	RealEnergy
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SGIP	Self-Generation Incentive Program
SoCalGas	Southern California Gas Co.
UCA	utility communication architecture
VMM	Virtual Maintenance Monitor
W3C	World Wide Web Consortium
WPP	wind power plant
XML	extensible markup language

Executive Summary

The purpose of subcontract NAD-1-30605-11 between the National Renewable Energy Laboratory and RealEnergy (RE) is to describe RE's approach to the challenges it faces in the implementation of a nationwide fleet of clean cogeneration systems to serve contemporary energy markets. These challenges fall into three categories:

- Market challenges
- Operational challenges
- Information integration challenges.

A series of deliverables has been written to address each of the challenge areas defined by the National Renewable Energy Laboratory and RE. The deliverables from Phase 1 (the base year, including all D-1 deliverables) and Phase 2 (the option year, including all D-2 deliverables) are distributed under the challenge areas as follows:

- Market challenges
  - D-1.10, Contractual and Regulatory Issues
  - D-2.06, Measure Regulatory Effectiveness of Interconnection in California
  - D-2.08, Utility Tariff Risk and Its Impact on Market Development
  - D-2.12, Impact of Incentives on Distributed Energy Resources Markets

- Operational challenges
  - D-1.08, Test Codes Using Simulated Data
  - D-1.09, Install and Test Energy Management Software
  - D-2.07, Survey of Practical Field Interconnection Issues
  - D-2.10, Trend Analysis for On-Site Generation

- Information Integration Challenges
  - D-1.05, Define Information and Communications Requirements
  - D-1.06, Develop Command and Control Algorithms for Optimal Dispatch
  - D-1.07, Develop Codes and Modules for Optimal Dispatch Algorithms
  - D-2.09, Evaluate Performance of Dispatch Systems
  - D-2.11, Information Design Hierarchy for Combined Heat and Power.

All D-1 deliverables are addressed in the Phase 1 (base year) final technical progress report.[1] This report fulfills deliverable D-2.5, the Phase 2 final annual technical progress report, and covers all D-2 deliverables.

[1] See: RealEnergy. "Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report." NREL/SR-560-33581. Golden, CO: National Renewable Energy Laboratory, April 2003.

Challenges to Combined Heat and Power Markets

Combined heat and power markets face risks from new tariffs—some of which have the undesirable effect of eliminating competition in the retail electricity industry. At the same time, the natural gas supply is decreasing (forcing prices up), and environmental concerns remain for other fossil and nuclear alternatives.

Incentives are being developed to encourage new, clean sources of electricity and efficiency, including combined heat and power. These can, in some cases, offset tariff and other cost increases. This report will assess incentives for combined heat and power in New York and California.

Finally, interconnection rules have been adopted in many states across the United States. This report examines California's Rule 21 and measures its effectiveness at reducing developer interconnection costs and delays.

Challenges to Combined Heat and Power in the Field

RE faces myriad challenges in the field. It has attempted to deal with these by adopting its own "best practices" and using its field trend data collection system as a tool for feedback on field performance.

Conclusions and Lessons Learned

From the work RE performed in Phase 1 and Phase 2, several general conclusions and lessons learned can be distinguished:

- It is less costly to overcome technological challenges than regulatory market challenges.
- Most information integration and field challenges are technological challenges.
- Some market challenges are not solvable at any cost.
- Technological challenges can only be addressed to the extent that their solutions are economically justified.
- Spark spread is the primary economic indicator for RE.
- Current market conditions are squeezing spark spread from two directions: increasing cost and decreasing revenue.
- Regulatory market challenges pose the greatest danger to the future of RE's business case.

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1 Introduction

Under subcontract NAD-1-30605-11 between the National Renewable Energy Laboratory and RealEnergy (RE), RE is to describe its approach to the challenges it faces in the implementation of a nationwide fleet of clean cogeneration systems to serve contemporary energy markets. RE's work in Phase 1 and Phase 2 (the base year and option year) of its subcontract addressed immediate challenges to combined heat and power (CHP) deployment. The tasks of these phases were divided into three themes: market issues, field issues, and integration issues.

Table 1-1. Structure and Themes in RE's Research

Phase	***Section***	***Task Title*** ***Theme:*** **Challenges to CHP Markets**	***Deliverable***
Phase 1	1.6	Contractual and Regulatory Issues	D-1.10
Phase 2	2.2	Utility Tariff Risk and its Impact on Market Development	D-2.08
Phase 2	2.3	Impact of Incentives on DER Markets	D-2.12
Phase 2	2.4	Measuring Regulatory Effectiveness of Interconnection in California	D-2.06
Phase	***Section***	***Task Title*** ***Theme:*** **Challenges to CHP in the Field**	***Deliverable***
Phase 1	1.4	Test Codes Using Simulated Data	D-1.08
Phase 1	1.5	Install and Test Energy Management Software	D-1.09
Phase 2	2.5	Survey of Practical Field Interconnection Issues	D-2.07
Phase 2	2.6	Evaluate Performance	D-2.09
Phase	***Section***	***Task Title*** ***Theme:*** **Challenges to CHP Integration**	***Deliverable***
Phase 1	1.1	Define Information and Communications Requirements	D-1.05
Phase 1	1.2	Develop Command and Control Algorithms for Optimal Dispatch	D-1.06
Phase 1	1.3	Develop Codes and Modules for Optimal Dispatch Algorithms	D-1.07
Phase 2	2.7	Trend Analysis for Building Energy and On-site Generation	D-2.10
Phase 2	2.8	Information Design Hierarchy for Combined Heat and Power	D-2.11

This research does not attempt to make an exhaustive list of challenges to CHP but rather provides in-depth analysis of immediate challenges to CHP developers in California and elsewhere in the country.

RE's Phase 1 and Phase 2 research touched on each of the challenge areas. In the base year, the focus was on certain information integration issues and implementation in the field. In Phase 2, the focus was on the market challenges that endanger spark spread, the economic rationale of all cogeneration projects. These issues are critical and of higher priority because failure to overcome economic challenges could render integration and field solutions moot.

The base year report[2] contained three information integration topics.

- Section 1.1, “Define Information and Communications Requirements,” discussed requirements for integration, communications, metering, monitoring, billing, alarm, and control. Input and output were discussed, as were the physical hardware and software necessary for implementation.
- Section 1.2, “Develop Command and Control Algorithms for Optimal Dispatch,” gave an overview of the existing and new building energy systems, discussed system interactions, and provided requirements for optimal dispatch.
- Section 1.3, “Develop Codes and Modules for Optimal Dispatch Algorithms,” made a complete procedural analysis of the new system. This included flowchart revision, a hierarchy of functions, function parameters and return values, and code for dispatch sequence.

The report also included two field implementation sections.

- In Section 1.4, “Test Codes Using Simulated Data,” a section called “Issues Preventing Optimal Dispatch” discussed how early technology implementation issues of the information system disallowed optimal dispatch and suggested revisions to code to address the issues.
- Section 1.5, “Install and Test Energy Management Software,” covered the extensive platform testing RE conducted prior to assembling its current hardware/software system platform.

Finally, Section 1.6, “Contractual and Regulatory Issues,” discussed regulatory and other market challenges RE faces when planning, designing, installing, and commissioning a project.

In Phase 2, which this report covers, three market sections are discussed.

- Section 2.2, “Utility Tariff Risk and Its Impact on Market Development,” discusses the effect of changes in utility tariffs on the profitability of CHP. It uses the example of current California electric and gas rates, with special emphasis on Southern California Edison (SCE) and Southern California Gas (SoCalGas) rate tariff filings.
- Section 2.3, “Impact of Incentives on DER Markets,” compares New York and California distributed generation (DG) incentive programs.
- Section 2.4, “Measure Regulatory Effectiveness of Interconnection in California,” discusses the relative effectiveness (from the perspective of the CHP user) of recent revisions to California's Rule 21.

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[2] See: RealEnergy. “Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report.” NREL/SR-560-33581. Golden, CO: National Renewable Energy Laboratory, April 2003.

Two sections discuss the CHP market from the perspective of the field (the practical operational issues that can prevent optimal installation, maintenance, and operation of CHP systems).

- Section 2.5, "Survey of Practical Field Interconnection Issues," covers problems encountered in electrical and thermal interconnections and gives best practices that RE has developed to solve problems encountered while interconnecting. This section explains how to avoid delays and costs and how to maintain safe, Rule 21-compliant practices during installation.
- Section 2.6, "Evaluate Performance of Dispatch Systems," covers issues RE has encountered in managing field integration. It takes a historical look at the first four generations of dispatch systems RE deployed, their capabilities, and their limitations. The focus throughout is on how technology and practice have evolved toward optimal dispatch and the limits to dispatch flexibility along the way.

Two more sections focus on integration:

- Section 2.7, "Trend Analysis for On-Site Generation," provides close-up analysis of four RE sites and compares in each case the pro forma expectations for performance with actual field performance trends to highlight commonalities and differences of the sites.
- Section 2.8, "Information Design Hierarchy for Combined Heat and Power," covers industry-wide integration design issues through implementation of a CHP data standard. Challenges to CHP integration are also discussed. The focus is on giving the background and showing development of a CHP information design hierarchy (called DCHP), in accordance with existing national and international standards—particularly International Electrotechnical Commission (IEC) 61850—for distribution automation. The discussion leads through a series of competing standards and technologies to the Electric Power Research Institute (EPRI) effort to model distributed energy resources (DER) including diesel engines. Although the work is mostly aimed at emergency backup generation (a far cry from CHP because of the fuel, short operating hours, and non-parallel interconnection), the use of diesel reciprocating engine as the modeled prime mover is very useful for the development of a draft DCHP. Primary additions to the EPRI work occur in the area of thermal recovery.

2 Utility Tariff Risk and Its Impact on Market Development

2.1 Executive Summary

A number of risks face the distributed energy industry in California today. Of these, tariff risks—financial risks from fees charged by regulated utilities—present the greatest threat to DER projects. This paper will demonstrate the magnitude of tariff risks in California and explain the tariffs' background, their nature, and the relative effect they have on project installations in the field.

Four tariffs will be examined. These are listed below with their phase-in date:

- SoCalGas Biennial Cost Allocation Proceeding (BCAP) – January 2005
- Standby charge – projects installed on or after Jan. 1, 2005
- Cost recovery surcharge (CRS) departing load fee – projects installed on or after Jan. 1, 2005
- SCE General Rate Case (GRC) 2003 – new tariffs implemented at the completion of GRC Phase II, possibly by summer 2005.

The effect on actual CHP projects is significant. The potential effects, according to RE's CHP profitability model, on a project in SCE and SoCalGas territory that nets $70,050 annually are shown below.

Table 2-1. Tariff Effect on Profitability of a Sample CHP Project

Tariff	Net Profit $/yr	Lost Profits %
No tariff change	$ 70,050	0%
Departing load fee	$ 46,858	33%
SoCalGas BCAP	$ 39,583	43%
Standby charge	$ 15,823	77%
SCE GRC	$ (30,765)	143%
All changes	$(138,652)	298%

2.1.1 Spark Spread

Spark spread is the most important financial indicator for CHP. It is equal to the difference between electricity price (the price at which the CHP generator can displace utility-supplied power, i.e., the current tariff) and the cost of fuel (natural gas, in this case) to run the generator plus the value of the captured thermal energy (both as a commodity and as an offset of the cost of other fuel formerly used to provide the thermal product).

Changes to the electricity tariff from the GRC have a considerably greater effect on spark spread than changes to gas prices from the BCAP. From the Summer 2004[3] on-peak rate to the fully implemented GRC Summer rate, there is a drop of more than $0.075/kWh because of the GRC. From the Summer 2004 on-peak rate to the Summer 2005 on-peak rate, spark spread declines by $0.0053/kWh because of the BCAP.

A customer in SCE territory that is also a customer of SoCalGas and that elects to install CHP in its facility will be negatively affected by the GRC and the BCAP. From the summer of 2002 to the summer of 2005, RE estimates that CHP spark spread (assuming no GRC phase-in) will shrink from $0.20/kWh to less than $0.045—more than a four-fold decline. Summer mid-peak and off-peak tariffs also will shrink to 22% and 11% of their value, respectively. The Winter off-peak energy rate (under SCE's latest GRC rate scenario) is only $0.01 less than Summer on-peak ($0.0845 versus $0.0731); that lowers the value of energy produced on-site and the value of displaced electric chiller use in the summer. Between the GRC and the BCAP, average spark spread for the Summer on-peak TOU-8 rate tariff period is reduced to less than $0.05. Given all assumptions about gas prices, tariff rates, etc. (see Section 2.2.2 for a complete list of assumptions)—including winter-only thermal heat load and summer-only cooling load and no tri-generation, not including facilities-related demand—by full GRC implementation, Winter off-peak operation could have a slightly better spark spread than Summer on-peak ($0.0477 versus $0.0449).

SCE's 2003 GRC and SoCalGas' BCAP tariff recommendation represent giant steps backward into the days of centralized power and monopoly utility service. By increasing fixed charges and lowering energy rates (except off-peak rates), the former discourages all forms of DER: energy efficiency, renewable energy, CHP, and demand management. The latter gives all non-core gas customers a strong incentive to abandon the deregulated gas commodities market and rejoin the utility as core customers. Cogenerators, by definition, cannot rejoin as core customers.

2.1.2 Tariff Priority

These considerations lead to a prioritization of defense against tariffs based on their effect.

Table 2-2. Tariff Risk Priority Ranking

Tariff Name	Risk $	Priority
Proposed SCE GRC-2 rates	$ 100,815	1
Standby charge	$ 54,227	2
BCAP transportation cost increase	$ 30,468	3
Departing load fee	$ 23,192	4
No tariff change	$ –	–

[3] "Summer" and "Winter" are capitalized in this paper when the term denotes the corresponding utility rate tariff period.

2.2 Introduction

This section assesses the regulatory risk and market development effects of non-interconnection utility tariffs. The assessment investigates the practical consequences of policy decisions and market trends on energy rates, demand charges, gas rates, standby charges, and exit fees. Based on RE's experience, policy decisions are rated according to their effects on project feasibility and overall market development.

2.2.1 Introduction to Tariffs

Tariffs are the means by which revenue requirements are assigned to rate groups for the provision of regulated utility services. Revenue requirements are the costs of providing utility services that are approved by the California Public Utilities Commission (CPUC) for recovery through customer rates. California regulated electric utilities include Pacific Gas and Electric (PG&E), SCE, and San Diego Gas and Electric (SDG&E). Regulated gas utilities include SoCalGas, PG&E, and SDG&E.[4]

2.2.1.1 Electricity Tariffs

Rate groups are categories of customers. These groups are determined by whether customers are "bundled." Bundled customers receive all electric services from regulated utilities; unbundled, or "direct access," customers buy their electric commodity from third-party suppliers and take only transmission and distribution services and customer services from a regulated utility.

Customer tariffs are further divided into end use and load size categories. These are:

- Residential
- Commercial
- Industrial
- Electric generators.

Rates typically consist of four components:

- Energy charges
- Demand charges
- Monthly customer charges
- Non-bypassable charges (such as public benefits programs).

Regulated utility services include:

- Electricity supply – production or procurement of power for customers
- Electricity delivery – transmission and distribution
- Customer services – interconnection to the delivery system and managing relationships with customers, including handling customer communications, measuring usage, maintaining records, and billing.[5]

---

[4] SoCalGas and SDG&E are owned by a single parent company, Sempra Energy.
[5] Southern California Edison. "Phase 2 of 2003 General Rate Case Marginal Cost and Sales Forecast Proposals." Application A. 02-05-004.

2.2.1.2 Gas Tariffs

Rate groups are categories of customers. These groups are determined by whether customers are "bundled." Bundled customers, called "core customers," receive all gas services from regulated utilities. "Non-core customers" buy their gas commodity from third-party suppliers and take only transmission and distribution services and customer services from a regulated utility.

Core and non-core customer tariffs are further divided into end use and load size categories. These are:

- Residential
- Commercial
- Industrial
- Cogenerators.[6]

Rates consist of four components:

- Commodity charges
- Transportation charges
- Monthly customer charges
- Non-bypassable charges.

Regulated utility services include:

- Commodity procurement
- Intrastate gas transportation
- Gas storage
- Customer services – handling customer communications, measuring usage, maintaining records, and billing.

2.2.2 Spark Spread as a Measure of Tariff Risk

For the DER developer, owner, or operator, tariff risk is a measure of the probability that the utility rates used for calculating return on invested capital will change for the worse against the assumptions by which a project was underwritten. For a customer or third-party owner of CHP, "spark spread" is a telling metric of tariff risk. It is the difference between the cost of natural gas and the price of electricity plus the value of the "thermal credit"—the captured waste heat.

A cogenerator typically buys gas and sells electricity. Therefore, an increased gas tariff rate or a decreased electric tariff rate reduces spark spread and hurts the market for CHP. A decreased gas tariff rate or an increased electric tariff rate increases spark spread and improves CHP market outlook. Both of these moves also affect the value of the thermal credit, which usually includes additional displaced gas or electric costs. The market for the thermal credit also plays a role.

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[6] Cogenerators must receive non-core service.

Figure 2-1 shows the relationships between electricity prices, gas costs, and the value of the thermal commodity. As gas costs rise, electricity prices or the commodity value (or both) must also go up to maintain the same spark spread. The reverse is also true.

Simply put, spark spread is the difference between the price the seller of electric generation receives for a kilowatt-hour of electricity and the price of fuel in an equivalent kilowatt-hour. Spark spread is the most significant determinate in a generating facility's gross margin. For a central station generating plant, spark spread is simple. Electricity is a wholesale product with only a price per kilowatt-hour, and fuel price is easily converted into kilowatt-hour equivalents.

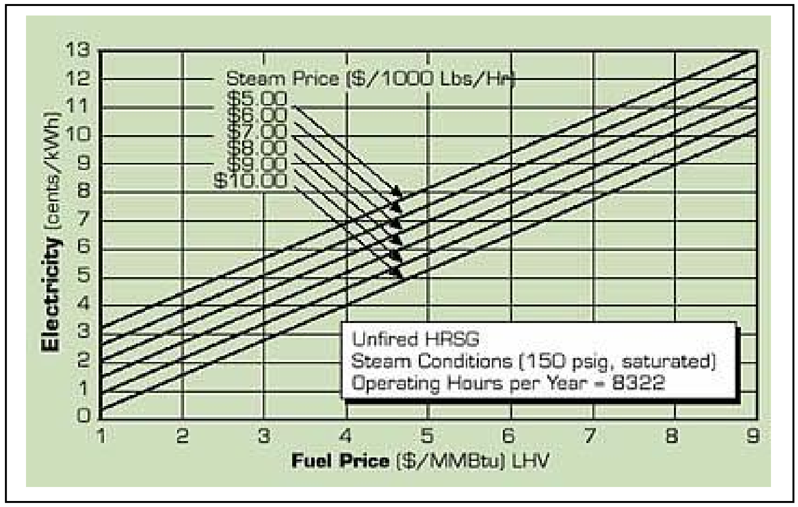

Figure 2-1. Example spark spread for CHP[7]

Determining the spark spread for a CHP project is slightly more complicated. First, the price of electricity is not a simple wholesale cents-per-kilowatt-hour number. The price of electricity is a factor of the utility's rate components and the percentage of those that can be captured or offset by the CHP plant's output. Several rate components must be calculated: demand charges, generation charges, customer charges, public benefits charges, taxes, and—as is frequently the case with CHP—"standby charges" or "exit fees." All of these rate components are discussed in detail later in the paper.[8] Second, one must factor the economic value of the recovered waste heat. Because an existing building will already have equipment to supply chilled and hot water—usually an electric chiller and a gas-fired boiler—the new thermal supply will offset operation of the chiller and boiler. Therefore, the overall spark spread must include the value of the kilowatt-hours reduced by not running the electric chiller and the natural gas not burned by not running the gas boiler. The waste heat can be used for absorption chilling, for heating (in which case it is a direct offset against burning fuel in a boiler), or both. In the first case, it is displacing kilowatts of demand and kilowatt-hours used to operate mechanical chillers; in the second case, it displaces building hot water supply from a gas (or other fuel) boiler. Chilled water and hot water are valuable commodities in themselves and can be billed on a per-therm basis.

[7] "Deregulation Stimulates Onsite Power Developments." *Energy User News*. September 2002. http://www.energyusernews.com/CDA/ArticleInformation/features/BNP__Features__Item/0,2584,84741,00.html. The figure is based on a 3-MW gas turbine; spark spreads are estimated to achieve a 3-year project payback.

[8] See Section 2.5 for a discussion of all rate components.

Because utility electric rates vary by time of day, day of week, and season, a different spark spread analysis must be performed for each rate calculation. The result must be converted into dollars per kilowatt-hour. Demand (dollars per kilowatt) must be converted to dollars per kilowatt-hour for both time- and facilities-related demand and the total added to the energy charges at the existing tariff rate. Gas costs must be converted into dollars per kilowatt-hour. Additional tariff costs—such as standby charges, departing load fees, and non-bypassable charges—must be converted to dollars per kilowatt-hour and subtracted from the total. The bottom line is that, all other things being equal, when the sum of the spark spread and the maintenance charge (expressed in cents per kilowatt-hour) is greater than 0, the plant should be dispatched.

The overall spark spread is calculated using the following formula:

> (electric energy charges avoided + electric demand charges avoided + electric chiller energy charges avoided + gas boiler gas costs avoided)
> – *(minus)* (gas costs + standby charges + non-bypassable charges + departing load fees)
> = *(equals)* spark spread $/kWh.

Table 2-3 is a representation. This example calculates spark spread for a 1,000-kW CHP plant for what might be typical summer peak and winter peak rates for a California or New York utility.

Table 2-3. Summer Peak Period Spark Spread

		Spark Spread Contribution	Notes
Electric Rate			
Generation (kWh)	$0.09	$0.09	The utility price per kilowatt-hour varies by time of day, day of week, and season. Assume 8 hours of summer peak Monday–Friday.
Demand (kW)	$15.00	$0.0714	The demand charge ratchets daily, monthly, or annually. To convert demand on a per-kilowatt basis to an equivalent kilowatt-hour charge, assume capture of 80% of the demand and divide that by the number of kilowatt-hours in the period.
Customer charge	$1,000		This is a fixed charge and is not offset by CHP output.
Public benefits program	$0.005		This is charged per kilowatt-hour and, being non-bypassable, is not offset by CHP output.
Standby charge (kW)	$6.00		Standby charges vary widely and usually have a clause to prevent double charging. Not all utilities charge for standby.
Exit fee	$0.005	($0.005)	Exit fees are charged by utilities on a per-kilowatt-hour basis against the generation they are not providing to the customer. The exit fee is a deduction against the spark spread. Not all utilities charge exit fees.
Taxes (percent of gross bill)			In some jurisdictions, city taxes are levied on delivered utility service. Within those, some may or may not charge for onsite generation.
Equivalent kWh Price		**$0.1564**	
Waste Heat Recovery			
Chilling (ton hours)	46,200		275-ton absorption chiller at full output
Chilling equiv. $0.00/kWh		$0.0198	Value of kilowatt-hour offset obtained from absorption cooling
Chilling equivalent demand reduction		$0.0157	Value of kilowatt offset obtained from absorption cooling
Heating (therms)			
Equivalent kWh Price		**$0.0355**	
Total Equivalent KWh Price		**$0.1969**	
Gas Rate			
Commodity (therms)	$0.55	$0.0605	Therms are converted to kilowatt-hours by dividing by the plant heat rate, 0.11 therms per kilowatt-hour.
Delivery (therms)	$0.06	$0.0066	
Customer charge	$300		
Public benefits programs	$0.04	$0.0044	See note above.
Taxes			See note above.
Total Equivalent KWh Price		**$.0715**	
Spark Spread		**$0.1254**	

The following analysis calculates these costs for electricity and gas tariffs from 2002 through 2005 and includes the latest tariff estimations[9] for:

- SCE's GRC 2003
    - TOU-8 primary voltage service (implemented in the GRC)
    - Departing load (implemented in the GRC)
    - Standby charge (implemented in the GRC)
- SoCalGas BCAP.

The analysis charts the change in electricity and gas prices in California from 2002 through 2005. It assumes SCE's GRC is passed in its present incarnation by summer 2004 and that the SoCalGas BCAP is in place in January 2005.

Tariffs in effect and new tariffs are shown at right. Although GRC Phase 2 will probably be complete by summer 2005 (if not sooner), SCE has proposed to phase in the new rate, 25% per year, over a 4-year period.

Table 2-4. New and In-Effect Tariffs

Tariff	Type	Entrance/Exit
TOU-8 (old)	elec	Summer 2002
EG	gas	Summer 2002
TOU-8 (new)	elec	Summer 2003
EG (BCAP)	gas	Winter 2004/5
GRC-2	elec	Summer 2005

Figure 2-2 shows the phase-in and demonstrates the tariff's eventual effect to 2009, given the latest data.

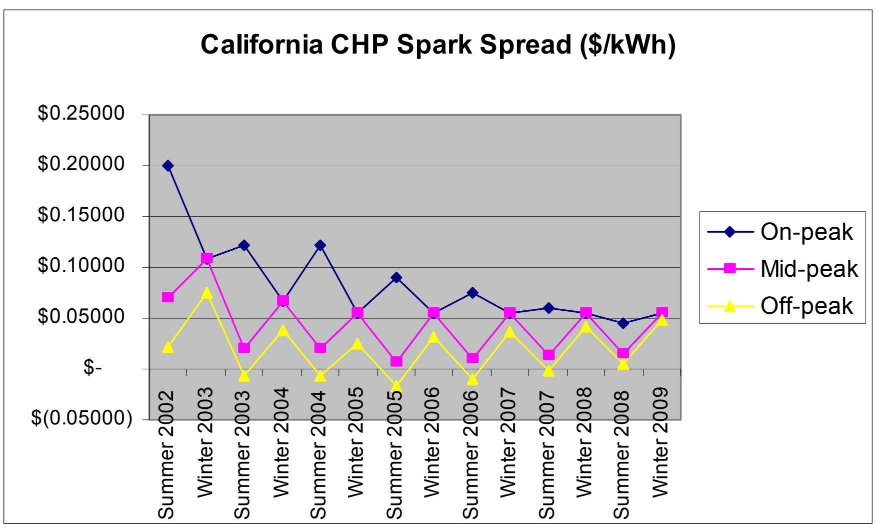

Figure 2-2. Effect of GRC and BCAP on spark spreads (4-year phase-in)

[9] Please note that these are only estimations. Neither the GRC nor the BCAP is adopted at this date, and many changes are likely prior to adoption.

The assumptions are:

- Fixed gas commodity rate of \$0.55/therm[10]
- SoCalGas BCAP increase of \$0.05309/therm (\$0.05709 to \$0.11018, 93% for transmission portion of bill)
- Heat rate of 12,217 Btu/kWh
- Electricity service level of TOU-8 primary (feeder size 2–50 kV)
- SCE GRC-2 energy rates of:
    - On-peak Summer: \$0.08457
    - Mid-peak Summer: \$0.07961
    - Off-peak Summer: \$0.07226
    - Mid-peak Winter: \$0.08087
    - Off-peak Winter: \$0.07312
- 4-year GRC phase-in
- Offset electric chilling in the summer and offset gas heating in the winter
- Time-related demand only (facilities-related demand not included)
- Standby at on-peak demand rate in 2005
- CRS at \$0.005 in 2005.

The picture that emerges shows that the magnitude of changes to the electricity tariff from the GRC have a considerably greater effect on spark spread than the changes in gas prices from the BCAP. From the Summer 2004 on-peak rate to the fully implemented GRC Summer rate, there is a drop of more than \$0.075/kWh because of the GRC. From the Summer 2004 on-peak rate to the Summer 2005 on-peak rate, spark spread declines by \$0.0053/kWh because of the BCAP. The increasing spark spread in Summer and Winter off-peak shows that off-peak rates actually increase in the GRC over the current TOU-8 rate.[11] By the end of this year, winter CHP spark spread will be negative, given \$5.50/MMBtu and the other assumptions above; by Summer 2008, spark spread is approximately \$0. This is cause for concern for any company—other than the investor-owned utilities (IOUs)—attempting to provide DER energy service to customers in California.

[10] At the time or writing, average California gas prices in 2004 were more than \$5/MMBtu.
[11] The increase in off-peak rates allows SCE to argue at one point in the GRC that it is not discouraging residential energy efficiency: “At present, SCE's proposed rate design uses the additional revenues from SCE's proposed monthly charge to lower rates in the lower usage rate tiers, so there is little impact on customer energy efficiency incentives.” (SCE-31, p. 38)

Figure 2-3 shows spark spread assuming no phase-in period for the GRC. Figure 2-4 shows spark spreads, post-BCAP and post-GRC, by CHP services provided. Tri-generation assumes summer heating load but no winter cooling load.

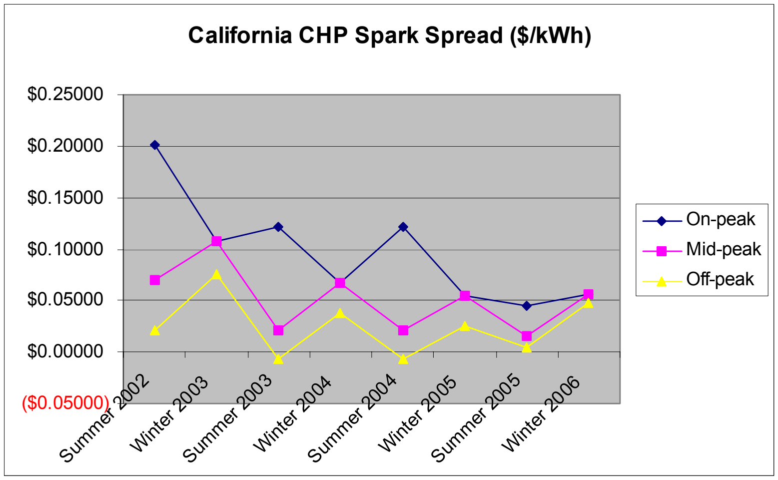

Figure 2-3. Effect of GRC and BCAP on spark spreads (no phase-in)

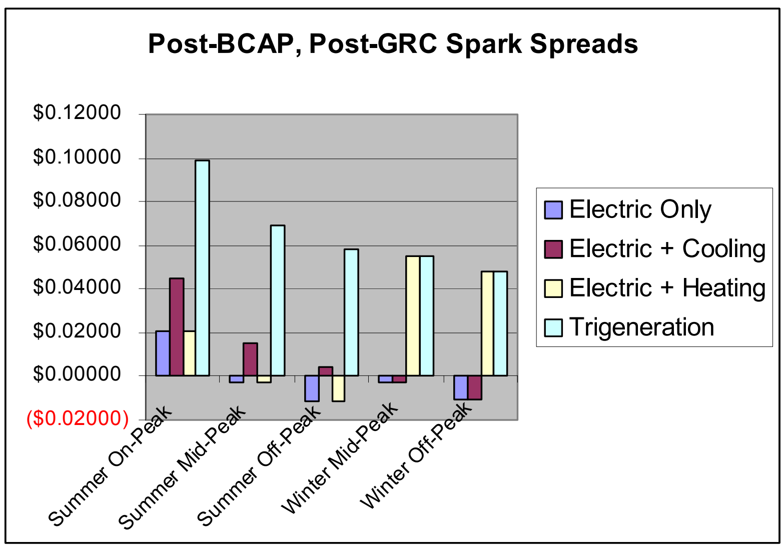

Figure 2-4. Spark spread, layered by services provided

2.3 Electricity Rates and Tariffs in California

2.3.1 Historical Background

The rates, tariffs, and assumptions used to calculate spark spread can change dramatically in a relatively short time. Although the type of rate volatility that California experienced is not common or typical, it serves to illustrate the point and demonstrate what may happen over the 15–20-year life of a CHP project.

About 70% of California customers get their electricity from the three large IOUs: PG&E, SCE, and SDG&E. Prior to restructuring, they controlled most generation, transmission, and distribution in the state.[12] They were vertically integrated and acted as regulated monopolies in their service areas.

The federal Public Utilities Regulatory Policy Act of 1978 encouraged smaller producers to generate electricity from renewable sources (wind and solar) and cogeneration (CHP) by requiring utilities to purchase this power from qualifying facilities. States were allowed to set the prices that utilities would pay for this power, and the CPUC began with the policy that the cost should be equivalent to its most expensive source of electricity—nuclear power. The 1992 federal Energy Policy Act provided further incentive for independent producers of electricity by giving them open access to the transmission systems of the utilities. Electricity from qualifying facilities was less than 1% of the state's total generation in 1980, but as a result of these policies, it had grown to 20% by 1996.

Although California's utilities and independent power producers occasionally sell power to other states, California is a net importer of electric power. In 1996, about one-sixth of California's power was imported from its neighbors, and its average price to consumers of $0.095/kWh was 75% more than the average price in 10 other Western states. The low cost of hydropower in the Northwest is a major reason for this difference. Under past regulation, private utilities were authorized to charge prices that gave their investors enough profit to encourage capital investment. Some economists argued this encouraged utilities to create extra grid capacity because this could be covered by higher prices to consumers for electricity. In the mid-1990s, California utilities did have more capacity than needed for their customers. By then, competition with the independent producers and the high costs they had to pay the qualifying facilities became liabilities for the utilities known as "stranded costs."

2.3.2 Restructuring Legislation AB 1890

The CPUC developed a restructuring plan. Its major components, enacted into law in 1996 by AB 1890, were:

- Three large IOUs—PG&E, SCE, and SDG&E—were required to divest themselves of half their power plants using fossil fuels. (Municipal utilities and other publicly-owned entities were not included in the restructuring plan.)
- A power exchange was to operate wholesale electricity auctions as a nonprofit corporation, through which utilities would buy all power not coming from their own plants or previous contracts (mostly with qualifying facilities). New long-term contracts with independent producers were not available until the power exchange began selling them in 1999.
- The utilities were required to turn over control of their transmission networks to the nonprofit California Independent System Operator (CAISO).

[12] The Los Angeles Department of Water and Power, as the largest municipal utility in the nation, also owns significant transmission, distribution, and generation assets.

- Retail prices for electricity were to be frozen until 2002 or until the stranded costs of the utilities were recovered.
- Consumers were allowed to buy electricity from their utility or from other suppliers, which were allowed to use the utility's distribution system.

Eventually, the IOUs sold off all their fossil fuel-powered generating capacity, which in California is fueled primarily by natural gas, while they maintained their hydropower and nuclear energy capacity. Because generating capacity in the Western states in the mid-1990s exceeded demand by about 20%, the expectation was that more competition between independent power generators would lower wholesale prices of electricity and enable the utilities to pay off their stranded costs. (Section 2.3.4.2 covers payment of stranded costs through "competition transition charges.")

The California Power Exchange began auctioning wholesale electricity in March 1998, but in June 1999, CAISO recommended that the IOUs be allowed to make long-term contracts. By July 1999, SDG&E had recovered its stranded costs and was allowed to begin charging its customers market prices for electricity.

That year, the California Energy Commission reported that about 60% of the state's fossil-fueled generating plants were at least 30 years old. Maintenance needs for old equipment was given as a reason for planned outages that reached 8,800 MW, or nearly 20%, in April 2000. Most of this came back online, but unplanned outages reached 3,400 MW in August and continued to be around 4,000 MW the following winter.

In 1998, hydropower from the Northwest had helped California get through a warm summer; but in 2000, California's net generation from hydropower decreased 13% from the above-average use of 1999. Other Western states suffered an 18% reduction of hydropower in 2000.

2.3.3 Fall of the Restructured Market

2.3.3.1 Events Preceding the Demise

The restructured electricity market in California had many flaws, but two were fatal:

1. Wholesale prices were market-based, fluctuating according to the market, while retail rates were frozen.
2. Utilities were encouraged to buy electricity at spot wholesale prices because the CPUC would not pre-approve utility long-term contracts because of the market design that required purchase through the power exchange. As mentioned above, new long-term contracts with independent producers were not available until the power exchange began selling them in 1999. No one anticipated the possibility that wholesale prices might exceed the frozen retail rates.

In 2000, the California economy was booming with an annual growth rate of 9%. Demand for natural gas was high. That year, the price of natural gas went from about \$3.50/MMBtu in April to more than \$6 by the end of October. Gas rates continued to climb throughout November rising from \$5 to almost \$20. On December 11, 2000, prices spiked to \$55/MMBtu (see Figure 2-9). Temperatures in May and June were warmer than usual, so electricity usage began to peak earlier than usual.

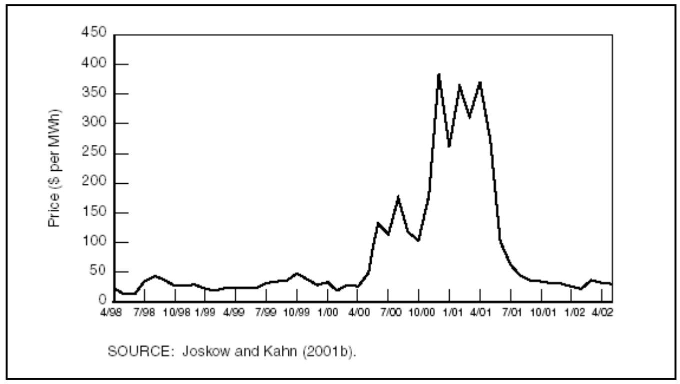

Figure 2-5. Average wholesale electricity prices in California, 1998–2002[13]

By June 2000, wholesale prices for electricity were consistently above the frozen retail price, which caused PG&E and SCE to lose money on every transaction. Customers of SDG&E, where competition transition charges (CTCs) had been paid off and the rate freeze had been lifted, saw their retail prices triple compared with the previous summer's. On June 14, 2000, PG&E interrupted service to 100,000 customers in San Francisco and implemented rolling blackouts. Prices paid by generators using fossil fuels for pollution credits went from \$10 in June to \$30 in August to \$45 by December. California's demand for electricity had increased 14% from the previous summer.

In October, the CPUC increased the borrowing authority of SCE from \$700 million to \$2 billion to pay for wholesale power. The next month, PG&E and SCE applied for rate increases. In December 2000 and January 2001, CAISO announced many Stage 3 emergencies,[14] warning of blackouts. The U.S. Department of Energy ordered electricity generators in other states to sell to California's wholesale market. The Federal Energy Regulatory Commission (FERC) imposed "soft" price controls that could be exceeded in emergencies, and it urged California's IOUs to make long-term supply contracts. According to AB 1890, the utilities were required to purchase power on the power exchange spot market.

In January 2001, the CPUC approved rate increases for PG&E and SCE—although it was clearly too little too late. Governor Davis directed the California Department of Water Resources (DWR) to buy power because of the deteriorating finances of the IOUs. After PG&E and SCE defaulted on their payments for power, the power exchange suspended its auctions. The next month, the state negotiated long-term contracts for power and began purchasing major transmission lines. In March, as rolling blackouts occurred, FERC directed 13 power suppliers to refund \$69 million they overcharged utilities in January. The CPUC approved more rate increases.

[13] Weare, C. "The California Electricity Crisis: Causes and Policy Options." Public Policy Institute Of California, 2003; pg l.
[14] A Stage 3 emergency is defined as less than 5% capacity reserve.

In April 2001, PG&E declared bankruptcy because of its $8.9 billion debt, and California's bond rating was downgraded. The next month, California authorized a $13 billion bond issue to pay for DWR electricity purchases. In June 2001, FERC imposed wholesale price caps for all Western states equal to the cost of generating electricity in California. The following month, moderate temperatures helped reduce demand for electricity, and decreasing natural gas prices helped lower wholesale electricity prices well below what the state was paying under its long-term contracts. Order was re-established in the markets.

The United States Congressional Budget Office report "Causes and Lessons of the California Electricity Crisis"[15] noted that the "political glue" that held together the restructuring plan was the expectation that wholesale prices would fall or at least remain stable. The three features of the plan that explained the extreme market problems were (1) freezing retail prices, (2) restricting long-term contracts, and (3) the design of the power exchange and CAISO markets. The first two caused a financial disaster for the IOUs when wholesale prices began to rise, and the third made them worse by letting independent producers avoid limiting wholesale prices and use their market power to raise prices higher.

The price freeze became a ceiling that blocked the utilities from passing on their increased costs to customers, who thus had no incentive to reduce their consumption. Also, the price freeze discouraged new retailers from entering the market. As the utilities operated at huge losses with deteriorating financial conditions, producers began demanding higher prices because of their financial risk. Some generators refused to sell to the utilities at all because of credit concerns.

With fixed retail prices, consumers had little incentive to conserve electricity that cost more than they paid. In San Diego, where retail prices did briefly fluctuate with the market, the doubling of retail prices led to a decrease in demand of 2.2%–7.6%, depending on the time of day. After legislators restored the retail price freeze in September 2000, San Diego customers no longer had that incentive and increased their use of energy when prices dropped back down. Higher prices also induce residential consumers to reduce their use of electricity in the long run by buying energy-saving appliances, adding insulation, and changing from electric to gas appliances; industrial consumers may purchase energy-efficient equipment, add generation facilities, or use cogeneration.

Restricting long-term contracts made California excessively dependent on the spot market, which increased to supply about half of the utilities' demand for power—compared with 10%–20% in many other states. The utilities had sold off much of their power-generating capacity and could no longer rely on that. Long-term guarantees and futures markets would have encouraged independent generators to build new capacity. The heavy reliance on the spot market to meet peak demand gave independent generators greater control over that market.

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[15] United States Congressional Budget Office. "Causes and Lessons of the California Electricity Crisis." September 2001.

The auction system of the power exchange let individual sellers use strategic bidding to gain higher prices. Although CAISO auctions were subject to a soft price cap, the price paid to successful bidders still reflected the cost of the last and most expensive supply from the highest bidder. The price caps that CAISO did set may actually have encouraged higher prices. Some independent power producers got around the price caps by selling power to municipal utilities in California or utilities outside the state because their out-of-market sales to CAISO were not subject to caps. Some individual sellers may have colluded to withhold supplies to increase prices, but controversy surrounds whether capacity was withheld for competitive reasons or legitimate operational needs.

2.3.3.2 The End of Direct Access

Electric service obtained from energy service providers other than IOUs, called "direct access," was the centerpiece of AB 1890. On Sept. 20, 2001, the CPUC issued a decision (D.01-09-060) that suspended the right of customers to buy energy from energy service providers. The decision stated, "PG&E, SCE, and SDG&E shall not accept any direct access service requests for any contracts executed or agreements entered into after Sept. 20, 2001." Customers that were receiving service under direct access on Sept. 20, 2001, were allowed to remain direct access customers. This represents about 12% of California's total load. Although many component pieces of AB 1890 are in effect today, this action by the CPUC marked the end of a first foray into electricity restructuring in California. It was a costly experiment, with a total price in excess of $45 billion.[16]

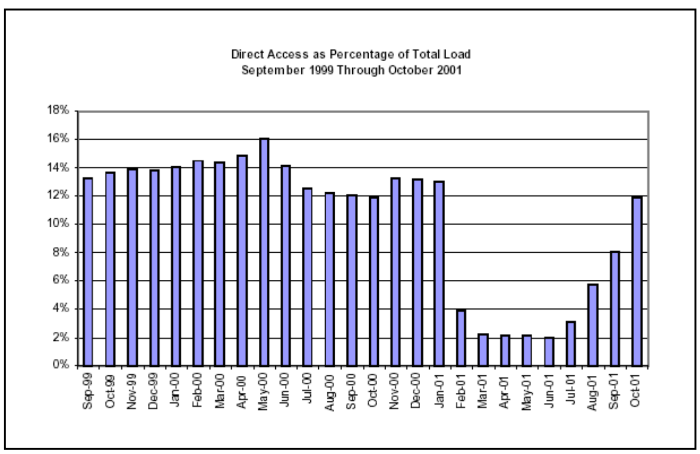

Figure 2-6. Direct access percentage of total California electric load

[16] See Note 13.

2.3.3.3 *The Growth of Independent Power Generation*

The CPUC order for utilities to divest their fossil-fired generation resulted in a shift of power generation ownership. In 2000, power plants owned by utilities provided only 28% of electricity compared with 40% the previous year. Meanwhile, independent power generators, including qualifying facilities, increased from 40% to 58%.

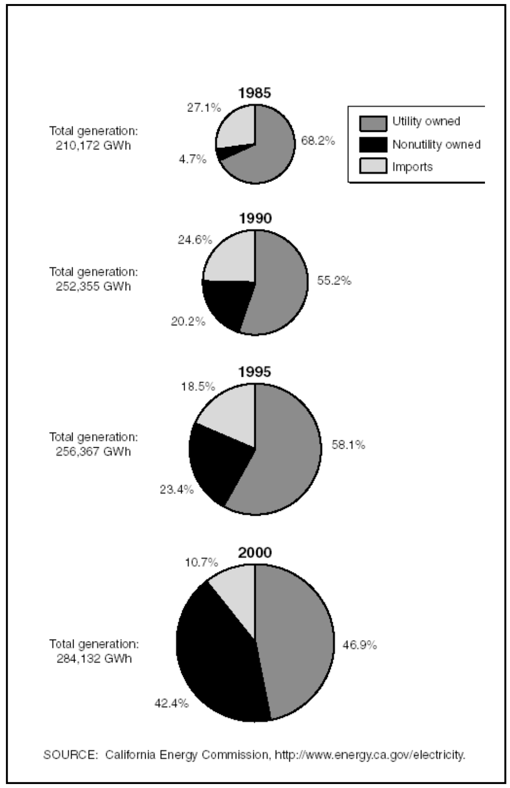

Figure 2-7. Total California electric generation

This was the continuation of a trend that started in the late 1970s. Independently owned power generation, as a percentage of total generation, is increasing. In California, all generation larger than 50 MW must go through the state's siting procedure, which is managed by the California Energy Commission. Because the new generation sources were mostly smaller than 50 MW, they did not show up in the commission's siting process. Only one new power plant larger than 50 MW—the 300-MW Crockett cogeneration plant—came on line in the '90s. Some observers took this to mean that no new generation had been added in the '90s.[17] In fact, during this decade, California added at least 4.5 GW of power—a little more than the state's nuclear capacity.[18] Most of the new capacity was non-utility DG smaller than 50 MW that did not require siting by the California Energy Commission. At the time, there was no provision for accounting for these small units, so their appearance was almost invisible.

This new generation, including 47.8 MW currently under contract from RE, competes in an electricity market in which the failure of electricity restructuring has increased market opportunity and market risk.

[17] The Public Policy Institute of California, for example, made this mistake. See page 20 of its report "The California Electricity Crisis: Causes and Policy Options," cited earlier.

[18] "Market Assessment of Combined Heat and Power in the State of California." *Onsite Energy*. July 1999; pp. 2–17.
Data source: Hagler Bailly Independent Power Database, 1998.
Data corroboration and nuclear power analogy: Lovins, A. "Electricity Solutions for California." Presented to the Commonwealth Club of San Francisco July 11, 2001.

2.3.4 Rate Effects of the California Electricity Crisis

AB 1890 and the resulting electricity crisis cost the state $45 billion–$50 billion.[19] SCE and PG&E filed for rate tariff increases as early as November 2000. The utilities later filed for a second rate increase. The DWR bond repayment expenses and long-term contracts were not covered by the utility rate increases. These had to be rate-based in new tariff components. Some new rates—such as CTCs and a public goods charge, later called a public purpose programs charge (PPPC)—were included in the original restructuring legislation, AB 1890.

AB 1890 and the collapse of restructuring did little to improve the electric service of the average customer, but changed the look—and price—of her electric bill. The tariff increases for electricity in California might have helped the spark spread, but they have largely been offset by increases in gas prices and increased risk and uncertainty. The have therefore undermined the stability of the energy marketplace as a whole and the marketplace for DER specifically.

2.3.4.1 Utility Rate Increases

On Jan. 4, 2001, the CPUC issued Decision 01-01-018, which gave SCE and PG&E authority to increase their rates by $0.01/ kWh for all customers:

> In this interim decision, we consider the emergency requests of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison) that they be allowed to raise rates on an interim basis, subject to refund. We will implement an immediate, interim surcharge, subject to refund and adjustment. On this basis, we will allow PG&E and Edison each to raise their revenues by increasing the electric bill of each customer by one cent per kilowatt hour (kWh), applied on a usage basis. The surcharge will be applied on an equal cents per kWh basis and will result in an increase of approximately 9% for residential customers, 7% for small business customers, 12% for medium commercial customers, and 15% for large commercial and industrial customers.[20]

Two and a half months later, on March 27, 2001, the same utilities filed for and were granted a second rate increase in Decision 01-03-082:

> This decision grants Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) authority to increase rates by adding to their current rates a three-cent per kilowatt-hour (kWh) surcharge in response to the current emergency in the electric industry. After an independent accounting review, an evidentiary hearing and a full opportunity to comment and testify provided to all parties, we conclude that the utilities have established the need for additional revenues on a going-forward basis in order for those utilities to comply with their statutory duty to provide adequate electric service to their customers. Today's decision does not address recovery of past power purchase costs and other costs claimed by the utilities.

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[19] The first figure is from Note 17; the second is from:
Tomashefsky, S. "California Development of DG Standby Rates and Exit Fees." Presented to the Midwest CHP Initiative Distributed Generation Tariff Workshop, St. Paul, Minnesota, May 14, 2003.

[20] California Public Utilities Commission. Decision 01-01-018. Jan. 4, 2001.

> The increase will be added to the utilities' currently controlled rates and will be in addition to the emergency surcharge approved on January 4, 2001 and made permanent by with this decision. It will cost the customers of the utilities approximately $2.5 billion dollars annually.[21]

Because these rate increases were implemented as increases in energy price, they helped make CHP and other forms of energy efficiency more cost-effective. However, the positive effects of the rate increases on the economics of CHP and DG were quickly offset by gas price increases, exit fees for generation provided by customer-sited plants, and rate reductions.

2.3.4.2 Competition Transition Charge

Electricity restructuring was packaged primarily as the introduction of competition into wholesale electricity markets.[22] IOUs had made investments in utility infrastructure, including major power generation stations, to meet the CPUC requirement that they provide sufficient electricity to meet California's demand. These investments were financed by the utilities, based on the assurance that repayment of the debt could be made through future electricity sales. In the restructured market, some of these power plant assets became "stranded"—meaning they could not operate competitively in the new marketplace.

In restructuring legislation, it was decided:

> ... that virtually all customers should pay a Competition Transition Charge to all IOUs to meet past financial obligations made on the customer's behalf to provide an accelerated recovery of the IOU investments. The CTC for investor-owned utilities varied by utility. Recovery of utility costs was already built into the existing regulatory structure and included in rates charged to all customers. If there had been no transition to a competitive market, customers would continue to repay these costs to utilities through their normal electricity bills.[23]

Some analyses have stated that the CTC does not result in an increase in electricity rates and therefore should not be viewed as an additional cost. Others see the CTC as a bailout of nuclear power.[24]

The CTC was determined by multiplying a CTC rate by electrical energy consumption. It appeared on all customer bills by June 1, 1998. The CTC collected depended on the difference between the retail price and the wholesale price of electricity. When wholesale prices exceeded the frozen retail rates, the CTC became negative. At that time, $20 billion of a total of $28 billion of CTC had been collected. Some of the additional stranded costs were to be collected as "tail CTC," as provided for in Public Utilities Code (PUC) 367(a). The electricity crisis delayed repayment of the stranded costs. For this reason, the three major utilities still charge CTCs for non-CHP (42.5% or more efficient) or zero-emission DG projects online on or after May 1, 2001.

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[21] California Public Utilities Commission. Decision 01-03-082. March 27, 2001.
[22] Some analysts have stated that there was wholesale competition in California electricity since the 1980s. (See "Electricity Solutions for California" by Amory Lovins, listed previously.)
[23] http://www.eia.doe.gov/cneaf/electricity/california/assemblybill.html
[24] http://www.consumerwatchdog.org/utilities/rp/rp001092.pdf

Decision 03-04-030, the CRS decision, explains:

> ... any tail CTC payments required by this decision are defined as in Public Utilities Code Section 367 (a) (1)-(6) and calculated as follows:
>
> - The above-market portion or uneconomic portion of these contract costs will be calculated by comparing the weighted average cost of the qualifying facility and power purchase agreement portfolio, in $/MWh, against the benchmark adopted in the direct access phase of R.02-01-011.
>
> - A revenue requirement will be derived for the qualifying facility and power purchase agreement portfolio by multiplying the uneconomic portion ($/MWh) times the forecast of MWh in the portfolio. A total "tail" CTC revenue requirement will be derived by adding the uneconomic portion of the qualifying facility and power purchase agreement revenue requirement to the employee-related transition costs and, in the case of SCE, any costs associated with the nuclear incremental cost incentive plan. The total "tail" CTC revenue requirement will be divided by the total applicable load to derive the CTC rate applicable to Departing Load. The total applicable load includes bundled, direct access, and Departing Load customers not otherwise exempted from ongoing CTC pursuant to statute or to this order.[25]
>
> - Any other charge established in the direct access phase of R.02-01-011 to recover the cost of above-market utility retained generation assets or power purchase obligations shall not be applied to Departing Load. (Definitions taken from the Settlement Agreement, Section 8.)[26]

Rulemaking 02-01-011 is the order instituting rulemaking of the suspension of direct access, pursuant to Assembly Bill 1X and Decision 01-09-060—the implementation of decisions for tariffs resulting from the failure of electricity restructuring in California.

2.3.4.3 Public Purpose Programs Charge

The restructuring legislation AB 1890 established funding for public interest programs. During 4 years, $248 million was to be allocated for the Public Interest Energy Research program, $540 million was to be allocated for the Renewable Technology Program, and about $912 million was for the California Board for Energy Efficiency.[27] The first two programs are administered by the energy commission; the third is administered by PG&E, SCE, and the San Diego Regional Energy Office on behalf of SDG&E. These funds have continued since the end of restructuring, and the Self-Generation Incentive Program (SGIP), also administered by the utilities and the San Diego Regional Energy Office, has been added. (For details, see: RealEnergy. "Distributed Energy Resources Incentive Impacts: A Comparison of New York and California Incentives." 2004.)

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[25] California Public Utilities Commission. Decision 03-04-030.
[26] Ibid.
[27] http://www.eia.doe.gov/cneaf/electricity/california/assemblybill.html

2.3.4.4 Department of Water Resources Bonds and Contracts

When the utilities began to default on their payments for wholesale electricity, Governor Davis ordered the DWR to take over the responsibility of purchasing wholesale power on behalf of customers. To pay for the wholesale electricity—and lacking budgets on hand to cover it—the state issued public bonds. The actual bond issuance is estimated at about $11.95 billion.[28] Charges to recover the bond payments are part of the fee for service delivery in the current utility tariffs.

When the DWR was tasked with purchasing electricity on behalf of the insolvent utilities, it moved quickly to avoid buying power on the power exchange and was granted authority to enter into long-term contracts. A meeting was convened with all the electricity generators in the state. DWR made it clear that it was open to all offers of electricity sales. Because the price of electricity was still very high, some of the early contracts were for multiple years at relatively high rates.

A report critical of fee purchases said that DWR had:

- Purchased at least $4 billion–$5 billion of energy beyond needs
- Locked the state into inflexible "take or pay" contracts
- Purchased too much off-peak power and not enough on-peak power
- Purchased too much dirty coal and gas-fired power and too little clean, renewable power (renewables account for a mere 1%–2% of the current DWR portfolio)
- Signed six contracts priced above FERC price caps.[29]

Many of the contracts were subsequently renegotiated. Today, payments for energy are made based on a weighted average of DWR electricity contracts and utility-retained generation.

2.3.4.5 Cost Responsibility Surcharge

Among the findings of fact, Decision D.02-03-055 states:

> There would be a significant magnitude of cost-shifting if DWR costs are borne solely by bundled service customers and direct access customers are not required to pay a portion of these costs that were incurred by DWR on behalf of all retail end-use customers in the service territories of the three utilities during a time when California was faced with an energy crisis.

And:

> It is reasonable to prevent this cost-shifting by imposing a direct access surcharge or exit fee rather than adopting an earlier suspension.

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[28] See Exhibit 3 of the bond charge proceedings in A.00-11-038l.

[29] Marcus, W. "A Blueprint for Renegotiating California's Worst Electricity Contracts: A Consumer/Environmental Agenda." Prepared for Utility Consumers' Action Network, Environmental Defense, The Utility Reform Network, Natural Resources Defense Council, Consumers Union, and the Sierra Club, 2002.

The upshot of the CRS is that direct access customers (those that left bundled service prior to Sept. 20, 2001) and on-site generation must pay their portion of the fees associated with the failed electricity restructuring market. Specifically, the CRS is to recover costs for:

- DWR bond charges (DWRBC)
- DWR ongoing power charges
- PPPC
- Nuclear decommissioning charge (NDC)
- SCE's historic procurement charge.[30]

The historic procurement charge was calculated for each customer in SCE's service territory. It applied to customers that departed after July 1, 2003. The calculation of the charge compares the generation revenue received since May 2000 with costs incurred to serve the customer's documented consumption. To determine the customer's cost responsibility, the utility multiplied the customer's cumulative under-collection as of Aug. 31, 2002, by the ratio of the starting balance of the costs in SCE's procurement-related obligations account. The historic procurement charge to be assessed when a customer departed was to equal the difference between the customer-specific historic procurement charge obligation at the start of the recovery period and the customer's total contributions to the procurement-related obligations account. The charge only applied to DG applications larger than 1 MW that did not meet California Air Resources Board 2007 emission standards.[31] The historic procurement charge was fully recovered in July 2003.

2.3.4.5.1 Cost Recovery Surcharge Exemptions

The following forms of generation are exempt from the CRS:

- Net-metered departing load
- Qualifying biodigester gas-fired generation
- Systems less than 1 MW eligible for participation in the CPUC's SGIP (see Section 2) or an energy commission program that meets PUC Section 353.2.

PUC Section 353.2 defines "ultraclean and low-emission distributed generation" as:

> ...any electric generation technology that meets both of the following criteria:
>
> 1. Commences initial operation between Jan. 1, 2003, and Dec. 31, 2008
> 2. Produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60% system efficiency on a higher heating value."

[30] Decision 03-04-030. April 3, 2003.
[31] http://www.eea-inc.com/rrdb/DGRegProject/States/CA.html#ExitFees

Generation larger than 1 MW that meets PUC Section 353.2 is exempt from DWR ongoing power charges CRS and SCE's historic procurement charge but must pay DWR bond charges and tail CTC.[32]

2.3.4.5.2 Cost Recovery Surcharge Exemption Caps

The CRS has an overall cap of 3,000 MW. When the cap is reached, all generation thereafter will pay the CRS. The California Energy Commission is tasked with certifying systems as eligible under the cap, taking applications for generation eligible for exemption, and tracking progress toward the caps on a quarterly basis. Utilities are required to provide data and cooperate with the commission. The program will be revisited after 3 years or 1,000 MW, whichever comes sooner.[33]

Net energy metered systems less than 10 kW need not apply for exemption; they are automatically exempt. Nonrenewable generation of all sizes, however, must apply to receive exemption and are subject to the following secondary caps:

- 600 MW before the end of 2004
- An additional 500 MW permitted until July 1, 2008
- A final tranche of 400 MW permitted after July 1, 2008.[34]

2.3.4.5.3 Cost Recovery Surcharge Rate Effect

Calculating the CRS is a matter of hitting a moving target. Historic procurement charges have been paid off. DWR bond charges are included in the delivery charge in the current SCE TOU-8 tariff but not in SCE's proposed TOU-8 tariff in its GRC of 2003. (See Section 2.6.2 for details on the GRC.) Furthermore, the NDC and PPPC differ in the two TOU-8 tariffs. The tables below summarize this situation.

Table 2-5. CRS Components in TOU-8 (New)

Component	Value ($/kWh)
NDC	$0.00043
PPPC	$0.00263
DWRBC	$0.00444
Total	$0.00750

Table 2-6. CRS Components in GRC

Component	Value ($/kWh)
NDC	$0.00037
PPPC	$0.00296
DWRBC	$0.00000
Total	$0.00333

RE estimates the CRS for a current customer in SCE territory as a blended average between the current TOU-8 tariff and the GRC TOU-8 rate, approximately $0.005/kWh.

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[32] The tail CTC definition included in this decision is described in detail in Section 2.3.4.2. Any other charge established in the direct access phase of R.02-01-011 to recover the cost of above-market utility retained generation assets or power purchase obligations shall not be applied to departing load. (Definitions taken from the Settlement Agreement, Section 8.)

[33] The foregoing CRS discussion is from: R.02-01-011, Decision 03-04-030. April 3, 2003.

[34] Decision 03-04-030. April 3, 2003.

2.4 The California Gas Market

2.4.1 Gas Market Deregulation

In an effort to open the natural gas market to competition, the CPUC began restructuring the California gas industry in 1988. The first change separated the California gas market into core and non-core customer segments based on customer load, end-use priority, and economic ability to use alternative fuels. (See Section 2.4.2 for details on core and non-core gas customers.) Retail choice has been available to residential and small commercial gas customers since 1995.

The CPUC endorsed restructuring in a collaborative settlement by PG&E and 25 other companies, called the Gas Accord, on Aug. 1, 1997. In January 1998, the CPUC opened a docket to investigate the possibility of restructuring gas markets statewide. The California legislature prohibited the CPUC from ordering any further deregulation of the natural gas industry until Jan. 1, 2000, with Senate Bill 1602, which was signed by the governor on Aug. 25, 1998. SB1602 allowed the commission to investigate competition and report its findings to the legislature. Assembly Bill 1421, passed in October 1999, mandated that local distribution companies (LDCs) offer bundled basic gas service to all core customers in their service territories unless the customers chose or contracted to have natural gas purchased and supplied by another entity.[35]

Non-core customers are now required to purchase natural gas service from a gas service provider instead of a utility. The utility still provides these customers with intrastate transportation of gas across its distribution system to the customer meter. The CPUC created an experimental transportation-only service for core customers that aggregated their loads in February 1991. The core aggregation transportation program was revised significantly by the CPUC and made permanent in July 1995. The core aggregation transportation program is an optional service that allows core customers to purchase gas from marketers that have met minimum aggregation levels of 120,000 therms/yr (lowered in November 2001 from 250,000 therms) in the SDG&E and SoCalGas service areas and 120,000 therms/yr in the PG&E service area. Customers must sign a 1-year agreement to purchase gas from gas service provider. Under this gas rate option, customers purchase their gas commodity from a gas service provider, also known as a core transport agent, and continue to use their LDC for gas transportation.

A customer supplier is responsible for ensuring that gas is delivered daily to the LDC's transportation system, balancing gas supply with gas use, and meeting gas reliability needs. As part of the LDC's service, the utility serves as a backup supplier in the event the gas service provider fails to arrange an adequate supply of natural gas. If customers do not purchase gas from a supplier, the LDC will continue to supply gas at the regulated rate. The California Energy Commission maintains a list of natural gas suppliers for Northern California and Southern California. Customers that choose not to purchase gas from a marketer, or who are not eligible for a customer choice program, are limited to gas utility rate options.

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[35] http://pnnl-utilityrestructuring.pnl.gov/gas/ioustates/california.htm

The LDC reads the meter and remains responsible for service, maintenance and repair, and emergencies. Three billing options are available to gas service providers:

- Dual billing, in which customers receive one bill from the gas service provider for gas service and one from the LDC for transportation services
- Gas service provider consolidated billing, in which the gas service provider sends one bill that includes the LDC's transportation charges
- LDC consolidated billing, in which the LDC sends one bill that includes the gas service provider's gas service charges.

In November 2001, the CPUC adopted new provisions that allowed tradable storage rights and transmission capacity on SoCalGas' and SDG&E's intrastate systems. In addition, the commission elected not to unbundle core interstate transportation from rates and eliminated core contribution to non-core interstate transition cost surcharges and the core subscription option. The core aggregation program threshold was also reduced, and new billing options—such as a billing credit for including the utility's billing to their customers—are now offered to core aggregators. The CPUC is developing a "Natural Gas Strategy" through Order Instituting Investigation 99-07-003. The effort outlines the costs and benefits of new natural gas strategies using the following criteria:

- Safety
- Consumer protection
- Environmental effects
- Labor effects.

2.4.2 Core and Non-Core Gas Customers

2.4.2.1 Core Customers

Core customers receive "bundled" service from the LDC for gas supply and all associated services. All residential customers and commercial customers with annual loads less than 250,000 therms/yr, as well as those with annual loads more than 250,000 therms/yr that so elect, are core customers. During a shortage, the gas utility may curtail deliveries to non-core customers, but it cannot curtail deliveries to core customers unless it is an emergency.

Benefit:
Core customers are somewhat protected from the volatility of gas markets through the benefit of the LDC's hedging and storage opportunities. However, LDCs do not aggressively hedge; under current policy, there is little potential and substantial downside risk for doing so. Still, core customers are assured delivery will not be interrupted except in emergencies.

Risk:
Although they are somewhat protected from market risk, core customers are not protected from tariff risk—the possibility that rates may go up as requested by the utility and approved by the CPUC. Core customers are dependent on the utility's ability to manage commodity price risk. They are dependent on utility forecasts and risk management practices on their behalf and have no recourse. However, there is a small market to hedge against retail gas price fluctuations. These hedges are called "dirty hedges" because they are not cleanly tied to wholesale prices and typically cover only up to 80% of the risk.

2.4.2.2 Non-Core Customers

Non-core customers include all cogeneration and commercial, industrial, and electricity-generation customers with annual loads more than 250,000 therms/yr that do not elect to be core customers. Non-core customers, including electricity generators, make commercial arrangements with a natural gas provider other than the LDC for gas supply and transportation services. However, they usually receive their gas shipments through utility-owned gas lines from third parties. Large customers located close to gas transmission pipelines can tap directly into the pipelines and avoid the LDC distribution system entirely. However, there is pressure to charge such customers a "departing load fee."

Non-core customers are also subject to market fluctuations of gas prices. These can be dramatic, as shown in Section 2.4.3. RE and other cogenerators in California are classified as non-core gas customers; they are subject to fluctuations in market rates as well as regulated gas tariffs. To reduce cost and avoid price risk, non-core customers can implement various risk-reduction strategies. Their success depends on good information. Non-core gas customers need to have access to market intelligence on gas demand and pricing.

Benefit:
Non-core customers have some control over their destiny in that they have the ability to hedge against fluctuations in commodity prices. If non-core customers predict gas market trends better than the local utility, they may receive gas commodity service at a lower price than if they received bundled service.

Risk:
If non-core customers do not practice adequate risk management, they may end up paying more for their gas commodity than bundled customers. Also, there is a cost for self-providing risk management (hedging and long-term contracting), so a non-core customer must do better than a bundled customer net of the cost of risk management to come out ahead. There is a greater chance of suffering service interruption. And, as the SoCalGas application demonstrates, there is a tariff risk on the transportation portion of the service still provided by the regulated utility.

2.4.3 California Gas Demand and Pricing Issues

According to the energy commission, the goal of California's gas policy is "to ensure a reliable supply of natural gas, sufficient to meet California's demand, at reasonable and stable prices and with acceptable environmental impacts and market risk."[36] Californians are becoming more energy-efficient. The average California household now uses less than half as much natural gas as it did in 1975. Yet natural gas demand is growing, and it is exceeding domestic supply. California's average demand is expected to decrease over the next few years but then increase because of thermal power plant gas consumption for electricity generation. Unless electricity tariffs increase at the same time, the spark spread will decrease.

2.4.3.1 Demand

According to an August 2003 report by the California Energy Commission, California's overall demand for natural gas will increase about 1% annually for the next 10 years. The residential and commercial sectors are expected to grow at 1% per year, industrial demand is expected to grow 0.1% per year, and the power generation sector is expected to increase about 1.5% per year.

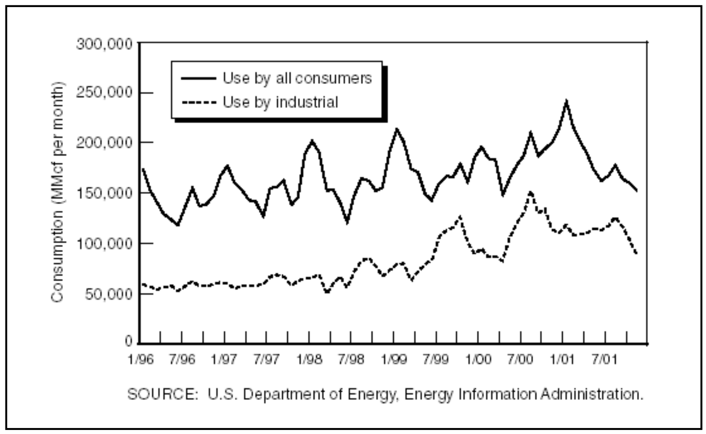


Figure 2-8. California gas consumption 1996–2001

New pipelines constructed since the 1990s have benefited California natural gas prices, but the market for natural gas has been extremely volatile since the summer of 2000. The following winter pushed prices alarmingly high, but they became relatively lower in August 2001. The high prices of the energy crisis reduced consumption, especially by industry. As a result of the crisis, SoCalGas has increased its storage, and two private storage facilities have provided a buffer for peak conditions.

Supplies of natural gas between 2003 and 2013 are anticipated to be sufficient but more costly because demand in North America is increasing and supplies are more limited than was expected. The United States is likely to become increasingly dependent on Canadian natural gas and liquefied natural gas imports, though developing unconventional sources of domestic natural gas will help meet the increasing demand. If supplies become tight, some natural gas customers might be priced out of the market in what is called "demand destruction."

During times of high prices, some industrial and power generation customers will switch to oil, but the energy commission does not expect much switching in California. The commission expects liquefied natural gas projects to be developed to serve the West Coast market by 2007. For the next decade, the Southwest will continue to be California's major resource for natural gas, though imports from the Rocky Mountain region and Canada will increase. The improvement of the Kern River pipeline from the Rocky Mountain region will provide much-needed expansion in pipeline capacity for California.

[36] California Energy Commission staff. "Natural Gas Market Assessment." August 2003; p. 73.

Increasing demand for natural gas and the expense of developing new wells and pipeline capacity mean that prices for natural gas will probably rise faster than inflation. The Western Energy Coordinating Council region will probably have the lowest-cost natural gas because PG&E owns the Gas Transmission Northwest pipeline, which delivers from Canada, and the Kern River pipeline. Electricity generators that receive their gas from PG&E, SoCalGas, and SDG&E are expected to pay the highest prices. PG&E's prices are expected to be a little less than SoCalGas rates until 2007, after which they will be similar. From now until 2013, customers of these utilities will probably pay \$4–\$6 per thousand cubic feet in constant 2000 dollars. Gas-fired generators that obtain gas from California utilities are expected to pay more than \$4 per thousand cubic feet in 2000 dollars by 2013.

2.4.3.2 Pipeline and Storage Capacity

Increasing use of new gas-fired power plants means additional pipeline capacity will be needed in Nevada, Arizona, and New Mexico. In California, the energy commission predicts PG&E will need more receiving capacity or storage after 2006. Because SoCalGas recently completed projects that added 375 million cubic feet per day in pipeline capacity, the company has enough intrastate slack capacity to serve its territory through 2013. California gas flexibility will also benefit from pipeline projects such as the Kern River Expansion, the Southern Trails, the North Baja Project, the Kern River Lateral, and the El Paso Lateral.

Storage capacity in California is currently about 243 billion cubic feet. SoCalGas owns all storage in Southern California, and in Northern California, PG&E storage facilities are supplemented by the private facilities of Wild Goose Storage and Lodi Gas Storage. Gas is stored to meet the high winter heating demands of the core market, but the economics sometimes cause the non-core customers to suffer. The following questions therefore arise:

- Should storage service for non-core customers be bundled like those of core customers?
- How will costs be allocated if enhanced storage is needed for non-core customers?
- Should more storage capacity be added by utilities or by private companies?

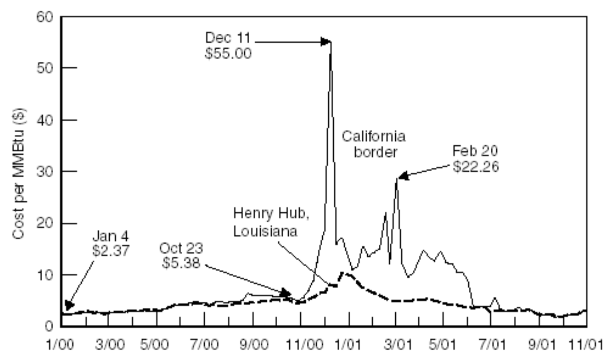
The energy commission staff analyzed 11 scenarios but concluded that long-term trends of the natural gas market are not likely to be affected by seasonal disruptions and price volatility if participants in the gas industry act reasonably with infrastructure investment and operate according to fundamental economic principles. The issues that need immediate action relate to risk analysis, access to new supplies (including liquefied natural gas), and storage of natural gas.

Increasing natural gas imports will ensure that California has adequate supply to meet demand at reasonable prices because of adequate pipeline and storage infrastructure. Yet wellhead and market prices are increasing, and both short-term and long-term prices are likely to remain volatile. Long-term increases in demand from burning natural gas for electrical generation may expose customers to gas price volatility.

Because natural gas production in North America will not meet future demand—making it uncertain that California will find enough supply to maintain reasonable prices—the state may need to give additional incentives to enhance production in-state, consistent with environmental safeguards; liquefied natural gas may be used despite its possible effects; and the state may develop government relationships with states that supply natural gas. Natural gas infrastructure is probably going to be inadequate in Northern California after 2007, especially for power plants. Non-core natural gas storage and use are not likely to mitigate seasonal shortfalls and price spikes for electricity generation demand.

2.4.3.3 Historical Gas Prices

Gas prices have been volatile over the past 5 years. Non-core customers, such as RE, are at risk from market fluctuations for the commodity portion of gas costs.[37] This is not a tariff risk but a market risk. However, it should be noted that in the 1990s PG&E, using ratepayer funds, fought and won a vigorous campaign to keep a new, non-CPUC-regulated gas pipeline from being built from the Southwest into the Bay Area.



SOURCE: Enerfax Daily, http://www.sagewave.com/D2/Include/Frame.asp?key=86575.

Figure 2-9. California gas price spikes 2000–2001

In the same way that regulatory risk must be managed through advocacy, market risk must be managed through market mechanisms. Small non-core customers are most at risk because their buying power is comparatively weak. They have fewer options for getting the price and service they want. Market rules prevent RE from aggregating its project sites if they are behind different delivery points. In determining size, each site must stand on its own.

There are three ways small non-core gas users can protect themselves against market fluctuations of the commodity price they pay gas service providers for gas service:

1. Purchase long-term, fixed-price contracts. This eliminates gas price fluctuations from the risk equation and leaves only electric price risk. If electric prices go up, then spark spread increases; if electric rates drop, then spark spread decreases. The biggest drawback of long-term contracts is that gas suppliers will require large credit risk coverage.

[37] There are risks in being a core customer, too. If the LDC makes a mistake in its own risk hedging, all bundled customers are subject to the risk of incurring some portion of charges for what is in reality the utility's mistake.

2. Purchase call options in the market. Options are the right, but not the obligation, to purchase gas at a specific "strike" price in the future. An option is a useful hedge when a CHP owner/operator believes gas prices may go up and needs to preserve a minimum spark spread. If the option is not exercised, the cost of the option is written off.

3. Purchase swap hedges. A swap is true insurance. The buyer pays an extra amount each month to reserve the right to buy at a capped price. Swaps preserve the ability to increase spark spread when gas prices go down while protecting against price increases.

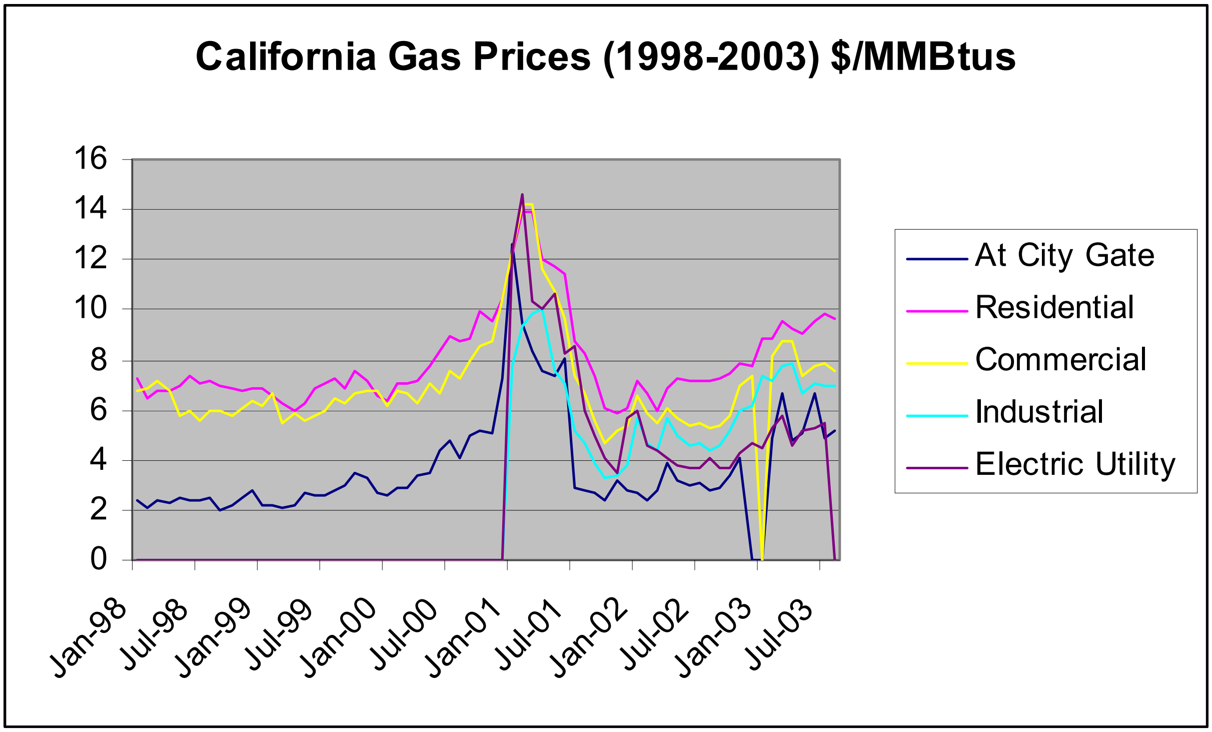


Figure 2-10. California gas prices (dollars per thousand cubic feet)[38]

[38] Energy Information Administration. "EIA's Natural Gas Prices for California." 2004. http://www.eia.doe.gov/emeu/states/ngprices/ngprices_ca.html.
Data sources: Natural gas prices extracted from the Oil and Gas Information Retrieval System.

- City Gate: Natural gas prices at City Gate (*Natural Gas Monthly*, Table 20)
- Residential: Average price of natural gas sold to residential customers, including taxes (*Natural Gas Monthly*, Table 21)
- Commercial: Average price of natural gas sold to commercial customers, including taxes (*Natural Gas Monthly*, Table 22)
- Industrial: Average price of natural gas sold to industrial customers, including taxes (*Natural Gas Monthly*, Table 23)
- Utilities: Natural gas prices for utility customers, including taxes (*Natural Gas Monthly*, Table 24)

2.5 Analysis of Existing Tariffs

To give a well-rounded context for California electric and gas tariff rates, this section provides a brief analysis of six sample tariffs commonly encountered by RE in the field. Many RE customers are commercial office facilities that range in peak annual demand from 500 kW to 2,500 kW or more. These customers have allowed RE to install and operate small cogeneration and heat-recovery units within their facilities. Some customers have gas meters; some do not. Although this distinction matters to RE (because if RE can tap into a pre-existing gas service, installation costs are lower), it does not matter in terms of the gas bill. In every case, the utility considers RE to be the gas customer for the cogeneration portion of the gas usage. On the electric side, conversely, the facility owner is the utility customer, and RE is the third party.

2.5.1 Purpose of Tariffs

Because IOUs are government-regulated entities, they have no competition for the regulated service they provide within their franchise. At the same time, the return they can make is capped. SoCalGas, for example, earns a capped rate of 8.68%. IOU tariffs represent utility commission-approved charges for goods and services provided. Those goods and services are not priced at market rates but at rates that allow the utility to earn its guaranteed rate of return on approved investments. However, many rate components are not for direct goods and services but for legislatively or regulatorily approved obligations.

2.5.2 Electric Tariffs for Large Commercial Customers

Electric tariffs in this analysis are for a commercial facility with a load in excess of 1 MW. Tariffs include current and past ("new" and "old") SCE TOU-8, SDG&E AL-TOU-DER, and PG&E E-20. Rate comparisons are for equivalent distribution "secondary" voltage services.[39]

2.5.2.1 SCE TOU-8 New and Old

On July 23, 2003, SCE filed a tariff letter that revised its TOU-8 tariff. This rate is still in effect. For purposes of comparison, RE considers the tariff in effect as the "new" TOU-8 and the tariff in effect prior to July 23, 2003, (and filed May 2001) as the "old" TOU-8. The two are identical except in their energy rates and the format of the tariff sheet.

Applicability:

TOU-8 applies to general service, including lighting and power (except agricultural water pumping) customers whose monthly maximum demand SCE expects to exceed 500 kW or has exceeded 500 kW in any 3 months during the preceding 12 months. With some exceptions, any customer whose monthly maximum demand is less than 500 kW for 12 consecutive months is ineligible for TOU-8 service. This applies throughout SCE's territory.

[39] Utility definitions of primary distribution service are not equivalent. Here, RE assumes primary service is on a distribution feeder with a voltage between 2 kV and 50 kV.

Energy and Demand Rates:
When SCE filed its new TOU-8 tariff letter, it reduced on-peak summer rates by nearly $0.05, peak summer and winter rates by more than $0.04, and off-peak rates by more than $0.035. This was because the company paid off its procurement-related obligations account and historical procurement accounts. The reason for displaying outdated rate tariffs here is to show another tariff risk that is a result of utility obligations pursuant to electricity restructuring. Demand rates remain unchanged.

Table 2-7. SCE TOU-8 (Old) Energy and Demand Rates

SCE TOU-8 (Old)	Period	Summer	Winter
Energy	On-Peak	$0.19544	N/A
	Mid-Peak	$0.10897	$0.12121
	Off-Peak	$0.08808	$0.08924
	Period	**Summer**	**Winter**
Demand	On-Peak	$17.95	N/A
	Mid-Peak	$2.70	$0.00
	Off-Peak	$0.00	$0.00
	Non-Coincident	$6.60	

Table 2-8. SCE TOU-8 (New) Energy and Demand Rates

SCE TOU-8 (New)	Period	Summer	Winter
Energy	On-Peak	$0.14701	N/A
	Mid-Peak	$0.06890	$0.07996
	Off-Peak	$0.05004	$0.05108
	Period	**Summer**	**Winter**
Demand	On-Peak	$17.95	N/A
	Mid-Peak	$2.70	$0.00
	Off-Peak	$0.00	$0.00
	Non-Coincident	$6.60	

Components of Delivery Charge:
The delivery charge is added to the cost of utility-retained generation or the DWR long-term contracts for energy to get the total energy tariff.

The new TOU-8 delivery charge is made up of:

- Transmission – Transmission owners tariff charge adjustments, which are FERC-approved, represent the transmission revenue balancing account adjustment, the reliability services balancing account adjustment, and the transmission access charge balancing account adjustment
- Distribution
- The NDC

- The PPPC
- The PUC reimbursement fee, described in Schedule RF-E
- The DWRBC.

These component values of the TOU-8 delivery charge rate do not fluctuate from one period to the next.

Table 2-9. SCE Value of Delivery Components (All Periods Primary Power)

Component	Sub-Components	Value ($/kWh)
Transmission		-$0.00003
	Transmission owners tariff charge adjustments	
	Transmission revenue balancing account adjustment	-$0.00047
	Reliability Services Balancing Account Adjustment	$0.00017
	Transmission access charge balancing account adjustment	$0.00027
Distribution		$0.00705
NDC		$0.00043
PPPC		$0.00263
PUC reimbursement fee		$0.00012
DWRBC		$0.00444
Total		$0.01464

Time Periods and Other Special Conditions:
Time periods are defined as follows:

- Summer season begins at 12 a.m. on the first Sunday in June and lasts until 12 a.m. the first Sunday in October of each year. Winter season runs from 12 a.m. on the first Sunday in October to 12 a.m. of the first Sunday in June of the following year.
- On-peak is noon to 6 p.m. summer weekdays except holidays.
- Mid-peak is 8 a.m. to noon and 6 p.m. to 11:00 p.m. summer weekdays except holidays and 8 a.m. to 9 p.m. winter weekdays except holidays.
- Off-peak is all other hours.
- Holidays are New Year's Day (Jan. 1), President's Day (the third Monday in February), Memorial Day (the last Monday in May), Independence Day (July 4), Labor Day (the first Monday in September), Veterans Day (Nov. 11), Thanksgiving Day (the fourth Thursday in November), and Christmas (Dec. 25).

A Schedule S standby tariff is required where customer-owned electrical generating facilities are used to meet part or all of a customer's electrical requirements.

2.5.2.2 SDG&E AL-TOU-DER

SDG&E's AL-TOU-DER is a special rate for large commercial customers with DER installed in their facilities. DER are defined in the special conditions of the tariff, detailed below.

Applicability:
Size of load – Applicable to all metered non-residential customers whose monthly maximum demand equals, exceeds, or is expected to equal or exceed 20 kW that have operational DER as defined below under Special Conditions.

Energy and Demand Rates:
SDG&E's AL-TOU-DER tariff has three base rates for energy:

- On-peak = 0.09927
- Mid-peak = 0.07525
- Off-peak = 0.07525.

Unlike the large commercial tariffs for SCE and PG&E, SDG&E's tariff has different delivery charges for each tariff period. It is also unique in that it has a winter on-peak tariff rate.

Table 2-10. SDG&E's AL-TOU-DER Energy and Demand Rates

SDG&E AL-TOU-DER	Period	Summer	Winter
Energy	On-Peak	$0.12010	$0.11890
	Mid-Peak	$0.09342	$0.09328
	Off-Peak	$0.09230	$0.09234
	Period	**Summer**	**Winter**
Demand	On-Peak	$5.55	$3.80
	Mid-Peak	N/A	N/A
	Off-Peak	N/A	N/A
	Non-Coincident	$10.32	

Components of Delivery Charge:

- Transmission – Transmission revenue balancing account adjustment of $0.00118/kWh and transmission access charge balancing account adjustment of $0.00001/kWh. Restructuring Implementation Rate is composed of rates for internally managed costs and externally managed costs
- Public purpose programs – public purpose programs rate is composed of the low-income public purpose programs rate of $0.002/kWh and the non-low-income public purpose programs rate of $0.00256/kWh
- NDC
- Trust transfer amount or fixed transition amount
- Restructuring implementation rate, which is the sum of the rates for internally managed costs and externally managed costs
- CTC
- Reliability must run generation rates
- DWRBC.

Table 2-11. SDG&E Value of Delivery Components (On-Peak Primary Power)

Component	Sub components	Value ($/kWh)
Transmission		-$0.00119
	transmission revenue balancing account adjustment	-$0.00118
	Transmission access charge balancing account adjustment	-$0.00001
Distribution		$0.00083
PPPC		$0.00456
NDC		$0.00074
Fixed transition amount		$0.00000
Restruc		$0.00053
CTC		$0.00643
Reliability must run		$0.00192
DWRBC		$0.00701
Total		$0.02083

Time Periods and Special Conditions:

	Summer May 1–Sept. 30	Winter All Other
On-Peak	11 a.m.–6 p.m. weekdays	5 p.m.–8 p.m. weekdays
Semi-Peak	6 a.m.–11 a.m. weekdays 6 p.m.–10 p.m. weekdays	6 a.m.–5 p.m. weekdays 8 p.m.–10 p.m. weekdays
Off-Peak	10 p.m.–6 a.m. weekdays plus weekends and holidays	10 p.m.–6 a.m. weekdays plus weekends and holidays

Distributed energy resources: Any electric generation technology that meets all of the following criteria:

a. Commences initial operation between May 1, 2001, and Dec. 31, 2004, except that ultraclean resources, as defined in Section 353.2(a) of the PUC, must commence initial operation between Jan. 1, 2003, and Dec. 31, 2005. Eligibility will automatically continue in effect for additional 6-month periods in the event that no decision has been adopted to revise rates consistent with the policies adopted in D.01-07-027

b. Is located within a single facility

c. Is 5 MW or smaller in aggregate capacity

d. Serves on-site loads or over-the-fence transactions allowed under Sections 216 and 218 of the PUC

e. Is powered by any fuel other than diesel

f. Complies with emission standards and guidance adopted by the State Air Resources Board pursuant to Sections 41514.9 and 41514.10 of the Health and Safety Code. Prior to the adoption of those standards and guidance, for the purpose of this article, distributed energy resources shall meet emissions levels equivalent to nine parts per million oxides of nitrogen, or the equivalent standard taking into account efficiency as determined by the State Air Resources Board, averaged over a 3-hour period, or best available control technology for the applicable air district, whichever is lower, except for distributed generation units that displace and therefore significantly reduce emissions from natural gas flares or reinjection compressors, as determined by the State Air Resources Control Board. These units shall comply with the applicable best available control technology as determined by the air pollution control district or air quality management district in which they are located.

g. This rate schedule shall terminate or no longer be applicable to customers after June 1, 2011.

2.5.2.3 PG&E E-20

PG&E's E-20 tariff is for large commercial facilities.

Applicability:
A customer is eligible for service under this tariff if its maximum demand has exceeded 999 kW for at least 3 consecutive months during the preceding 12 months. If 70% or more of a customer's electricity end use is for agriculture, it will be served under an agricultural tariff.

Energy and Demand Rates:
Energy and demand rates are shown in Table 2-12.

Table 2-12. PG&E's AL-TOU-DER Energy and Demand Rates

PG&E E-20	*Period*	*Summer*	*Winter*
Energy	On Peak	$0.16341	N/A
	Mid Peak	$0.09368	$0.10171
	Off Peak	$0.09184	$0.09266
	Period	*Summer*	*Winter*
Demand	On Peak	$11.80	N/A
	Mid Peak	$2.65	$2.65
	Off Peak	N/A	N/A
	Non Coincident	$2.55	

Components of Delivery Charge:
Of the following, only distribution charges vary from one period to the next; all other charges remain the same:

- Transmission
- Distribution
- PPPC
- NDC
- Reliability services
- DWRBC.

Table 2-13. PG&E Value of Delivery Components (On-Peak Primary Power)

Component	Value ($/kWh)
Transmission	$0.00000
Distribution	$0.00423
PPPC	$0.00298
NDC	$0.00028
RS	$0.00000
DWRBC	$0.00444
Total	$0.01193

Time Periods:

<u>Summer – Service from May 1 through Oct. 31</u>

Peak: Noon–6 p.m. Monday–Friday except holidays
Partial-peak: 8:30 a.m.–noon and 6 p.m.–9:30 p.m. Monday–Friday except holidays
Off-peak: 9:30 p.m.–8:30 a.m. Monday–Friday
All day Saturday, Sunday, and holidays

<u>Winter – Service from Nov. 1 through April 30</u>

Partial-peak: 8: 30 a.m.–9: 30 p.m. Monday–Friday except holidays
Off-peak: 9: 30 p.m.–8: 30 a.m. Monday–Friday except holidays
All day Saturday, Sunday, and holidays

2.5.2.4 Electric Tariff Comparisons

Figure 2-11 shows a comparison of the energy rates for a commercial customer with a load more than 1MW in each of the three IOU territories. The differences among the rates reflect the utilities' cost recovery and ratemaking procedures. The drop in energy rates for SCE reflect the difference between the TOU-8 rate before and after July 2003, when SCE paid off its procurement-related obligations account and its historic procurement charge. This had the effect of reducing energy rates in the time-of-use time bins from 25% summer on-peak to 43% in the off-peak summer. Demand rates, however, have remained the same for SCE.

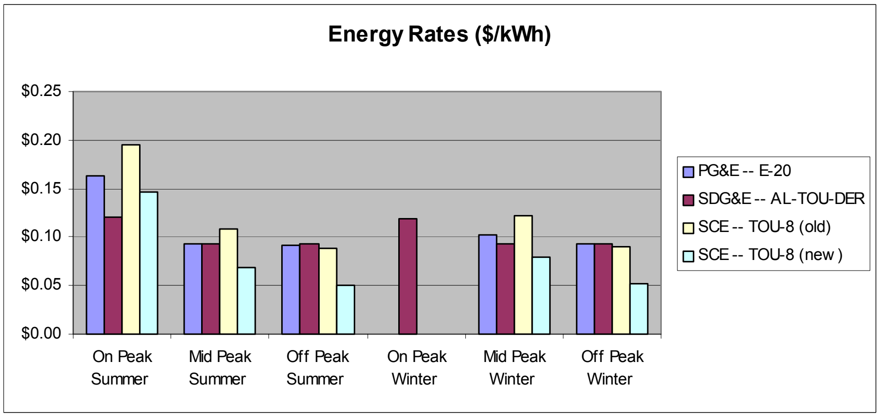


Figure 2-11. Comparison of large commercial energy rates

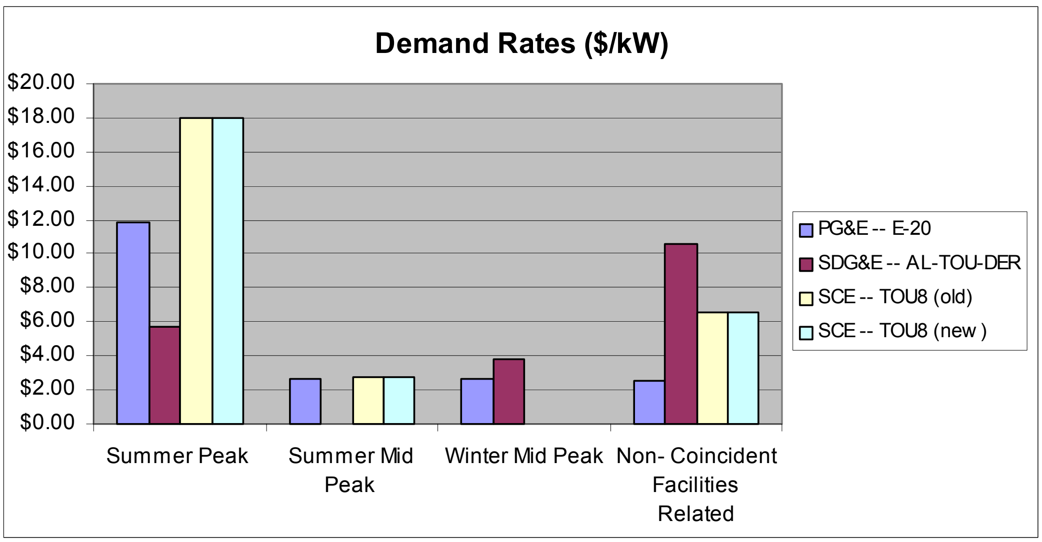


Figure 2-12. Comparison of large commercial demand charges

2.5.3 Standby Tariff Schedule S

Utilities and owners of DER have very different perspectives on the necessity of standby tariffs. Utilities argue that when customers install generation on-site, the utility must be ready to supply the capacity of the generator in case of failure—just as it would if the generator were not there at all. Many utilities—including all the IOUs in California—have therefore developed standby tariffs with commission-approved demand charges equal to the capacity of the generator (or as otherwise determined by the utility).

Owners of DER, on the other hand, see standby tariffs as onerous and unnecessary. They argue that by charging the full capacity of the generator at all times, the utility is assuming that the on-site generator has 0% reliability. Owners also point out that regular prime mover maintenance is scheduled for off-peak periods when transmission and distribution system loads are lightest and capacities are least expensive. (Note, for example, that all California IOUs' off-peak demand charges are $0.00 or "N/A.") Reliabilities of many DER technologies range 90%–99.9%. If a technology does fail, it is no different than when a large customer load is starting up and a corresponding increase in demand charges occurs. Furthermore, the existing utility infrastructure is already in the rate base; hence, the utility sees no additional costs resulting from a customer's installation and operation of DER, especially when it is a non-exporting facility. Therefore, DER owners say, standby tariffs should be eliminated because the existing electric tariff covers this situation. There is anecdotal evidence that one large utility in the eastern United States admitted that there was no "utility standby"—it was really a revenue-protection measure.

2.5.3.1 Reprieve From Standby Service for Distributed Energy Resources

Qualifying DER have won by reprieve from standby charges in California. The legislature passed SBX 28, which created PUC Section 353, which directed the CPUC to establish tariffs that did not discriminate against customers that chose to deploy DER. The CPUC implemented the legislation when it issued Decision D.03-04-060, effective April 17, 2003. The decision stated that DER generation operated in CHP applications and renewable resources, as defined in D.02-10-062, 5 MW or smaller, installed between May 1, 2001, and Dec. 31, 2004, and meeting all other criteria in Section 353.1 of the PUC shall not be charged rates or tariffs that are different from another customer without DER until June 1, 2011. In other words, they are exempt from the otherwise applicable standby and generation reservation charges. In SCE territory, the Dec. 31 date will roll back every 6 months until SCE's 2003 GRC is approved by the CPUC. For installations after that time and for non-qualifying DER, Schedule S applies.

The transmission charge for a customer that receives primary power (2–50 kV) under Schedule S is $0.23, the distribution charge is $4.10, and the subtotal delivery charge is $4.33. Utility-retained generation standby is $2.27. The total for delivery and utility-retained generation is $6.60/kW. The generation reservation charge is $0.36/kW. Both standby charges are assessed monthly for each meter located at the customer facility.

2.5.3.2 Standby Service Under Southern California Edison's General Rate Case

A new standby tariff was proposed as part of the GRC. It was designed to meet the CPUC's requirements adopted in Decision D.01-07-027. Specifically, the CPUC identified three classes of standby service: supplemental service, backup service, and maintenance service. Supplemental service is the service provided to the customer as if it had no on-site generation facilities (i.e., that portion of the customer's load that is regularly provided by the utility as if the customer were a full-service customer). Backup service is an on-demand service required during unscheduled outages of the on-site generation that ensures utility capacity is available for a customer to call on to meet load. Maintenance service is provided during utility-approved scheduled outages for maintenance.

In the new Schedule S, supplemental service is provided under the customer's otherwise applicable tariff. For the purposes of this paper, RE considers the otherwise applicable tariff to be TOU-8 at primary voltage. To receive maintenance service, SCE requires the customer to sign a customer physical assurance agreement, which states that it has equipment in place to prevent the necessity of SCE providing power in case of an unscheduled outage. If the customer does not sign the agreement or put the equipment in place, it is subject to SCE's backup service rates, including a capacity reservation charge. Both the maintenance and backup service include energy charges and customer charges. These charges are summarized below.

It should be noted that in D.01-07-027 the CPUC chose to ignore arguments made by the DER industry that the evidence it used to make its findings and rulings was outdated. For instance, it did not take into account the creation of PUC Section 353.

Maintenance Service – Primary Voltage Greater Than 1 MW:

- Standby energy charges for primary voltage service: $0.00522/kwh
- Utility-retained generation and DWR energy charges: utility-retained generation = $0.06091/kWh, DWR = $0.10412/kWh[40]
- Total standby energy charges for primary voltage service: utility-retained generation = $0.06613/kWh, DWR = $0.10934
- Standby customer charge: $1,900/month

Backup Service – Primary Voltage Greater Than 1 MW:

- Capacity reservation charge: $3.46/kW
- Standby energy charges for primary voltage service: $0.00561/kwh
- Utility-retained generation and DWR energy charges: Same as above
- Total standby energy charges for primary voltage service: utility-retained generation = $0.06652/kWh or DWR = $0.10973
- Standby customer charge: $1,900/month

(Note: The standby customer charge may have increased to $4,200/month with GRC-2. See Section 2.6.2 for more details on GRC-2.)

2.5.4 Cogenerator Gas Tariffs

Some RE customers have existing gas service,[41] and some do not. In any case, when RE installs its gas-fired generator, the gas utility requires it to apply for service as a cogenerator. If the existing customer has gas service, it is usually as a small commercial core customer. The utility requires RE to take gas service as a cogenerator—a non-core service by definition. There is no option for RE to take service as a core customer.

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[40] Energy received by every utility customer since DWR began purchasing power on behalf of the utilities is a combination of power purchased by DWR and power purchased by the utility. Each customer's rate, then, is a blended average of these energy charges.

[41] The customer thermal load, when it exists, is usually a small hot water boiler that serves the domestic hot water needs of the facility. In these situations, if RE chooses to displace the boiler, it provides trigeneration: electricity, chilled water, and hot water.

This section examines the non-core tariffs for cogenerators offered by PG&E, SoCalGas, and SDG&E.

2.5.4.1 Southern California Gas GT-F

Schedule GT-F is applicable for firm intrastate transmission-only service for commercial and industrial, enhanced oil recovery use at each facility classified as non-core—as defined in Rule No. 1—and electric generation plants.

The customer charge for electric generators using less than 3 million therms/yr is $50. The GT-F5 electric generation rate for customers using less than 3 million therms/yr is $0.06422/therm. For customers using 3 million therms or more per year, the rate per therm is $0.03318.

2.5.4.2 San Diego Gas and Electric EG

SDG&E Schedule EG is applicable to natural gas service classified as firm or interruptible intrastate transportation of natural gas for customers classified as electric generation plants or cogeneration whose facilities meet the efficiency standards specified in Section 218.5(a) and (b) of the California PUC. Service rendered under this schedule is not available to entities that are affiliates of Sempra Energy.

For customers using less than 3 million therms/yr, the customer monthly charge is $50. Volumetric charges are $0.06198/therm. Customers using 3 million therms or more per year pay volumetric charges of $0.03094/therm.

2.5.4.3 Pacific Gas and Electric Gas Cogeneration

The PG&E gas cogeneration rate schedule applies to the transportation of natural gas on PG&E's local transmission or distribution system to cogeneration facilities. To qualify for service under this schedule, the customer must be a cogeneration facility that sequentially uses natural gas to produce electricity and useful thermal energy, as specified in California PUC Section 218.5. Customers receive service under this schedule in conjunction with a rate schedule that would otherwise apply if the customer did not meet the requirements to qualify as a cogeneration facility.

The transportation charge is $0.02029/therm. Non-core end-use customers must procure gas supply from PG&E or from a supplier other than PG&E. A natural gas service agreement is required for service under this schedule. The initial term of the service will be 1 year.

The volume of gas transported under this schedule is limited to the lesser of (1) the cogeneration gas allowance for each kilowatt-hour of net electricity generation fueled by natural gas or (2) the quantity of gas actually consumed in the cogeneration generator less the energy used to operate the equipment of the cogeneration facility. The cogeneration gas allowance equals incremental heat rate/100,000 Btu/therm, where Btu/kWh = 10.681 = 0.10681 therms/kWh.

PG&E will eliminate this gas cogeneration tariff on April 1, 2004. Initial utility plans for the tariff to replace the gas cogeneration tariff included a provision for separating small and large generators into two rates, which would mean an increase in the transmission tariff of 870% to small cogenerators. On Dec. 18, 2003, PG&E reached Gas Accord 01-10-001. This accord keeps in place the discounted gas rate under which RE has underwritten its projects and preserves the ability of small generators to get gas under the same terms and conditions as large generators when the gas cogeneration tariff is eliminated. At that time, the gas cogeneration tariff replacement rate will rise to $0.026/therm.

2.6 Analysis of Proposed Tariffs

2.6.1 Trouble on the Horizon for Combined Heat and Power

The California energy crisis brought inevitable increases in electricity rates to pay for the huge debts incurred when the wholesale rates for electricity spiked. Because the retail rates were frozen, the utilities had to make special emergency tariff filings to get the rate increases they needed to pay for wholesale energy.

Two tariff rate case proceedings now have potentially grave consequences for CHP market development in California, one electric and the other gas. The electric rate case is the SCE GRC; the other is the SoCalGas BCAP proceeding.

2.6.1.1 Southern California Edison's General Rate Case

SCE is proposing to shift most of its revenue recovery from energy to a fixed services charge (FSC) proposed for all rate classes. Ironically, after raising energy rates to pay for restructuring, SCE is now proposing to lower them—even though it still must buy electricity on the wholesale market. The specific TOU-8 tariff (common for RE customers) is discussed above. Under the original SCE proposal, on-peak energy prices would fall from $0.195/kWh to $0.066/kWh (later amended to a drop from about $0.14 to $0.07–$0.08); the FSC would rise from $299 /month to $l,900/month (later amended to $4,200). Shifting the burden of rate recovery to a bill component that has nothing to do with energy usage is certain to have a chilling effect on markets, not only for CHP but also for all DER products and services.

2.6.1.2 Gas Rate Case of Southern California Gas

The SoCalGas and SDG&E BCAP rate tariff proposes to bifurcate the non-core rate for cogenerators into two rates: one for large gas customers and one for small gas customers, defined as:

> Non-core Customer, Large: Those retail non-core Commercial and Industrial, Electric Generation and Enhanced Oil Recovery customers whose historical non-core peak day usage at a single premises is greater than or equal to 10 thousand decatherms (10 Mdth) on any day over the most recent 24 months or electric generation customers whose annual usage is greater than or equal to 3 million therms per year. For customers with less than 12 months of historical usage, the annual usage shall be determined on a pro rata basis using the months for which usage is available. Non-core Customer, Small: All retail non-core customers (i.e., commercial and Industrial, Electric Generation, and Enhanced Oil Recovery) not defined as Large Non-core Customers.[42]

[42] http://www.socalgas.com/regulatory/bcap/docs/TARIFFS.pdf

Whereas all customers now pay the lower rates of the large customers, the added tariff would be for smaller customers and at a higher rate and has the potential to substantially raise the transportation rates RE pays for gas in the respective service territories. The proposed 93% SoCalGas rate increase is for small electric generation from $0.05864/therm to $0.11326/therm.

The effect of both of these tariff changes would be to squeeze spark spreads and increase tariff risk for new and existing projects.

2.6.2 Southern California Edison General Rate Case Application[43]

On May 3, 2002, SCE filed an application with the CPUC for " ... authority to increase its authorized revenues for electric service in 2003 and to reflect that increase in rates."[44] The 2002 GRC increase was for $286 million to:

> ... replace an aging distribution infrastructure and business systems ... to remove and dispose of aging distribution infrastructure, such as poles and transformers ... [to pay for] high rates of inflation in the costs of health care and other benefits ... [to pay for] increase costs for system inspections, replacements, and repairs ... [and because] SCE-owned generation is returning to cost-of-service ratemaking.[45]

SCE estimated that the rate increase would raise customer bills an average of 10.3%.

Now, more than a year and a half later, it appears the rate increase will be smaller—perhaps only 1%–3%. What should concern all players in DER markets—including users of CHP, DG, energy efficiency, and other distributed energy technologies—is the way SCE is allocating costs and, consequently, how it is structuring its proposed tariff rates. The end result of the GRC as currently proposed is a tenfold increase in fixed customer costs, a 50% reduction in energy rates, and the elimination of most demand charges except for summer on-peak demand. If the DER market is to combat the tariff risk of this GRC design, it needs to understand why SCE is taking this approach, how SCE derives its marginal costs, and end-point tariff implications.

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[43] This section uses documents for Application A.02-05-004, found on SCE's Web site: http://www3.sce.com/law/cpucproceedings.nsf/vwUCategoryTitle?OpenView&Count=255. The following documents are referenced:

- Application 2002-05-03 (referred to in this paper as SCE application)
- SCE-13 Updated Testimony (Phase 2) 03-24-03 (SCE-13)
- SCE-14 Updated Testimony (Phase 2) 03-24-03 (SCE-14)
- SCE-15 Updated Testimony (Phase 2) 03-24-03 (SCE-15)
- SCE-16 Updated Testimony (Phase 2) 03-24-03 (SCE-16)
- SCE-17 Updated Testimony (Phase 2) 03-24-03 (SCE-17)
- SCE-18 Updated Testimony Part 1 (Phase 2) 03-24-03 (SCE-18a)
- SCE-18 Updated Testimony Part 2 (Phase 2) 03-24-03 (SCE-18b)
- 09/29/03 Phase 2 of 2003 GRC Rebuttal Testimony.

[44] SCE application, cover page.
[45] SCE application, p. 2.

Table 2-14. Estimated Effect of SCE's Request on Rates

Customer Group	$ Million	Increase over current Base Rates - %	Increase over total current Rates - %
Residential	112.2	10.5%	3.2%
Lighting - Small & Medium Power	101.1	10.5%	2.4%
Large Power	62.6	10.4%	2.1%
Agricultural & Pumping	9.3	10.5%	2.7%
Street & Area Lighting	1.2	2.1%	1.2%
Total	286.4	10.3%	2.6%

2.6.2.1 Rate Components of the General Rate Case[46]

We have seen already how its payments of the procurement-related obligations account and historic procurement charge account reduced SCE's energy rates in the TOU-8 and other tariffs in 2003. In its latest GRC numbers (GRC-2),[47] SCE has raised its energy rates from its Sept. 9, 2003, (GRC-1) rates.[48] The major difference in energy rates between current TOU-8 rates and those proposed in the GRC is the precipitous drop in summer on-peak energy rates. All other time bins remain relatively unaffected by the GRC rate application proposal.

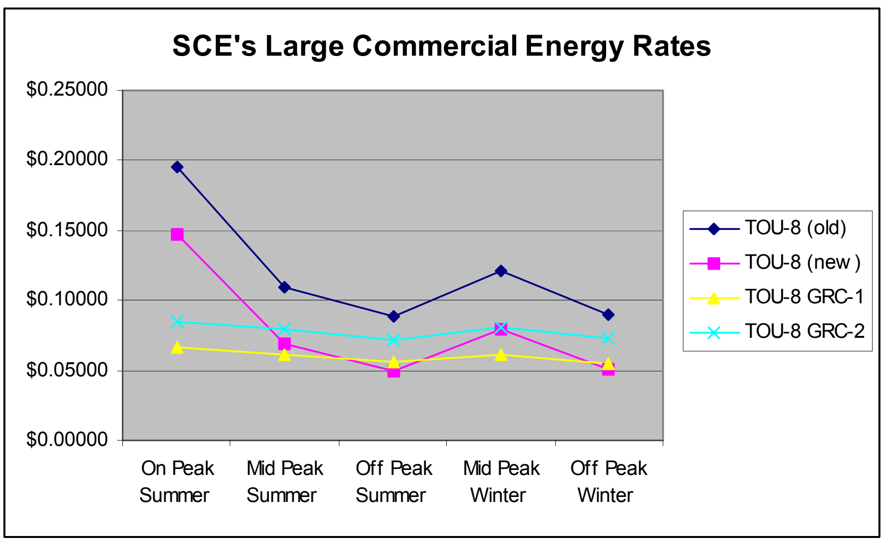

Figure 2-13. SCE's TOU-8 Energy Rates in 2003

[46] All rates quoted are for TOU-8 customers on primary distribution service (2–50 kV).
[47] From SCE's working papers for its GRC application (called here GRC-2), January 2003.
[48] SCE-16, Appendix B (called here GRC-1), p. 8.

Most DER aim to reduce peak energy usage and rely on the reduction energy costs as a form of revenue for payment of energy-efficient equipment purchase and installation. RE, for example, sizes its projects according to peak building load so it can capture as much summer on-peak operation as possible within the confines of project economics. This approach, however would be drastically altered by a tariff that is flat across successive tariff time bins. SCE's proposed reduction from $0.15 down to $0.08 by regulatory fiat is a perfect example of tariff risk. A project that made sense economically in 2002 would not make sense today if GRC-1 or GRC-2 were implemented.

SCE's treatment of demand charges has been similar, as illustrated in Figure 2-14. There have been few changes in mid-peak and off-peak rates. The major change again is in summer on-peak charges. Demand charges have dropped in the latest proposals from about $18 to just more than $12 in GRC-2 and about $6 in GRC-1.

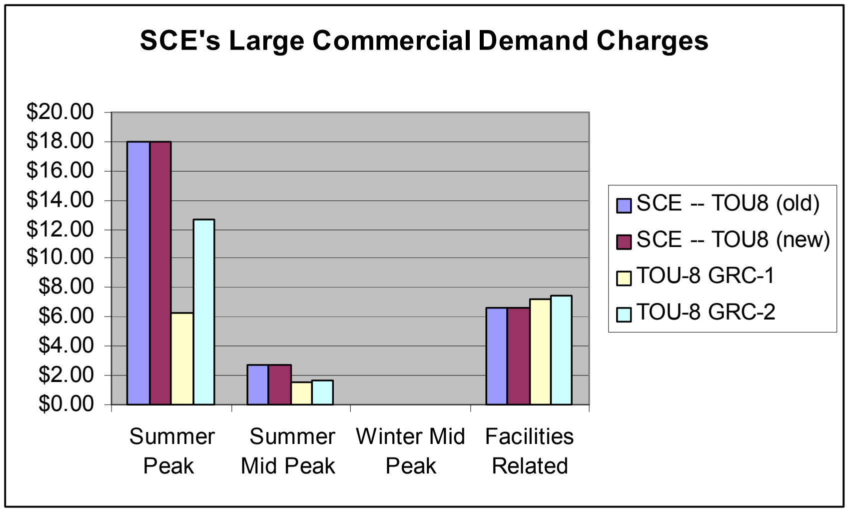

Figure 2-14. SCE's TOU-8 demand charges in 2003

The rate drop makes sense when a tariff component is paid off, as between the old and new TOU-8 rates. But when there has been no rate component dropped, revenues must still be collected in their entirety. Where does SCE go about collecting this additional revenue? It is requesting in its application to collect under the FSC. This represents an increase in customer charge of 1,400%.

2.6.2.2 Explicit and Implicit Rationale for This Approach

It is worth inquiring into why SCE is requesting to shift its revenue collection from energy to a fixed monthly customer charge. It should not be too shocking to discover that some of the reasons lead back to the failure of electricity restructuring in California. It is especially interesting in light of SCE's stated disinterest in the matter of revenue allocation: "In general, SCE shareholders are financially indifferent to the revenue allocations and rate designs chosen by the commission."[49] The basis of this financial indifference is surely the rate of return on invested capital authorized by the commission to a regulated utility. However, an authorized return on an investment does not guarantee that return and does not address the overall amount of revenue collection potential. Also, the recent electricity crisis showed that utilities are at risk when restructuring markets go awry. It stands to reason then that SCE would propound rate design based on an implicit strategy to avoid the risks that were inherent in the failed market design.

[49] SCE-31, p. 13.

The utility sees two primary risks:

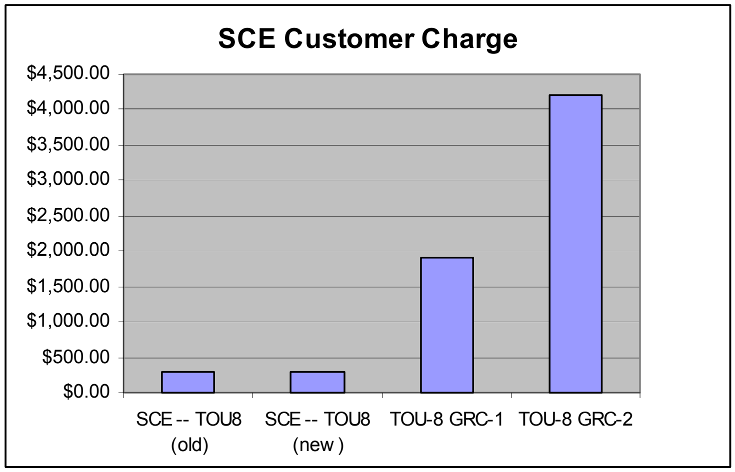

Figure 2-15. SCE's TOU-8 customer charge

- Bankruptcy because of market forces unleashed by wholesale electricity and gas restructuring or other unforeseen causes
- Shrinkage of future revenues from generation and retail delivery of electricity, starting with the exit of large industrial and commercial customers in favor of direct access, self-generation, and other DER technologies, using the distribution system for off-peak power or " left over" on-peak and mid-peak power.

If this represents an accurate picture of the utility's implicit concerns, it stands to reason that SCE would formulate a strategy of revenue allocation and rate design that would guard against these eventualities. However, the second concern is not valid in so much as direct access customers still are using the wires to receive delivery of power.

The following excerpt shows clearly the linkage between AB 1890, risk, and ratemaking:

> At present, SCE's future role in the provision of some utility services is unclear. Restructuring legislation (AB 1890) created a wholesale generation market and allowed customers to directly access that market for electricity supply. Utility rates were unbundled, with the generation component intended to be market-based at the end of a transitional rate freeze period. Direct access customers were permitted to obtain some metering and billing services from their electricity supply provider instead of SCE. SCE's higher voltage transmission facilities were transferred to Federal Energy Regulatory Commission jurisdiction and placed under the operational control of the California Independent System Operator. With the catastrophic failure of California wholesale electricity market in 2000, direct access was suspended to new entry and SCE's remaining generating facilities were returned to cost of service ratemaking through at least 2005. In early 2001, SCE became financially unable to procure electricity for its customers, and the California Department of Water Resources took over this responsibility. The Commission is currently engaged in a proceeding[50] which [sic] will establish the policies and procedures under which SCE is anticipated to resume procurement for its customers in 2003 …. Thus, we present marginal costs reflecting our provision of the full chain of services that provide electricity to customers.[51]

[50] Rulemaking 01-10-024, Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development. Oct. 25, 2001.
[51] SCE-14, p. 7.

In this light, SCE's high FSC and low on-peak energy charge accomplish important tactical advantages. They will:

- Ensure that SCE will be able to count on a certain amount of fixed revenue, which reduces risk from volatile wholesale energy (or gas) prices, despite low fixed retail rates
- Reduce the profitability of all (especially commercial and industrial) customer DER, which reduces the likelihood that these customers will self-generate or reduce energy or demand usage through efficiency.

These objectives are not stated anywhere and could not be expressed except obliquely without causing difficulties to the utility's case, given California's political climate, but they do seem to pervade the logic of SCE's application.

As an example of how SCE argues for the first tactical advantage without stating it, consider this:

> Finally, ORA argues that higher residential customer charges benefit SCE's shareholders because they will "obtain a large increase in fixed or guaranteed revenues." As noted by NRDC, all of SCE's commission-authorized cost recovery mechanisms are, or are soon expected to be, subject to balancing accounts. As a result, SCE will recover its authorized revenue requirements or its recorded costs as the case may be. Therefore, ORA is wrong that SCE needs higher FSCs to increase its fixed or guaranteed revenues. SCE proposed the higher FSCs for the sole purpose of eliminating intra-class cost subsidies by moving various rate components toward their cost-based levels.[52]

What SCE is implying is that energy rates have been subsidizing customer fixed costs (or what SCE calls "grid infrastructure"). As recently as January 2001, however, wholesale energy prices reached $0.40/kWh (see Figure 2-5.) The utilities defaulted on their payments, and the state stepped in to purchase electricity—in effect, massively subsidizing energy rates. Insisting on low fixed energy rates today to prevent intra-class subsidy presents itself as a case of acute corporate amnesia. The demise of some provisions of electricity restructuring and subsequent low marginal energy costs is no indication of future energy prices—as the utility knows. Also, SCE describes "grid infrastructure" as a cost driver that, in the course of analysis for this application, it "has developed."[53] If there is an intra-class cost subsidy, it is because SCE has developed a new cost driver that needs a new cost subsidy—the funds have to come from somewhere.

As an example of how SCE argues for the second tactical advantage without stating the motivation for it, consider this:

[52] SCE-31, p. 7.
[53] SCE-14, p.12.

> NRDC and TURN oppose an increase in residential monthly charges due to the diminished effect this would have on customer incentives to invest in energy efficiency. At present, SCE's proposed rate design uses the additional revenues from SCE's proposed monthly charge to lower rates in the lower usage rate tiers, so there is little impact on customer energy efficiency incentives.... Currently, upper-tier residential rates are around $0.20/kWh, compared to marginal energy costs of around $0.05/kWh.... the putative benefits and deviating from marginal cost-based ratemaking to support additional energy efficiency needs to be weighed against this distortion.[54]

SCE does not address the parallel but reverse situation in TOU-8 rates, in which marginal costs are distorted in the form of excess FSCs that are used to lower on-peak energy rates and to disincentive efficiency and all forms of demand reduction, especially on-site generation.

It is likely the utility is less concerned about "intra-class subsidy" than it is about inter-class subsidy (i.e., exit from the system of some percentage of load by industrial and commercial customers). It is politically unpopular for residential rates to increase as a result of departure of load. At the same time, high-capacity commercial and industrial end users may realize savings under SCE's GRC proposal because they could reduce overall energy costs through low energy rates and high FSC, compared with low FSC, high energy rates, and the specter of capital investments in energy efficiency and on-site generation.

One defensible statement that may be made of all American energy markets: They use various fuel subsidies to reduce energy costs and thereby discourage energy efficiency and encourage greater consumption. This has been less so in past California electricity markets, but SCE's GRC is a powerful retroactive move in that direction. A high fixed cost will subsidize a low fixed energy cost when wholesale electricity prices rise above $0.075 on average (less distribution costs). Analysis of SCE's marginal cost methodology is instructive because it shows how the utility can redefine its cost drivers to argue for change on the basis of the (redefined) marginal costs of its rate class components.

2.6.2.3 Marginal Cost Methodology

SCE begins its marginal cost analysis by identifying cost drivers, i.e., aspects of customer requirements that cause SCE to incur costs. Calculating changes in each cost driver gives the marginal cost for each. It is performed using this formula:

Marginal cost = change in total cost / change in cost driver.

Marginal costs derived in this way are then attributed to customer requirements, including peak demand and customer type. Rate components are thereby associated with energy charges, demand charges, and monthly customer charges based on the corresponding marginal cost.

SCE performs revenue allocation by comparing the revenues collected if all customers were charged rates that equal marginal costs with the authorized revenue requirements by rate group.

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[54] SCE-31, p. 38.

So far, the marginal costing process described is similar to one SCE has used since 1981.[55] However, with the 2003 GRC, SCE has introduced some significant changes, including:

- A new cost driver called "design demand" is "developed" for use in marginal costing.
- The minimum distribution system cost study used since 1981 is replaced with a calculation of grid infrastructure marginal costs.

The notion of design demand is a cost bucket into which SCE puts that portion of distribution system cost that is associated with demand for capacity. The balance of the system marginal cost is dubbed grid infrastructure marginal cost. Grid infrastructure turns out to be nearly 80% of distribution revenue requirement cost. This approach allows SCE to shift usage costs for demand and energy into a fixed monthly customer charge.

SCE presents marginal costs for four cost drivers:

- Electricity usage
- Design demand
- Grid infrastructure
- Number of customers.

Electricity Usage
The cost of procuring electricity supply from the wholesale generation market to meet the changes in customer electricity usage varies hourly. In addition, there is a price volatility component associated with meeting customer supply needs from the wholesale market because of the uncertainty inherent in electricity and gas prices.

Design Demand[56]
SCE devotes testimony and analytical effort to an estimation of the portion of the delivery system that is design demand-related, based on marginal cost analysis. At the conclusion, though, SCE simply asserts "the remainder is grid infrastructure-related."[57] It estimates the total distribution grid infrastructure marginal cost revenues at approximately $1.45 billion[58]—two and a half times greater than the total design demand marginal cost revenues of $0.56 billion. In other words, SCE is saying that 72% of the total distribution revenue requirement should be considered as grid infrastructure costs to be recovered through fixed customer charges (the FSC) and 28% should be considered demand-related. This creates a significant "intra-class" subsidy or reallocation that affects the revenue allocation among rate groups and the rate design of each tariff rate schedule. Including marginal customer cost revenue of $0.65 billion,[59] approximately 79% of the total distribution and customer-related revenue requirement would ultimately be collected through FSCs under SCE's proposal.

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[55] Decision 92749. March 1981.
[56] Parts of this section and the analysis of SCE's GRC are from:
Sirvaitis, R. "Direct Testimony of Robert V. Sirvaitis on Behalf of the Joint Parties Interested in Distributed Generation/Distributed Energy Resources." Aug. 15, 2003.
[57] SCE-14, p. 25, Line 8.
[58] SCE-16 Workpapers, p. 77.
[59] SCE-16 Workpapers, p. 77.

Grid Infrastructure
Grid infrastructure and design demand are delivery-related cost drivers that attempt to reflect how the electric delivery system is designed and constructed. SCE says, "A substantial portion of the delivery system represents infrastructure which, like streets and roads, is extended to those who live in an area regardless of actual usage. The remaining portion of the delivery system is designed and constructed to meet the expected peak demand placed on it."[60] This logic is open to question. A road would not be constructed assuming zero demand, and it is not likely to be constructed until there is sufficient demand to warrant it. This reasoning is closer to the intent of the original marginal cost in previous rate cases that estimated a minimum demand. The new marginal cost methodology differs from methods used in previous proceedings. It focuses on determining design demand marginal costs of the delivery system based on the assertion that the "remainder is grid infrastructure-related."

The Joint Parties Interested in Distributed Generation/Distributed Energy Resources said of SCE's proposal:

> This rate design proposal ... results in significant increases in the monthly Customer [or] Fixed Services Charges to be collected from customers as a result of this proceeding and establishes a framework for continuing significant increases to Customer [or] Fixed Services charges over the next 4 years, without regard to customer usage. Within each rate group, smaller customers are charged the same amount per month as larger customers, even though their non-coincident demands are significantly different. This is discriminatory and inequitable. SCE's proposal to establish Fixed Services Charges and increase these charges over the next 4 years establishes a revenue stream that is independent of usage [that] may collect over 75% of the total distribution and customer-related revenue requirement. Such pricing provides little or no incentive for customers to manage their demand usage and appears to be a mechanism to deter customers from seeking viable alternatives to traditional electric service while protecting SCE from the effects of competition.[61]

Number of Customers
Finally, the number of customers is a cost driver that reflects the marginal costs of customer interconnection to the delivery system and various customer services, including the costs of a meter, service drop, protection equipment, final line transformer, and customer service costs, including customer communications, measuring usage, maintaining records, and billing.

2.6.2.4 Next Steps in the Ratemaking Process
Parties to SCE's GRC ratemaking application had until the end of February 2004 to reach agreement on cost allocation. No settlement has been reached. A hearing will be held in March 2004 at the CPUC. Thereafter, the CPUC will issue a decision on SCE's application. Phase I should be over by July, and then Phase II will commence again. Phase I establishes the basis for SCE's revenue requirement, i.e., the 1.5% increase. Phase II will deal with the cost allocations.

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[60] SCE-14, p. 3, lines 12-13.
[61] Same as Note 56.

2.6.3 Southern California Gas Rate Case Application

On Sept. 3, 2003, SoCalGas filed Application A.03-09-008 with the CPUC to revise its rates for gas service effective Jan. 1, 2005. This BCAP application proposed to revise SoCalGas rates to update the allocation among its customers' non-gas costs of service, excluding the costs of unbundled storage. The purpose is to update the allocation of the non-gas commodity costs and to update the rates accordingly.

According to SoCalGas:

> The application proposes 100% balancing account treatment for non-core transportation revenues due to the significant number of factors that affect non-core demand, and consistent with SoCalGas' treatment of core transportation revenues. The application also proposes new non-core service offerings and revisions to various tariffs. Proposed rates for small businesses and small industrial customers are also slightly lower. Proposed rates are higher for large commercial and industrial customers, as well as electric generation customers, primarily due to an expected reduction in gas demand that will result in fewer therms across which to spread required costs.[62]

SoCalGas was required to file a BCAP in September of 2001. In December of 2001, the CPUC issued the "GIR" D.01-12-018, adopting a "comprehensive settlement agreement." Subsequent to the comprehensive settlement agreement, the CPUC ordered SoCalGas to amend its BCAP application. The GIR decision was finalized in January 2004 and was to be adopted in late January, requiring the BCAP application to be modified yet again. After that modification, the real work of the proceeding will begin. In essence then, SoCalGas rates have not changed since 1999.

2.6.3.1 Proposal Summary

In this application, SoCalGas proposes an increase in overall transportation rates of $79.3 million, or 4.7%. A typical winter bill for a residential customer using 75 therms will decrease by $0.12 under the proposed rates from the average $62.64 under present rates.[63]

The major rate/tariff issues are:

1. Segmentation of non-core into large and small customer classes
2. Revision of firm non-core service
3. Adoption of differentiated volumetric rates
4. Revision of method of allocating SGIP costs
5. Adoption of new peaking service
6. Requirement for contracts for firm transmission service.

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[62] Southern California Gas Company. "Southern California Gas Company Notice of Proposed Changes to Gas Rates Biennial Cost Allocation Proceeding (BCAP) Application No. 03-09-008." Sept. 17, 2003. www.socalgas.com/regulatory.

[63] All SoCalGas utility information on the BCAP is found at: http://www.socalgas.com/regulatory/bcap/.

The only issues of interest here are those that increase tariff risk to CHP by increasing transmission rates, i.e., issues 1 and 3. The rate increase is caused by bifurcating non-core tariffs into large and small customer classes and giving the small customer class a higher volumetric rate. For the electric generation customer class, this means a rate increase of 81.2%. Small EG has a 93% rate increase, part of an overall 73.4% increase for non-core customers.

Meanwhile, core rates are *decreasing* 0.8%–0.5% for residential and 2.4% for non-residential.

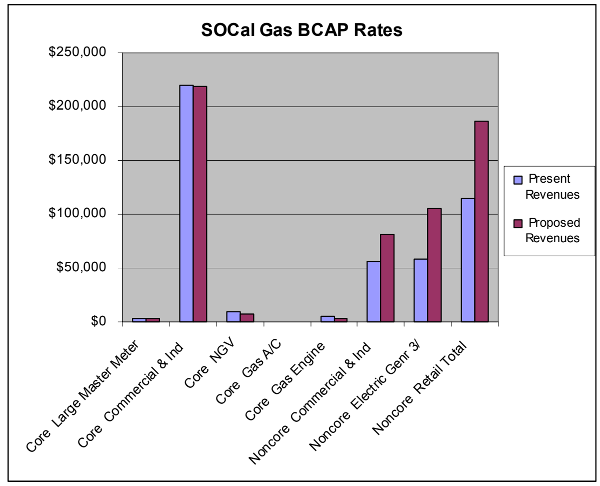

Figure 2-16. Projected BCAP revenues ($000)[64]

2.6.3.2 Biennial Cost Allocation Proceeding Analysis

It is interesting, but ultimately fruitless, to speculate why SoCalGas suggests this rate change. There is the bureaucratic reasoning: "...the application proposes 100% balancing account treatment for non-core transportation revenues." This seems to indicate that the reason is consistency of application of transportation revenues. But, again, why?

Table 2-15. BCAP Revenues, Core Vs. Non-Core

	Present Revenues	Proposed Revenues	Increase (Decrease)	%Change
CORE				
Residential	$1,162,576	$1,157,962	($4,614)	-0.40%
Large Master Meter	$3,466	$2,649	($817)	-23.60%
Commercial & Ind	$219,813	$219,090	($723)	-0.30%
NGV	$9,613	$7,006	($2,607)	-27.10%
Gas A/C	$231	$179	($52)	-22.40%
Gas Engine	$5,503	$3,185	($2,318)	-42.10%
TOTAL CORE	$1,401,201	$1,390,070	($11,131)	-0.80%
NONCORE				
Commercial & Ind	$56,158	$81,693	$25,535	45.50%
Electric Genr 3/	$58,091	$105,283	$47,192	81.20%
Retail Noncore Total	$114,249	$186,976	$72,727	63.70%
WHOLESALE :				
Long Beach	$2,405	$4,368	$1,964	81.70%
SDG&E	$20,112	$43,637	$23,525	117.00%
Southwest	$1,877	$4,166	$2,290	122.00%
Vernon	$1,852	$4,340	$2,489	134.40%
Wholesale Total	$26,245	$56,512	$30,267	115.30%
INTERNATIONAL				
DGN	$976	$1,825	$849	87.00%
Unalloc.Costs to NSB	$15,159	$0		
Unbundled Storage	$21,000	$22,704	($13,454)	-37.20%
Public Purpose	$112,595	$112,627	$32	0.00%
SYSTEM TOTALS	$1,691,424	$1,770,714	$79,290	4.70%

Perhaps it is because SoCalGas does not believe there is significant growth in this sector:

> "SoCalGas forecasts that non-core C/I electric generation demand will increase moderately over the BCAP period. SoCalGas expects that increasing demand will result from the capital cost incentive program, as mentioned above, additional customer interest in self-generation, moderated by relatively high natural gas prices, and a continuing weak manufacturing environment. Consequently, for calendar years 2005 and 2006, the forecasted non-core C/I electric generation demand is 14,843 MDth and 14,843 Mdth, respectively."[65]

Zero is indeed very modest growth.

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[64] The electric generation rate includes a "common electric generation adjustment" of $12.9 million in proposed rates.

[65] Prepared direct testimony of Mark Otrhalek, Southern California Gas Co., 2003. http://www.socalgas.com/regulatory/bcap/docs/MOTRHALEK.pdf

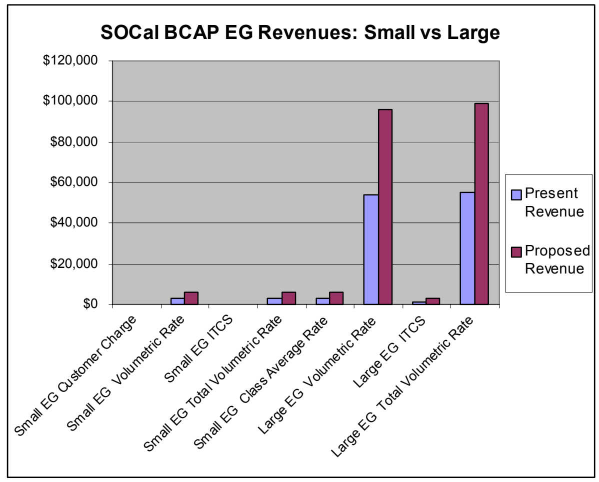

Figure 2-17. BCAP revenues, small vs. large

But if SoCalGas makes the same return either way, what does it matter? The "size of pie" argument does not have much support. SoCalGas is only asking a 4.7% overall increase—modest when you consider there's been no increase since 1999. SCE's GRC also appears to be a modest increase. In its latest revisions of the application, it is requesting an only 1%–3% increase. In fact, there is an eerie parallelism between the two applications: both request modest overall increases, sharp changes for the worse in rates for cogenerators, and mild decreases in rates for residential and small commercial customers. SCE's GRC takes a chop at the head of cogeneration spark spread by reducing on-peak electric rates; SoCalGas takes a chop at the feet by increasing gas costs for cogenerators. The result is a drastic reduction in the profitability of cogeneration in California. Yet nowhere in either of these applications is there one word mentioned that the utility has any such intention. The net effect of these proposals, whether intentionally or not, is anticompetitive.

One development especially troubling for the DER industry is SoCalGas' push to lock customers into 15-year contracts. This is counter to generally accepted utility rate design. Its justification is that it is the only way to make economically efficient investments. Yet it also states that its system will need no new major investment until 2020. However, if it were to achieve the approval of a 15-year contract, it would have the effect of freezing out any competitive threat from alternate providers.[66]

Also troubling to DER is SoCalGas' G-30, a proposed core customer rate that would likely apply to many of RE's existing customers. The change involves an increase of cost of interruptible service so that it would be 30% more than firm service. This is counterintuitive because a customer that is willing to be interrupted usually pays less, not more. The increase would support an unstated motive of SoCalGas to move all customers into core service on 15-year contracts. As part of this new G-30 class, SoCalGas is proposing a new non-core "peaking service" rate. It is unclear what this rate would be and how it would apply.

Finally, as of the Dec. 17, 2003, scoping ruling, SoCalGas is moving to equalize costs for electric generators with SDG&E. The effect of this is an additional $0.02/therm increase in the small electric generator rate for SoCalGas.

[66] Greenberg, S. "California PUC Gas Proceedings January 2004 Status Report." *Distributed Energy Strategies*. January 2004.

2.6.3.3 Biennial Cost Allocation Proceeding Timetable
The CPUC will hold formal evidentiary hearings devoted to analyzing the need for the requested rate changes and accept testimony from SoCalGas and other interested parties. The CRS decision is still not final, and the BCAP is put on hold until the CRS is final. The newest estimate is that the CRS should be finalized by the end of April.

2.7 Tariff Modeling and Results
Although the foregoing analyses show clearly the tariff risk posed by SCE's GRC and SoCalGas' BCAP, it remains to determine their effect on overall spark spread and, more importantly, on project profitability.

RE has developed an in-house analytical model that, given correct input assumptions, estimates project profitability of a CHP system quite accurately. Inputs must be given for installation as well as for operational parameters of a given building. To assess the tariff risk and market development effect of the new electric and gas tariffs in play in California today, RE made a series of model runs against a base case. The tariffs modeled included:

- No tariff change
- Departing load fee
- BCAP non-gas commodity cost increase
- Standby charge
- Proposed SCE GRC-2 rates.

2.7.1 The RealEnergy Tariff Model Assumptions
RE's tariff model can be applied to the operating characteristics of any host facility, typically large commercial office buildings. The particular building used for these runs has a peak demand of 4.6 MW, uses more than 21 MWh of electricity annually, and has an annual chiller load of 2.176 million tons. The hot water load is more than 43,000 therms/yr. Building load shape follows the occupancy pattern of a typical office building. Monday through Friday, approximately 20% of the load runs around the clock, 40% comes on at about 6 a.m. and runs until about 10 p.m., and 40% comes on at 10 a.m. and runs until about 5 p.m. On Saturday, the load is approximately 60% of weekday load. Sunday approximates off-peak usage. This load shape follows the TOU-8 rate tariff off-peak, mid-peak, and on-peak very closely, except for Saturday. For this reason, the building is an excellent candidate for on-site generation—assuming high energy rates for on-peak, that is. The building is on a primary voltage (2–50 kV) feeder.

The CHP project modeled for this building is a pair of 750-kW natural gas internal combustion engines (ICEs), for a total of 1,500 kW of generation capacity. The absorption chiller (the thermal load for captured heat) is 442 tons. Capital cost of the completed and installed project is estimated to be \$3,160,000. Gas prices assumed for these runs are \$4.32/MMBtu. Thermal efficiency (heat rate) is 12,217 Btus/kWh.

2.7.2 *Result Scenarios*

Runs are performed for the following tariffs and assumed values:

Tariff:	**Value/Reference:**
Proposed SCE GRC-2 rates	See Section 2.2.2, under Assumptions Assumes full (2009) GRC phase-in
Standby charge	\$3.61/kW / Section 2.5.3.2
BCAP non-gas commodity cost increase	\$0.05462 / Section 2.2.2, under Assumptions[67]
Departing load fee (base case)	\$0.005 / Section 2.3.4.5
No tariff change	N/A

The results are shown below.

Table 2-16. Output From RE's Tariff Model

Overall CHP Tariff Risk	SCENARIO DESCRIPTION				
	A	B	C	D	E
	Departing Load (BaseCase)	Current Tariff Situation	BCAP Non-gas commodity cost increase	Standby Charge incurred by Owner	Proposed SCE GRC Rates
Customer Information					
Customer Type	Office Building				
Tariff	SCE TOU8s				
Maximum Annual Demand (kW)	4,646				
Annual Load (kWh)	21,047,281				
Annual Chiller Demand (Tons/yr)	2,175,940				
Annual Thermal Load (Thersm/yr)	43,273				
Key Project Parameters					
System Size (kW)	1,500	1,500	1,500	1,500	1,500
Chiller Size (tons)	442	442	442	442	442
Total Capital Costs (\$000)	3,160	3,160	3,160	3,160	3,160
1st Year Gas Price (\$/mmbtu)	4.32	4.32	4.87	4.32	4.32
Average System Heat Rate (btu/kWh)	12,217	12,217	12,217	12,217	12,217
Sensitivity Assumptions					
Departing Load Fee (\$/kWh)	0.005	0	0.005	0.005	0
BCAP Non-Commodity Fuel Cost Increase (\$/therm)	0	0	0.05462	0	0
Standby Charge incurred by REI (\$/kW)	0	0	0	3.61	0
Project Economic Metrics					
Estimated Annual Electric Costs prior to DG (\$)	\$ 2,297,285	\$ 2,297,285	\$ 2,297,285	\$ 2,297,285	\$ 2,297,285
Estimated Annual Gas Costs prior to DG (\$)	\$ 16,682	\$ 16,682	\$ 16,682	\$ 16,682	\$ 16,682
Total Utility Bill Prior to DG (\$)	\$ 2,313,967	\$ 2,313,967	\$ 2,313,967	\$ 2,313,967	\$ 2,313,967
Electric Charges Displaced by DG	\$ 610,113	\$ 610,113	\$ 610,113	\$ 610,113	\$ 526,800
Chiller & Thermal Costs Displaced by DG	\$ 116,140	\$ 116,140	\$ 116,626	\$ 116,140	\$ 98,637
Total Electric and Thermal Costs Displaced	\$ 726,252	\$ 726,252	\$ 726,739	\$ 726,252	\$ 625,437
Total Utility Bill After DG (\$)	\$ 1,587,714	\$ 1,587,714	\$ 1,587,228	\$ 1,587,714	\$ 1,688,530
Annual Project Operating Costs (\$)	\$ 392,394	\$ 369,202	\$ 423,348	\$ 446,621	\$ 369,202
Estimated Annual Savings (un-levered)	\$ 333,858	\$ 357,050	\$ 303,391	\$ 279,631	\$ 256,235
Estimated Cost of Debt (First Year)	\$ 287,000	\$ 287,000	\$ 287,000	\$ 287,000	\$ 287,000
Project Costs plus Year 1 Debt Service	\$ 679,394	\$ 656,202	\$ 710,348	\$ 733,621	\$ 656,202
Estimated Annual Savings (levered)	**\$ 46,858**	**\$ 70,050**	**\$ 16,391**	**\$ (7,369)**	**\$ (30,765)**

[67] There is a very slight (0.1 mils) difference between the BCAP tariff increase per therm used in the spark spread analysis in Section 6.1 and the rate used in this model. It is accounted for by a different existing tariff number, \$0.0571/therm in Section 6.1 (from an actual bill) and \$0.05864/therm here. (From analysis by S. Greenberg, Note 66.)

The magnitude of tariff risk in ascending order is summarized below.

Table 2-17. Tariffs Prioritized According to Risk

Tariff Name	Risk $	Priority
Proposed SCE GRC-2 rates	$ 100,815	1
Standby charge	$ 54,227	2
BCAP transportation cost increase	$ 30,468	3
Departing load fee	$ 23,192	4
No tariff change	$ -	-

It is clear that the reduction of on-peak energy rates in SCE's GRC poses the greatest threat of the tariffs discussed in this paper—not only to the project modeled but also to the DER industry as a whole. Whether SCE intends the GRC to eliminate the profitability of projects such as the one contemplated by RE is not resolved. Nonetheless, even if all of the other tariffs turn out favorable to DER, the GRC by itself can transform a project that makes $70,000 annually into one that loses $30,000/yr.

2.8 Conclusions

2.8.1 The Retrenchment of Monopoly Power

The Congressional Budget Office report[68] drew some lessons from the California electricity crisis. If markets instead of regulation are going to determine the price of power, the report said, then prices must be allowed to respond to changes. The retail price freeze was a major cause of the crisis, and customers need to face the real costs of electricity. Customers exposed to price changes will curtail use when prices rise and may increase their use when prices fall. Price signals also guide consumers into planning future power use, and some consumers may even be compensated for reselling their power to others. If consumers faced real-time price changes, they could use real-time meters, backup power supplies, and dual-fuel capabilities to reduce their use during peak-use periods.

Given the retrenchment of old-fashioned utility power going on in California today, the recommendations of the Congressional Budget Office—surely one of America's more conservative and cautious institutions—seem lightheaded and far-fetched. SCE's 2003 GRC and SoCalGas's BCAP tariff recommendation both represent giant steps backward into the days of centralized power and monopoly utility service. By increasing fixed charges and lowering energy rates, the former discourages all forms of DER: energy efficiency, renewable energy, CHP, and demand management. The latter gives all non-core gas customers a strong incentive to abandon the deregulated gas commodities market and rejoin the utility as core customers. Cogenerators, by definition, cannot rejoin the party. Between the two of them, GRC and the BCAP reduce the average spark spread for Summer on-peak TOU-8 rate tariff period (at $5.50/MMBtu gas) to less than $0.045.

[68] See Note 15.

During the energy crisis in California, many people complained that no power plants were built in the 1990s. That was a fallacy. In fact, more than 4.5 GW[69] of new capacity was added—but mostly in the form of small, decentralized non-utility units. Small plants were built instead of large ones because they were "cheaper, faster, more reliable, and less risky."[70] California gas and electricity utilities recognize the danger to their monopolies of on-site generation and energy efficiency, and they are taking measures to ensure there is little further encroachment into their utility service territories. They cannot do so by fiat—only by recommending and passing rate tariffs that create insurmountable economic barriers to DER. If the CPUC wishes to encourage technological innovation and diversity of energy solutions, it must act forcefully to reject the GRC and BCAP as presently formulated.

Five national laboratories have concluded that half of the world's energy could be renewable in 50 years. Wind power has been adding 5 GW of power each year in the US.[71] CHP competes against nuclear power and most central station power—plus it's two to three times more efficient and eliminates line losses. Yet, if the utilities are successful in shutting out DER technologies through tariff strategies, the only way of serving incremental new load will be ratepayer-financed, utility-owned fossil- and (taxpayer-insured) nuclear-fired central station plants built and operated at a loss.

[69] See Note 12.
[70] See Note 18.
[71] See Note 12.

3 Effect of Incentives on DER Markets (D-2.12)

3.1 Executive Summary

Public incentive funding for CHP projects provides the following benefits:

- Society increases its knowledge of deployment of a diverse, efficient, and secure energy resource.
- The CHP community gets information about CHP innovation and lessons learned.
- RE diversifies its product offering to include innovative features in its standard portfolio.
- End users acquire cost-effective equipment with innovations tailored to their energy needs.

Both New York and California provide incentives for a variety of project types, including:

- Photovoltaics (PV)
- Fuel cells
- Wind turbines
- Microturbines
- ICEs
- Small gas turbines.

New York requires all natural gas-fired technologies to provide CHP to get the incentives.

The average effect of California incentives on an individual project is about a 40% reduction in cost; the average effect of New York incentives is less than a 12% reduction in project cost. This is an estimate based on the cost of installation of a mixed portfolio of DER technologies of common sizes. This portfolio mix assumes three identical projects from each of five generator technologies: PV, wind, fuel cells, microturbines, and ICEs. These 15 projects are assumed to be owned and operated by different entities, so that each application is separate from the others. All of the last three technologies, it is assumed, are CHP configurations that run on natural gas. Incentives for California and New York implementations are shown below.

Table 3-1. Effect of California and New York Incentives on DER Technologies

Technology	kW Size	Quantity	Portfolio Installed Cost	CA Portfolio Incentive	Net CA Portfolio Cost	NY Portfolio Incentive	Net NY Portfolio Cost
Photovoltaic	100	3	$1,393,504	$696,752	$696,752	$325,151	$1,068,353
Wind	500	3	$2,005,318	$1,002,659	$1,002,659	$100,000	$1,905,318
Fuel Cell w/CHP	100	3	$470,123	$188,049	$282,074	$78,354	$391,769
Microturbine w/CHP	30	3	$81,076	$24,323	$56,753	$10,810	$70,266
IC Engine w/CHP	1000	3	$3,535,558	$1,060,667	$2,474,891	$353,556	$3,182,002
Totals	5190	15	$7,485,580	$2,972,451	$4,513,129	$867,871	$6,617,709
Percentage Incentive					**39.7%**		**11.6%**

3.2 Introduction

3.2.1 Objectives

This section quantifies the effect of current California incentives on the California DER market and compares the market effect of incentives and incentive effects with those in New York, taking into account program differences. Results of this task shall be derived from the development and population of a spreadsheet model to assess incentive effects. Assumptions and uncertainties shall be explicitly defined.

The results of this task shall be an assessment of the strengths and weaknesses of existing DER incentives in California and New York from the perspective of the DER development community, an assessment of their effects on DER markets to date, and recommendations for improved incentives to accelerate DER market development. This report includes a definition of the effect of incentives on a portfolio and includes a model and definition of assumptions in a spreadsheet comparison of effects on DER in Section 3.5.

3.2.2 Comparing and Contrasting California and New York Programs

California and New York have multiple incentive programs covering:

- PV
- Wind
- Microturbines with CHP
- Fuel cells with CHP
- ICEs with CHP.

California's SGIP, funded through the CPUC, covers all the above technologies and includes non-CHP configurations. It is aimed, however, at commercial and industrial end users. The PV and wind components are for units 30 kW–1MW in size—considerably larger than most residential installations.

The New York State Energy Research and Development Authority (NYSERDA) has separate programs for PV, wind, and CHP technologies. The differences in structure of the three make comparison with SGIP more difficult. Programs in this evaluation include:

State	Technologies	Program	Dollars	Per
California	CHP, DG,[72] Wind, PV	SGIP	$125 million	Year (2001–2004)
New York	CHP	PON[73] 800	$ 12 million	Year (2002–2006)
	Wind	PON 792	$ 2.5 million	Program
	PV	PON 691	$ 3 million	Program

[72] SGIP program level "3-R" allows funding for non-CHP DG if the fuel is from a renewable source such as digester gas.
[73] PON is Program Opportunity Notice.

As the comparison shows, the California program is almost seven times larger, funded at $125 million per year, while the New York programs receive about $17.5 million. Of the New York programs, only the PON 800 is renewed annually. Because of this difference, and the similarity of population and economic development characteristics of the two states, New York must try to do more with its smaller budget. In fact, the California program accepts all applications that fit its pre-existing criteria; New York only funds "trailblazers"—projects that are innovative technologically or in their application of existing technologies. For this reason, only about one of three CHP projects and three of four PV projects are funded in New York, whereas all California CHP, PV, and wind projects are funded once they meet the qualification criteria.[74]

The result is that from 2001 to the present, more California projects have received more incentive dollars. In California, 340 projects received $216 million; in New York, 92 projects received $43 million.[75] Because of its targeted approach, however, New York has attempted to foster innovation and reward environmentally preferred DER to a greater extent than California, which has been more focused on market transformation. A complete comparison of similarities and differences is included in Table 3-10.

3.3 California Incentives

3.3.1 Historical Background and Objectives

In 1996, California Governor Pete Wilson signed energy deregulation into law. This required that California IOUs[76] sell off most of their electricity generating plants. By the summer of 2000, a major energy crisis occurred when wholesale prices became higher than capped retail prices. Every electricity transaction resulted in lost money for the California utilities.[77] This led to huge utility debts and, later, rate increases to cover those debts.

A determination that California ratepayers should not be beholden to non-California electricity wholesalers led Governor Gray Davis to sign California Assembly Bill 970 into law on Sept. 6, 2000. One of the provisions of the law required the CPUC to implement financial incentives for installing DG.

The purposes of the SGIP are to:

- Encourage the use of DG in California to reduce peak electric demand
- Give preference to new renewable energy capacity
- Ensure the use of clean self-generation technologies with low and zero operational emissions.

[74] Data on PON 792 are not yet available.
[75] These numbers include data from PON 800 and PON 691. Data from PON 792 are not yet available.
[76] SCE, PG&E, and SDG&E.
[77] Although this crisis (brought on by regulatory and legislative fiat) pushed PG&E into bankruptcy and SCE to insolvency, representatives of these utilities were present in numbers at every meeting that led up to the restructuring law AB 1897; apparently, no one foresaw the eventual outcome.

California PUC Section 399.15 (b) paragraphs 6 and 7 called for "incentives for distributed generation to be paid for enhancing reliability" with "differential incentives for renewable or super clean distributed generation resources." Additional objectives of the SGIP are to:

- Make use of an existing network of service providers and customers to provide access to self-generation technologies quickly
- Provide access at subsidized costs that reflect the value to the electricity system as a whole and not just to individual consumers
- Support continuing market development of the energy services industry
- Provide access through existing infrastructure, administered by the entities with direct connections to and trust of small consumers
- Take advantage of customers' heightened awareness of electricity reliability and cost.

California has long been an innovator in the use of renewable energy and DG applications and thus was prepared to benefit from a government-sponsored incentive system. Since 1975, per capita energy use in California has essentially leveled off and has not exceeded 8,000 KWh. Meanwhile, per capita energy use in the United States has continued to climb. Since 1999, it has been more than 12,000 kWh.

3.3.2 Self-Generation Incentive Program Description

On March 27, 2001, by Decision 01-03-073, the CPUC adopted the SGIP and allocated $125 million annually (including administrative costs) through 2004. The SGIP is available to most of California through the service territories of the IOUs. The SGIP is administered in SDG&E's territory by the San Diego Regional Energy Office. On that day, the CPUC adopted the Energy Division's annual budget recommendations to the utilities according to Table 3-2.

Table 3-2. Annual Budgets Adopted by CPUC for 2001–2004

Utility	Demand Responsiveness	Self Generation	Total
PG&E	$3,000,000	$60,000,000	$63,000,000
SCE	$5,940,000	$32,500,000	$38,440,000
SDG&E	$3,930,000	$15,500,000	$19,430,000
SoCalGas	N/A	$17,000,000	$17,000,000
Total	**$12,870,000**	**$125,000,000**	**$137,870,000**

The SGIP is complementary to the Emerging Renewables Buydown Program of the California Energy Commission. It appeals to commercial, industrial, and agricultural markets and includes nonrenewable-fueled self-generation technology up to 1,000 kW capacity. A statewide working group coordinates these programs.

DG incentives can be beneficial because they help deliver the benefits of clean, reliable, diverse energy sources. DG can:

- Reduce peak electric demand
- Promote new renewable energy capacity
- Reduce operational emissions
- Create efficiencies by using heat and power in cogeneration or trigeneration applications
- Reduce voltage variations, power surges, and other disruptions
- Provide standby power during outages.

The following DG technologies are included in the SGIP, with or without the thermal recovery:[78]

- PV
- Fuel cells
- Wind turbines
- Microturbines
- ICEs
- Small gas turbines.

These systems are installed on the customer's side of the utility meter and provide some or all of the customer's electric load. SGIP offers financial incentives according to technology as summarized in Table 3-3.

Table 3-3. Summary of SGIP Levels

Incentive Category	Maximum Incentive ($/watt)	Maximum Incentive as % of Eligible Project Cost	Minimum System Size (kW)	Maximum System Size Incentivized (kW)	Eligible Generation Technologies
Level 1	$4.50	50%	30	1,000	PV, fuel cells,[1] wind turbines
Level 2	$2.50	40%	None	1,000	Fuel cells[2]
Level 3-R	$1.50	40%	None	1,000	Microturbines,[1] ICEs,[1] small gas turbines[1]
Level 3-N	$1.00	30%	None	1,000	Microturbines,[2,3] ICEs,[2,3] small gas turbines[2,3]

[1] Renewable fuel operation
[2] Non-renewable fuel operation
[3] Sufficient waste heat recovery and reliability

At first, the CPUC directed the annual $100 million incentive budget to be divided equally among Levels 1, 2, and 3. Program administrators could reallocate portions, but renewable Level 1 allocations could not be reallocated to nonrenewable technologies of levels 2 or 3 without CPUC approval. Unused budgeted money could be carried over.

[78] Unlike California, New York's incentive makes no distinctions on the basis of fuel (renewable versus non-renewable) but requires CHP capability on all thermally intensive technologies.

3.3.2.1 Self-Generation Incentive Program Projects 2001 and 2002

Table 3-4 and Table 3-5 summarize the total active projects, as of January 2003, for the program years 2001 and 2002. Level 3R was added in 2002.

Table 3-4. Summary of Active 2001 Projects

Incentive Level	Projects	kW	Incentives
Level 1	12	2,291	$7,979,166
Level 2	1	200	$367,632
Level 3	43	15,452	$9,906,503
Total	**56**	**17,943**	**$18,253,301**

Table 3-5. Summary of Active 2002 Projects

Incentive Level	Projects	kW	Incentives
Level 1	157	26,875	$87,158,828
Level 2	1	600	$1,500,000
Level 3N	118	57,625	$33,680,452
Level 3R	8	1,585	$1,462,433
Total	**284**	**86,685**	**$123,801,714**

3.3.2.2 Self-Generation Incentive Program Participants

Host Customers

One hundred ninety five host customers requested funding for program year (PY) 2001, and many of these were among the 288 host customers that requested funding for projects in PY 2002. ICEs using nonrenewable fuels were primarily used by the commercial, industrial, and agricultural sectors. PV was popular among the transportation, communications, and utilities sectors. Most host customers used third parties for applying to the program.

Third-Party Applicants

Energy service companies, energy consultants, and contractors made up most of the third-party applicants in PY 2001 and PY 2002. About 80% of those participating in PY 2001 requested funding again in PY 2002. About 20% requested multiple program administrators. PV was dominated by one third-party applicant.

Manufacturers

Most of the 50 manufacturers participated in both PY 2001 and PY 2002. Multiple manufacturers supplied PV, ICEs, and microturbines using nonrenewable fuels, but in both years, only three manufacturers supplied fuel cells. Yet one manufacturer dominated suppliers within each technology category.

3.3.2.3 Photovoltaic Case Study: Santa Rita Jail

The Santa Rita Jail was constructed in Dublin, California, between 1984 and 1989. Its 18 housing units for 4,300 inmates and staff of 609 occupy 1 million ft^2 of space. This jail's peak load in August 2000 was 3,212 kW, and its total electric bill for July 2001 was $161,175.

Powerlight (a California-based manufacturer of PV) made a proposal, which was accepted in November 2000. Construction costs for the project were estimated at $10.3 million, with $8.2 million for the 1.18-MW solar array, $1 million for the chilled water plant retrofit, and $1.1 million for the cool roof. Incentives totaled $5,045,000 and included $2,560,000 from the CEC buydown grant at $4.50/W, $1,770,000 from PG&E's self-generation grant, $306,000 from an AB 970 solar grant, $84,000 from a smart controls AB 970 grant, $45,000 from a cool roofs AB 970 grant, $250,000 from a cross-cutting CPUC grant, and $30,000 from AB 29X early project completion. Thus, these incentives paid for nearly half the construction costs.

Construction began in March 2001. Phase 1, with 530 kW of solar power, became operational in July 2001, Phase 2 in October 2001, and Phase 3 in April 2002. PV was interconnected with the building's electrical system. After the solar project was installed, the peak demand was reduced in August 2003 to 2,154 kW—a reduction of 1,058 kW from August 2000. From January 2003 to September 2003, the solar electrical generation was 1,160,737 kWh, which resulted in a cost savings of $163,817. The total area covers 3 acres of roof and has a maximum solar generation of 879 kWac. The annual generation of 1.4 million kWh produces an annual cost savings of $211,000 from solar generation and $207,000 in energy efficiency. The Santa Rita Jail project helped Alameda County's energy program win several awards for 2002.

3.3.3 Self-Generation Incentive Program Evaluation

The California SGIP was evaluated based on specific criteria approved by CPUC Administrative Law Judge Gottstein on April 24, 2002, for the following goals:

1. Encourage the deployment of DG in California to reduce peak electrical demand.
2. Give preference to new (incremental) renewable energy capacity.
3. Ensure deployment of clean self-generation technologies with low and zero operational emissions.
4. Use an existing network of service providers and customers to provide access to self-generation technologies quickly.
5. Provide access at subsidized costs that reflect the value to the electricity system as a whole and not just to individual customers.
6. Help support continued market development of the energy services industry.
7. Provide access through existing infrastructure, administered by the entities (i.e., utilities and the San Diego Regional Energy Office) with direct connections to, and the trust of, small consumers.
8. Take advantage of customers' heightened awareness of electricity, reliability and cost.[79]

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[79] Regional Economic Research, Inc. "Self-Generation Incentive Program Second Year Process Evaluation." San Diego, 2003; pp. 2–3.

3.3.3.1 Encouraging Distributed Generation to Reduce Peak Demand

Although results indicate that only 64% of non-participant observers are aware that they can generate their own electricity, educating third parties such as energy service companies and other contractors helped market the program to customers. In the first year of the program (PY 2001), Incentive Level 1 reservations totaled $12.5 million, and Incentive Level 3 reservations totaled $12 million. But Incentive Level 2 reservations were only $0.9 million. In the second year (PY 2002), carryovers and reallocations enabled Level 1 reservations to reach $79.1 million, and Level 3 reservations totaled $32.8 million. Level 2 reservations remained low at $1.5 million.

Preliminary results, as of the end of 2002, indicate an effect on peak demand and are shown in Table 3-6.

Table 3-6. Overall Effects on 2002 ISO System Peak Demand

Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Effect (kWp)
Level 1 Photovoltaic	11	1,130	790
Level 2 Fuel Cell	2	400	400
Level 3 ICEs/Microturbines	17	6,752	5,472
Total Estimated Effect	**30**	**8,282**	**6,662**

3.3.3.2 Giving Preference to Renewable Energy Capacity

For PY 2002, Level 3 was divided into levels 3N (for nonrenewable fuels) and 3R (for renewable fuels). Larger financial incentives were given for using renewable fuels, and nonrenewable systems were required to use sufficient waste recovery and meet reliability criteria.

Applicants had difficulty meeting the 90-day proof of project advancement deadline and were given extensions, but the 1-year reservation confirmation and incentive claim form deadline was usually met (except for projects that used new construction and those of some public sector institutional customers).

3.3.3.3 Ensuring Deployment of Clean Technologies With Low Emissions

Technological and market obstacles unrelated to the program are believed to be the reason for minimal adoption of Level 2 fuel cells, but the robust use of Level 1 PV allowed the reallocation of Level 2 funds to Level 1 technology. Twenty-three percent (21 out of 90) of Level 1 projects were completed successfully, as were one out of three Level 2 projects.

3.3.3.4 Providing Access to Self-Generation Technologies

The SGIP administrators primarily focused their promotion on third-party vendors, who would be likely to market the program. Administrators provided workshops and distributed information at conferences, trade shows, and other events sponsored by the energy service industry. Most SGIP customers learned of the program through third-party vendors.

3.3.3.5 Providing Subsidized Costs to Benefit the Whole Electrical System

This criterion was not addressed by the PY 2002 process evaluation or the program effect evaluation.

3.3.3.6 Supporting Market Development of the Energy Services Industry
Evaluators questioned host customers to assess whether they would have installed their systems without help from the program and found that only 14% would have. Even for the popular ICE, only 27% reported that they would have installed without incentives. Thus, it can be concluded that DG technologies were used more frequently because of the incentive program.

Most customers learned about the program from suppliers rather than from their utility companies. Only half of the energy service companies reported that they were assisted in marketing by the program administrators, and they reported that this was by information provided via the Internet. Administrators reported that they spent only 1.8% of their PY 2002 budget on marketing. Evaluators concluded that administrators' tracking of the energy services industry's marketing could be improved.

3.3.3.7 Providing Access to Small Consumers
Because program administrators focused their promotion on third-party vendors, outreach to small customers was indirect and could be improved.

3.3.3.8 Using Consumer Awareness of Electricity Costs
Although customers did participate because of third-party marketing, this criterion could also be improved by developing more diverse marketing.

3.3.3.9 Process Assessment

Program Administrators
Administrators found increased awareness and improved completion rates in the second year. They suggested extending the 1-year completion deadline for new construction projects, extending the program beyond 2004, and simplifying insurance requirements.

Participant Host Customers
Most satisfied host customers had worked with third-party vendors; others found the application process complex and difficult, especially regarding interconnection, air pollution, and building permits-, and installing net generation meters. Projects that used new construction and public institutions had difficulty meeting deadlines.

Participant Suppliers
Most suppliers were satisfied with the program, but some complained of incentive payments being delayed, interconnection problems, excessive documentation requirements, and conflicting information given by utility personnel. Energy service companies reported that the program helped develop the market for distributed energy, especially in PV. However, suppliers believed that customer awareness about DG opportunities could be much improved.

Nonparticipants
Those not participating in the program explained the main reason was the high initial cost of a DG system.

Third Parties
Energy service companies reported that the program greatly benefited their industry. Many suppliers did not think the program was marketed effectively to customers. Customers working with third parties were the most satisfied.

Utility Field Representatives
Program administrators tried to get utility account representatives to educate customers, and some conducted workshops for them. But customers and suppliers complained that utility field representatives did not influence customers to participate in the program.

Problems
Although program administrators made efforts to facilitate the interconnection process, suppliers and host customers reported they had difficulties. Customers often complained that the meters were not installed in time or that they did not understand the billing related to their contributions to the grid. Many host customers had difficulty meeting the deadline for obtaining air emissions permits. Suppliers were concerned that the utilities were not giving the customers useful information. Many were upset that they were going to be assessed standby charges and exit fees and believed the utilities were discouraging DG generation by imposing these disincentives.

In April 2003, the CPUC announced that photovoltaic projects smaller than 1 MW and net-metered or eligible for CPUC and California Energy Commission incentives would not have to pay exit fees. Now program administrators may include this information in their marketing efforts.

The extent of insurance documentation required was another complaint in the application process. A statewide database was implemented to make sure participants already receiving other funding were not receiving funding in excess of their eligible project costs. In regard to on-site verifications, program administrators can help identify problems early in the process by giving inspection contractors information at the reservation request stage.

3.3.4 Self-Generation Incentive Program Second Year Evaluation Recommendations

3.3.4.1 Program Design Recommendations[80]

Resolve incentive structures and payment mechanisms
First, separate incentive levels should be developed for microturbines and ICEs because the market development, costs, and environmental effects of these technologies are different. Also, the different incentive for Level 3R projects needs to be reassessed because of changing fuel clean-up costs. Second, the percentage of project cost limit can be eliminated so that all incentives are paid according to the dollar-per-watt basis. This change will simplify the incentive, relieve burdensome administration, shorten processing time for incentive claims, and reduce the impression that suppliers are gaming the eligibility system.

Develop and communicate an exit strategy
Because of concerns that the incentives may end abruptly at the close of 2004, the working group should develop a plan for a transitional strategy for the gradual fading of incentives. This plan should be communicated to participants and other interested persons. Assembly Bill 1685 would extend the SGIP for 3 years through 2007.

Reduce or eliminate requirements of proof of project advancement
The requirement of submitting copies of applications for the air pollution permit and the electrical interconnection before the 90-day deadline should be eliminated.

Extend the 1-year deadline for projects with new construction
PY 2002 administrators already extended the 1-year deadline by 6 months for institutional customers. The 1-year deadline could be changed to 2 years for projects involving new construction if proof of progress is submitted at the 1-year mark to reserve funding.

Reduce or eliminate requirements of the 1-year deadline
The requirement for the final project cost breakdown can be eliminated. Instead of the final permit to operate, an authority to construct permit with a temporary permit to operate, which is obtained faster, may be accepted.

3.3.4.2 Implementation Recommendations

Assign a working group representative to help with permits and relationships
This representative could educate outside people about the program, answer participant questions, and resolve problems between participants and agencies.

Clarify net metering installation and issues
Installing technicians can be educated about the need for lead-time, and participants using PV and wind projects can be advised to plan ahead.

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[80] The recommendations are drawn from the "Self-Generation Incentive Program Second Year Process Evaluation" submitted by Regional Economic Research in April 2003.

Revise program documents for requesting site data
The SGIP handbook and documents should explain that applicants and third parties are obligated to electronically transfer project data to the measuring and evaluation team. The program should compensate host customers or third parties for providing data.

3.3.4.3 Marketing Recommendations

Address standby charges and exit fees
The CPUC decision to exempt photovoltaic projects from exit fees should be communicated to participants. Program administrators should communicate with participants about these issues and respond to their concerns.

Improve public access by Web site links to program information
Key Web sites and industry sources can disseminate information about the program so customers can discover whom to contact to participate.

3.4 New York Incentives

3.4.1 New York State Energy Research and Development Authority
In the state of New York, the public service commission has implemented a systems benefit charge on electric rates to increase energy efficiency and provide programs for the public good. Because of increasing difficulties in providing energy services in "load pockets," the program has been expanded to include transmission and distribution concerns. Three-quarters of the money collected from the systems benefit charge is allocated to NYSERDA, and one-quarter is allocated to the electric utilities for their own programs.

NYSERDA calls its programs "Energy$mart," and they include low-interest loans and energy-efficiency programs for schools, agriculture, homes, and communities as well as pollution control and monitoring of air, water, and solid waste emissions. NYSERDA offers incentives for funding projects that demonstrate the use of CHP in industrial, commercial, municipal, and institutional organizations. The CHP DER programs of NYSERDA provide about $12 million annually in the state of New York for 5 years (2002–2006).

3.4.1.1 New York State Energy Research and Development Authority Photovoltaic Incentives
NYSERDA PON 716 requests applications for financial incentives from PV installers for customers who pay the systems benefit charge on their electric bill. About $2.5 million in PV incentives are available to eligible installers for new grid-connected, end-use PV systems that are smaller than 15 kW. Incentives based on direct current module ratings at standard test conditions are:

- $4/W for those eligible for net-metering
- $4.50/W for those eligible for net metering and installed in New York ENERGY STAR-labeled homes
- $5/W for those not eligible for net metering (with a 70% cap for systems 10–15kW).

Additional funds for incentives may be made available because of program success, customer demand, or overall performance. NYSERDA anticipates that about two-thirds of the total PV incentive funds will be allocated to net-metered systems. NYSERDA can also provide assistance to customers by reducing their loan rates with participating banks by 4% for up to 10 years.

3.4.1.2 New York State Energy Research and Development Authority Wind Incentives

NYSERDA aims to develop and implement complementary programs that encourage a sustainable market for installing end-use wind systems by providing financial incentives. These end-use wind systems must be connected on the customer's side of the electric meter so that the electricity generated by the wind will offset the customer's electricity purchasing.

NYSERDA PON 792 announced more than $2.5 million of incentives to encourage the installation of new, end-use wind energy turbines for residential, commercial, institutional, or governmental use. Installers of grid-connected wind systems that use qualified equipment and meet eligibility requirements may receive up to $100,000 per installation. Installers must pass on these incentives directly to end-use customers. Incentives for all systems larger than 80,000 W are limited to 15% of costs. Incentives for systems of 500–10,000 W range from 50% of the costs for residences, businesses, institutions, and government to 60% for commercial farmers and 70% for schools that incorporate the study of wind energy into their curricula. Incentives for these categories in the size of 10–80 kW are based on complicated formulae using the factors 0.5, 0.643, and 0.786 respectively.

Installers must have the requisite education, training, and experience, and they must meet all NYSERDA requirements, including a minimum 5-year warranty for the full system. To be eligible for incentives, all wind systems must use new equipment, be grid-connected, and have end-use applications. Monitoring equipment must also be installed, and installers that provide NYSERDA with accurate data for the first 24 months may qualify for a $500 bonus. NYSERDA may make inspections during and up to 1 year after installation of the wind system.

3.4.1.3 New York State Energy Research and Development Authority Combined Heat and Power Incentives

In the state of New York, CHP is already generating 5,000 MW of capacity installed at 210 sites. Industry accounts for 78% of this with a few large CHP systems. A 2002 report by NYSERDA called "Combined Heat and Power Market Potential for New York State" estimated that 8,500 MW of new CHP potential at 26,000 sites is possible in New York. Although only 16 sites remain that could support a plant greater than 20 MW, about 74% of the remaining capacity is less than 5 MW and can be found at commercial and institutional facilities. The report compares the effect of a base case scenario with 764 MW of CHP being installed by the year 2012 with an accelerated case scenario in which 2,200 MW might be installed by 2012.

Factors that are preventing the increased use of CHP include:

- Deficiencies in small CHP technologies
- Lack of sales and services infrastructure
- Lack of awareness of CHP by users and building owners
- Market and regulatory hurdles.

Some of these hurdles are competing products and services, difficult CHP implementation between users and local power distribution utilities, interconnection regulations, higher New York tariffs for supplementary power services, expensive and time-consuming permit processes, unprepared local building codes, and difficulties financing CHP systems.

NYSERDA PON 800 has announced a program of $12 million in incentives to support DG and CHP.

Table 3-7. NYSERDA Programs of PON 800

Category	NYSERDA Cost Share	Maximum Award
A: DG/CHP demonstration projects	15%–60%	$1,000,000
B: DG/CHP feasibility studies	50%	$100,000
C: DG/CHP technology transfer studies	75%	$100,000
D: New product development	50%	$500,000
E: New product feasibility studies	50%	$100,000
F: Request to NYSERDA as data integrator	100%	To be negotiated

Each project will be considered for only one funding category. NYSERDA has reported the number of CHP demonstration programs by size for the years 2002 and 2003.

Table 3-8. NYSERDA's CHP Demonstration Program by Size (kW)

Expected Installations	2002 kW	2003 kW	Total kW
Less than 500 kW	3,048	4,701	7,749
500 kW–1 MW	4,020	4,561	8,581
1–5 MW	23,988	20,760	44,748
5–20 MW	0	6,700	6,700
More than 20 MW	0	0	0
Total	**33,058**	**38,725**	**67,778**

CHP technologies include ICEs, steam turbines, gas turbines, microturbines, and fuel cells. NYSERDA has compared these technologies in a number of ways.

Table 3-9. Comparison of CHP Technologies

	Internal Combustion Engine	Steam Turbine	Gas Turbine	Microturbine	Fuel Cell
Technology Status	Commercial (3%of CHP, 66% of sites)	Commercial (14% of CHP, 13% of sites)	Commercial (83% of CHP, 21% of sites)	Early entry	Early entry/ development
Electric Efficiency (LHV)	25%–45%	5%–15%	25%–40% (simple) 40%–60% (combined)	20%–30%	40%–70%
Size (MW)	0.05–5	0.01–100	0.5–50	0.025–0.25	0.2–2
Installed Cost ($/kW)	800–1,500	800–1,000	700–900	500–2,000	>3,000
Operations and Maintenance Cost ($/kWh)	0.007–0.015	0.004	0.002–0.008	0.005–0.015	0.003–0.015
Availability	92%–97%	Near 100%	90%–98%	90%–98%	>95%
Start-Up Time	10 sec	1 hr–1 day	10 min–1 hr	60 sec	3 hrs–8 hrs
Fuels	Natural gas, biogas, propane, liquid fuels	All	Natural gas, biogas, propane, distillate oil	Natural gas, biogas, propane, distillate oil	Hydrogen, natural gas, propane
NOx Emissions (lb/MWh)	0.4–10	Function of boiler emissions	0.3–2	0.4–2	<0.05
Uses for Heat Recovery	Hot water, low-pressure steam, district heating	Low-pressure–high-pressure steam, district heating	Direct heat, hot water, low-pressure–high-pressure steam, district heating	Direct heat, hot water, low-pressure steam	Hot water, Low-pressure–high-pressure steam
Thermal Output (Btu/kWh)	1,000–5,000	N/A	3,400–12,000	4,000–15,000	500–3,700
Useable Temp (°F)	200–500	N/A	500–1,100	400–650	140–700

3.4.2 New Jersey's Proposed Incentives

New Jersey Clean Energy is proposing financial incentives for CHP installations that enhance energy efficiency by on-site power generation, recover and use of waste heat, and reduce demands on the electric power grid. Installations must be on the customer side of the utility meter to be eligible. This program is intended to reduce greenhouse gas emissions by using waste-heat recovery systems and efficient power generation that will meet FERC efficiency requirements for qualifying facilities. CHP systems that use turbines up to 750 kW may be eligible for $1/W up to 60% of installed costs, while turbines of 750–3,000 kW may receive $0.50/W up to 30% of installed costs. CHP systems that use reciprocating engines up to 750 kW may qualify for $0.60/W up to 60% of installed costs, and those 750–3,000 kW are eligible for $0.50/W up to 30% of installation costs.

To be eligible, CHP systems must be permanently installed and not be backup generators or operate on diesel cycle. Eligible project costs include self-generation equipment, engineering and design, construction and installation, engineering feasibility studies, interconnection and related metering, permitting, warranty or maintenance contracts, some gas-line installation, air-emission control equipment, primary heat-recovery equipment, and heat-recovery piping and controls.

New Jersey Clean Energy also has proposed financial incentives for fuel cells that operate on renewable fuel. They would receive $2.50/W up to 40% of project cost. Microturbines and ICEs would receive $1/W up to 30% of cost. These systems may have capacities up to 1.5 MW, though they are paid only for capacity up to 1 MW.

In January 2004, RE and other supporting entities offered suggestions related to the above proposals, which they learned about in a December 2003 workshop. They want other CHP technologies that convert previously wasted energy into electricity to be added to the fuel cells, microturbines, and reciprocating engines proposed by New Jersey Clean Energy. They suggest the following definition for "other technologies":

> The technology uses RECYCLED ENERGY, defined as:
>
> 1. Exhaust heat resulting from any industrial process
> 2. Industrial tail gas that would otherwise be flared, incinerated, or vented
> 3. Energy extracted from a pressure drop in any gas, excluding any pressure drop to a condenser that subsequently vents the resulting heat.[81]

Backpressure steam turbine generators, Stirling engines, organic Rankine cycles, and gas expanders are examples of these technologies that produce zero marginal emissions. They also propose allowing systems up to 5 MW, although they still would be paid only for 1 MW. They object to disqualifying backup generators because they help reduce peak demand. The supporting entities propose that fuel cells that operate on nonrenewable fuel receive the incentive of $3/W watt up to 60% of the project cost, that microturbines and "other technologies" qualify for $1/W up to 40% of cost, and that reciprocating engines be eligible for $1/W up to 40% of project cost. In these three categories, they believe that all systems up to 5 MW should qualify.

3.5 Comparison and Evaluations

A comparison of New York and California programs, support, major hurdles, metrics, and outcomes follows.

[81] Daniels, T. "Comments by Joint Parties on New Jersey Proposed CHP Incentive Program" with letter to Victor Bozzo. Jan. 9, 2004.

Table 3-10. New York and California Incentive Comparison

	New York Incentives	California Incentives
Program	Solicitation-based	Subscription-based
	Demonstration program	Deployment program
	Innovative applications	Predefined qualification
	Thermally intensive generation must be CHP	Non-CHP is OK
	Cost shares project costs	$/kW with technology bias
	Central not-for-profit administration	IOU administration
	Separate and distinct renewables programs	Renewables and nonrenewables included together in tiers
Support	New York Public Service Commission support	CPUC and California Energy Commission programs bifurcated support
	Utility-run DG pilot program	Utility administration payment
	Some standby rate exemption, preferred gas rates, environmental advocates supported, strong project	Associated standby and exit fee waiver (through Dec. 31, 2004), Interconnection Rule 21 support through issue discussion
Major Hurdles	Utility buy-in, standby rates, interconnection delays, cost, unclear emissions regulations	Strict air emissions regulations, time delays, network interconnection, supplemental review time/cost
Metrics	Application and technology evaluation with 3-year data	Megawatts installed and cost-effectiveness through incentive and replication
Outcomes	$43 mission committed to date	$216 million committed to date
	92 CHP projects funded, 42 installed	Through 2002, 161 (CHP or non-CHP) projects funded with nonrenewable fuel, 169 projects (mostly PV) funded, and eight renewable fuel DG technologies installed
	All CHP prime mover technologies represented (engines, turbines, and fuel cells)	Only two fuel cells installed
	All sectors (residential, commercial, agricultural, industrial) covered	Sector not considered
	No time delay data	Time delays between commitment of funds and commissioning

California's SGIP has pioneered financial incentives to encourage DER by allocating $125 million annually from 2001 through 2004. In addition, California budgeted $12,870,000 annually for demand responsiveness. NYSERDA has developed a program that provides about $12 million annually from 2002 to 2006. New Jersey Clean Energy is in the early stage of deciding what incentives to propose and is considering suggestions made by RE and other entities.

SGIP provides for up to 50% of project costs at $4.50/W for PV, wind turbines, and fuel cells that use renewable fuels for Level 1. For Level 2, it provides up to 40% of costs at $2.50/W for fuel cells that use nonrenewable fuel. For Level 3R, it provides 40% of costs at $1.50/W for microturbines, ICEs, and small gas turbines that use renewable fuel. For Level 3N, it provides 30% of costs at $1/W for microturbines, ICEs, and small gas turbines that use nonrenewable fuel but have sufficient waste heat recovery and reliability.

NYSERDA offers about $2.5 million in incentives for PV at $4/W, $4.50/W, and $5/W. It provides incentives for wind turbine systems depending on their size. The smallest category may receive 50%, 60%, or 70%, depending on the user. The middle size of 10–80 kW has complicated formulae for the three kinds of users, and the largest category is limited to 15% of costs. NYSERDA offers to share costs for six categories of CHP, but the largest award of up to $1 million is for demonstration projects and ranges 15%–60% of costs. New product development may receive up to $500,000 and 50% of costs. Technology transfer studies may be funded up to $100,000 and 75% of costs, and feasibility studies may get up to $100,000 and 50% of costs.

In California, Level 1 projects jumped from receiving $7,979,166 in 2001 to $87,158,828 in 2002. California had only one Level 2 project in 2001 and one in 2002, but the latter received $1,500,000. Its Level 3 projects received $9,906,503 in 2001. In 2002, Level 3N awarded $33,680,452, and Level 3R projects received only $1,462,433.

NYSERDA projects by kilowatt for CHP in 2002 were 33,058 kW. For 2003, the number was 38,725 kW.

A survey of California customers indicated that the majority (86%) would not have installed these energy projects if it had not been for state-financed incentives.

Because of the differences and lack of data, comparisons between the California and New York programs are difficult. The California program preceded New York’s by 1 year and is funded at an annual level about ten times larger than that of New York. The incentive rate for PV is similar at about $4.50/W. Both programs seem to be working; the number of projects increases each year. Evaluations done on California’s SGIP are generally favorable with some constructive criticism for minor improvements in administration. The Santa Rita Jail project with PV is apparently a great success at saving money and improving the environment.

Table 3-11. New York and California Maximum Incentive Funding

Technology	*Fuel*	*Min kW*	*Max kW*	*Estimated Cost $/kW*	*Estimated Total Cost*	*CA Max Incentive*	*CA Max %*	*NY Max Incentive*	*NY Max %*
Photovoltaic [1]	Solar	30		$4,645	$139,350	$69,675	50%	$97,545	70%
Photovoltaic [2]	Solar		1000	$4,645	$4,645,015	$2,322,507	50%	$750,000	70%
Wind [3]	Wind	30		$3,548	$106,440	$53,220	50%	$63,864	60%
Wind [4]	Wind		1000	$1,337	$1,336,878	$668,439	50%	$100,000	15%
Fuel Cell [5]	Renewable	30		$1,567	$47,012	$23,506	50%	$28,207	60%
Fuel Cell [5]	Renewable		1000	$1,567	$1,567,077	$783,539	50%	$940,246	60%
Fuel Cell w/CHP	Natural Gas		1000	$1,567	$1,567,077	$626,831	40%	$783,539	50%
Microturbine [5]	Renewable		50	$901	$45,042	$18,017	40%	$22,521	50%
Microturbine w/CHP	Natural Gas		50	$901	$45,042	$13,513	30%	$18,017	40%
IC Engine [5]	Renewable		1000	$1,179	$1,178,519	$471,408	40%	$471,408	40%
IC Engine w/CHP	Natural Gas		1000	$1,179	$1,178,519	$353,556	30%	$353,556	30%
Gas Turbine [5]	Renewable		1000	$683	$683,251	$273,300	40%	$273,300	40%
Gas Turbine w/CHP	Natural Gas		1000	$683	$683,251	$204,975	30%	$204,975	30%

NOTES:
[1] New York minimum kW for PV in PON 691 is 15 kW; maximum incentive is 70% or $5/W, whichever is less.
[2] New York has no maximum kW for PV in PON 691; project max is $750,000.
[3] New York max wind incentive is 70% for educational institutions with a wind curriculum; the situation is rare enough that the commercial farms max of 60% is used instead.
[4] New York max wind incentive is 15% for units >80 kW; project max is $100,000.
[5] New York requires that all fuel cell, microturbine, IC, and GT projects must be CHP to be funded; California projects must be CHP unless they run on renewable fuel.

Project cost data for all technologies except solar and wind are from:
Onsite Energy. "Market Assessment of Combined Heat and Power in the State of California." July 1999. http://www.energy.ca.gov/reports/2000-10-17_700-00-009.PDF.

PV costs come from http://solstice.crest.org/articles/static/1/binaries/REPP_FL_100202.pdf.

Wind costs come from http://www.energy.ca.gov/distgen/economics/capital.html.

Table 3-11 shows maximum incentives for various technologies, sizes, and fuels under California and NYSERDA incentive programs. It should not be assumed that NY programs pay more per project than California. The 60% payout is a maximum; many projects that receive funding will receive lesser percentages. NYSERDA's program is intended to fund only "trailblazer" CHP projects that provide a model of success for others to follow. For that reason, not every proposal that seeks funds will receive them. In fact, typically, only one of three proposals is awarded funding. RE has applied for NYSERDA funding for 12 projects and has received funding for three—a 25% success rate. These projects were funded because they provided benefits of CHP to end users in innovative ways.

Funding has averaged around 30% of project cost. In California, however, RE has received self-generation incentive funds of 30% of applicable costs on all eligible projects.

Based on their recommendations to New Jersey Clean Energy, the energy service companies such as RE and others want these incentives to be continued and expanded to include other technologies that are energy-efficient.

As part of this task, RE will also show the overall effect of these incentives on the cost of installation of a mixed portfolio of DER technologies in common sizes. This portfolio mix assumes three identical projects from each of five generator technologies: PV, wind turbines, fuel cells, microturbines, and ICEs. These 15 projects are assumed to be owned and operated by different entities, so each application is separate from the others. All of the last three technologies, it is assumed, are CHP configurations that run on natural gas. Incentives for California and New York implementations are shown below.

Table 3-12. Model Portfolio Incentive Effects

Technology	*kW Size*	*Quantity*	*Portfolio Installed Cost*	*CA Portfolio Incentive*	*Net CA Portfolio Cost*	*NY Portfolio Incentive*	*Net NY Portfolio Cost*
Photovoltaic	100	3	$1,393,504	$696,752	$696,752	$325,151	$1,068,353
Wind	500	3	$2,005,318	$1,002,659	$1,002,659	$100,000	$1,905,318
Fuel Cell w/CHP	100	3	$470,123	$188,049	$282,074	$78,354	$391,769
Microturbine w/CHP	30	3	$81,076	$24,323	$56,753	$10,810	$70,266
IC Engine w/CHP	1000	3	$3,535,558	$1,060,667	$2,474,891	$353,556	$3,182,002
Totals	5190	15	$7,485,580	$2,972,451	$4,513,129	$867,871	$6,617,709
Percentage Incentive					**39.7%**		**11.6%**

The overall effect of California implementation is about a 40% reduction in cost; the effect in New York is less than a 12% reduction in cost.

3.6 Conclusions and Recommendations

Evaluation of California's SGIP indicates that it is successful and that most, if not all, participants in the program want it to be continued. NYSERDA has been providing funding for demonstration projects for CHP—trailblazer applications meant to help demystify and encourage replication of projects that provide on-site electricity and thermal energy. These real-world experiments assist developers in pushing the envelope in innovative technologies and applications for the DER marketplace. So far, results have been favorable.

Incentive effects in New York and California range 12%–40% on a diverse portfolio of technologies. In California, the incentives have been shown to make a difference between a "go" or "no go" decision in more than 75% of installations.

Energy incentive programs such as those in New York and California are an important step toward developing energy independence, fuel diversity, and a secure, distributed approach to energy deployment. Preservation of the natural environment and reduction of pollution are two powerful reasons programs such as these are excellent investments for the public.

4 Regulatory Effectiveness of Interconnection in California (D-2.6)

4.1 Executive Summary

The purpose of this task is to develop and apply metrics to rate the effectiveness of California's Interconnection Rule 21 in eliminating interconnection as a barrier to distributed energy systems.

Metrics Approach

To complete this work, it was necessary to devise four metrics to evaluate the effectiveness of Rule 21 in eliminating barriers to interconnection. These are:

1. Time to interconnect
   Measures the delays in approval and installation of interconnection
2. Cost of interconnection
   Measures the cost of interconnection under revised Rule 21.
3. Process improvement
   Evaluates whether revised Rule 21 has improved the interconnection process
4. Simplified interconnection
   Measures the number of applications that qualify for simplified interconnection, supplemental review, and detailed study and the number of applications that are suspended or withdrawn.

Each of these metrics, to the extent practicable, has been compared with a baseline of projects that received interconnection before the revised Rule 21 came into effect. However, it is important to note that there is scant data available for the baseline, mostly because controls had not yet been put in place to track projects.

Metrics employ a four-step process:

1. Collect data for a baseline made up of interconnection projects or requirements under conditions of the old Rule 21 or equivalent non-Rule 21 situations.
2. Collect data for a trendline[82] made up of interconnection projects or requirements under conditions of the revised Rule 21
3. Compare the trendline to the baseline.
4. Compare the results of Step 3 with the objective to yield progress toward the objective.

Each metric has baseline data sources and trendline data sources.

[82] The term "trendline" is used throughout this report to mean the new situation that has resulted from the implementation of regulatory change—in this case, implementation of the revised Rule 21.

Time to Interconnect Results
Without being able to determine with certainty the specific causes for improvement in interconnection times, the generalization can be made that it is getting easier and faster to interconnect under the revised Rule 21. Customers and utilities alike deserve credit for these improvements. There are dramatic improvements in all utility territories.

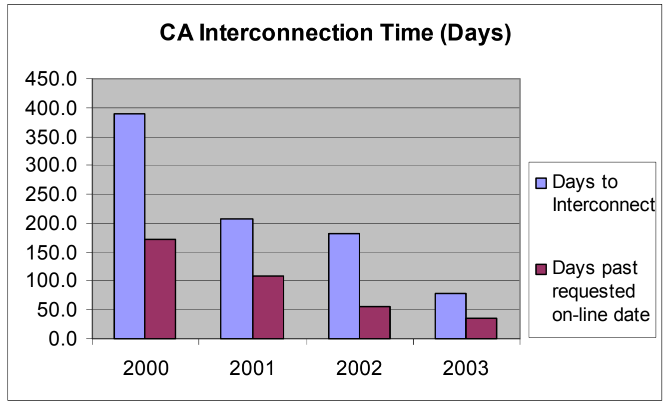

Figure 4-1. Reduction of interconnection delay

In 2001, the reduction of total days to interconnect were:

- A 39% reduction for projects <1 MW
- A 61% reduction for projects 1MW or more.

In 2002, total days to interconnect were reduced:

- 52% for projects <1 MW
- 53% for projects 1MW or more.

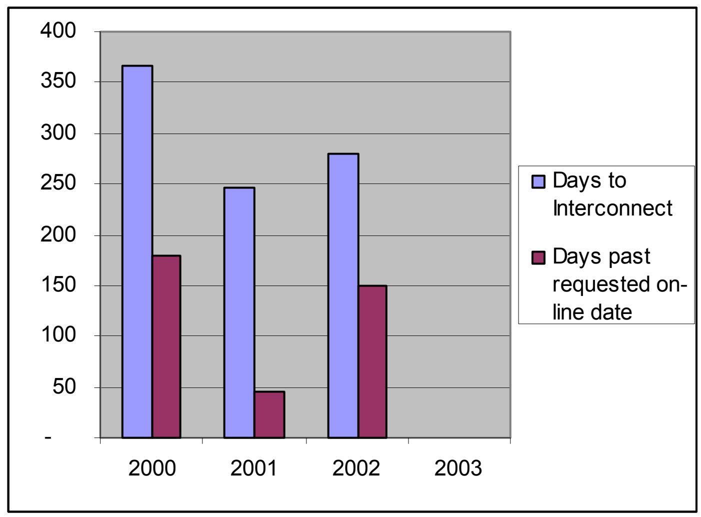

Figure 4-2. RE interconnection delay

In 2003, total days to interconnect were reduced:

- 79% for projects <1 MW
- 82% for projects 1 MW or more.

These numbers have a high degree of credibility because they have been tracked by the California IOUs for release to the public since 2001. Time reductions exceed the objective target and are the most direct measure of achievement of the revised Rule 21.

The story for RE has not reflected the overall California experience. Baseline year 2000 is about equal in both cases. In 2001, overall interconnection time decreased 50% less in RE's case, though days past requested online date dropped to less than 50 in RE's case. In 2002, total interconnect time actually increased to 275, while days past requested online went back up to 150. Several RE projects for 2003 have come online recently, but data are not yet available.

RE has not received equal treatment from the IOUs. It has taken an average of 425 days for RE to interconnect in SDG&E territory, 307 days in PG&E territory, and 199 days in SCE territory. PG&E has done an excellent job of managing customer expectations regarding lengthy interconnection times. RE has waited an average of just 2 days more than the expected online date in PG&E territory. It has waited an average of 114 more days in SCE territory and 223 more days in SDG&E territory. However, the overall RE project database is still fairly small, and it is not accurate to attribute project delay to interconnection alone. There are numerous causes of non-interconnection delay. Also, it should be noted that RE had more trouble early on interconnecting in PG&E territory than in any other.

Cost to Interconnect Results

Using the National Renewable Energy Laboratory (NREL) "Making Connections" report as a baseline and selecting only those projects with explicit cost overruns because of issues relevant in California, RE made dollars-per-kilowatt estimates of cost reductions from revisions to Rule 21. The results are summarized below. Two out of the four projects produce interconnection cost savings. Statewide average savings are positive and are estimated to be approximately 13%. Note that the percentage savings is calculated based on a reduction from the total estimated Rule 21 interconnection cost. It is not based on the reduction of unexpected cost.

Table 4-1. Estimated Cost Savings Under Revised Rule 21 in California

Case #	*Assumed Rule 21 Utility*	*Technology*	*kW*	*MC Cost Overrun*	*Saved by Rule 21*	*MC Cost Overrun $/kW*	*Estimated Rule 21 IC Cost*	*Estimated Unexpected IC Cost*	*Total Cost Savings*	*Cost Savings $/kW*	*Percent of Cost Reduction*
Case #15	SCE/SDG&E	NGMT	75	$50,000	$50,000	$667	$56,150	$7,650	$42,350	$565	43%
	PG&E						$61,150	$12,650	$37,350	$498	38%
Case #14	SCE/SDG&E	Propane IC	120	$7,000	$3,500	$58	$66,150	$7,650	($650)	($5)	-1%
	PG&E						$71,150	$12,650	($5,650)	($47)	-9%
Case #12	SCE/SDG&E	NGIC	140	$5,000	$5,000	$36	$56,150	$7,650	($2,650)	($19)	-5%
	PG&E						$61,150	$12,650	($7,650)	($55)	-14%
Case #9	SCE/SDG&E	Steam turbine	703	$132,000	$132,000	$188	$154,350	$75,850	$56,150	$80	27%
	PG&E						$165,350	$86,850	$45,150	$64	21%
Statewide average										**$135**	**13%**
SCE/SDG&E average										**$155**	**16%**
PG&E average										**$115**	**9%**

It is clear that RE interconnections would cost more absent revised Rule 21, but it is not possible to say how much more—at least, not with certainty. Interconnection is still a significant cost—$130–$160/kW. Overall cost can be as high as $120,000 for a detailed study project and is well more than $50,000 for the simplest radial system.

Interconnection Process Results

NREL's "Making Connections" report lists 10 process improvements that should be made to reduce interconnection barriers. Weighting these equally, RE found that Rule 21 has made about 83% progress toward achieving these improvements. Difficulties still exist in the fundamental right of an entity to interconnect. This can still be withheld by the utility for any justification it deems "reasonable." There are likely to be more questions of anti-competitiveness by utilities in the future as CHP becomes available to a broader market.

Simplified Interconnection Results
There have been dramatic improvements in the number of interconnection applications that are passed by the utilities as “simplified” or as supplemental review. However, all rotating generator sets (with the notable exception of certified Tecogen units that otherwise pass initial review) will be treated as supplemental review and will be denied the fast-track approval available under Rule 21.

Overall Regulatory Effectiveness
One of RE’s primary concerns about interconnection in California is the significant differences in Rule 21 implementation that exist among utilities in California. Despite the best efforts of the framers of Rule 21, utilities still can exercise discretion in the field to effectively block interconnection or make any requirements they deem necessary and prudent to business practices. It is the willingness of the utilities to cooperate that has allowed the revised Rule 21 the level of success it enjoys today. Beyond a certain level of technical detail, there is little in Rule 21 to guarantee a generator a right to interconnect. If this could be addressed, it should be—but it is not clear whether it is possible to specify the level of detail necessary to cover the realm of possible interconnection configurations in the field.

4.2 Introduction

4.2.1 Objective
The purpose of this task is to develop and apply metrics to rate the effectiveness of California's Rule 21 in eliminating interconnection as a barrier to DER.

4.2.2 Background
RE currently has more approved interconnections for distributed energy systems than any other entity. These systems are also located in more service territories and date back to 2000, prior to the adoption of Rule 21. RE hence makes for an excellent case study of the effect of Rule 21 on deployment of distributed energy systems in California.

Electric utilities traditionally generated, transmitted, and distributed their own power using large power plants within their franchise territories. The interconnection of these power plants was an internal affair between the utility generation and transmission departments. With the advent of the Public Utility Regulatory Policies Act of 1978, utilities were required to allow interconnection and purchase power from “qualifying facilities.”

In California, these interconnections were performed under Public Utility Commission Rule No. 21, or simply “Rule 21.” These Public Utilities Regulatory Policy Act power plants, owned by independent power producers, ranged from 50 kW to large power plants with hundreds of megawatts of capacity. These large power plants are usually interconnected with the utility transmission system, and their interconnection has serious reliability and safety implications for the grid.

The cost of the interconnection, although expensive, was not overwhelming when compared with the cost of the power plant. Rule 21 did not differentiate between large and small plants, and for small plants, it was cumbersome and expensive to comply with. In fact, if required to meet the same requirements as 50–500 MW power plants, smaller plants can be rendered uneconomic. Furthermore, most of the smaller plants less than 5 MW generate at relatively low voltages and connect through host facility points of common coupling with the grid at the distribution system level.

As DG began to be seen as a viable and important component of the electric infrastructure in the mid 1990s, the industry, legislators, and regulators at the California Energy Commission and the CPUC began to assess the rules, regulations, rates, and tariffs that affected the deployment of DG. In proceeding 10-25-98, the CPUC directed that Rule 21 should be standardized to address some of the problems and concerns of the DG industry. The California Energy Commission stepped in to facilitate a working group approach and created a Rule 21 Working Group. This working group was composed of DG stakeholders that worked together to create a new Rule 21 that all parties could support, to tailor interconnection requirements to the safety and reliability effect commensurate with the size and type of the project, and to reduce the cost and time to interconnect where feasible.

Each of the three largest IOUs in the state—PG&E, SCE, and SDG&E—had its own Rule 21 prior to this work. After 1 year of diligent, often contentious, deliberations by the multi-stakeholder group, a consensus was reached on many technical and contractual issues, and a revised Rule 21 was completed, submitted to the CPUC, and formally adopted on Dec. 21, 2000.[83] At the same time, the working group recognized that many issues remained and that there would be a need for periodic revision of the rule. This process has been ongoing. The question explored in this study is: What effect has the revised Rule 21 had on the timeliness and cost-effectiveness of interconnection?

Some right to interconnect has been established,[84] but several primary barriers to obtaining permission to operate in parallel with a utility's system remain. These are the technical interconnection requirements that must be fulfilled, the time required to fulfill them, and the cost. As Section 4.3 and Section 4.4 will explore in greater detail, the time required to go through the interconnection process may have a direct relationship with cost.

[83] The three utilities have subsequently filed additional advice letters updating Rule 21 to ensure consistency.
[84] SCE had a policy prior to the formation of the interconnection working group that stated that a generator that was not a qualifying facility or net energy metering customer had no right to interconnect to its distribution system. The case is described in DOE's "Making Connections" report (p. 63, Case 15).

4.2.3 Regulatory Metrics

To complete this work, it has been necessary to devise four metrics to evaluate the effectiveness of Rule 21 in eliminating barriers to interconnection:

1. Time to interconnect
   Measures the delays in approval and installation of interconnection
2. Cost of interconnection
   Measures the cost of interconnection under revised Rule 21.
3. Process improvement
   Evaluates whether revised Rule 21 has improved the interconnection process
4. Simplified interconnection
   Measures the number of applications that qualify for simplified interconnection, supplemental review, and detailed study and the number of applications that are suspended or withdrawn.

4.2.4 Metrics Process

Each of these metrics, to the extent practicable, has been compared with a baseline of projects that interconnected before the revised Rule 21 came into effect. However, it is important to note that there is scant data available for the baseline, mostly because controls had not yet been put in place to track projects.

Metrics will employ a four-step process:

1. Collect data for a baseline made up of interconnection projects or requirements under conditions of the old Rule 21 or equivalent non-Rule 21 situations.
2. Collect data for a trendline made up of interconnection projects or requirements under conditions of the revised Rule 21.
3. Compare the trendline to the baseline.
4. Compare the results of Step 3 with the objective to yield progress toward the objective.

Each metric has baseline data sources and trendline data sources. The following sections will cover the baseline and trendline data sources and methodologies for comparison.

4.2.4.1 Data Sources

Although a significant amount of data from RE’s projects is available, it is not possible to completely describe RE’s economic and technical data for each project in the baseline and trendline because some of the data are proprietary and protected. In those cases, the data have been aggregated and are represented in general terms. Although RE has been able to reach definitive conclusions, because of the confidential nature of some data, there are a few gaps in the understanding of cost-effectiveness.

Five data sources were used to determine the cost-effectiveness of California interconnections under the revised Rule 21:

1. RE's internal project data
2. Baseline data from the "Making Connections" report on pre-2001 interconnections
3. Lists of DG interconnections under revised Rule 21 provided by PG&E, SCE, and SDG&E to the California Energy Commission
4. Details of the interconnection review process provided by the three major utilities (and interconnection applications separated into groups of those approved through initial review, those approved through supplemental review, and those approved following detailed interconnection studies)
5. The revised Rule 21.

RE started installing its systems as recently as 2000;[85] like the industry, RE's business case is relatively new. Its internal project data are the first source for information.

For years prior to 2000, there are few available studies of the costs of interconnection. The only notable exception for pre-2000 baseline data is the NREL-sponsored report "Making Connections."[86] "Making Connections" is a case study of 65 interconnections undertaken across the United States. This information was gathered from interviews with manufacturers, developers, and owners of DG projects. All major technologies, fuels, sizes, and operating modes were represented. Interconnection barriers are described in detail. Most of the baseline data for this comparison come from "Making Connections." However, "Making Connections" does not disclose absolute cost or delay information. Instead, it is based on interviews with DG developers and presents relative costs and delays—i.e., dollars and months more than the customer's expected expenditure. The report does not claim to be balanced. It states: " … these cases primarily represent the developers' views of what they encountered in seeking to interconnect these facilities. Therefore, the cases reported here may not reflect what might be a very different utility position with respect to some of the cases." Although this report used the NREL report as a baseline, it used a very different approach to data collection. Where the NREL report relied on interviews with developers, this report attempted to use only factual data. Section 4.3 contains a detailed description of what information is used from the NREL report and how it is applied to measure progress toward the objectives.

[85] http://www.realenergy.com/news/news_articles/2000/2000-10-16_p_and_i.pdf
[86] Aldefer, R.B.; Eldridge, M. Starrs, T. "Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects." NREL/SR-200-28053. Golden, CO: National Renewable Energy Laboratory. May 2000.

The third data source for determining cost-effectiveness is the series of California Interconnection Status Reports (CaIS Reports) provided monthly by each of the large California IOUs as a courtesy to the California Interconnection Working Group[87] at the request of the California Energy Commission.[88] These data are available to all stakeholders and have not been seriously challenged by anyone. They are therefore deemed to be accurate and usable for both baseline and trendline data. CaIS Reports contain information about all distribution-level interconnections in the IOU territories—except net energy metering projects, which are solar PV projects less than 1 MW. Data have been collected monthly since April 2001. Fields include customer type, city, total gross kilowatts, technology, interconnect type, operating mode, date received, requested online date, contract execution, authorized interconnect date, and status. Time to interconnect is well-documented and includes absolute and relative delay information. No absolute or relative interconnection costs are disclosed.

The fourth data source was a summary listing provided by each of the California utilities. Although each utility provided the data in a different format, the information showed how utility review was conducted by each utility (which applications were approved following initial review, which were approved following supplemental review, and which were approved following a formal interconnection study). The utility charges for these reviews generally were available, but the cost of performing the interconnection is a more complex matter, and those costs were not obtained. Although the relative cost of performing those interconnections could be inferred in many cases, it should be noted that the engineers and contractors working on RE's interconnections have also worked on projects for a number of other developers. Their experience and cost estimates have been included in the narrative description and cost generalizations.

The last data source for determining cost-effectiveness is the revised Rule 21 itself. "Making Connections" contains recommendations for reducing interconnection barriers. Where these recommendations serve as a relevant baseline, they can be compared to the revised Rule 21 see to what extent they were fulfilled. The revised Rule 21 can also be compared with baseline situations to see whether the improved requirements would reduce cost.

4.2.4.2 Cost-Effectiveness Methodology

To measure regulatory effectiveness, it is useful to define the baseline, trendline, and comparison result data type. Each objective below begins with a description of the overall methodology for measuring cost-effectiveness.

Time to Interconnect Metric
Description: Compare Rule 21 time delays of approval with baseline time delays
Baseline data source: "Making Connections," CaIS Reports
Trendline data source: CaIS Reports (including RE time to interconnect)
Result: Numerical comparison

[87] This is a multi-stakeholder group that has met since January 2000 to discuss and resolve technical and policy issues of interconnection of DG in California.
[88] Summaries of CaIS Reports can be found at: http://www.energy.ca.gov/distgen/interconnection/rule21_stats.html.

Cost of Interconnection Metric
Description: Reconstruct Rule 21 trendline cost data from "Making Connections" projects and compare them to baseline "Making Connections" cost data. Removal of technical and business barriers from baseline projects counts as qualitative improvement in cost-effectiveness
Baseline data source: "Making Connections"
Trendline data source: RE costs of revised Rule 21 compliance
Result: Qualitative discussion with numerical data as available

Process Improvement Metric
Description: Compare the baseline interconnection process, as applied in particular baseline projects, with the revised Rule 21 interconnection process. An improved process is scored as a percentage of actual achievement against a standard of complete success (where success = 100% and failure = 0%)
Baseline data source: "Making Connections"
Trendline data source: RE experience, revised Rule 21
Result: Scored qualitative comparison

Simplified Interconnection Metric
Description: Document results of efforts to expand applications eligible for simplified interconnection.[89] Under Rule 21, there are three tracks for interconnection application review and approval: (1) approval upon initial review resulting in simplified interconnection, (2) approval upon supplemental review through simplified interconnection or with additional requirements, and (3) approval following a detailed study, which probably results in additional requirements. The first is usually the fastest and least expensive track; the third is usually the longest and costliest track. The simplified interconnection objective aims to measure the number of projects that take the fast track. Expanded eligibility for simplified interconnection represents a qualitative improvement in cost-effectiveness
Baseline data source: "Making Connections"
Trendline data sources: (1) RE experience, (2) revised Rule 21, (3) special utility interconnection reports
Result: Quantitative comparison of total projects passing on initial review (and supplemental/detailed study) as a percentage of total interconnections

4.3 Regulatory Effectiveness Baselines

4.3.1 Baseline Methodology
"Making Connections" is based on interviews with developers of 65 DG projects across the United States. Of these, 26 were selected as case studies and given detailed treatment. Twenty-five of the 65 projects gave figures on how much the cost to interconnect exceeded expectations; 39 of 65 gave figures on how much the time to interconnect exceeded expectations.

[89] According to Rule 21,simplified interconnection is interconnection that conforms to the minimum requirements under this rule, as determined by Section I. See Rule 21 Section I for details: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html.

The report is useful for an assessment of Rule 21 cost-effectiveness because it contains baseline information that relates to the four technical and economic objectives.

1. It contains data for all case studies reporting time overruns, which are useful as a baseline of comparison for the time reduction objective.
2. It contains data for all case studies reporting cost overruns, which are useful as a baseline of comparison for the cost reduction objective
3. It contains descriptions of each case study, which are useful in assessing the applicability of baseline costs to the trendline.
4. It provides an "action plan," which is useful in determining whether the process improvement objective has been met.

Not all of the 65 projects in the NREL report can be used in the baseline. Solar and wind generation projects equal to or smaller than 10 kW are eligible in California for net energy metering.[90] Small net energy metering projects were not originally covered under Rule 21.[91] A separate regulatory code[92] describes how utilities are required to handle these projects. This paper will not include net energy metering less than or equal to 10 kW because California law mandates that the costs associated with such projects be borne by the utility.

Furthermore, projects in the NREL study delayed by issues unlikely in pre-Rule 21 California have been removed from the baseline. NREL study projects are also excluded from the baseline when the barrier to project operation is something other than interconnection (environmental regulations or standby rates, for example). When net energy metering projects and projects with non-interconnection issues are eliminated, 41 sites are left in the baseline (six inside California and 35 outside).

The time delay baseline is supplemented here by CaIS projects in California that began the process of interconnection prior to Dec. 21, 2000—the date the CPUC issued its decision to adopt the revised Rule 21. Twelve CaIS projects fit this description, and all are from SCE and SDG&E. None of these projects went on line prior to Dec. 21, 2000. All went into service after that date. In consideration of how these projects were administered, however, their inclusion in the baseline makes sense.

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[90] Net energy metering is the utility tariff that allows customers to install certain renewable energy generators (primarily PV and wind turbines) and sell excess power back to the utility at the customer's retail rate. This is sometimes called "spinning the meter backward" because the meter actually does turn in reverse when the system is exporting power.
[91] Now that California has expanded the net energy metering program, some IOUs essentially perform initial review (and supplemental review, if necessary) on net energy metering projects. Efforts are under way to bring net energy metering projects into harmony with Rule 21, although some differences will remain. One of these differences is that the utilities are required to absorb the cost of net energy metering interconnection studies.
[92] PUC Section 2827.

- They did not use the revised Rule 21 application form.
- They did not go through initial review, as defined by the new Rule 21.
- They were not subject to the time limits and constraints imposed by the new Rule 21.
- There was no such thing as simplified interconnection when they applied.
- There was no such thing as certified equipment when they applied (although the concept of interim approval may have been applied periodically).
- They were processed by the utility, at the time they were received, the same way baseline projects were processed.
- There is no provision under the revised Rule 21 that would reduce the time to review or the cost to implement interconnections that were already under way under the old Rule 21.
- Although projects received prior to Dec. 21, 2000, may have become subject to the provisions of Rule 21 as of that date, they would have been processed in a manner identical to projects interconnected during the baseline period.

For these reasons, the 12 early CaIS projects are included in the baseline.

4.3.2 Baseline Time to Interconnect

4.3.2.1 Considerations in Constructing the Baseline

The baseline for the time reduction objective comes from these sources:

- The "Making Connections" report
- The California DG lists (CaIS Reports), modified as described in Section 4.3.1
- Early RE interconnections.

Both "Making Connections" and CaIS Reports have time-related data, but they are in different formats. "Making Connections" shows only relative time overruns, i.e., months beyond expected completion date. The CaIS data track the actual date that the interconnection application was received, the requested online date, and the actual date that the project was cleared for interconnection. By subtracting the requested date of interconnection from the actual date of interconnection, it is possible to derive the number of days the customer perceives the interconnection to be early or late. The last step to put the "Making Connections" and CaIS data in the same format (relative to days early or late) is to convert "Making Connections" baseline data to days by multiplying months late by the average number of days per month.

Although the point of the original "Making Connections" report was to show how interconnection remains a barrier to DG, the time delays in this baseline cannot necessarily be imputed to the utility. It is likely some delays resulted from events on the customer side of the project. The date the customer requests to be online may be unreasonable. With the exception of a few "Making Connections" case studies, the data below come without any report of cause. This report does not seek the cause of any delay. Testing the time reduction objective, and the other objectives as well, requires only a comparison of the trendline to the baseline to see whether the conditions of the objective are met.

4.3.2.2 Time Delay Baseline

4.3.2.2.1 California Time Delay Baseline

There are 16 projects in the California time delay baseline. Four are from "Making Connections;" 12 are from the CaIS list. For this report, time delay is defined as the time span to interconnect beyond what the developer thought was reasonable. Project delays range from 30 days to 286 days. Table 4-2 shows the results for California, sorted in ascending order.

Table 4-2.California Interconnection Time Delays

State	Project ID[1]	Kilowatts	Technology	Time Delay Total Days
California	13.32CA	132	PV	30
California	0.52CA	2100	Wind	61
California	0.01SCE	235	Fuel cell	92
California	0.01SDGE	23,500	Natural gas combustion turbine	100
California	0.07SDGE	200	Natural gas ICE	117
California	0.57SDGE	400	Natural gas ICE	117
California	0.02SCE	1,275	Natural gas ICE	117
California	0.03SCE	14	PV	144
California	0.04SCE	14	PV	144
California	0.10CA	7.5	PV/propane	152
California	0.22CA	37	Natural gas turbine	183
California	0.05SCE	60	Natural gas microturbine	201
California	0.08SDGE	400	Natural gas ICE	240
California	0.04SDGE	14,769	Natural gas combustion turbine/steam	255
California	0.06SDGE	200	Natural gas ICE	265
California	0.05SDGE	200	Natural gas ICE	286

[1]The project IDs are different for CaIS data and "Making Connections." The CaIS project IDs are composed of a sequential number #.## (numbered sequentially for each utility by date the application was received), followed by the three- or four-letter acronym for the California utility service territory where a project is located. The "Making Connections" project IDs are a sequential number ##.## followed by the state two-letter code. The two most significant digits of the sequential number denote the "Making Connections" case study number (1–26). If the project is not included in the "Making Connections" case studies, the corresponding number in the project ID is 0. This system was invented specifically for this paper because it became necessary to link up project characteristics in "Making Connections" and eliminate redundancy and avoid double counting in the CaIS lists. No ID system is implemented in either original source. The ID system facilitates quick distinction between the CaIS projects and the "Making Connections" projects and allows tracking of specific projects and cross-referencing by interested readers.

4.3.2.2.2 Non-California Time Delay Baseline

Twenty-two projects in the time delay baseline are from non-California states. These delays range 0–5,475 days. All non-California projects are from the "Making Connections" report. Table 4-3 shows the non-California baseline. The Iowa wind turbine, ID 0.28IA, has a delay of 15 years; the New England cogeneration plant, ID 0.57NE, has a delay of 6 years. These represent statistical outliers and are left out of the baseline calculations.

Table 4-3. Non-California Interconnection Time

State	Project ID	Kilowatts	Technology	Time Delay Total Days
CO	0.29CO	100	Hydro pump	0
CO	0.50CO	1,925	Cogeneration	0
IL	0.47IL	1,200	Cogeneration	0
MN	0.19MN	20	Wind	0
MN	18.21MN	35	Wind	0
MN	0.41MN	600	Wind	0
MN	0.62MN	23,000	Wind	0
TX	16.37TX	500	Wind (multi sites)	0
CO	12.33CO	140	IC Engine	30
MS	3.60MS	15,000	Cogeneration	61
OH	20.18OH	20	PV/Wind	61
PA	17.23PA	43	Photovoltaic	61
IL	21.17IL	17.5	Wind	91
IL	0.49IL	1,650	ICE	91
NE	0.65NE	56,000	Waste-to-energy	183
HI	14.30HI	120	ICE	243
NE	0.25NE	50	Cogeneration	365
NY	0.40NY	560	Cogeneration	365
MD	9.43MD	703	Steam turbine	426
NE	0.39NE	500	Cogeneration	730
NE	0.57NE	8,000	Cogeneration	2190
IA	0.28IA	90	Wind	5475

4.3.2.2.3 National Time Delay Baseline

The national baseline is the average of the California baseline (Table 4-2) plus the non-California baseline (Table 4-3).

Table 4-4 shows averages for each, sorted by kilowatt size. These averages and size categories become the basis for comparison with the trendline.

Table 4-4. Average Interconnection Time Baselines

	Average Time Delay – All (Days)	Interconnection Average (Days)
National baseline <1 MW	308	366
National baseline 1 MW+	300	456
Non-CA baseline <1 MW	523	N/A
Non-CA baseline 1 MW+	361	N/A
California baseline <1 MW	178	366
California baseline 1 MW+	157	456

4.3.3 Baseline Cost of Interconnection

4.3.3.1 Considerations in Constructing the Baseline

Ultimately, all effects result in cost effects, and it is the cost reduction that is the most significant benefit for DG interconnections. Although this study endeavors to reach meaningful conclusions, four facts inform possible ways of constructing the cost metric:

- No hard cost data are available for the NREL study relative to either the cost to the utility of an interconnection study or to the cost to the developer of installing and testing required interconnection equipment.
- RE hard cost data are available for the period after Dec. 12, 2000, when the revised Rule 21 went into effect.[93]
- CaIS and some "Making Connections" projects contain time delays but no cost information.
- Most of the "Making Connections" costs are estimates and were not actually incurred at the time the report was written.

4.3.3.1.1 Using Relative Cost Data

RE has supplied interconnection cost data for its projects and given total costs for electrical interconnection. These cannot be directly compared with the baseline, however, because "Making Connections" contains only relative data. To overcome this issue, the baseline costs are examined to assess whether they would accrue to the project under the revised Rule 21. If the revised Rule 21 creates a condition or conditions that eliminate the cost, that fact will register in the cost reduction metric. After going through this exercise, however, a lack of baseline cost data still makes baseline-to-trendline cost comparison highly speculative. For this reason, this paper limits the comparison to a discussion of pre- and post-Rule 21 interconnection cost issues.

[93] RE's cost data prior to Dec. 21, 2000, were not available in time to include in this report.

RE's experience has shown that although the requirements in the revised Rule 21 were put in place to reduce costly interconnection fees, minimize detailed studies, and replace burdensome technology-specific requirements with functional requirements, there are still many areas in which the technical requirements of Rule 21 are either ambiguous or missing entirely. Although it is a given that with the myriad contingencies one may encounter when developing a DG project, no one expected Rule 21 to pertain to all interconnection situations, still utility discretion is burdensome beyond what a project developer would consider reasonable. In many situations, the revised Rule 21 gives no clear advantage to a developer such as RE over the old Rule 21.

A project-by-project assessment of the revised Rule 21 effects on baseline project costs is carried out to help inform the following discussion. Results of this work are important to the use of metrics, but the work itself is not directly relevant to RE's projects. Projects with insufficient information to make a determination will be excluded from the results. "Making Connections" estimates, where given, are used at face value.

4.3.3.1.2 Carrying Cost of Money

The lack of cost data in the CaIS projects cannot be replaced because interconnection labor and material costs are not available. However, there are calculable costs associated with delay, and they can be derived from the interest rate paid for capital borrowed to finance the project. The third restriction described in Section 4.3.3.1 can be overcome for carrying costs by attributing an assumed cost of money to each technology and time delay, thereby quantifying its cost value. In this way, all CaIS projects may be included in the cost overrun baseline and trendline, and a portion of interconnection cost overrun may be accounted for. All "Making Connections" projects with reported time delays can be valued in the same way. Including projects without labor and material cost overruns is equivalent to setting those cost overruns to zero—in other words, the interconnection costs what the customer *expects* that it should cost and no more. Although this is not a totally accurate picture, it is a conservative assumption and useful for assessing overall cost-effectiveness.

To derive the time value of money, or carrying cost, assumptions were made about how much money is spent during the process of interconnection. This varies considerably from one project to the next, so it makes sense to choose values that represent average expenditures for each technology type. The rationale behind assessing these costs is that if the technology had been installed and the project up and running at the customer's expected online date, the investment would be available to produce returns. However, the delays result in interest payments on the capital cost of the project without receiving any of the expected cash flows to pay for those costs.

Many factors are involved in the overall purchase and installation cost of DER. A recent study of the market in California for CHP contains a table of approximate cost per kilowatt for a variety of prime movers and sizes, which is useful for the purposes of this paper.[94]

[94] Onsite Energy. "Market Assessment of Combined Heat and Power in the State of California." July 1999. http://www.energy.ca.gov/reports/2000-10-17_700-00-009.PDF.
PV costs come from http://solstice.crest.org/articles/static/1/binaries/REPP_FL_100202.pdf.
Wind costs come from http://www.energy.ca.gov/distgen/economics/capital.html.

Table 4-5. Carrying Costs for DER Technologies and Sizes

Representative On-site Generation Cost and Performance	Microturbine	Gas Engine	Fuel Cell	Gas Engine	Gas Turbine	Gas Turbine	PV	Sm Wind	Lg Wind
Size kW	50	100	200	800	5,000	25,000	10	10	1000
Heat Rate (Btu/kWh HHV)	11,741	11,147	6,205	9,382	9,125	7,699	n/a	n/a	n/a
Recov. Exhaust Heat (Btu/kWh)	4600	1600		1200	3709	2800	n/a	n/a	n/a
Recov. from Coolant (Btu/kWh)		2600	1600	2500			n/a	n/a	n/a
Package Cost ($/kW)	$350	$500	$900	$300	$300	$300	$4,000	$3,000	$800
Heat Recovery	$150	$100	$75	$75	$75	$75	$0	$0	0
Emission Controls	$0	$70	$0	$29	$51	$50	$0	$0	0
Project management	$18	$25	$45	$15	$15	$15	$45	$45	45
Site & Construction Management	$25	$35	$63	$21	$21	$21	$63	$63	63
Engineeering	$14	$20	$20	$12	$12	$12	$20	$20	20
Civil	$50	$75	$100	$38	$15	$13	$100	$100	100
Labor/Installation	$70	$100	$120	$38	$45	$45	$120	$120	120
CEMS	$0	$0	$0	$0	$30	$20	$0	$0	0
Fuel Supply-compressor	$40	$0	$0	$0	$20	$15	$0	$0	0
Interconnect/Switchgear	$50	$75	$38	$31	$10	$3	$38	$38	37.5
Contingency	$18	$25	$27	$15	$15	$15	$27	$27	27
General Contractor Markup	$78	$103	$139	$57	$61	$58	$139	$57	$61
Bonding/Performance Guarantee	$24	$31	$14	$17	$18	$18	$14	$17	$18
Carry Charges during Constr.	$15	$20	$27	$11	$24	$23	$80	$61	$45
Carry Costs per kW per day	$0.0424	$0.0555	$0.0738	$0.0310	$0.0660	$0.0633	$0.2189	$0.1672	$0.1239

The table makes the following assumptions:

- Of total construction cost, 50% is paid during the period of interconnection delay
- Interest rate is 7%
- Construction (for a project without delays) takes 1 year for units 1 MW or more and 6 months for units less than 1 MW.

The final line simply divides the "carry charges during construction" by 365 to show the carrying costs per kilowatt per day. To derive the total cost overrun because of delay, the technology and size are matched to the project, and the carrying cost per kilowatt per day is multiplied by the number of days of delay.

Another cost of delay, lost opportunity cost, is not included in this analysis.

4.3.3.2 The Reconstructed Baseline

The interconnection cost overrun per kilowatt, the delay carrying cost per kilowatt, and the cost overrun total are included for every project in the baseline for baseline because they did not have adequate cost or time data, as described in Section 4.4.2.

The first column shows how much interconnection hardware and labor cost overrun the project had, the second column shows how much cost overrun there is from delay, and the third column is the sum of the first two.

Table 4-6. Cost Baseline

State	Project ID	Kilowatts	Technology	Baseline Interconnection Cost Overrun ($/kW)	Baseline Delay Cost Overrun ($/kW)	Baseline Total Cost Overrun ($/kW)
CA	0.10CA	7.5	PV/propane	$0	$33	$33
CA	0.22CA	37	Natural gas turbine	$243	$8	$251
CA	15.27CA*	75	Microturbine	$667	$0	$667
CA	13.32CA*	132	PV	$189	$7	$196
CA	0.52CA	2,100	Wind	$19	$8	$27
IL	21.17IL*	17.5	Wind	$38	$15	$53
OH	20.18OH	20	PV/wind	$0	$10	$10
PA	17.23PA*	43	PV	$820	$13	$833
NE	0.25NE	50	Cogeneration	$1,000	$20	$1,020
IA	0.28IA	90	Wind	$167	$915	$1,082
HI	14.30HI*	120	ICE	$58	$14	$72
CO	12.33CO*	140	ICE	$36	$2	$37
NE	0.39NE	500	Cogeneration	$1,000	$31	$1,031
MD	9.43MD*	703	Steam turbine	$188	$28	$216
MS	3.60MS	15,000	Cogeneration	$129	$3	$132
NE	0.65NE	56,000	Waste-to-energy	$0	$12	$12

This table is purely illustrative and is not directly comparable with the revised Rule 21 situation or to RE costs for reasons described in greater detail in Section 4.4.2.

4.3.4 Baseline Process Improvement

The "Making Connections" report offers a "Ten-Point Action Plan for Reducing Barriers to Distributed Generation." These 10 points are treated in this paper as baseline conditions that, if fulfilled by the new Rule 21, are considered evidence of qualitative fulfillment of the process improvement objective. The rationale for this approach is that to the extent Rule 21 is making progress toward achieving one or more of these 10 points, it is making progress toward "[improving] the process of interconnection of DG to the electrical system," as required by the process improvement objective.

Some of these points do not concern interconnection and should be modified or eliminated from consideration for our comparison:

- Point 3 recommends acceleration of control technology and is beyond the scope of this study.
- Point 7 recommends the formulation of new regulatory principles and will be narrowed to include interconnection only.
- Point 8, addresses regulatory tariffs and utility incentives, which are issues outside the scope of this study and will be narrowed to include interconnection only.

Table 4-7. "Making Connections" Ten-Point Action Plan

Reduce Technical Barriers

1. Adopt uniform technical standards for interconnecting distributed power with the grid.
2. Adopt testing and certification procedures for interconnection equipment.
3. Accelerate development of distributed power control technology and systems.

Reduce Business Practice Barriers

4. Adopt standard commercial practices for any required utility review of interconnection.
5. Establish standard business terms for interconnection agreements.
6. Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.

Reduce Regulatory Barriers

7. Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.
8. Adopt regulatory tariffs and utility incentives to fit the new distributed power model.
9. Establish expedited dispute resolution processes for distributed generation project proposals.
10. Define the conditions necessary for a right to interconnect.

The revised Rule 21 was among the first in the nation to adopt uniform standards for interconnecting DG, to develop and adopt testing and certification procedures, to adopt standard application forms and review processes, and to develop utility tools to assess the effect of distributed power on the grid. The working group has used the NREL "Making Connections" report as a springboard from which to launch improvements in the processing and review of DG interconnections, and on an ongoing basis, the working group continues to help implement many of the recommendations. This report assesses the cost effect of those improvements.

4.3.5 Baseline Simplified Interconnection

4.3.5.1 Baseline Has No Simplified Interconnection Process

The simplified interconnection objective baseline is simple to construct because the old Rule 21 did not provide for simplified interconnection.[95] All projects had to go through what is now called detailed study. Any interconnection made with less than a detailed study, therefore, represents progress toward the objective. Evidence for this progress is found in the revised Rule 21. As shown in Section 4.4.4, the utilities have provided information about interconnections requiring simplified, supplemental, and detailed study. To the extent that Rule 21 provisions and certification provide process improvement and opportunities for simplified interconnection or supplemental review (thereby avoiding a detailed study), they successfully fulfill the simplified interconnection objective.

4.3.5.2 Overall Baseline Results

The 65 baseline interconnection projects tracked in "Making Connections" produced the following results:

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[95] A project qualified for simplified interconnection is one that is approved following only the initial review, and in some cases following the supplemental review, and does not require a detailed study.

- Twenty-nine were completed and interconnected (with no further detail on categorization).
- Nine are operating in parallel, serving on-site load with no export.
- Two were disconnected from the grid, with no report of whether they are shut down or in isolated operation.
- Seven were installed but were not then interconnected, perhaps operating isolated from the grid (i.e., not in parallel) in the interim.
- Thirteen were pending
- Five were abandoned.

4.4 The Regulatory Cost-Effectiveness of the Revised Rule 21

On Dec. 21, 2000, CPUC Decision 00-12-037[96] approved in its entirety the Rule 21 language adopted by the California Energy Commission. PG&E, SDG&E, and SCE have now replaced their former Rule 21 with the approved model tariff, interconnection application form, and interconnection agreement. Each utility filed again in late 2002 to make additional changes and increase rule uniformity. The interconnection working group continues to consider changes to Rule 21 and its associated documents with the goals of simplifying the process of interconnection, complying with evolving tariffs, and keeping the utility implementations uniform. A third tariff advice letter filing is expected for all three utilities by the end of 2003 or early in 2004. Advice letters are changes recommended by the utilities. Upon adoption by the CPUC, they become part of the rule.

4.4.1 Trendline Time to Interconnect

The amount of time to interconnect is not necessarily a direct reflection of utility interconnection practices. Although improvements in interconnection times may indicate increasing knowledge and experience on the part of the developer or the utility regarding interconnection practices, the improvements or delays could just as easily be caused by other design, engineering, entitlement, or permit processes. Furthermore, “delay” is inherently a subjective phenomenon. The “requested online” date is relative to the customer’s expectation and therefore may be unreasonably short (for example, some applications list the day the application is handed in) or long (for example “sometime within the next 5 years”). The cost data are also relative to customer expectations and must be treated with this limitation in mind.

4.4.1.1 California Context for Interconnection Time Delay

Without being able to determine with certainty the specific causes for improvement in interconnection times, the generalization can be made that it is getting easier and faster to interconnect in California under the revised Rule 21. Customers and utilities alike deserve credit for these improvements. Year 2000 projects depicted below are in the CaIS baseline. There are dramatic improvements in all utility territories.[97]

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[96] http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/4117.htm

[97] There is no written standard for exactly how the utilities should count times, however, which may explain some divergence in their results.

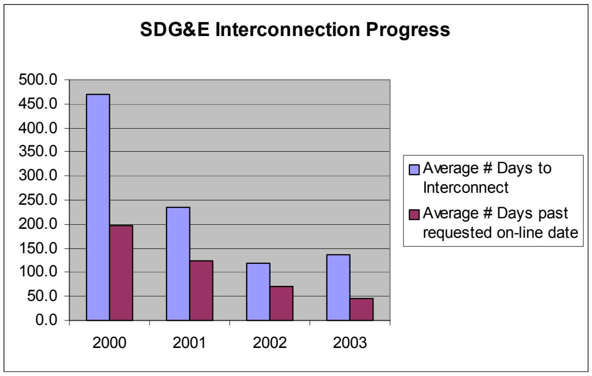


Figure 4-3. SDG&E annual progress

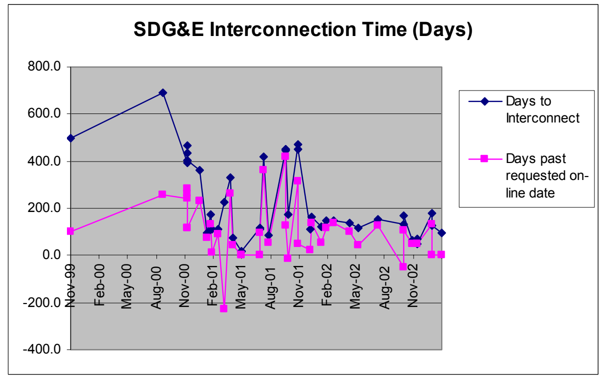


Figure 4-4. SDG&E project delay

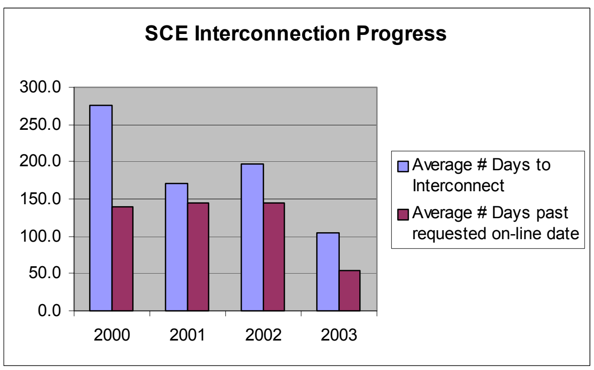


Figure 4-5. SCE annual progress

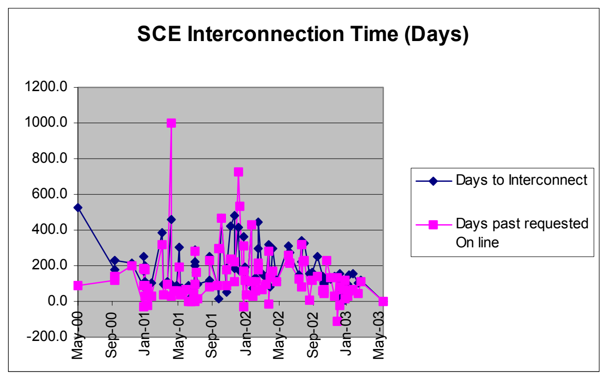


Figure 4-6. SCE project delay

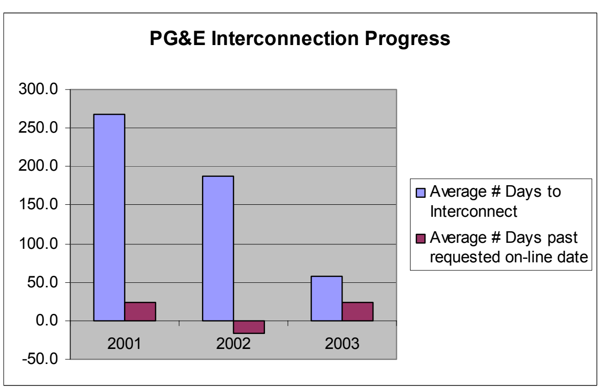


Figure 4-7. PG&E annual progress

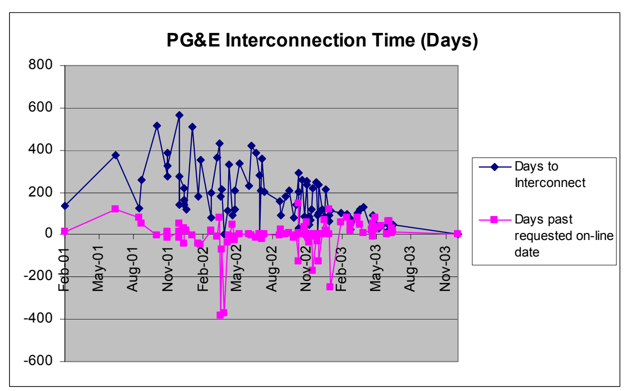


Figure 4-8. PG&E project delay

In SDG&E territory, the average days to interconnect has improved by almost 100% 2 years in a row. Average days past requested online date improved over the 4 years tracked by 200%. Although PG&E had no interconnections in 2000, by 2003 it reduced average interconnection time to less than 60 days. Its average interconnection time delay was negative in 2002, meaning its average customer set expectations at a point later than the interconnection was delivered. In 2001 and 2003, PG&E's time delay was less than 25 days—the best of the IOUs. The results for all utilities combined (Figure 4-9) are similar. The annual progress is remarkable and in large measure attributable to the changes introduced by the revised Rule 21.

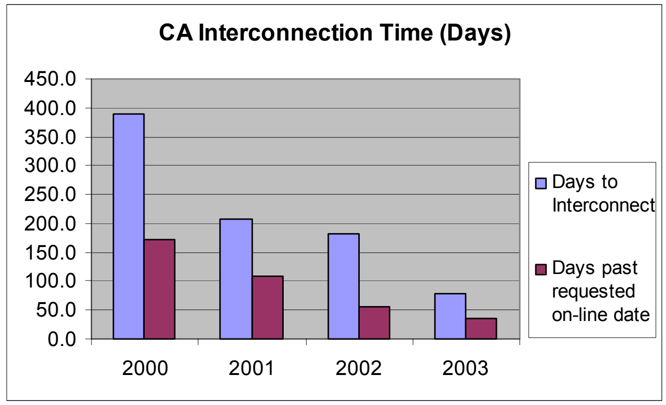


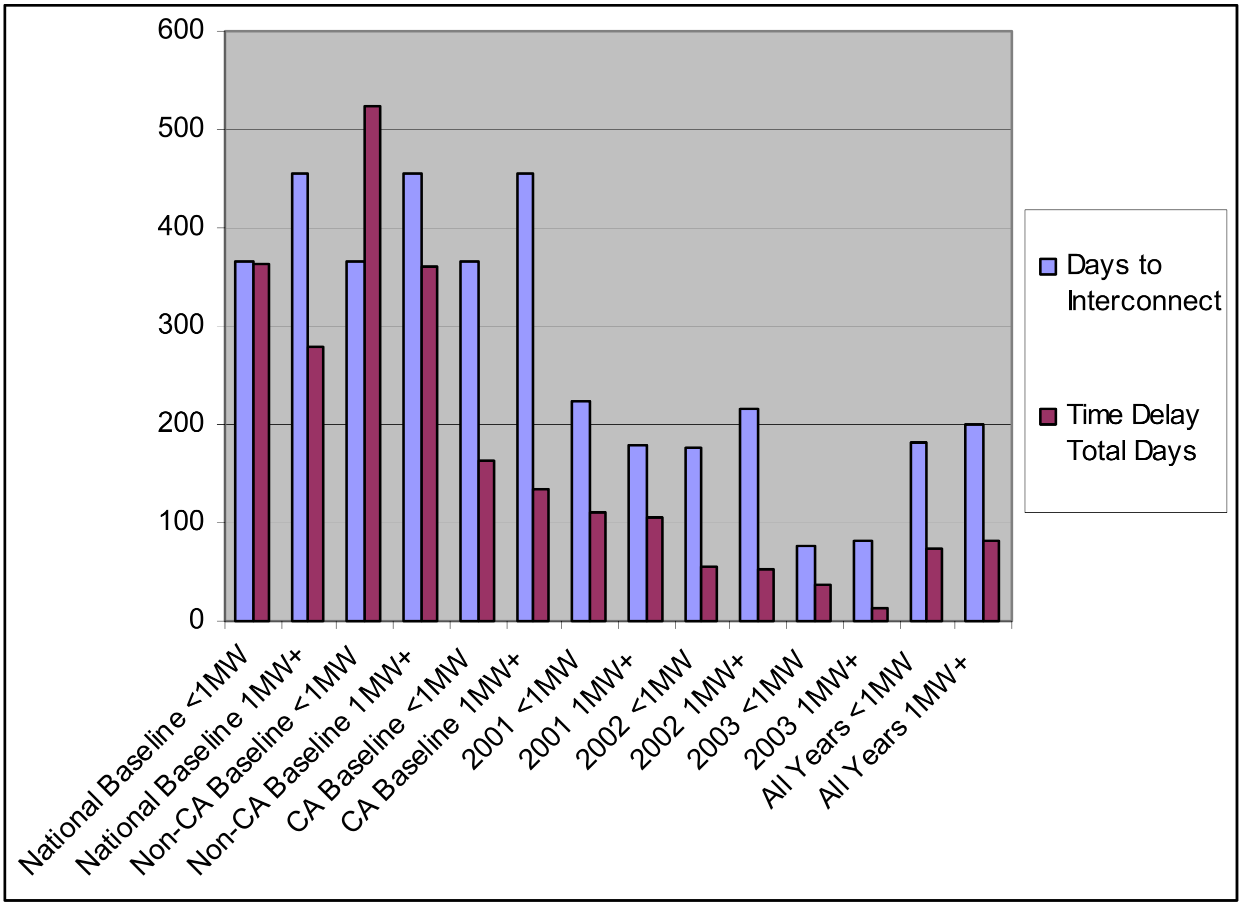
Figure 4-9. California annual progress

4.4.1.2 Trendline Versus Baseline Comparison

In 2001, the total days to interconnect was reduced by 39% for projects less than 1 MW and by 61% for projects larger than 1 MW. The time to interconnect in 2001 was reduced by 33%–79% for projects less than 1 MW and by 22%–62% for projects larger than 1 MW. In 2002, the total days to interconnect was reduced by 52% for projects less than 1 MW and by 53% for projects larger than 1 MW. The time to interconnect in 2002 was reduced by 66%–89% for projects less than 1 MW and by 61%–85% for projects larger than 1 MW. In 2003, the total days to interconnect was reduced by 79% for projects less than 1 MW and by 82% for projects larger than 1 MW. Time delays in 2003 were reduced by 78%–93% for projects less than 1 MW and by 89%–96% for projects larger than 1 MW.

These numbers have a high degree of credibility because of the source and the sheer quantity of data. Time reductions exceed the objective target and are the most direct measure of achievement of the revised Rule 21.

Figure 4-10. Time Delay Trendline Versus Baseline



4.4.1.3 RealEnergy Experience of Time Delay

The story for RE has not reflected the overall California experience. Baseline year 2000 is about equal in both cases. In 2001, overall interconnection time decreased 50% less in RE's case, though days past online date dropped below 50 in RE's case. In 2002, total interconnect time actually increased to 275 days, while days past requested online went up to 150. Several RE projects for 2003 have come online recently, but data are not yet available.

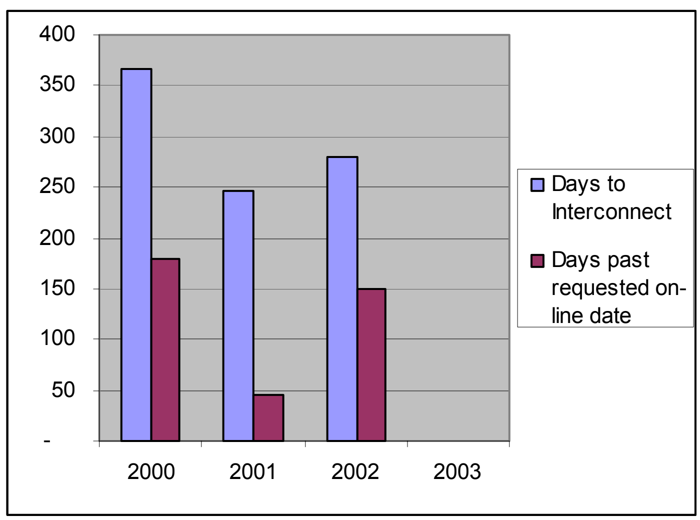


Figure 4-11. RE interconnection progress

RE has not received equal treatment from the IOUs. It has taken an average of 425 days for RE to interconnect in SDG&E territory, 307 days in PG&E territory, and 199 days in SCE territory. PG&E has done an excellent job of managing customer expectations regarding interconnection times. RE has waited an average of just 2 days more than the expected online date in PG&E territory; 114 days more in SCE territory; and 223 days more in SDG&E territory. However, the overall RE project database is still fairly small, and it is not accurate to attribute project delay to interconnection alone. There are numerous causes of non-interconnection delay.

A summary of interconnection times of all RE project undertaken in territories of California IOUs is presented in Table 4-8.

Table 4-8. RE Interconnection Times in California

Project ID	Technology	Kilowatts	Electric Utility	Time to Interconnect	Interconnection Delay
0.00SDGE	PV	110	SDG&E	72	27
0.09SDGE	ICE	600	SDG&E	296	-35
0.08SDGE	ICE	400	SDG&E	391	240
0.06SDGE	ICE	400	SDG&E	436	265
0.05SDGE	ICE	400	SDG&E	464	286
0.07SDGE	ICE	800	SDG&E	401	117
0.42SDGE	ICE	800	SDG&E	561	462
0.67SDGE	ICE	600	SDG&E	Not complete	Not complete
0.00aSCE	PV	110	SCE	47	2
0.00bSCE	PV	110	SCE	57	12
0.27SCE	ICE	400	SCE	98	38
0.08SCE	ICE	1000	SCE	174	89
0.05SCE	Microturbine	60	SCE	216	201
1.02SCE	ICE	200	SCE	223	135
1.11SCE	ICE	600	SCE	361	314
1.94SCE	ICE	600	SCE	21	-108
1.96SCE	ICE	800	SCE	259	130
1.95SCE	ICE	600	SCE	238	109
1.14PG_E	ICE	400	PG&E	239	-4
0.26PG_E	ICE	600	PG&E	389	16
0.27PG_E	ICE	800	PG&E	324	-12
0.25PG_E	ICE	400	PG&E	275	7
9.00PG_E	ICE	800	PG&E	Not complete	Not complete
9.01PG_E	ICE	1200	PG&E	Not complete	Not complete
1.68PG_E	ICE	1030	PG&E	Not complete	Not complete

4.4.2 Trendline Cost of Interconnection

Comparing baseline costs to trendline costs is difficult because baseline costs are given only for items that customers perceived as unreasonable. All other costs are unstated. One-to-one comparison of the unstated costs with the RE trendline is impossible. This makes a real cost comparison highly speculative and turns the analysis in these alternative directions:

- Report RE's interconnection costs, project-by-project
- Discuss differences evident between the "Making Connections" baseline[98] and RE's current experience and highlight issues solved and issues remaining.

4.4.2.1 Barriers Affecting Interconnection Costs

RE has faced four major barriers to interconnection after the revision to Rule 21 that drive up costs. These are:

1. At the inception of the revised Rule 21, RE and the utilities had to overcome a substantial learning curve to get the new interconnection process up to speed.
2. Systems did not (and do not) qualify for simplified interconnection but must face supplemental review.
3. RE has received different treatment from the three utilities.
4. All utilities have added new requirements for interconnection, which make the process more costly and time-consuming.

4.4.2.1.1 Learning Curve

Under the first release of Rule 21, as reported in the base year report, RE encountered problems during supplemental review of its applications. These problems included:

- Application requirements were not standardized across projects.
- There was a lack of staff, in general, and, more specifically, experienced utility personnel with an understanding of DG/CHP and issues surrounding safe interconnection that made the utilities overly cautious in their reviews.
- There was a lack of formalized communication among departments within the utility and between the utility and applicants.
- There was an insufficient definition and standardized protocol of a complete application.
- Different requirements among utilities stopped RE from developing a more standardized application package and required the installation of different types of protection devices.

[98] Based on a comparison of "Making Connections" baseline projects with likely treatment under Rule 21 of those same costs.

In the second release of the revised Rule 21 (at the end of 2002), some of these issues were improved or resolved.

- Applications are now standard.
- Utilities have added staff and increased the breadth and depth of their experience with interconnection.
- Utilities have a designated interconnection project manager to work with each applicant (as required by Rule 21, Section C.1.a).
- Rule 21 itself is now more consistent among utilities in its implementation.

In addition, interconnection agreements are now standard among utilities[99]—and all utilities now have agreements that accommodate third-party operation of the generating facility.[100] Also, all utilities now accept the same design drawing package. This results in major savings of time and engineering effort for RE. Experience, both within RE and within the utility, has also reduced the number of times it was necessary to revise an application.[101]

However, despite these improvements, utilities are still (and will probably continue to be) very cautious. Also, there is still no clear definition of when an application is complete, which renders the 10- and 20-day timelines for utility review (Rule 21, Section C.1.c.2 and C.1.c.3) effectively meaningless.

4.4.2.1.2 No Simplified Interconnection

RE and the utilities are now most of the way up the learning curve and have established ways to complete interconnections. However, RE interconnections take longer than the average California interconnection. The primary cause is that RE must go through supplemental review—a more expensive and time-consuming process. Lack of certification is one screen in utility initial review that prevents approval of RE projects through simplified interconnection.[102]

Screens that send RE into supplemental review include:

- Screen 1: Networked secondary system? (if yes)
- Screen 3: Equipment certified? (if no)
- Screen 4: Aggregate capacity <15% of line section peak load? (if no)
- Screen 5: Starting voltage drop screen met? (if no).

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[99] An exception to the standardization of agreements is that PG&E does not have agreements for inadvertent export.

[100] In the base year's Task 6, the lack of third-party agreements with the utility jeopardized RE's business plan by putting liability that should have been borne by RE as the generating facility owner/operator on the customer and making RE's customer relations tenuous.

[101] In the early stage of Base Year Task 6, every application was sent back to RE from one to four times.

[102] See Figure 6.3.5-1 on Pg. 110 in the base year report:
RealEnergy. "Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report." NREL/SR-560-33581. Golden, CO: National Renewable Energy Laboratory. April 2003.

Supposing the RE DG is to operate on a radial distribution feeder (so it passes Screen 1 above) and is a synchronous machine (so it avoids Screen 5), screens 3 and 4 remain to kick the project into supplemental review. The ICEs RE uses will likely be certified in the future, but Screen 4 will remain an issue post-certification. RE's projects consistently exceed 15% of line section peak.

In early 2003 (the time of the base year report), RE noted, "Only SDG&E (among the major IOUs) will supply the distribution system maps necessary to determine whether an electricity producer's proposed system exceeds the 15% maximum of line section peak load." As a footnote, the report noted: " ... even after repeated requests, RE was never given an opportunity to independently verify that its proposed systems did in fact exceed the 15% maximum line contribution in either SCE or PG&E territory. RE was simply informed that its systems failed the screen." No further data would be released because the utilities deemed it "proprietary." This necessitated a supplemental review.

4.4.2.1.3 Differential Treatment

Each utility, as mentioned before, has some discretion in the application of Rule 21. However, discretion leads to differential treatment of the same type of project/facility in different utility territories. Data show that RE's most costly and time-consuming interconnections occur in PG&E territory. This is partly because of the high percentage of network interconnections; four of seven of RE's PG&E interconnections are on networks.[103] But other differences show up in PG&E projects on radial systems.

PG&E requires battery backup power because it does not accept relays operating in fail-safe mode. PG&E also requires two sets of protection on the customer side of the meter for over/under voltage and over/under frequency. PG&E does not allow built-in protection on the generator to count for one of the redundant devices. It requires two new, additional devices. This adds \$2,000–\$3,000 per utility service meter to the project.

4.4.2.1.4 New Requirements

Table 4-10 provides approximate average costs for the interconnection equipment of all of RE's interconnected projects in California. The table does not include electrical construction costs—such as electrical facility upgrades and metering/control—necessary to accommodate the customer site. It includes only the costs incurred to meet Rule 21 and utility requirements from the supplemental review.

The only baseline interconnections included are the three PV projects. Despite their size (for PV, 110 kW is quite large), these are the fastest interconnections RE has had. It is interesting to note that the trendline (revised Rule 21) interconnections have taken longer than these PV interconnections (an average of 199–425 days under Rule 21 versus 47–72 days for the three PV projects). The application fees have been higher, too (\$1,400 versus \$500).

[103] These include projects 9.00PG_E, 9.01PG_E, 1.68PG_E, and 0.26PG_E. After numerous team meetings and a long negotiation process, the latter was treated as a supplemental review despite its presence on a network.

This is not to say that all interconnection fees have gone up since the rule was revised. In fact, RE's ICE projects (except those on networks in PG&E territory) are now processed as supplemental review with a fee of $1,400. In "Making Connections" baseline project 15.27CA, a 75-kW ICE project constructed in California, developers were warned by the utility that they could pay up to $50,000 for an interconnection study—and even then the DG might not be able to interconnect.[104] In contrast, for RE's projects today, detailed studies cost $7,500 or less. Also, it is clear from the description of "Making Connections" Case Study 15 that the California utility, operating under the old Rule 21, brought many objections—including a refusal to interconnect the project because it was not a qualifying facility—that would be inadmissible under the revised Rule 21. The conditions of interconnection are becoming more certain.

Interconnection requirements are more certain for RE today than for developers working under the old Rule 21, and certainty is necessary to stimulate investment. This does not mean, however, that interconnection is becoming less expensive. In some ways, costs to interconnect are rising. For example, since the last utility advice letter filing for Rule 21, all three IOUs have begun to require the installation of a revenue-grade net generation output meter to allow automatic utility computation of the various tariffs that self-generators must pay or may have to pay in the future. Net generation output metering costs $5,000–$7,500 per service meter. For a facility with three service meters, the requirement for net generation output metering could easily add more than $20,000 to the cost of interconnection.

4.4.2.2 RealEnergy Project Interconnection Costs

Column A of Table 4-10 shows the RE facility ID, a sequential number followed by a utility acronym.[105]

Columns B and C (technology and kilowatts) are self-explanatory. Note that the engines RE specified for most of its projects are 200 kW each, so its projects are built in increments of 200 kW.

Column D, number of meter services, becomes important in calculating costs because costs calculated in columns J and M (hardware to meet rule 21 and net generation output metering) are factors of the number of meters in the facility.

Column E shows interconnection application fees charged under Rule 21 ($800 for initial review and $600 for supplemental review, for a total of $1,400).

Columns F, G, and Q are engineering costs for drawings to satisfy initial review, supplemental review, and detailed study, respectively.

[104] "Making Connections" Case Study 15, p. 63.

[105] The three-digit numbers are given to each project sequentially, according to the date the application was received. 1.24SCE, for example, would be the 124th application received by SCE. Numbers beginning with 9.xx are projects that should be in the database but have not been located there yet. Numbers 0.00, 0.00a, and 0.00b are baseline projects that are not in the database.

Column H is the field engineering necessary to install the generators. The costs are approximated as follows:

- ICE 1: $20,000
- ICE 2: $22,000
- ICE 3: $24,000
- ICE 4: $26,000
- ICE 5: $28,000.

Column I is for review of the engineering by an outside consulting engineer.

Column J is the distribution system protection called for in Rule 21. It costs $2,000–$3,000 for hardware and $8,000–$9,000 for labor per meter service.

Field commissioning testing, detailed in Column K, consists of a pre-test involving the project vendor and a day of utility testing and measurement for the project. The cost breakdown for commissioning test provided in Table 4-9.

Table 4-9. Cost Breakdown of Commissioning Testing

	Simplified Interconnection	Supplemental Review or Detailed Study
Pre-test	$3,000	$7,500
Utility test	$3,000	$5,000
Total	$6,000	$12,500

Columns N and O are the discretionary costs required by PG&E only, as described in Section 4.4.2.1.3.

Detailed studies (Column P) have cost RE $7,500 in fees in the past. These costs are not specified in Rule 21, and the utility could raise them at any time in the future.

Columns R and S are meeting costs and equipment/installation costs, respectively, for detailed studies. The meetings were conducted between RE and the utility to resolve how to interconnect systems with their network. These costs will be reduced or possibly eliminated from future interconnections.

Columns P, Q, R, and S together are actual costs (or averages) RE has paid for its detailed studies projects.

Table 4-10. RE Approximate Project-by-Project Non-Customer-Side Interconnection Costs

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
Project ID	Technology	kW	# Meter Services per Project	Initial & Supplemental Review Utility Study Fees	Drawings - Simplified Interconnect	Drawings - Supplemental Review	Field Engineering Costs- Supplemental	Engineering peer review	Hardware to meet Rule 21	Field Testing Commissioning	Building Shutdown 24/7 bldg Backup power, etc	NGOM	O/U Freq O/U Voltage Redundancy (only PG&E)	Battery Backup (only PG&E)	Detailed studies Utility Fees	Drawings - Detailed Study	Detailed Study Meeting Costs	Hardware to meet Detailed Study	TOTAL Interconnection Cost
0.00SDGE	PV	110	1	$500	$2,500	$0	$0	$1,500	$0	$6,000	$0	$6,250	$0	$0	$0	$0	$0	$0	$16,750
0.09SDGE	IC Engine	600	2	$1,400	$0	$4,500	$24,000	$1,500	$24,000	$12,500	$10,000	$0	$0	$0	$0	$0	$0	$0	$77,900
0.08SDGE	IC Engine	400	1	$1,400	$0	$4,500	$22,000	$1,500	$12,000	$12,500	$10,000	$0	$0	$0	$0	$0	$0	$0	$63,900
0.06SDGE	IC Engine	400	2	$1,400	$0	$4,500	$22,000	$1,500	$24,000	$12,500	$0	$0	$0	$0	$0	$0	$0	$0	$65,900
0.05SDGE	IC Engine	400	2	$1,400	$0	$4,500	$22,000	$1,500	$24,000	$12,500	$0	$0	$0	$0	$0	$0	$0	$0	$65,900
0.07SDGE	IC Engine	800	2	$1,400	$0	$4,500	$26,000	$1,500	$24,000	$12,500	$10,000	$12,500	$0	$0	$0	$0	$0	$0	$92,400
0.42SDGE	IC Engine	800	2	$1,400	$0	$4,500	$26,000	$1,500	$24,000	$12,500	$0	$12,500	$0	$0	$0	$0	$0	$0	$82,400
0.67SDGE	IC Engine	600	1	$1,400	$0	$4,500	$24,000	$1,500	$12,000	$12,500	$0	$6,250	$0	$0	$0	$0	$0	$0	$62,150
0.00aSCE	PV	110	1	$500	$2,500	$0	$0	$1,500	$0	$6,000	$0	$6,250	$0	$0	$0	$0	$0	$0	$16,750
0.00bSCE	PV	110	1	$500	$2,500	$0	$0	$1,500	$0	$6,000	$0	$6,250	$0	$0	$0	$0	$0	$0	$16,750
0.27SCE	IC Engine	400	1	$1,400	$0	$4,500	$22,000	$1,500	$12,000	$12,500	$10,000	$0	$0	$0	$0	$0	$0	$0	$63,900
0.08SCE	IC Engine	1,000	1	$1,400	$0	$4,500	$28,000	$1,500	$12,000	$12,500	$10,000	$0	$0	$0	$0	$0	$0	$0	$69,900
0.05SCE	Microturbine	60	1	$1,400	$0	$4,500	$0	$1,500	$12,000	$12,500	$0	$0	$0	$0	$0	$0	$0	$0	$31,900
1.02SCE	IC Engine	200	1	$1,400	$0	$4,500	$20,000	$1,500	$12,000	$12,500	$0	$6,250	$0	$0	$0	$0	$0	$0	$58,150
1.11SCE	IC Engine	600	2	$1,400	$0	$4,500	$24,000	$1,500	$24,000	$12,500	$0	$12,500	$0	$0	$0	$0	$0	$0	$80,400
1.94SCE	IC Engine	600	1	$1,400	$0	$4,500	$24,000	$1,500	$12,000	$12,500	$0	$6,250	$0	$0	$0	$0	$0	$0	$62,150
1.96SCE	IC Engine	800	2	$1,400	$0	$4,500	$26,000	$1,500	$24,000	$12,500	$0	$12,500	$0	$0	$0	$0	$0	$0	$82,400
1.95SCE	IC Engine	600	1	$1,400	$0	$0	$24,000	$1,500	$12,000	$12,500	$0	$6,250	$0	$0	$0	$9,000	$0	$0	$66,650
1.14PG_E	IC Engine	400	1	$1,400	$0	$4,500	$22,000	$1,500	$12,000	$12,500	$0	$6,250	$3,000	$2,000	$0	$0	$0	$0	$65,150
0.26PG_E	IC Engine	600	3	$1,400	$0	$4,500	$24,000	$1,500	$36,000	$12,500	$10,000	$0	$9,000	$2,000	$0	$0	$0	$0	$100,900
0.27PG_E	IC Engine	800	1	$1,400	$0	$4,500	$26,000	$1,500	$12,000	$12,500	$10,000	$0	$3,000	$2,000	$0	$0	$0	$0	$72,900
0.25PG_E	IC Engine	400	2	$1,400	$0	$4,500	$22,000	$1,500	$24,000	$12,500	$0	$0	$6,000	$2,000	$0	$0	$0	$0	$73,900
9.00PG_E	IC Engine	800	2	$1,400	$0	$0	$26,000	$1,500	$24,000	$12,500	$0	$12,500	$6,000	$2,000	$7,500	$9,000	$16,000	$43,000	$161,400
9.01PG_E	IC Engine	1,200	3	$1,400	$0	$0	$30,000	$1,500	$36,000	$12,500	$0	$18,750	$9,000	$2,000	$7,500	$9,000	$16,000	$52,000	$195,650
1.68PG_E	IC Engine	1,030	2	$1,400	$0	$0	$24,000	$1,500	$24,000	$12,500	$0	$12,500	$6,000	$2,000	$7,500	$9,000	$16,000	$36,000	$152,400

4.4.2.3 Constructing the Cost of Interconnection Trendline

Based on Table 4-10, it is possible to construct the trendline cost of interconnection for a project under the revised Rule 21 that qualifies for simplified interconnection, supplemental review, or detailed study. The following estimation is based on an 800-kW ICE-driven CHP system in a facility with two meter services.[106] Also, it is assumed that the project is not in PG&E territory and that redundant protection and battery backup are unnecessary. For the scenario of simplified interconnection, it is assumed that there is such a system that is Rule 21-certified, although none is today. The building is assumed to contain some critical processes that require the use of backup electricity during start-up. Finally, it is assumed that certification does not eliminate the need for field engineering but does cut the cost by 50%.[107]

Table 4-11. Estimated Trendline Interconnection Costs (SDG&E and SCE)

	Cost Component	***Simplified Interconnection***	***Supplemental Review Interconnection***	***Detailed Study Interconnection***
Interconnection Study		$800	$1,400	$8,900
Protection at PCC to meet Rule 21	*Equipment*	$0	$6,000	$6,000
	Labor	$0	$18,000	$18,000
Engineering Drawings		$2,500	$4,500	$9,000
Field Engineering		$13,000	$26,000	$26,000
Engineering Peer Review		$1,500	$1,500	$1,500
Commissioning Testing	*Cust/Vend Pre-test*	$7,500	$7,500	$7,500
	Utility test	$5,000	$5,000	$5,000
NGOM		$12,500	$12,500	$12,500
Detailed Study Requirements	*Equip & Eng*	$0	$0	$43,667
Building Shutdown		$10,000	$10,000	$10,000
TOTAL		$52,800	$92,400	$148,067

Costs in for projects in PG&E territory would include over/under frequency/voltage redundant protection and battery backup. Also, these projects have a greater likelihood of detailed study requirements.

From this cost structure (and the variable costs in Section 4.4.2.2), it is possible to create trendline costs for one, two, and three service meter installations of all sizes. But, rather than reproduce the whole table, it is sufficient to say that adding or subtracting a service meter in the facility adds or subtracts approximately $18,250 to the cost; adding or subtracting an engine adds or subtracts approximately $2,000 in engineering costs for the interconnection.

[106] This is selected as typical of RE installations.
[107] This is an estimate; actual costs will not be known until a larger rotating machine is certified and installed.

4.4.2.4 Trendline Versus Baseline Comparison

Do the costs RE has incurred interconnecting under the revised Rule 21 represent a decrease, no change, or an increase in interconnection cost? Has Rule 21 been effective in reducing the equipment and labor costs of interconnection? Answering these questions requires adequate data on the cost of interconnection prior to Dec. 21, 2000.

The best data available (besides RE's first projects) are from "Making Connections," but it lacks sufficient detail to make simple comparisons. The RE trendline shown in Table 4-11 is not directly comparable with the "Making Connections" cost baseline in Table 4-6. It therefore becomes necessary to try an alternative approach: to treat the cost reduction baseline projects as if the revised Rule 21 were in effect to gauge whether cost reductions do indeed result. This is a judgment made with only partial interconnection information because no detailed site information is available. Where no explanation for cost data is available in the "Making Connections" report, the project is removed from the trendline. After following this procedure for each of the cost reduction baseline projects,[108] seven projects are left. After a second pass, three more projects must be removed because they are expanded net energy metering.[109] Although these would undergo initial review, their costs will probably not differ from the baseline. The RE PV projects offer no evidence of anything that would be unlike their treatment under the revised Rule 21. Therefore, the three expanded net energy metering projects must be removed from consideration, which leaves four "Making Connections" projects: one in California and three in other states—all less than 1 MW.

Cost data for "Making Connections" projects is relative, as mentioned previously. That means some costs are expected by the customer and not considered to be excessive; others are not expected and appear to be excessive because they do not fit any expectation. A more accurate assessment of cost-effectiveness could be completed with absolute cost data. It would not be necessary to guess which items of information are "expected" and which are "unexpected." To minimize the arbitrariness of customer expectations, the cost assessments below are based on a single set of unvarying customer expectations applied to all projects. The expectations assume a customer that is technically astute but not conversant with Rule 21—for example, a DG developer from out of state working in California for the first time.

Expected costs (those that the developer would face anywhere) include:

- Protection at the point of common coupling (PCC) for each meter
- Engineering drawings
- Field engineering
- Engineering peer review
- Building shutdown costs
- Commissioning pre-test and utility test.

[108] From "Making Connections" only.
[109] Expanded net energy metering is net energy metering larger than 10 kW.

Unexpected costs (those that are unique to California utility implementation of Rule 21) include:

- The interconnection study cost
- Net generation output meter (for each meter)
- Redundant over/under voltage/frequency protection (PG&E)
- Battery backup (PG&E)
- Detailed study utility fees
- Detailed study drawings
- Detailed study engineering
- Detailed study hardware and installation.[110]

Reconstructing the costs for the following projects is a four-step process:

1. Determine whether the project would require supplemental review or detailed study.
2. Apply trendline costs to each project, assuming (1) treatment in SCE or SDG&E or (2) treatment in PG&E, and divide the costs into expected and unexpected, as above.
3. Determine the estimated total interconnection cost by subtracting the unexpected revised Rule 21 cost from the cost of interconnection reported in the "Making Connections" study.
4. Calculate the cost reduction (or increase).

4.4.2.4.1 Case 15: 75-kW Microturbine in California (ID 15.27)

Developers of this project reported that the IOU involved told them it had no obligation to interconnect and would not be able to because they were not a qualifying facility as defined under the Public Utilities Regulatory Policy Act. Later, the utility agreed to attempt the interconnection under an "experimental" or "test" agreement.[111] The utility indicated that it would require the project developer to pay for a "method of service study required for all ... facilities except (net energy metered) projects." The utility indicated that this could cost up to $50,000 and take 6 months to perform. It also said the study cost was "non-negotiable" and that if the developer did not pay, it would have to abandon the project.[112] Therefore, the developer added a projected cost overrun of $50,000 to the budget.

No 75-kW microturbines are certified, so this project would not qualify for simplified interconnection. A detailed study would not be required for a non-exporting project of this size on a radial feeder. The study cost, then, would be for supplemental review. Assume one service meter, one prime mover, and non-continuous operation (i.e., interruption is OK).

[110] The cost for meetings to discuss detailed studies requirements are left out under the assumption that, now that RE has paid them, others may not have to.
[111] "Making Connections," p. 64.
[112] Ibid.

Baseline ("Making Connections") Costs
Original "Making Connections" cost overrun = $50,000
Assume that 100% of this cost is eliminated under Rule 21, except for the supplemental review fee (considered an "unexpected cost" below and subtracted there).

Revised Rule 21 Costs

Expected Costs
- Protection at the PCC = $12,000
- Engineering drawings = $4,500
- Field engineering = $18,000
- Engineering peer review = $1,500
- Building shutdown costs = $0
- Commissioning pre-test and utility test = $12,500

Unexpected Costs
- Interconnection study fee (Supplemental) = $1,400
- Net generation output meter = $6,250
- Redundant over/under voltage/frequency protection (PG&E) = $3,000
- Battery backup (PG&E) = $2,000

Total revised cost overrun – SDG&E/SCE = $7,650
Total revised cost overrun –PG&E = $12,650

Total cost savings under revised Rule 21 – SDG&E/SCE = $50,000 – $7,650 = $42,350
Total cost savings under revised Rule 21 – PG&E = $50,000 – $12,650 = $37,350

4.4.2.4.2 Case 14: 120-kW Propane Gas Internal Combustion Engine in Hawaii (ID 14.30HI)

As with other baseline projects, the utility asked for protection beyond what the generator provided.

> The utility required synchronizing equipment and parallel operation monitoring for the induction generator that has a reverse power relay installed (already) that shuts down the entire cogeneration plant. This cost was $7,000[113] for equipment that the developer argued was unneeded.[114]

Under the revised Rule 21, utilities do not require synchronizing equipment for induction generators. There is a screen in the initial review to cover starting voltage drop, but in RE's experience, no additional hardware protection has been necessary for its induction generators. However, utilities do not accept prime mover manufacturer reverse-power relays to satisfy Rule 21 unless the equipment is certified. They require a reverse power function at the PCC that may be redundant to the generator protection package.

[113] $7,000 is used as the total "barrier-related cost."
[114] "Making Connections," p. 62.

Assume the ICE is not Rule 21-certified, so the interconnection requires supplemental review. Assume one service meter, one prime mover, and (because the facility is a hospital and the engine is to serve base load) that facility shutdown would interrupt critical operation and that backup equipment is necessary to interconnect.

Baseline ("Making Connections") Costs
Original "Making Connections" cost overrun = $7,000

Revised Rule 21 Costs

Expected Costs

- Protection at the PCC = $12,000
- Engineering drawings = $4,500
- Field engineering = $18,000
- Engineering peer review = $1,500
- Building shutdown costs = $10,000
- Commissioning pre-test and utility test = $12,500

Unexpected Costs

- Interconnection study fee (supplemental) = $1,400
- Net generation output meter = $6,250
- Redundant over/under voltage/frequency protection (PG&E) = $3,000
- Battery backup (PG&E) = $2,000

Total revised cost overrun – SDG&E/SCE = $7,650
Total revised cost overrun – PG&E = $12,650

Total cost savings under revised Rule 21 (SDG&E/SCE) = $7,000 – $7,650 = -$650
Total cost savings under revised Rule 21 (PG&E) = $7,000 – 12,650 = -$5,650

4.4.2.4.3 Case 12: 140-kW Gas Internal Combustion Engine in Colorado (ID 12.33CO)

The issue in this case was power factor.

> The utility initially required the customer to bring the total facility power factor up to 0.90 from an average of 0.86—this would have required the customer to install capacitor banks, or capacitors on many of its inductive loads in the building to correct the power factor. ... In the opinion of the project manager, the requirement should be for the generators to supply their fair share of the VARs (volt-amperes), and no more.

The technical solution provided to this problem under the revised Rule 21 is in Section D2f:

> **Power Factor.** Each Generator in a Generating Facility shall be capable of operating at some point within a power factor range of 0.9 leading to 0.9 lagging. Operation outside this range is acceptable provided the reactive power of the Generating Facility is used to meet the reactive power needs of the Host Loads or that reactive power is otherwise provided under tariff by SDG&E. The Producer shall notify SDG&E if it is using the Generating Facility for power factor correction.

Under the revised Rule 21, the customer can advise the utility that it will use the generator to provide all, or a portion, of the reactive power required to bring the facility power factor up to 0.9 lagging. This may require active control of the generator's reactive power output to maintain a 0.9 value at the PCC. The installation ultimately resulted in an additional charge of $3,000 for equipment that was considered redundant and a $2,000 equipment testing charge that was considered unnecessary.

Under the revised Rule 21, these charges may have been eliminated. The project would require supplemental review, however. Assume one service meter, one non-certified prime mover, and non-continuous operation (interruption OK).

Baseline ("Making Connections") Costs
Original "Making Connections" cost overrun = $3,000
Additional cost ("Making Connections") = $2,000
Total cost overrun ("Making Connections") = $5,000
Assume that 100% of the cost is unnecessary under Rule 21.

Revised Rule 21 Costs

Expected Costs

- Protection at the PCC = $12,000
- Engineering drawings = $4,500
- Field engineering = $18,000
- Engineering peer review = $1,500
- Building shutdown costs = $0
- Commissioning pre-test and utility test = $12,500

Unexpected Costs

- Interconnection study fee (supplemental) = $1,400
- Net generation output meter = $6,250
- Redundant over/under voltage/frequency protection (PG&E) = $3,000
- Battery backup (PG&E) = $2,000

Total revised cost overrun (SDG&E/SCE) = $7,650
Total revised cost overrun (PG&E) = $12,650

Total cost savings under revised Rule 21 (SDG&E/SCE) = $5,000 – $7,650 = -$2,650
Total cost savings under revised Rule 21 (PG&E) = $5,000 – 12,650 = -$7,650

4.4.2.4.4 Case 9: 703-kW Steam Turbine in Maryland (ID 9.43MD)

Like many of "Making Connections" examples, this project met significant resistance from the utility and the whole interconnection environment. Examples include:

- The customer paid for a utility study that the utility then discarded.
- The customer fulfilled the utility technical requirements only to have a new set of technical requirements added on.
- The utility demanded operational control of the generator.
- The project suffered 2 years (and counting) of delay.
- No utility point person was established.
- No dispute resolution process was available.
- There was no public utility commission support for dispute resolution in the case.
- There was no technical procedure for dealing with networks.

All but the last of these issues have been successfully handled in the procedures of the revised Rule 21. There is no clear technical approach at this date for handling network interconnection. It is still a costly and unclear procedure. This has a bearing on the outcome of the cost-effectiveness of the project.

The revised Rule 21 does have an initial review screen that sends all DG projects located on a network to supplemental review. There is no supplemental review technical guidance at this time for networks.

The direct costs incurred in meeting the interconnection standards were $88,000. In addition: "... the project owner paid for $44,000 in fees incurred by consultants for the utility to design the requested network protection. Upon completion, the utility expressed dissatisfaction with the result, and started (over)."[115] It is unclear whether this is equivalent to a detailed study, but, in any case, it is unlikely that an interconnection today would be subject to the cost of an unused study. One other fact is pertinent to this cost reconstruction: "... the building is served by three 13.8-kV distribution feeders." This is interpreted to mean that the building had three utility services, which triples some protection costs.

Assume a detailed study, three service meters, a non-certified prime mover, engineering costs equivalent to three ICEs, and non-continuous operation (interruption OK).

Baseline ("Making Connections") Costs
Original cost overrun ("Making Connections") = $88,000
Additional cost ("Making Connections") = $44,000
Total cost overrun ("Making Connections") = $132,000

[115] "Making Connections," p. 54.

Revised Rule 21 Costs

Expected Costs

- Protection at the PCC = 3 x $12,000 = $36,000
- Engineering drawings = $4,500
- Field engineering = $24,000
- Engineering peer review = $1,500
- Building shutdown costs = $0
- Commissioning pre-test and utility test = $12,500

Unexpected Costs

- Interconnection study fee (supplemental) = $1,400
- Net generation output meters = 3 x $6,250 = $18,750
- Redundant over/under voltage/frequency protection (PG&E) = 3 x $3,000 = $9,000
- Battery backup (PG&E) = $2,000
- Detailed study utility fees = $7,500
- Detailed study drawings = $4,500
- Detailed study engineering, hardware and installation = $43,700

Total revised cost overrun – SDG&E/SCE = $80,350
Total revised cost overrun – PG&E = $91,350

Total cost savings under revised Rule 21 – SDG&E/SCE = $132,000 – $80,350 = $51,650
Total cost savings under revised Rule 21 – PG&E = $132,000 – $91,350 = $40,650

These results and their treatment in SCE/SDG&E or PG&E are summarized in Table 4-12. Two of the four projects produce interconnection cost savings. Statewide average savings are positive and estimated to be approximately 13%. Note that the percentage savings is calculated based on a reduction from the total "estimated Rule 21 interconnection cost," not the reduction of unexpected cost.

Table 4-12. Results of "Making Connections" Case Studies Estimated Treatment Under Rule 21

Case #	*Assumed Rule 21 Utility*	*Technology*	*kW*	*MC Cost Overrun*	*Saved by Rule 21*	*MC Cost Overrun $/kW*	*Estimated Rule 21 IC Cost*	*Estimated Unexpected IC Cost*	*Total Cost Savings*	*Cost Savings $/kW*	*Percent of Cost Reduction*
Case #15	SCE/SDG&E	NGMT	75	$50,000	$50,000	$667	$56,150	$7,650	$42,350	$565	43%
	PG&E						$61,150	$12,650	$37,350	$498	38%
Case #14	SCE/SDG&E	Propane IC	120	$7,000	$3,500	$58	$66,150	$7,650	($650)	($5)	-1%
	PG&E						$71,150	$12,650	($5,650)	($47)	-9%
Case #12	SCE/SDG&E	NGIC	140	$5,000	$5,000	$36	$56,150	$7,650	($2,650)	($19)	-5%
	PG&E						$61,150	$12,650	($7,650)	($55)	-14%
Case #9	SCE/SDG&E	Steam turbine	703	$132,000	$132,000	$188	$154,350	$75,850	$56,150	$80	27%
	PG&E						$165,350	$86,850	$45,150	$64	21%
Statewide average										**$135**	**13%**
SCE/SDG&E average										**$155**	**16%**
PG&E average										**$115**	**9%**

4.4.3 Trendline Process Improvement

The baseline for the process improvement metric is the Ten-Point Action Plan contained in the NREL "Making Connections" report, shown in Table 4-7. To the extent these are fulfilled in the revised Rule 21, progress is being made toward the process improvement objective.

Table 4-13 shows how each of the ten points are or are not fulfilled by the revised Rule 21. A brief description of each point follows.

Table 4-13. Fulfilling the Process Improvement Objective

Barrier Types	*Baseline conditions*	*Met in Trend line?*	*% Met*	*Rule 21 Code*
Technical	1. Adopt uniform technical standards...	Y	100%	Section D, I, J, P1547
Technical	2. Adopt testing and certification procedures...	Y	100%	Section J
Technical	3. N/A	N/A	N/A	N/A
Business Practice	4. Adopt standard...practices for...utility review.	Y	50-100%	Section C & I
Business Practice	5. Establish standard...interconnection agreements.	Y	100%	Standard Agreements
Business Practice	6. Develop tools for utilities to assess...[DER]...on the grid.	Y	50%	FOCUS-II Task 2.2
Regulatory	7. Develop...regulatory principles compatible with [DER]...	Y	100%	Objectives of FOCUS-I
Regulatory	8. Adopt regulatory tariffs and utility incentives...	Y	100%	Interconnection tariff
Regulatory	9. Establish expedited dispute resolution processes...	Y	100%	Section G
Regulatory	10. Define the conditions necessary for a right to interconnect.	Y	50%	Section B.1
Total			83%	

4.4.3.1 Adopt Uniform Technical Standards

4.4.3.1.1 California Context

Uniform technical standards have been the cornerstone of the revised Rule 21 effort from the start. Although the Rule 21 revision effort was contemporaneous with the Institute of Electrical and Electronics Engineers (IEEE) national technical standards development (in the P1547 Working Group), it was never the intent of the California technical interconnection group to create a separate California "standard." In fact, it was implicit that when the national standard was released, Rule 21 would embrace it. Meanwhile, Rule 21 worked out many of the procedural details of technical implementation of interconnection requirements.

The IEEE Standards Board approved IEEE 1547 Standard for Interconnecting Distributed Resources With Electric Power Systems on June 12, 2003. The IEEE standard was very technical, limited in scope, and did not cover a wide range of issues—such as grid effect evaluations—addressed in Rule 21. In November 2003, the California interconnection working group began the process of reconciling its technical requirements (Section D), the initial review (Section I), and certification and testing (Section J) with IEEE 1547.

4.4.3.1.2 RE Experience

Despite the relative standardization of technical issues, many technical issues are beyond the specificity of Rule 21, and these remain to the discretion of the utility. For example, SCE and SDG&E do not require redundant over/under frequency and over/under voltage protection, but—without official interim utility approval—allow the RE meters or prime mover protection package to cover redundant protective measures. PG&E requires purchase of additional relays to provide redundant protection.

4.4.3.2 Adopt Testing and Certification Procedures

4.4.3.2.1 California Context

Section J of the revised Rule 21 covers procedures for testing and certification for interconnection devices.

4.4.3.2.2 RE Experience

So far, other than its PV installations, none of the protective equipment RE uses has been certified under the revised Rule 21.[116] One packager of RE's ICEs has applied for certification but has not yet received it. For these reasons, RE installations are consistently stopped in the initial review screen for certified equipment. Because it fails this screen, RE must go through supplemental review[117] and pay additional engineering and time delay fees as a result. Testing procedures also do not negate the need for a field commissioning test, which has a significant cost.

4.4.3.3 Accelerate Development of Distributed Power Control Technology and Systems

The development of control technologies is not within the scope of the subcontract and is not a part of the California interconnection discussion of Rule 21 itself. Therefore, this point is not applicable as a measure of progress toward the objective. However, RE believes that it is within the control technologies that the greatest progress toward standardization and plug-and-play can be met.

4.4.3.4 Adopt Standard Practices for Utility Review

4.4.3.4.1 California Context

Section C of Rule 21 establishes standard fees and timelines for utility administration of the interconnection process. Rule 21 Section I lays out in detail how the utility is to review each interconnection and the set of steps, or "screens," each interconnection must pass to qualify for simplified interconnection. If the interconnection fails a screen or screens, it enters supplemental review. The interconnection working group also established a less formal guideline for supplemental review that describes some of the steps and processes that should occur.

[116] Technically, the PV inverters have been Underwriters Laboratories-listed but not Rule 21-certified.
[117] It is likely utilities might not pass RE on the line section screen, either. This is more difficult to contest.

Because each of the IOUs is under CPUC jurisdiction for the Rule 21 tariff, Section C and Section I function in California as a standard set of requirements for utility review. Although the supplemental review guideline does not have the authority of regulatory jurisdiction, it does serve as a template for how a utility should carry out the supplemental review process.

4.4.3.4.2 RE Experience

There are sections of Rule 21 that do not spell out the technical details of implementation and so give discretion to the utilities to make technical determinations in the field. Although the rule is nearly identical in the three IOU tariff letter implementations, there is an uneven application among utilities. It is unlikely Rule 21 can remedy this. RE has had to solve it through expensive ad hoc meetings with the utilities.

4.4.3.5 Establish Standard Interconnection Agreements

4.4.3.5.1 California Context

SDG&E, SCE, and PG&E have filed tariffs for interconnection agreements. With a few exceptions, the agreements are identical. For a description of variations, please see Section 6 of the California Interconnection Guidebook.[118] SDG&E and SCE have the same agreements:

- Customer non-export ("Generating Facility Interconnection Agreement")
- Customer inadvertent export ("Generating Facility Interconnection Agreement [Inadvertent Export]")
- Customer agreement for third-party installation and operation ("Customer Generation Agreement")
- Third-party inadvertent export ("Generating Facility Interconnection Agreement [3rd Party Inadvertent Export]")
- Third-party non-export ("Generating Facility Interconnection Agreement [3rd Party Non-Exporting]").

The primary difference of the interconnection agreements of PG&E, when compared with the agreements of SCE and SDG&E, is that there is no accommodation for inadvertent export. There is no customer inadvertent export agreement, and there is no third-party inadvertent export agreement. PG&E, then, has three agreements:

- Customer non-export ("Generating Facility Interconnection Agreement")
- Customer agreement for third-party installation and operation ("Customer Generation Agreement [3rd Party Generator on Premises] [Non-Exporting]");
- Third-party non-export ("Generating Facility Interconnection Agreement [3rd Party Non-Exporting]").

[118] http://www.energy.ca.gov/distgen/interconnection/guide_book.html

4.4.3.5.2 RE Experience

The lack of an inadvertent export agreement in PG&E territory is a serious obstacle for RE operations. Because RE has not yet installed load-following capabilities (because of shortcomings of prime mover controller devices), it must shut down when building load drops below generation. This is an issue for:

- RE revenue stream
  Electric revenues are interrupted.
- RE operations
  The engine must be restarted, sometimes manually.
- RE maintenance
  Stopping and starting the engine increases maintenance costs and failure rates.

4.4.3.6 Develop Tools for Utilities to Assess Distributed Power on the Grid

4.4.3.6.1 California Context

The contract with the energy commission (#500-00-013) includes a task to "select and monitor twelve (12) DG projects." The scope of work document states:

> The purpose of this task is to improve the cost-effectiveness of DG interconnection while maintaining the safety and reliability of the grid. This will be accomplished by gaining precise technical feedback on what effect interconnecting DG has on the local distribution grid. The … team will provide data, analysis, and recommendations to the Energy Commission for its use and for the Interconnection Workgroup.

At present, 12 sites have been selected, and instrumentation has been installed.

There are several reasons this effort is judged to have fulfilled 50% (rather than 100%) of the "Making Connections" action point. First, monitoring and demonstrating that 12 generators are not harming the grid only begins to make a case for statistical reliability; it does not demonstrate that the 13th or some subsequent generator will not cause problems. Second, this study does nothing to demonstrate the benefits to the grid of an interconnected onsite generation resource. At this time, anecdotal evidence seems to indicate that utilities and CAISO have little confidence in the real benefits to the grid resulting from multiple DG facilities operating in parallel.

4.4.3.6.2 RE Experience

There is no effect on RE operations.

4.4.3.7 Develop Regulatory Principles Compatible With Distributed Power

4.4.3.7.1 California Context

One of the regulatory "quiet revolutions" the revised Rule 21 initiated was the idea of performance-based interconnection requirements. The old Rule 21—different for each of the IOUs—prescribed and proscribed technological solutions to the challenges of safe and reliable interconnection of DG. For example, in certain situations, expensive electromechanical relays were required; digital relays that did the same thing at a lower cost were unacceptable because they did not meet the letter of the rule. The revised Rule 21, on the other hand, sets performance standards and allows any technology that meets those standards to be used. This approach ensures the safe and reliable operation of the grid and drives technological innovation. Each new model requires certification regardless of any certification of previous models. Certification may be simpler if a new uncertified model is based on a previously certified design. Performance-based interconnection requirements in revised Rule 21 are described in detail in the final report.[119]

The objectives elaborated in the report include a number of "principles compatible with DER":

- Facilitate consensus on the technical issues of interconnection.
- Make interconnection a single uniform process that is internally consistent and predictable statewide.
- Provide a method of simplified interconnection.
- Explore the role of advanced communications and metering for interconnection scheduling and dispatch.
- Replace prescriptive interconnection requirements with performance-based interconnection requirements.
- Lower the cost of interconnection.
- Fulfill the need for interim standards.
- Address safety issues.
- Define the scope and feasibility of type testing.
- Accelerate the adoption of DG by training and informing government agencies.
- Define the scope of technologies covered by Rule 21.
- Make changes to utility tariffs proceeding from interconnection rules.
- Facilitate interconnection of small units.
- Eliminate utility discretion of study fees.

[119] See "Objective 5: Replace the Current Prescriptive Interconnection Requirements With Performance-Based Interconnection Requirements" in the final report at http://pier.saic.com/PDF/P600-01-006.pdf. February 2001, pp. 24–39.

This point of the action plan is only fulfilled for interconnection, not for any other tariff. It is 100% fulfilled with the present effort.

4.4.3.7.2 RE Experience

Although the revised Rule 21 is more "compatible with DER" than the old Rule 21, in practice it allows exceptions that become issues for RE operations—such as the lack of certified equipment available in CHP applications. Also, RE and DER providers continue to face other regulatory challenges outside interconnection.

4.4.3.8 Adopt Regulatory Tariffs and Utility Incentives

4.4.3.8.1 California Context

Like the previous item, this seems concerned with many issues outside interconnection. For example, utility incentives for certain forms of DG exist in California. They have a large effect on project economics and make it considerably easier for an end user to justify the installation of DG. However, these incentives are not an interconnection issue.

Related tariffs that affect DG project economics (such as standby rates and exit fees) also have nothing to do with interconnection. It is clear that the interconnection work has done little to foster these other tariffs. However, it is worth noting that the magnitude and depth of other regulatory programs that support DG demonstrate legislative and regulatory intent to facilitate the deployment of DG. This adds considerable weight to the argument that the CPUC should continue to press utilities to make interconnection simpler, easier, and more cost-effective.

The only tariff considered in this report that affects interconnection cost-effectiveness is the revised Rule 21, so this point is 100% fulfilled.[120] Evidence of fulfillment is the completed rule itself.

4.4.3.8.2 RE Experience

Some non-interconnection incentives, such as the SGIP, have been quite useful.

4.4.3.9 Establish Expedited Dispute Resolution Processes

4.4.3.9.1 California Context

Section G of the revised Rule 21 has a two-step process of dispute resolution:

1. The dispute is reduced to writing—the so-called "dispute letter"—and submitted to the other party along with suggestions for resolution. Disputants are required to meet within 45 days of the date of the letter to work out a resolution.
2. If no resolution emerges within the 45-day timeframe, the dispute may be put before the CPUC at the request of either party.

[120] Although other tariffs affect project cost-effectiveness, Rule 21 is considered most relevant to the cost of interconnection.

Although 45 days may not be what the writers of "Making Connections" had in mind when they referred to an "expedited" process, it is considerably better than an unbounded process in which disputes may take a year or more to resolve.

4.4.3.9.2 RE Experience

RE has been forced to go to "dispute resolution" under Rule 21 once, with PG&E. The issue was over network interconnection, a subject on which Rule 21 is ambiguous. Although it is unfortunate the parties were unable to reach resolution without dispute resolution, once the process was entered into, the parties were able to work well and with a strong commitment from management to resolve the issues. Because the actual resolution is still pending, details will be provided in another report or addendum.

4.4.3.10 Define the Conditions Necessary for a Right to Interconnect

4.4.3.10.1 California Context

It is possible to consider the revised Rule 21 as itself the complete set of conditions necessary for a right to interconnect. This is true, at least insofar as the rule encompasses all requirements for interconnection. Every provision of the revised Rule 21 is meant to ensure the safety and reliability of the electrical system while allowing interconnection to proceed. The technical requirements in Section D are a particularly clear example of the efficacy of the performance-based interconnection requirements to establish limits that may be achieved as the market sees fit. By far the most compelling statement in favor of a *rationally pre-*determined *right* (as opposed to a right *arbitrarily* determined at the time—by fiat) is this clause from Section B.1:

> [The utility] shall apply this Rule in a non-discriminatory manner and shall not unreasonably withhold its permission for a Parallel Operation of Producer's Generating Facility with [the utility's] Distribution System.[121]

But the statement falls over easily: A reasonableness standard does not exist for interconnection. And although Section D is constructed to cover many technical situations, others arise that are not specifically defined. In those cases, the interconnection applicant will find himself in the unfortunate position of trying defend his position against the utility's bureaucracy and propensity to make a determination in its own favor.

It is possible, under the revised Rule 21, for the utility to declare that *all* projects require a detailed study. The cost of the study alone, absent the costs of any additional technical requirements the completed study may call for, can be enough to discourage a customer and cause him to abandon the DG project effort.

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[121] California Interconnection Rule 21, Section B.1.

When the revised Rule 21 went into effect, it was difficult for utilities to meet the 10-day timeline for initial review. There is anecdotal evidence that at least one utility initially solved this problem by determining that every project required a detailed study. Many projects were withdrawn in that utility's service territory during the first year the rule was in effect. Other utilities, meanwhile, met the commitment by declaring applications were never complete; therefore, the 10-day clock never officially started.

Given this rocky start, it is surprising that interconnection in California has attained the success it has. Since that rocky beginning, the utilities' willingness to cooperate has improved; hence, the Rule 21 progress report gets a passing grade—not because of Rule 21 in and of itself but because the parties involved have committed to making it work. However, there is still much room for improvement.

4.4.3.10.2 RE Experience

Despite the best intentions of the framers of the revised Rule 21, the future success of the rule is not assured because no *right to interconnect* has been firmly established. Section B.1. makes the attempt, though, and wins a partial score. But Rule 21 gives RE little assurance of a right to interconnect—because it might be called into a detailed study because of a concern by the utility (whether rational or not) over RE's effect on the line segment or electric feeder.

4.4.4 Trendline Simplified Interconnection

4.4.4.1 California Context for Simplified Interconnections

Recall from Section 4.3.5 that supplemental review and initial review do not exist in the baseline. Any projects that received authorization to interconnect did so only after detailed study. Many baseline projects, as noted, did not pass at all. Therefore, progress toward the simplified interconnection objective is counted as a decrease in the number of projects not passing and, of those passing, an increase in the ones passing after initial or supplemental review.

In fact, the Trendline under the revised Rule 21 shows dramatic improvement over the baseline. In the baseline, more than 70% of projects required detailed study; the rest were withdrawn, suspended, or disconnected.[122]

In contrast, SDG&E has more than 80% passing after supplemental review,[123] almost 17% passing after initial review, and just 2% withdrawn.

SCE has nearly as many projects passing after initial review as supplemental review and has only one detailed study. More than 10% of SCE's projects are suspended, however.[124]

[122] Disconnections are not shown here because there were none in the trendline.

[123] Given the initial review requirements for the use of certified equipment and the relatively small but growing list of certified equipment, the low percentage of simplified interconnections is to be expected. Many simplified interconnections are likely passing by means of interim utility approval.

[124] This includes only projects that are suspended and not resumed by the customer.

PG&E shows more projects passing after initial review than supplemental review. After 3 years, however, about 35% of its project applications have been withdrawn, and more than 10% have required detailed study.[125]

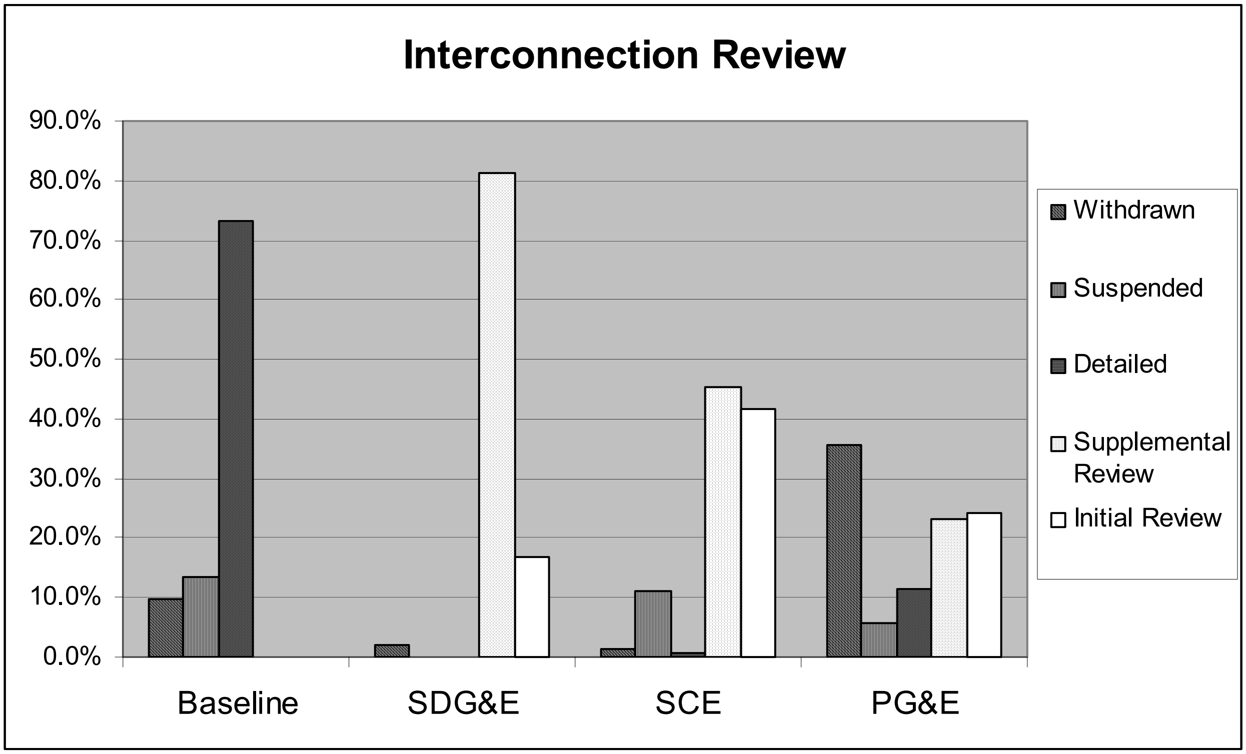

Figure 4-12. Simplified interconnection progress

Many of the projects that withdrew applications in PG&E territory did so during 2001 and 2002, when the program was in its early stages. There appears to be a reduction of the withdrawal rate more recently. However, the number of detailed studies among projects not yet online has increased from 10% to 22%.[126]

If withdrawal, suspension, and detailed study are considered indicative of a failure to progress toward the simplified interconnection objective[127] and initial and supplemental review are considered indicative of success, a picture emerges. Figure 4-13 shows the results and compares the baseline of the old Rule 21 to the trendline of the revised Rule 21.

[125] This does not include projects not yet online.
[126] One plausible explanation for this is that more of PG&E's overall load is served by network distribution systems that require technical review beyond what is needed for radial systems.
[127] Of course, any interconnection that is made is a success—even if it needs a detailed study. The point, though, is to contrast *progress* toward simplified interconnection.

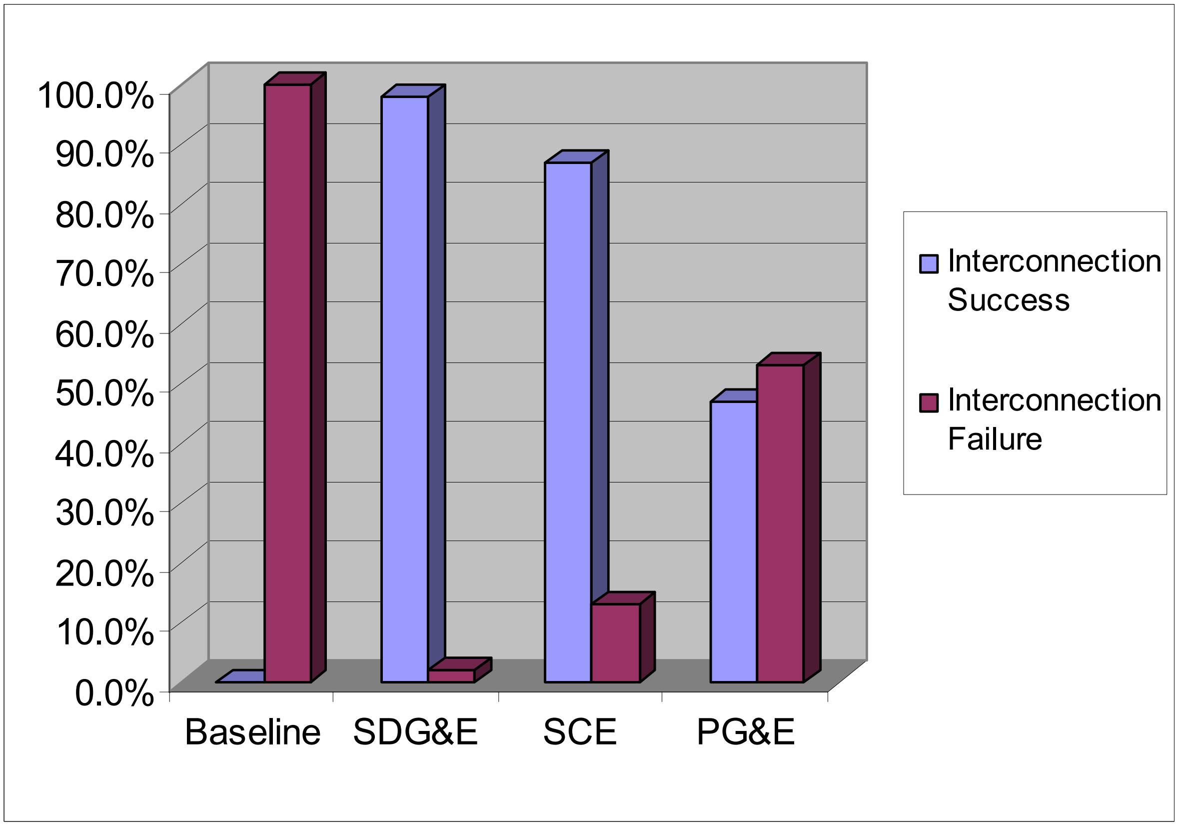

Figure 4-13. Simplified interconnection success and failure

4.4.4.2 RE Interconnections

RE has submitted applications for 25 projects within the territories of the three major California IOUs. Three have been approved as simplified interconnections, three have been approved as detailed studies, and 19 have been approved after supplemental review. These are summarized in Table 4-14.[128]

The projects that received simplified review (two in SCE territory and one in SDG&E territory) are net energy metering projects that were given expedited review because their inverters are certified.

None of RE's ICE projects qualified for simplified review because the generator is not certified under Rule 21. In all three utility areas, these projects qualify after supplemental review.

[128] One supplemental review awaits final utility approval.

The exceptions are in PG&E territory, where three projects have required detailed study. These projects have gone beyond supplemental review because they are interconnecting with a network distribution system. Because very few network-type interconnections have been approved, the utilities are concerned about safety and reliability of the distribution system. PG&E requires additional hardware because network protectors are old and not designed for reverse or low power flow (which might occur if a DER is serving most of a customer's load on a network), concern about short circuit contribution[129] from the generator, and little practical experience and resource knowledge for generation on distribution systems in general and network distribution systems in particular.

For these reasons, utilities have been exceedingly cautious about allowing interconnections on network systems. PG&E has network systems in San Francisco and Oakland (high-density and high load-areas), SDG&E has no network systems, and SCE has a small network in Long Beach.

Table 4-14. Level of Utility Review of RE Interconnections

Project ID	Technology	kW	Utility	Level of Review
0.00SDGE	PV	110	SDG&E	Simplified
0.09SDGE	ICE	600	SDG&E	Supplemental
0.08SDGE	ICE	400	SDG&E	Supplemental
0.06SDGE	ICE	400	SDG&E	Supplemental
0.05SDGE	ICE	400	SDG&E	Supplemental
0.07SDGE	ICE	800	SDG&E	Supplemental
0.42SDGE	ICE	800	SDG&E	Supplemental
0.67SDGE	ICE	600	SDG&E	Supplemental
0.00aSCE	PV	110	SCE	Simplified
0.00bSCE	PV	110	SCE	Simplified
0.27SCE	ICE	400	SCE	Supplemental
0.08SCE	ICE	1000	SCE	Supplemental
0.05SCE	Microturbine	60	SCE	Supplemental
1.02SCE	ICE	200	SCE	Supplemental
1.11SCE	ICE	600	SCE	Supplemental
1.94SCE	ICE	600	SCE	Supplemental
1.96SCE	ICE	800	SCE	Supplemental
1.95SCE	ICE	600	SCE	Supplemental
1.14PG_E	ICE	400	PG&E	Supplemental
0.26PG_E	ICE	600	PG&E	Supplemental
0.27PG_E	IC Engine	800	PG&E	Supplemental
0.25PG_E	IC Engine	400	PG&E	Supplemental
9.00PG_E	IC Engine	800	PG&E	Detailed
9.01PG_E	IC Engine	1200	PG&E	Detailed
1.68PG_E	IC Engine	1030	PG&E	Detailed

[129] Short circuit contribution ratio is defined in Rule 21 as the ratio of the generating facility's short circuit contribution to the short circuit contribution provided through the distribution system for a three-phase fault at the high-voltage side of the distribution transformer connecting the generating facility to the distribution system.

4.5 Results, Conclusions, and Possible Improvements

4.5.1 Interpreting the Results

4.5.1.1 Technical Effect of Rule 21 Changes

4.5.1.1.1 Statewide Effect

The “Making Connections” report has a 10-point action plan to remove interconnection barriers from the marketplace for DER. Although this plan was not consulted expressly during the early working group sessions of the revised Rule 21 effort, California’s interconnection rule achieves nearly all of the points of the plan. The revised Rule 21 eliminates many of the interconnection barriers identified in the “Making Connections” report.

The simplified interconnection objective has been fulfilled to a remarkable degree as well. Nearly 80% of utility interconnections since the start of the revised Rule 21 have been completed successfully, with about 14% withdrawn and 7% suspended. Seventy-four percent of those interconnections have been through initial or supplemental review. More than 31% of interconnections have required only initial review prior to receiving permission to interconnect.

4.5.1.1.2 Effect on RE Operations

By interconnecting under the revised Rule 21, RE does reap the benefits of procedural improvements. However, RE has not enjoyed simplified interconnection and may not be able to do so in the future. Although it is possible that multiple ICE manufacturers will have their units Rule 21-certified, there is still the issue of 15% line section load that would appear to throw RE into supplemental review. Thus far, only SDG&E has been cooperative in working with RE to calculate line section load; the others have simply said that RE is over 15%. None of the utilities has allowed RE to perform independent verification. Finally, the utilities do not give equal treatment under Rule 21 because it lacks technical specificity in key areas. This is not easily remedied because of the myriad characteristics that are possible in regard to the site and its relation to the distribution system.

4.5.1.2 Cost Effect of Rule 21 Changes

4.5.1.2.1 Statewide Effect

The time reduction objective has succeeded to an extraordinary degree. The days for all three IOUs to interconnect has dropped an average of 39% per year, from 389 days in baseline year 2000 to 78 days in 2003. The days past customer-requested online date has dropped 41% per year, from 173 days in 2000 to just 35 days in 2003. It is impossible for this rate of reduction to continue; it will likely level off in 2004.

Results of the cost reduction objective are mixed and moderate. There are no baseline data for units more than 1 MW. For units smaller than 1 MW, it appears there is a reduction of interconnection cost of about 13% statewide, which amounts to about $135/kW.

4.5.1.2.2 Effect on RE Operations

The reductions of time to interconnect achieved statewide are not as evident in RE operations. It still takes 200–425 days on average for RE to interconnect a facility. A range of 8–16 months for interconnection should not be considered an expedited process. There has been some reduction of time in RE projects, but these were due to improvements in package delivery by RE and processing by the utilities.

It is clear that RE interconnections would cost more absent the revised Rule 21, but it is not possible to say how much more—at least not with certainty. Interconnection is still a significant cost: $130–$160/kW. Overall cost can be as high as $120,000 for a detailed study project and is well more than $50,000 for the simplest radial system.

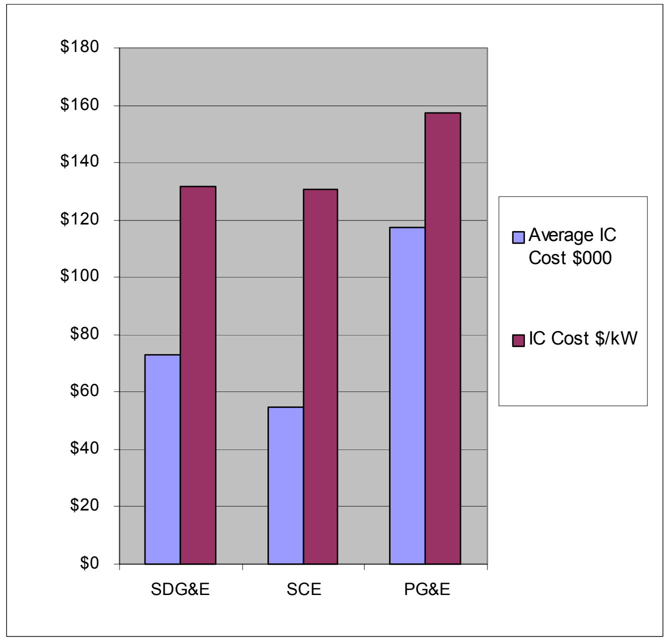

Figure 4-14. RE Cost of Interconnection

4.5.1.3 Rule 21 Effect on Municipal Utilities

There are no data available at this time that confirm or deny progress of the revised Rule 21 in cost-effectiveness in municipal utility districts.

4.5.2 Conclusions

The revisions to Rule 21 have made dramatic improvements in the ability to interconnect in California. For example, there have been significant procedural improvements. Simplified interconnection has helped small certified units interconnect quickly and less expensively, and the number of simplified interconnections is surprisingly high. Time delays have decreased dramatically statewide.

There is a good chance that RE will be able to interconnect with a certified genset in the future, though it is not able to do so now. But the question remains whether a certified genset will qualify it for simplified interconnection without tools for estimating and handling the 15% line section screen.

In regard to cost reduction, the costs the marketplace should expect to pay are becoming more certain. Whether costs to fulfill the requirements represent a real reduction from the interconnection costs of projects prior to 2001 remains an open question.

4.5.3 Possible Improvements in Rule 21 Cost-Effectiveness

One of RE's primary concerns about interconnection in California is the significant differences in Rule 21 implementation that still exist among utilities. Despite the best efforts of the framers of Rule 21, utilities still can exercise discretion in the field to effectively block interconnection or make requirements they deem necessary and prudent to business practices. It is the willingness of the utilities to cooperate that has allowed the revised Rule 21 the level of success it enjoys today, but beyond a level of technical detail, there is little in the rule that guarantees a generator a right to interconnect. If this can be addressed, it should be, but it is not clear whether it is possible to specify the level of detail necessary to cover the realm of interconnection configurations in the field.

The other area for improvement is network interconnection. RE is working closely with PG&E to develop standards and guidelines for network interconnection. These are expected be in place on an interim basis in early 2004. After review and revision, they can be incorporated into Rule 21 in 2005.

5 Survey of Practical Field Interconnection Issues (D-2.07)

5.1 Executive Summary

Since its inception, RE has implemented more than two dozen CHP projects—some with greater degrees of success than others. Many of the early projects required design modifications and rework even after perceived completion. Over the course of 3 years, design and construction have improved, as have the operating results. The resolution of technical obstacles has contributed to improved RE processes. These “lessons learned” have been identified and discussed in prior sections as examples of RE best practices.

The best practices are to:

- Conduct due diligence
  Conduct a thorough site investigation before any design effort is started. Site-specific technical issues and existing facility problems must be identified for the design stage to be successful.

- Design from lessons learned
  The designers and contractors must have proven experience (mechanical, electrical, control, and structural) with successful CHP installations.

- Meet utility requirements
  The electrical designer should have a thorough understanding of local utility interconnection requirements. Early communication with the utility should be established to identify and resolve any issues and make sure all requirements can be met at a reasonable cost.

- Implement quality assurance
  Insist the designers and contractors use industry-standard quality assurance and quality control procedures. Use high-quality equipment.

- Plan start-up and commissioning.
  Employ an experienced start-up and commissioning team. Have and use a well-written start-up and commissioning plan.

5.2 Introduction

5.2.1 Purpose

The purpose of this task is to report technical field issues not caused by regulatory factors encountered at RE's installations. Technical issues include problems in electrical and thermal interconnection design, site layout, operation, and system start-up. In each case, problems were documented, and solutions—including recommendations for future improvement—were reported. The result is a collection of best practices—specific strategies RE has developed to improve thermal and electrical interconnection time- and cost-efficiency.

5.2.2 Background

RE has encountered technical obstacles to the interconnection of electrical and thermal systems in the design and installation of CHP equipment in some retrofit projects. An analysis of more than 20 projects identified obstacles and illustrated how they were overcome. To protect confidentiality, the results are presented as general observations and lessons learned.

5.2.3 Project Assessment, Design, and Implementation

Before a CHP project can be designed, a field investigation must determine the type of design and equipment required. This investigation should cover all areas of design and include site access and available space; noise restrictions; appearance; structural, electrical, and mechanical issues; and local code requirements. A project's success depends on how these are addressed during the design phase.

Another factor important to the success of a project is the skill and experience of the designers and contractors. The developer should work with designers that have experience integrating CHP electrical, mechanical, and structural systems with building systems. Designers with standard commercial/industrial experience typically are not familiar with the special requirements of utility-paralleled generators. Conversely, designers with typical utility-paralleled generator experience are often not familiar with the requirements of interfacing with building systems. These concerns apply equally in the selection of contractors.

5.3 Technical Field Issues

5.3.1 Aesthetics/Appearance

In many cases, the customer or local planning authority has specific requirements to improve the appearance of the installation to the public or neighbors. These can be as simple as a chain-link fence with colored slats to an architecturally designed enclosure. The requirements are generally related to the location of the installation and the surrounding neighborhood.

The added costs for architectural treatment can be considerable. For example, a 20-foot-by-60-foot-by-10-foot finished enclosure can cost more than $30,000. In the quest to find a suitable location for a CHP plant, the initial site survey is often performed by a mechanical engineer. The result is that architectural issues are often not considered until after the location decision has been made. When this is the case, the cost of delay and additional engineering can be more than the cost of the enclosure—in effect eliminating any choice. It is incumbent on the developer to make certain architectural issues are addressed in the siting decision.

5.3.2 Noise

Although a well-designed CHP system is quiet, an operating CHP plant can produce noise and vibration above typical ambient levels. Important factors to consider are the location of the plant relative to mechanical equipment and work, living, and public spaces and the time of day of operation.

Vibration is as important as noise, and in many cases, it is a contributing factor to noise. When vibration is a consideration, the entire system must be isolated. It is common to overlook a small component to save money, yet that component will convey vibration as effectively as a larger one.

The cost of retrofitting to abate noise and vibration can render a project uneconomic. In many cases, noise problems can be addressed as part of the appearance treatment. A properly designed wall can resolve both. An acoustic assessment of the site and facility is recommended to establish a baseline and will be required to determine an adequate solution if mitigation measures are required. Even if mitigation measures are not required by code, the baseline is important if complaints are made after the operation of the system commences.

5.3.3 Site Constraints

Physical constraints must be identified early in the site investigation. These constraints include access to the site, parking, laydown areas for construction, space for new equipment, access to and clearance for new and existing equipment, and working space for maintenance. Some space requirements, such as the working clearances of the National Electric Code, are set by code. It is important to have the operations and maintenance departments visit the site and review the design layout prior to final approval to identify and account for these considerations. Quite often, what may appear to be a capital savings design approach is offset by increased operations and maintenance costs related to accessibility constraints.

5.3.4 Electrical Design

Sufficient "homework" should be done to identify operational issues that could affect electrical design. Gather as much information about the facility's electrical consumption and usage patterns as possible. Fifteen-minute interval data for one year should be considered minimum. Review of customer utility bills may be a first screen, but it is not sufficient for design work. When utility interval data is not available, the facility's building management or energy management software is often a good source of data. In addition, engineering logs or readings from clamp-on recorders are good sources of information.

After gathering data, a thorough analysis of facility loads and profiles and the expected operating modes of the CHP plant should be performed. For example, if the generator is to operate under export control, a sudden reduction in load (from a large motor stopping) could activate the utility export control protection. Such issues have to be addressed early in the project to incorporate mitigating measures into the design.

Technical issues of electrical design are of two types: integrating generation equipment with the facility electrical system and meeting the utility's interconnection requirements. This is a natural division. The first deals with "good engineering practice" and code requirements, and the other deals with utility requirements. There may be some overlap, especially if modifications are needed to meet utility interconnection requirements.

5.3.4.1 Integration With Facility

Integrating the generator electrical equipment into the facility electrical system can be challenging. The designer has to deal with the condition of existing equipment, the availability of space, where and how to tie in the generation, the addition of devices to the switchboard, and equipment ratings. The design should be based on electrical codes applied locally. It must be approved by the local code authority through the plan check process and be capable of receiving final inspection sign-off.

5.3.4.1.1 Due Diligence

Due diligence is especially important in older facilities. A facility's electrical system may not have been regularly maintained, or compatible electrical equipment may no longer be available. Modifications that are not to code could have been made, or the installation of CHP equipment could trigger an upgrade to bring equipment into compliance with codes.

An initial site investigation should identify problems with existing equipment. If problems are found, the owner should be notified to correct them before any work is started. It is highly recommended that a planned maintenance service and inspection be performed prior to detailed electric design.

5.3.4.1.2 Tie-In Point

Another result of the initial site investigation is the identification of the electrical tie-in point. This is where the generation output will be supplied to the facility. The designer must determine if there is space on the existing switchboard for a new breaker or switch. If not, the designer must determine if the bus can be tapped or if a new bus section is required.

If there are multiple electrical services, then there may be multiple tie-in points. The existence of multiple utility meters (services) can be a cost driver for the project. For example, the customer's utility bill may show a total demand of 2 MW. However, upon examination, three metered services may be found: one with a peak demand of 1,000 kW, one with 700 kW, and one with 300 kW. These services require substantially different engine-genset sizing and equipment.

5.3.4.1.3 Space Requirements

Some facilities lack space. Suitable CHP plant locations include roofs, basements, parking areas, and mechanical rooms. Facility space for a potential CHP installation is often storage because it is easier and less costly to find additional storage space than to settle on a less-than-favorable CHP plant location. If there is simply no space near the tie-in point, an expensive bus tap may be required from the existing switchboard to a new one outdoors or to another room.

There also must be sufficient space for working clearances required by code or the utility. This is typically 36 inches or 42 inches in front of the equipment. In addition, there are code requirements for room access that depend on the number and placement of access doors. Thought must also be given to the location of metering and protective equipment. In some cases, the main breaker or disconnect switch needs to be within visual sight of the CHP plant.

5.3.4.1.4 Addition of Devices

To comply with utility protection requirements, it may be necessary to add devices to the existing switchboard. This can present design challenges if the existing equipment is not designed to accommodate such devices.

Of particular interest is the addition of current transformers (CTs) at the PCC for export power control. To monitor power flow across the PCC, a means of measuring the current flow is needed. CTs transform the relatively high current levels (hundreds to thousands of amps) at the PCC to lower levels (typically 5 A maximum) for use by relays and transducers. Unless the switchboard was built to accommodate CTs, it may be difficult to locate a section of the switchboard busbar with sufficient clearance to mount the CTs. One solution is to have the utility relocate the customer revenue meter and CTs. The utility meter section will then be available for placing the protection CTs. Depending on the situation, the utility's charge can run from a few thousand to tens of thousands of dollars.

5.3.4.1.5 Equipment Loading and Ratings

A concern of the designer, and the code authority plan checker, is the effect the generation project has on equipment loading and ratings. Adding a generator to a switchboard will change the current (amp) loading on the switchboard. Generally, the loading will be higher at start-up and until the generator begins to pick up building load. If an induction generator has been selected, the initial starting current can be substantially higher than the running current unless a soft-start configuration has been selected. The generator will also increase the short-circuit current level on the switchboard in the event of an electrical fault. The designer has to take these factors into account and provide calculations to the code authority as part of the plan check approval process.

5.3.4.2 Interconnecting With the Local Utility

Although RE has experience interconnecting with Public Service Electric and Gas in New Jersey, ConEd in New York, and NStar in Boston, the experience is relatively limited. This report focuses on the efforts and results of more than 20 interconnections in California with four utilities: PG&E, SCE, SDG&E, and the Los Angeles Department of Water and Power. The projects in New Jersey, New York, and Boston are just becoming operational or are still in construction and design. Accordingly, the discussion of these projects is limited to pertinent comparisons where appropriate.

5.3.4.2.1 Meeting Rule 21

Rule 21 is the CPUC-approved rule that governs the interconnection of electric generators with the utility grid. The utilities regulated by the CPUC include PG&E, SCE, and SDG&E. In the past, each of these utilities had its own version of Rule 21 based on its practices and experiences. Today, each utility's version represents a CPUC-approved standard interconnection process, which was the result of a collaborative effort to streamline and standardize requirements among these utilities. Although some aspects of interconnection have been standardized in California, many areas are still not standardized, and the marketplace is far from "plug and play."

Even though there is uniformity of language and technical requirements among the utilities' versions of Rule 21, the rule is subject to interpretation. In reality, not all utilities interpret the rule the same. An example is PG&E's interpretation of the passage "the failure of any one device shall not potentially compromise the safety and reliability" of the utility system. PG&E interprets this to mean that it can require redundant relays; SCE and SDG&E have accepted single multifunction relays that have a "fail safe" feature.

In addition, the rule has been undergoing revision since the first revised version was published. A separate "Supplemental Review Guidelines" document has been developed. Also, a change to the export screen of the initial screening process is being considered. This would allow incidental export of power if specific protection features were included in the design.

This discussion focuses on Rule 21 generation facility design requirements. Of particular interest are the requirements for isolation, protection, and net generation output metering. The important point is that utility implementation of Rule 21 is far from "plug and play" and may never get there. Almost any project has the potential to get caught in a morass of technical requirements and costs. The choice of generation, protection, metering, and communications technology as well as the operational characteristics of the section of the grid the project is interconnecting with determine how the project will be configured and what it will cost. Working with a designer that has adequate interconnection experience with the relevant utility is a critical consideration.

5.3.4.2.2 Radial and Network Connections

In general, most CHP projects of smaller than 2 MW and all RE projects to date have interconnected with the utility at the distribution system level (as opposed to the transmission system level). Although there is no unified definition of what voltage delineates distribution from transmission, in California and for all RE interconnections, the distribution system is at utility line voltages less than 69 kV.

There are two types of distribution system: "radial" and "networked." Radial systems are the most common; networked systems are limited to select urban core areas.[130] To the extent that interconnection standards have been established, they pertain to radial systems. RE currently has three operational CHP network interconnections and three more about to come on line.

5.3.4.2.3 Radial Interconnection

A radial system is a single line that radiates from a substation. It is normally not connected to another substation or circuit sharing a common supply. Radial system interconnections typically go through a single transformer and electric feed for each facility. Other than the requirements covered in the network interconnection section below, all requirements discussed here pertain to radial systems.

[130] Networks exist in downtown areas of San Francisco, Oakland, and Long Beach.

Understanding the local utility's process and requirements is important. When submitting an application for interconnection, it is useful to schedule a meeting with the utility's interconnection team to explain the project and, more importantly, establish a relationship. Understanding ahead of time the requirements, format, and preferred means of communication will save time during the approval process.

5.3.4.2.4 Network Interconnection

Whereas a radial interconnection has a single utility feed per customer service, networks have multiple feeds and transformers per service. Utilities are particularly sensitive to interconnections on network systems because the resulting change in network load flow could affect a device called a network protector. The network protector is located between the service transformer and the customer's service. It is designed to protect the transformer (and network) in the event of a fault. In many cases, these protectors are old and not designed to operate under very low or reverse flow current. Once open, network protectors have no synchronizing capability.

RE and PG&E have developed a network interconnection guideline that allows for the summation of the kilovolt-ampere flows through the spot network bus provided that a minimum number of network protectors always remain closed. During the next 12 months, these interconnections will be closely monitored, and the information will be shared with IEEE, EPRI, and other professional standards and research organizations with the goal of achieving a network interconnection standard within the next 18–24 months.

5.3.4.2.5 Visible Disconnect

One of the first issues an electrical designer faces in complying with Rule 21 is the requirement for an accessible, lockable, manual disconnect device with a visible air gap. (Initially, this requirement was interpreted to mean that the device's enclosure had to have a window to see the air gap. This was not the intention of the requirement.) The requirement for a visible air gap effectively eliminates the use of a standard molded-case circuit breaker as the visible disconnect. The only viable options are a disconnect switch or a draw-out breaker.

The accessibility of this device by utility personnel can be an issue. Generally, the utility requests that this device be located near the main service equipment. This is not always possible for projects in which the generator is located some distance from the main service.

In some cases, it is possible to combine this requirement with isolation devices for the generation meter. This will be examined in the discussion of net generation output metering.

5.3.4.2.6 Net Generation Output Meter

The requirement for a net generation output meter relates to the utility's need to bill for non-bypassable charges. These charges are based on the net energy output of the generator (gross output minus auxiliary loads). Generators have individual meters, and the generation facility should have a totalizing meter if more than one generator is used.

If utility-, PUC-, or ISO-approved meters are used, there is no justification for an additional utility-owned net generation output meter. However, RE's experience in California has been that this utility requirement has become more stringently enforced over the past 2 years. Initially, the utility would accept a kilowatt-hour reading from an RE-owned device, but this is no longer the case. Separate external metering equipment must be included in the design, with the meter supplied by the utility at the customer's expense. This unnecessary cost is burdensome, and the DG industry must work to reverse this trend.

If an external meter is to be used, a meter enclosure and a means of isolating the meter from all power sources must be provided. For smaller-capacity generators, a self-contained meter housing known as a "can" may suffice. For larger projects, an EUSERC (Electric Utility Service Equipment Requirements Committee) meter section may be required. The meter isolation device, one on each side of the meter, must have a visible air gap and be lockable open. In this type of design, the same disconnect device can be used for the generator disconnect and one of the meter disconnects.

5.3.4.2.7 Utility Protection

The protection requirements of Rule 21 relate to the protection of the utility system, not the generator, from any adverse effects of the generator. The utility requires the generator to detect faults on, and subsequently remove itself from, the utility system. It also requires that the generator not energize any portion of the utility's de-energized system, not overload any utility devices or equipment, and be physically isolated from the utility when necessary.

The protection of the generator is primarily the concern of the developer and designer. However, utility personnel frequently believe it is their responsibility to protect the customer's facility. This is not the utility's legal obligation. The generation developer will have to exert itself to keep the utility from interfering in the relationship between the developer and the customer. However, the need to protect the customer cannot be overstated. The utility's insight is often valuable and useful but must be measured against latent utility bias to stop DG projects from developing on the utility grid. The best practice for the developer is to carefully explain to the customer all the requirements and potential effects of installing onsite generation.

The utility will have some interest in generator protection for larger systems because these could have a larger effect on the utility system. A skilled designer should follow "good engineering practice" to produce a design satisfactory to all concerned. Part of "good engineering practice" is to consult with the utility early in the design phase to make sure its concerns are addressed. This will reduce, and may eliminate, conflicts with the utility during interconnection. In this regard, some utilities are more cooperative than others. Utilities that use a centralized staff for the review process tend to be more conducive, experienced, and skillful in resolving design issues.

Perhaps the most important component of utility protection is the intertie (or interconnection) relaying system (including any sensing devices). The intertie relay package is key to detecting abnormal electrical conditions and initiating appropriate action. The generator controller also plays an important part by regulating generator real and reactive power levels. The relaying system can be built into the generator package (as in photovoltaic inverters), separate from the generator package (as in most engines), or a combination of both.

Smaller PV installations generally use inverters certified to Underwriters Laboratories Standard 1741; they are therefore capable of being certified to Rule 21. Historically, engine generator packages use separate external relays for utility protection and have not been certified to Underwriters Laboratories 1741. A few engine genset manufacturers have recently attempted to certify their complete packages with varying degrees of success. Once an interconnection relay package and configuration have been approved, it is likely they will be approved again at another location with less scrutiny. Therefore, it is important to be knowledgeable of the systems and configurations that have already been used and are in service.

A popular method of utility protection is microprocessor-based multifunction relays. Established relay manufacturers have responded to the growing DG market by offering easy-to-use multifunction relays at relatively low costs, generally in the range of $1,200–$2,400. Using one relay package for all protection functions, as opposed to multiple discrete relays, greatly reduces design effort, complexity, and cost. Less effort is also spent in field commissioning and testing the installed protection system. The designer must address the possibility of relay failure by using redundant relays or the relay fail-safe features. Substantial savings can be achieved by incorporating the protective relays, system controls, and metering into an integrated panel at the factory. Minimizing site assembly work reduces installation costs.

A relay’s protective features sense voltages and currents on the electric system. Normally, system voltages and currents are too high to be used directly by the relay. External instrument transformers (voltage or potential transformers and CTs) transform system levels of voltage and current to levels usable by the relay, typically 120 VAC and 5 A. (Some manufacturers provide relays that accept 480 VAC directly.) Only instrument transformers designed to comply with American National Standards Institute/IEEE Standard C57.13 and Underwriters Laboratories-listed (or recognized) should be used.

The rating, accuracy, and performance of PTs and CTs are critical to the operation of the intertie relay. When using export control, CTs must be carefully selected and located. The CT ratio and accuracy must be chosen with consideration of the ampere rating of the switchboard and the trip setting required for export control. A CT ratio based on the full current rating of the switchboard may not have the resolution at the current (ampere) level for the export trip setting. Also, it may be difficult to install the CTs in the proper location in the switchboard because of space constraints.

Finally, Rule 21 has established the default trip settings for the intertie relay. Normally, the default trip settings for voltage and frequency are adequate, depending on what value of nominal voltage is used. The trip settings for export control, depending on which option is chosen, may be difficult to obtain. Option 1 of the screen (maximum export) specifies a trip setting of 0.1% of the service transformer rating. This setting is almost impossible to obtain with the relays and CTs used today. Option 2 (minimum import) specifies a trip setting of 5% of the gross nameplate rating of the generator. This option is normally chosen but can be difficult to implement satisfactorily. One problem, described in the previous section, relates to CT ratio and accuracy at low current levels. Another problem relates to the customer's facility. For example, if the facility has large motors that can start and stop at any time, the generator must be able to respond to load variations within 2 seconds, or the relay will trip the generators.

RE has seen situations in which the digital protection supplied with the generator control package was more sensitive than the interconnection relay. When this occurs, it may appear that the interconnection relay system is not working. In fact, the generator relay is tripping the generator prior to the interconnection relay operating. It is important to understand the set points of the entire system when writing test protocols to avoid this unnecessary and confusing situation when demonstrating the functionality of the system for utility final approval.

Many already approved and operating generators are changing from the export control option to the new incidental export option. Normally, this requires additional protection in the form of fault detection on the primary side of the customer transformer. Some utilities have standardized on special transformer packages for this purpose. Even though there is an added cost to the customer for the equipment, the added cost can be returned in the form of additional savings within 1 or 2 years.

5.3.5 Mechanical Design of Combined Heat and Power Installations

RE's primary areas of concern about the mechanical design of a CHP installation are the proper sizing of equipment, the integration of CHP controls with the building automation system, the physical interconnection with the building systems and commissioning, and operation and maintenance.

5.3.5.1 Due Diligence

A thorough examination of existing conditions is critical. Collecting as-built drawings and interviews with the facility operations, maintenance, and engineering staff is vital. To ensure a successful design, the designer must also spend adequate time at the location. CHP design will be flawed if it is approached as a desk job.

The four systems that must be understood prior to mechanical design are building controls and automation, chilled water operation, hot water (both domestic and hydronic), and structural. It is important to understand the operational conditions of dynamic systems during all times of the day and through the full range of seasonal variation. Although understanding each system is critical, it is even more important to understand how the CHP plant will interact with the facility as a seamless system.

5.3.5.2 Sizing of Equipment

A thorough analysis of the facility thermal demand and operating profile should be performed to properly size the generator, chillers, heat exchangers, and dump radiators. If the system is sized too small, incremental savings or return on investment will be left on the table; if the system is sized too big, it will not operate efficiently or dispatch as often as it should because of part-loading of major components. It is vital that a detailed, hourly analysis of the building's native loads be performed against the types and sizes of DG plant configurations to determine the optimal size and investment. Part of this process involves understanding the existing efficiency of the building's systems because the value of thermal energy is linked to the avoided cost of the building producing the thermal energy on its own.

One problem that surfaces in chilled and hot water systems is load sharing between the CHP plant and the building plant. Ideally, the CHP plant is base-loaded, and the building systems handle peaks. But in low-load conditions, when building loads are only moderately more than CHP plant capacity, it can be difficult for the building systems to unload and operate stably. Load sharing can be a problem, especially for older chillers that cannot be unloaded below 40%. Newer chillers can unload further, but higher thresholds still may be required because of maintenance or operational concerns. After equipment has been installed, operational difficulties are addressed through refinements in control strategies before equipment modifications are considered.

It is important to understand how flows and pressure vary in the existing system. Frequently, the CHP plant causes flow or pressure to increase. This may exceed the allowable operational or protection settings on existing equipment.

5.3.5.3 Control Integration

The automatic control system of the CHP plant must integrate seamlessly with the existing building automation system to preserve the plant's economics and ensure it does not cause disruption or operating problems for the building. When possible, the CHP plant should be dispatched before host building systems to maximize use of the CHP output.

This integration is challenging because of the variety of building automation system types deployed in commercial buildings. RE’s experience has ranged from very old, pneumatic-style controls to quite modern, fully networked systems. The integration strategy has been different in each case. The most expensive and limited strategy is to install a new building automation system control panel in the building to accept the CHP control points and pass information back to the CHP plant controls. An easier strategy is one in which the building automation system can accept a network connection using an open protocol such as Modbus. In this case, the information is simply passed through the network, and the hardware installation requirements are more limited. In every case, the controls programming scope is substantial and requires a great deal of attention to detail because the building automation sequence of operation must be tailored to work with the CHP plant.

Control system design is not required to obtain a building permit. The electrical and mechanical designs can be completed without the control system. However, the design of the control system must be integrated into the overall system design. Inadequate integration leads to unnecessary problems during start-up and commissioning.

5.3.5.4 Building Integration

It is a substantial mechanical engineering task to design the physical interconnection of a CHP plant's thermal systems (chilled and hot water) with an existing building's central plant or heating, ventilating, and air conditioning system. The strategy varies depending on how the host building systems are configured, and a good deal of site investigation and data-gathering is required to fully understand how the building system operates and how it should operate with the CHP plant. For example, the CHP plant may be designed for constant-volume pumping, but the building may have a variable-volume system. Often, pre-existing problems must be addressed before CHP plant integration is accomplished. If a connection cannot be made at the central plant, where 100% of the thermal load is available, a trade-off is required between cost and load that can be captured at an alternate location.

The location of the physical tie-in should be where the greatest thermal load is available to be served at the least cost. For chilled water, it is best to tie in to an existing chiller at a location just before the return-water inlet. For hot water, the tie-in is usually in series with the return line to the boiler. Control problems can develop for chilled water delivery because of slow absorption chiller response time and the possible need for colder water than the chiller can deliver.

CHP installations in high-rise buildings can have water pressure issues that affect equipment design and ratings. A high-rise building system may have water pressures in excess of 150 psi. If the CHP equipment is in the basement, the designer must be aware of the effect the increased head pressure will have on piping and equipment such as pumps, chillers, valves, and heat exchangers.

5.3.5.5 Site-Specific Considerations

Many mechanical design requirements are based on site-specific conditions. Some general mechanical considerations are:

- Piping design and layout need to reduce system loss as much as is practicable.
- Ninety-degree elbows and T-connections should be avoided.
- Adequate length of straight-run piping is critical for accurate flow measurement.
- The installation of conduit and wire in close proximity to high-temperature pipes and equipment should be avoided.
- The installation and removal of strainers is important.
- A provision for recirculation on long runs to and from heat exchangers to points of connection is often required.
- Emergency plans should be made for containment of spills.

It is critical that project engineers and designers work with the contractors and journeymen to ensure the system is built per the design. In many cases, the contractor or journeymen will propose modifications that will enhance the design, lower costs, etc. It is important these suggestions be taken seriously and properly reviewed to ensure there are no unintended consequences.

Whether the CHP unit is located in a mechanical room or outdoors greatly affects requirements for air ventilation for cooling and combustion. A genset in a mechanical room may require forced ventilation (fans and duct work), which will add to the parasitic load and may reduce engine operating efficiency by reducing room air pressure. The length and routing of exhaust can also affect engine performance by increasing back pressure. Exhaust output should be positioned in a location where environmental effects from noise and fumes are minimized.

Equipment foundation design is also dictated by site structural requirements. Rooftop installations require a thorough investigation of the roof structure and supporting structural design calculations for the foundation. Vibration from the engine and other equipment (fans, pumps, air intake, and exhaust) needs special attention. It is a best least-cost practice to address potential vibration problems upfront rather than re-engineering a solution after the equipment has been installed.

Finally, site safety and operations and maintenance work can be enhanced by proper equipment configuration and layout. Access to and clearances for equipment, pipe, and conduit layout and routing and pipe insulation are important. RE has found it is better to envision site design as a whole at the beginning of a project rather than to progress piecemeal. A site kick-off meeting with the design group, the customer, and construction and operations and maintenance personnel to establish overall design parameters and identify site-specific issues is recommended.

5.3.5.6 Quality Assurance and Control

Quality assurance and control begins with due diligence and continues through design and construction. A successful project is the culmination of the quality assurance and control process. Every project should start with a well-thought quality assurance and control plan and procedures. All project team members must buy in and observe the quality assurance and control plan. This plan must identify critical checkpoints that must be passed before moving on to the next phase of development and construction. In this way, a strong foundation will be laid for project success.

The developer should decide early on what balance of first cost and operating reliability is tolerable. This will guide the promulgation of equipment specifications and design approaches. On the one hand, first-cost savings derived from components of lesser quality might lead to reduced operating reliability and availability. On the other hand, extra costs from building redundant systems may be wasted if a weak link remains in the design. In general, RE has found that—for other than "five nines" reliability requirements—it is best to use high-quality components and minimize the use of redundant components.

If QC is left to project start-up, the project will be delayed as problems are discovered and corrected. Peer review is a critical part of quality assurance. Even the best people make errors and omissions.

5.3.6 Start-Up, Commissioning, and Operations and Maintenance

5.3.6.1 Plant Start-Up and Commissioning

As much as design and construction efforts attempt to avoid problems, when systems are operated together for the first time, issues will almost always surface. Start-up and commissioning are two distinct project stages. Start–up is the process to get the plant safely operational. Commissioning is the process of tuning, optimizing, and ensuring the plant works as specified.

5.3.6.2 Start-Up

Use an experienced start-up and commissioning team that drafts and uses a well-thought-out start-up and commissioning plan. Managing expectations is critical during start-up. There will be intense pressure to get the project running. It is easy to give in to this pressure. However, if steps are passed over, time will be lost later to go back and fix problems, and there will be frustration because the customer will think the project does not work.

If excellent quality assurance and control practices have been observed, start-up might take 2 weeks for a 1-MW CHP plant. However, even with the best quality assurance and control, start-up problems will be found. It is best to allow half as much time for start-up as you plan for initially. During start-up, a representative from each trade and craft should be present. Often, their time is spent observing. Although this appears costly, it is less costly than losing entire days while the resources needed to correct a problem are remobilized.

5.3.6.3 Commissioning

Commissioning often takes several weeks. Adequate time and budget should be allocated for in-field commissioning of all systems individually and of the plant as a whole. Once the plant is operational and presumably earning a return on investment, there is often pressure to get it fully automatic and at full output as soon as possible. Expectations must be managed to not leave the impression that the plant or design is flawed.

Formal commissioning and acceptance is critical. A final retention payment should be negotiated with the contractor until plant performance is proved. Completion of as-built drawings and operational manuals is a vital step in long-term operational performance. Their completion is often overlooked, but their importance in the months and years ahead will be demonstrated the first time a major problem arises and they are not available or are sub-standard.

Optimal performance will be achieved only after the plant has been broken in and fine-tuned. Realistic expectations for the first 30, 60, and 90 days of operation should be established. The tuning process must be repeated to account for seasonal variations in thermal load. Heat rate and performance tests should be performed annually to ensure ongoing performance and DG plant economics.

5.3.6.4 Operations and Maintenance
CHP engine maintenance is more intense than the maintenance required for normal building equipment. Generally, engines are serviced and tuned every 750 hours of operation. Additional effort will be needed for sites with multiple engines. At sites with long run hours, this work has to be done at inconvenient hours (weekends, late at night, or early in the morning). The CHP plant owner has to be certain the operations and maintenance provider is capable of meeting the operation and scheduling requirements of the CHP plant. This includes 24/7 emergency service, off-shift staffing, and up-to-date communications and maintenance software and equipment.

Engine manufacturers are attempting to drive down costs by using cheaper parts. This results in a lower up-front engine cost but higher life-cycle costs because of breakdowns and servicing/replacement costs. Engine downtime costs money in lost revenue and higher operations and maintenance costs. RE's experience is that the initial capital savings are quickly absorbed by even slightly higher-than-expected availability rates. Better-engineered systems include modular design and engine protection features. These enable staff to distinguish between major and component failures and provide quick and easy servicing and parts replacement.

5.4 Conclusions and Recommendations
Since its inception, RE has implemented more than two dozen CHP projects—some with more success than others. Many early projects required design modifications and rework even after perceived completion. Over the course of 3 years, design and construction have improved—as have the operating results once the project is complete. The resolution of technical obstacles of each project has contributed to improving the RE process. These lessons learned were identified and discussed in prior sections as examples of RE "best practices."

The general philosophy of the "best practices" can be summarized as:

1. Conduct due diligence.
   Conduct a thorough site investigation before any design effort is started. This should include site access, available space, facility load demands and usage patterns, noise restrictions, appearance, local code requirements, and the condition of existing equipment. Site-specific technical issues and existing facility problems must be identified for the design stage to be successful.

2. Design from lessons learned.
   Designers and contractors (mechanical, electrical, control, and structural) must have proven experience with successful CHP installations. If the design team does not have a history of successful projects and has not incorporated lessons learned into its design improvements, the project's chance of success will be greatly reduced.

3. Meet utility requirements.
   The electrical designer should have a thorough understanding of local utility interconnection requirements. Early communication with the utility should identify and resolve issues and ensure all requirements can be met at reasonable cost.

4. Implement quality assurance.
   Insist designers and contractors use industry-standard quality assurance and control procedures. Use high-quality equipment. The capital savings of using lesser-quality equipment are usually lost with the first equipment- related failure. The use of quality equipment and installation workmanship will help ensure the CHP system performs as designed.

5. Plan start-up and commissioning.
   Employ an experienced start-up and commissioning team. Have and use a well-written start-up and commissioning plan. With sufficient attention to design and installation, start-up problems should be minimized. The system must be commissioned after start-up and periodically tuned to ensure projected economic benefits are realized.

6 Trend Analysis for On-Site Generation (D-2.10)

6.1 Executive Summary

6.1.1 Introduction

The objective of this task is to present and analyze the 2003 trend data from four RE projects to demonstrate actual performance against expected (pro forma) performance. The sample projects were chosen to be representative of the size, type, and location of units in RE's portfolio. Two of the projects (SD1 and SD2) are in SDG&E territory, and two (SC1 and SC2) are in SCE territory. The projects and sizes are summarized in Table 6-1.

Table 6-1. Generation Data Included Sites

RE Sample Sites	Total Load (kWh)	RE Generation (kWh)	Utility Generation (kWh)
SD1	5,770,331	2,016,139	3,754,191
SC1	6,260,140	1,019,702	5,240,438
SD2	3,196,625	1,138,226	2,058,399
SC2	10,923,023	4,378,439	6,544,584

The total load column represents metered data of actual building load in 2003. RE generation is the actual metered output from the site generators. Utility generation is the difference between the two.

Each ICE has heat recovery capability, so every installation combines heat and power. Heat is recovered as hot water and is used for the building's heating load or cooling load[131] or cascades to provide both. RE then has three potential revenue streams:

- Electricity
- Cooling
- Heating.

6.1.2 Pro Forma Versus Actual Operation

The generation totals above were disappointing because RE had higher pro forma expectations of each of the projects. Building load, pro forma expectations, and actual performance for the four projects are:

- SD1 – Electricity Generation Performance Results
    - Building load = 5,770,331 = 100% of total
    - Pro forma = 4,215,422 = 73% of total
    - Actual generation = 2,016,139 = 35% of total

[131] Hot water is used to power an absorption chiller. The chilled water output from the absorber offsets chilled water produced by the building's electric-powered chillers.

- SC1 – Electricity Generation Performance Results
    - Building load = 6,251,254 = 100% of total
    - Pro forma = 3,146,383 = 50% of total
    - Actual generation = 972,641 = 16% of total

- SD2 – Electricity Generation Performance Results
    - Building load = 3,193,739 = 100% of total
    - Pro forma = 2,263,955 = 71% of total
    - Actual generation = 1,138,226 = 36% of total

- SC2 – Electricity Generation Performance Results
    - Building load = 10,923,023 = 100% of total
    - Pro forma = 8,155,560 = 75% of total
    - Actual generation = 4,295,327 = 39% of total.

6.1.3 Conclusions

RE attributes the disappointing results to three external factors for which it gathers no trend data and over which it has little or no control and three internal factors for which it does gather trend data and which it may control:

- External factors
    - Declining electric utility rate tariffs
    - Increasing natural gas prices
    - Building load

- Internal factors — Cogeneration system performance, which can be further broken down as:
    - Engine genset malfunctions
    - Heat recovery system malfunctions
    - Balance of plant malfunctions.

6.2 Introduction

The objective of this task is to present and analyze trend data from RE projects to demonstrate actual performance against expected performance. Four RE projects from 2003 were selected for this analysis. The results indicate opportunities to improve operations for current projects and improve investment underwriting for future projects.

RE captures input and output data on a continuing basis for all projects. This task assesses trends, opportunities, and problems in system performance and analyzes thermal and electrical data without regard to the proprietary system that made the data available. Areas of analysis include building electric load curve analysis for system sizing and optimal dispatch (as discussed in Section 7, "Performance of Dispatch Systems (D-2.09)") and thermal load analysis based on delivered thermal byproducts (chilled water and hot water).

6.2.1 Overview of RealEnergy's Combined Heat and Power Market Approach

RE employs DG/CHP technologies to:

- Generate substantial cost savings or revenues (depending on facility type and client preference)
- Provide efficient, cost-effective alternatives for facility owners/operators
- Provide clean and reliable electrical power
- Provide thermal energy (hot and chilled water).

RE offers these services at no cost or risk to building owners and operators. Through its ownership of DG plants, RE allows its clients to realize the benefits of DG while RE assumes all risks related to installation, ongoing operations, and maintenance. These include:

- Capital exposure
- Inefficient commodity purchasing (gas, electricity)
- Entitlements and permits (air, building, and interconnection)
- Utility interconnection/tariff issues (standby, departing load, rate volatility)
- Choice of appropriate technology, manufacturer, and contractor
- Integration with existing facility systems
- Optimizing thermal applications and system operations
- Managing multiple systems and locations
- Realizing profits/savings
- Surplus sales (ancillary services).

Because RE takes these risks, it is able to offer its customers an unusual set of benefits:

Table 6-2. RE Customer Benefits

Economic	Technical
New and durable revenue/savings source	No technology risk
No capital outlay or risk	Increased power quality
Economic return from unused space	Enhanced heating, ventilating, and air conditioning or process infrastructure and capacity
Load shaping for effective commodity management	Additional cooling or heating capacity
Load shaping for lower commodity costs for residual load	Reduced grid uncertainty
Reduced capital outlays for plant and equipment	Positive environmental statement

This business model has been popular, and since its inception, several competitors have imitated it. The actual structure of its offering to customers depends on customer type. Its offering to commercial office building customers (the only ones considered in this analysis) is called a Lease and Energy Services Agreement. Under this option, RE designs, builds, owns, operates, and maintains a CHP plant at the customer's facility. All development, fuel procurement, and operational risks are borne by RE.

The target market segments and minimum facility specifications RE looks for are:

- Commercial real estate with a minimum office size of 200,000 ft^2
- Industrial and manufacturing facilities with annual energy expenditures of $750,000 or more, including:
    - Light manufacturing
    - Food processing
    - Data centers
    - Corporate facilities
    - Grocery stores.
- Government, education, and healthcare with annual energy expenditures of $750,000 or more
- Hospitality facilities with 200 rooms or more for full service or 250 rooms for partial service.

When it encounters a prospective customer, RE goes through a four-step process to develop a new project:

1. RE qualifies the customer.
    - Identifies client objectives, issues, and opportunities
    - Confirms general conditions and optimum economic and operating tolerances
    - Determines scale of opportunity
2. RE writes a preliminary agreement.
    - Gathers and analyzes energy bills and utility interval data
    - Maps thermal and process load profiles, evaluates existing energy applications and related costs such as planned plant/utility investment and operation and maintenance costs
    - Evaluates and prescribes equipment options and system configuration
    - Executes a term sheet that outlines business terms and success criteria

3. RE makes a program proposal.

- Presents a proposal that addresses client objectives, including an overview of benefits
- Presents a pro forma that summarizes system operations and economic benefits
- Executes a contract document that reflects economic benefits and operational parameters

4. RE implements the program and provides ongoing services.

- Constructs a fully permitted system capable of the services defined in the agreement
- Performs ongoing operations and maintenance
- Analyzes client consumption, needs, and costs and develops an energy system that reduces risk and maximizes savings or revenue opportunities.

6.2.2 Sample Projects for Trend Analysis

RE's initial investors came from the commercial real estate business, so most of the company's early projects were in large commercial real estate facilities. To analyze trend data for these facilities, it is useful to compare common facilities in different utility territories. For a full year of trend data, 2003 was selected. Selected projects therefore had to run throughout 2003.

Four commercial office buildings were chosen for the trend data comparison: two in SDG&E territory and two in SCE territory. RE also has projects in PG&E and Public Service Electric and Gas territories. The selected projects are called SD1, SC1, SD2, and SC2, where “SD” refers to San Diego and “SC” refers to the Los Angeles Basin portion of SCE territory.

Table 6-3. Characteristics of Trend Projects

Project ID	Utility	City	Prime Mover	Quantity	Generator Type	Thermal Recovery	Thermal Recovery Hot Water
SD1	SDG&E	San Diego	ICE	3	Induction	150-ton absorption chiller	None
SC1	SCE	Los Angeles	ICE	3	Synchronous	150-ton absorption chiller	None
SD2	SDG&E	San Diego	ICE	2	Synchronous	100-ton absorption chiller	None
SC2	SCE	Hawthorne	ICE	5	Synchronous	250-ton absorption chiller	None

6.2.3 Expected and Actual Trends

This analysis consists of comparisons of expected conditions and actual information from trend data. Trend data use a full year of information from 2003. The analysis examines the variances, quantifies them, and determines their possible causes. In some cases, the reasons are simple, such as changes in gas prices or overall building load. Although gas commodity prices are a matter of public record, the building load data used as the basis of pro forma estimations were not available as input to this report. For this and other reasons, the causes of discrepancies may not be obvious.

The trend categories compared are:

- Building load
- Electricity generated
- Tons of absorption cooling (provided through capture of waste heat)
- Therms of natural gas consumed.

When electricity generation was lower than expected, there were two possible causes:

- The unit ran fewer hours than the total hours in the period
- Power output was lower than the nameplate-rated specification.

The first cause is called reduced availability; the second is called reduced capacity. Total system reliability can be measured by multiplying the two.[132] Using trend data from the trend categories, it is possible to measure and compare pro forma and actual availability, capacity, and reliability. Of course, it is not possible to say why a cogeneration, or cogen, system was unavailable. It could be because of an engine failure or scheduled maintenance or it may have been shut down for economic reasons (because the spark spread was negative). Likewise, partial capacity could be the result of load following (although that possibility may be eliminated here because no load following was used). By looking at operation during the on-peak period, however, it is possible to distinguish availability issues from capacity issues because economics dictate that the unit run at 100% output for 100% of the time during these periods. RE expected the units to run at 100% capacity, less 5% parasitic loads, when they ran. However, the units were typically available less and at a lower capacity than expected.

Thermal under-production is considered here to be directly attributable to reduced cogeneration system reliability.

Several trends that diverge from pro forma expectations are not tracked by RE's information system yet are useful for understanding operating characteristics. These are:

- Natural gas commodity prices
- Utility tariffs.

Tariff and price effect on spark spread has been treated at length in "Tariff Risk and DER Market Development."[133] Spark spread drives run/no-run decisions. When spark spread becomes negative because of electricity tariffs, gas prices, or any other reason, the engines must he shut off to avoid losing money. No spark spread calculations are performed here.

[132] Availability is defined here as the ability of an individual engine to produce at least 50% of the manufacturer nameplate kilowatts (200 kW x 50% = 100 kW) continuously for one 15-minute period. This approach was necessary because data for individual engines were not available for this report and all sites had multiple engines.
[133] For a full discussion of tariff and price issue effect on spark spread, see: RealEnergy. "Tariff Risk and DER Market Development." March 2004.

Pro forma and trend data comparisons were carried out for each of the four RE facilities. Section 6.3 presents the pro forma numbers; Section 0 discusses the trend data, variances, and interpretations.

6.3 CHP Performance Expectations

The baseline load data used to make pro forma estimations are not available. Therefore, site electric load data are calendar year 2003 data collected by RE's post-installation power measurement utility meter.

6.3.1 Common Performance Expectations

RE made certain assumptions when underwriting projects during 2000–2002—when sample projects included here were funded, designed, and built. At that time, the ICE selected was the Hess Microgen rich-burn Model 220. Although the manufacturer specified its engine could run at 220 kW, RE assumed 200 kW in its pro formas. Determining how many engines to install at a particular site was a matter of estimating how many 200-kW engines could operate profitably given the estimated load shape, utility rate, and gas prices. Also, RE expected it could control the engine kilowatt output in response to overall load. The marginal engine was approved if it could operate, at some point on the load curve, better than break-even. The company also chose Thermax or Century hot water-powered absorption chillers specified at an intake temperature of 205°F cogeneration water that produces chilled water at 42° F. The chiller size was dependent on the waste heat produced by the engines and the building's chiller load. In almost all cases, building chiller load exceeded the maximum size of the absorption chiller. Each Hess Microgen 220 is specified to generate enough waste heat to produce approximately 50 tons of chilled water per hour. Although hot water production for domestic loads was included in some pro formas, in RE's southern California projects, the total volume of use is minimal. Therefore, the cost of gathering and trending hot water production is not justified and no hot water trend data is available.

The net income projections for the cogeneration systems are based on the expected total generation, total demand reduction, and total thermal production. Those projections were derived based on the following:

- The cogeneration systems were expected to have a downtime (nonavailability) of no more than 2% during the peak for the entire fleet.
- The downtime (nonavailability) in all utility rate tariff periods was expected to be 7% or less.
- The maximum capacity was calculated by the formula (200 – 10)kW x number of engines.[134]
- Pro forma reliability is 95% x 98% = 93%.

In its individual pro formas, however, RE estimated lower availability for each project by tariff period. These estimated run times are a better comparison to actual availability than the blanket 98% availability assumed for the gensets.

[134] Five percent parasitic loads were included in the pro forma, hence the subtraction of 10 kW.

RE's revenues were not merely a function of kilowatt-hours and therms. Under its contract, RE was obligated to calculate its charges to the customer exactly as they would be calculated by the local public utility. Demand charges represent 30% to 60% of a customer's bill, so even a short outage of 15 minutes could result in a large loss in monthly revenue.[135]

The two prime cost drivers were fuel consumption and operations and maintenance costs. A Hess Microgen product specification sheet from December 2001 specified the heat rate for the 220 model at 10,090 Btu/kWh.[136] Discrepancies in RE's results convinced it that for its own internal calculation, it should raise the heat rate expectation to 11,500, including 5% parasitic loads. The operations and maintenance costs were based on $0.015/kWh. However, there is a minimum monthly charge. If the output of the cogeneration system drops below the point at which the minimum charge applies, the cost per kilowatt goes up proportionally. In addition, RE was charged a very high rate of additional operations and maintenance charges for the correction of items not covered under the operations and maintenance service contract. RE later raised its pro forma assumption for operations and maintenance charges to $0.02/kWh.

Table 6-4. Operational Pro Forma Assumptions

System		System Performance	
Number of Prime Movers	n	Downtime – Peak	4%–7%
Unit Type	Hess Microgen 220	Downtime – All	2%
Unit Operation	Load follow	Heat Rate	11,500
Installed Capacity (kW)	200 * n	Parasitic Loads	5%
Chiller Size (tons)	100–250	Max kWh output/yr	5,256,000
Cooling Tower (Client/RE)	RE		
Heating Hot Water (Yes/No)	No		
Domestic Hot Water (Yes/No)	Yes/No	**Downtime**	
Steam (PSI/No)	No	Impact by Downtime – All? (Yes/No)	Yes

RE also made assumptions about commodity gas prices fluctuating with the market from about $4/MMBtu to $4.70/MMBtu, access fees paid by RE to the customer fluctuating from 7.5%–10%, property tax, insurance, communications, and other expenses. Based on these assumptions, RE expected to operate in all tariff periods—on-peak, mid-peak, and off-peak. It did not expect to receive any incentive payment (at least not prior to its involvement in the California SGIP). These expectations are summarized in Table 6-5.

[135] Demand charges in SCE and SDG&E are calculated using the highest ratchet of demand in any 15-minute interval within the monthly billing cycle. This demand is then multiplied by a dollar-per-kilowatt amount to determine the monthly charge.
[136] Hess Microgen has reportedly increased its specified heat rate in response to updated heat rate measurements.

Table 6-5. Market, Fee, and Infrastructure Pro Forma Assumptions

General		Hours and $/kWh	SDG&E	SCE
Gas price ($/MMBtu)	$4–$4.70	On-Peak Hours	1,183	522
Operations and maintenance ($/kWh)	$0.015–$0.0175	Mid-Peak Hours	2,865	2,954
Access fee (% of gross revenue)	7.5%–10%	Off-Peak Hours	4,712	5,284
Property tax (% project cost)	0.85%	Total	8,760	8,760
Insurance (% project cost)	0.45%	On-Peak $/kWh	$0.250	$0.39–$0.40
Communications (/site/yr)	$1,200	Mid-Peak $/kWh	$0.089	$0.14–$0.15
Other (/site/yr)	$2,000	Off-Peak $/kWh	$0.087	$0.089

6.3.2 Project SD1

SD1 is a commercial building in San Diego with more than 540,000 ft^2 of office space. In its pro forma estimation, RE expected to generate electricity 1,159 peak hours a year—i.e., to have 98% availability. In the mid-peak, RE expected 96% availability, or about 2,741 hours a year. In the off-peak, RE expected 74% availability, or about 3,495 hours a year. Total availability was estimated at 84%. It expected to sell 100% of the captured thermal energy (net of system inefficiencies). RE expected a 95% capacity factor from its three ICEs. Total generation was to be 4,215,422 kWh, for a total system reliability of 80%. Availability, capacity, and reliability are summarized in Table 6-6.

Table 6-6. SD1 Pro Forma Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	660,824	1,159	98%
Power – Mid-Peak	1,562,449	2,741	96%
Power – Off-Peak	1,992,149	3,495	74%
Total	4,215,422		
ICEs		3	
Total Availability (hours/year)		7,395	84%
Total Net Capacity (kW)		570	95%
Total Reliability (kWh)		4,215,422	80%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	130,480		100%
Chilled Water – Mid-Peak	290,290		100%
Chilled Water – Off-Peak	44,185		100%
Total	464,955		

6.3.2.1 Site Electric Load

Historical data showed SD1 had a previous average building demand of 1,206 kW on-peak, 1,047 kW mid-peak, and 502 kW off-peak. In 2003, however, building demand averaged 1,170 kW on-peak, 809 kW mid-peak, and 451 kW off-peak in the summer. Peak kilowatts were 1,780 in summer and 1,622 in winter. So the average pro forma building demand is higher than the 2003 average, yet the actual 2003 kilowatt-hour consumption is greater than the pro forma. This apparent paradox is due to two factors. First, the building instituted substantial energy efficiency and demand reduction measures, hence, the lower demand. Second, building occupancy increased, so total consumption increased.

Table 6-7. SD1 Site Electric Load Summary for 2003

Project SD1	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	2,531,687	867,992	771,536	892,159
Winter kWh	3,238,644	296,505	1,775,893	1,166,246
Total kWh	5,770,331	1,164,497	2,547,429	2,058,405
Summer Maximum kW	1780.99			
Winter Maximum kW	1622.16			
Summer Weekday Minimum kW	988.72			
Winter Weekday Minimum kW	928.19			
Summer Average kW		1,170	809	451
Winter Average kW		677	936	428

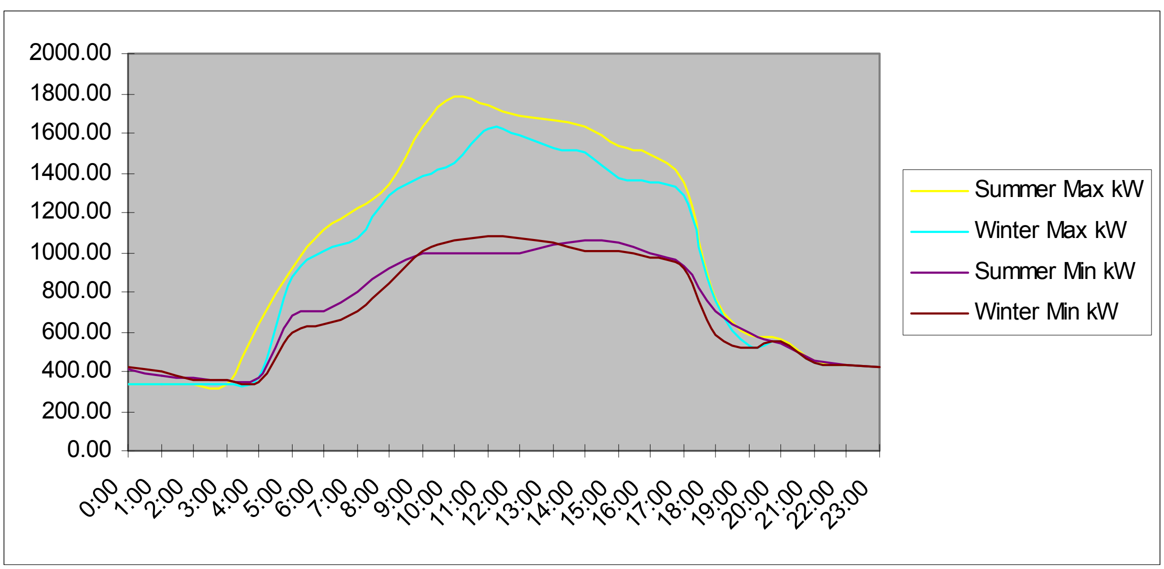

Figure 6-1. SD1 weekday minimum/maximum building loads (kW)

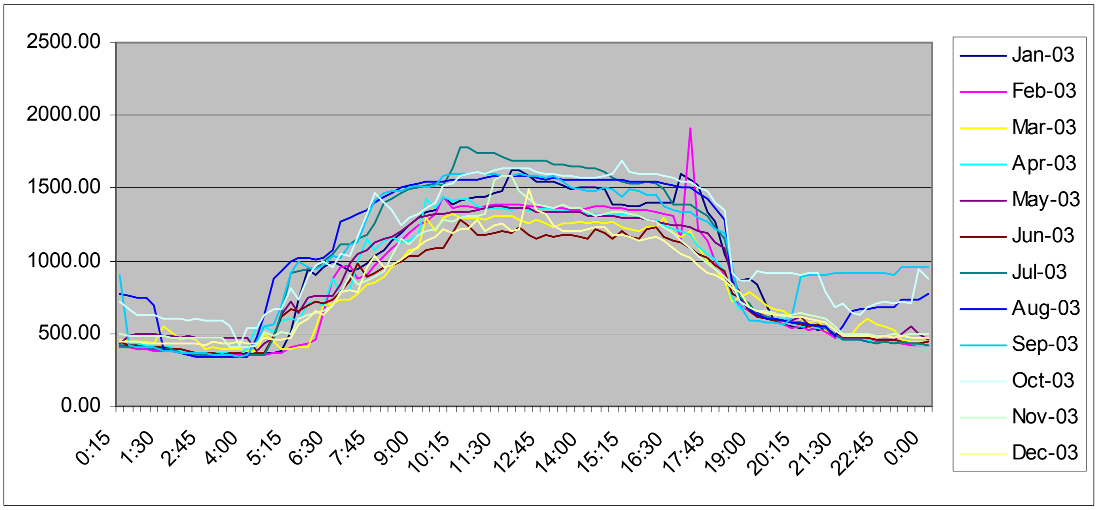

Figure 6-2. SD1 maximum kilowatts by month

6.3.2.2 Site Chiller Information

The building had an existing electric chiller with an efficiency of 0.80 kW/ton-hour. RE expected to displace 20% of the operation of this chiller by capturing waste heat to feed an absorption chiller.

6.3.2.3 Performance Expectations

The following figures summarize RE's pro forma performance expectations. Figure 6-3 shows the pro forma ratio of RE-generated kilowatt-hours to utility-supplied kilowatt-hours during the three tariff periods. Figure 6-4 shows the pro forma division of RE-generated kilowatt-hours among the three tariff periods and generator use as a percentage of total generation capacity.

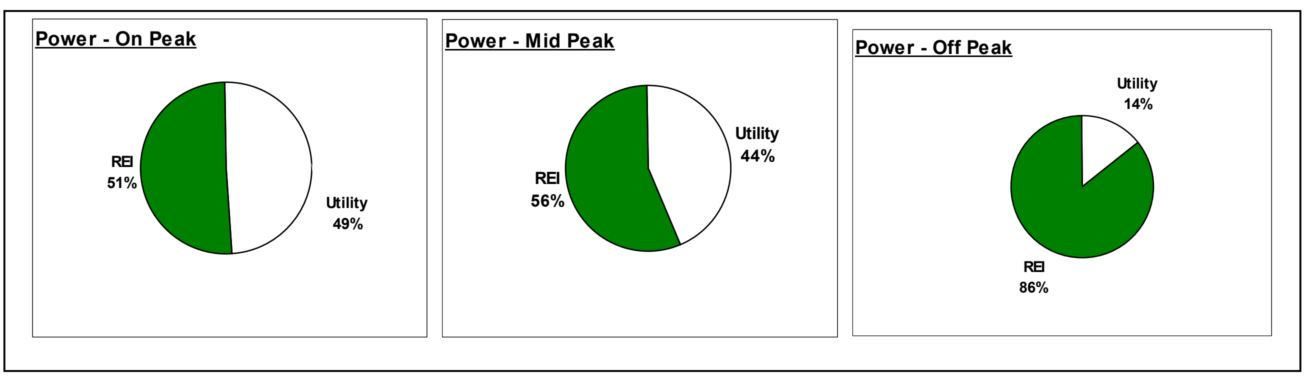

Figure 6-3. SD1 pro forma utility versus RE power generation by tariff period

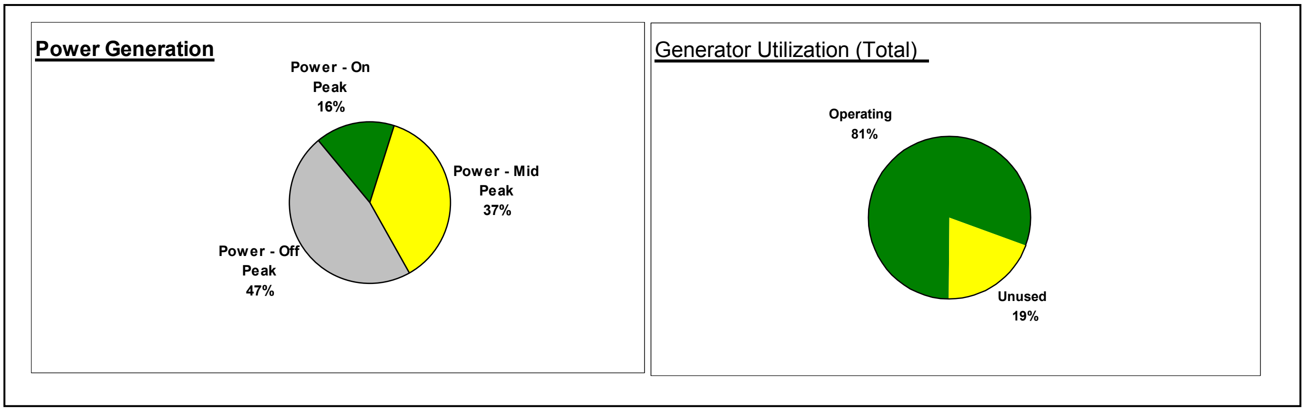

Figure 6-4. SD1 pro forma generator use by tariff period

6.3.3 Project SC1

SC1 is a commercial office building in Los Angeles with more than 400,000 ft^2 of space. In its pro forma estimation, RE expected to generate electricity during 97% of on-peak hours, or about 514 hours a year. In mid-peak, RE expected to generate electricity 87% of the time, or about 2,553 hours a year. Overall availability was expected to be 5,520 hours a year, or 63%. Off-peak, RE expected to generate electricity 46% of the time, or about 2,453 hours. It expected to sell 100% of the captured thermal energy (net of system inefficiencies). Three ICEs were expected to maintain 95% capacity factor (570 kW). Total generation was pro formed at 3,146,383, or 60% of maximum.

Table 6-8. SC1 Pro Forma Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	293,066	514	97%
Power – Mid-Peak	1,454,977	2,553	87%
Power – Off-Peak	1,398,339	2,453	46%
Total			
ICEs		3	
Total Availability (hours/year)		5,520	63%
Total Net Capacity (kW)		570	95%
Total Reliability (kWh)		3,146,383	60%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	73,370		100%
Chilled Water – Mid-Peak	229,884		100%
Chilled Water – Off-Peak	0		–
Total	303,254		

6.3.3.1 Site Electric Load

RE estimated that SC1 site load would be 1,947 kW on-peak, 1,580 kW mid-peak, and 1,159 kW off-peak. In 2003, the site averaged 1,857 kW on-peak, 1,462 kW mid-peak, and 1,042 kW off-peak in the summer. Peak kilowatts were 2,609 in summer and 2,288 in winter. The pro forma building load was higher than the 2003 average but lower than the 2003 peak—although RE reported a 2,946-kW peak (from utility bills) in the pro forma year.

The following figures present details of 2003 SC1 building load.

Table 6-9. SC1 Site Electric Load Summary

Project SC1	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	600,909	235,689	223,490	95,942
Winter kWh	418,793	0	393,182	24,336
Total kWh	1,019,702	235,689	616,673	120,279
Summer Maximum kW	525.13			
Winter Maximum kW	625.86			
Summer Weekday Minimum kW	312.06			
Winter Weekday Minimum kW	-15.73			
Summer Average kW		435	199	44
Winter Average kW		99	191	5

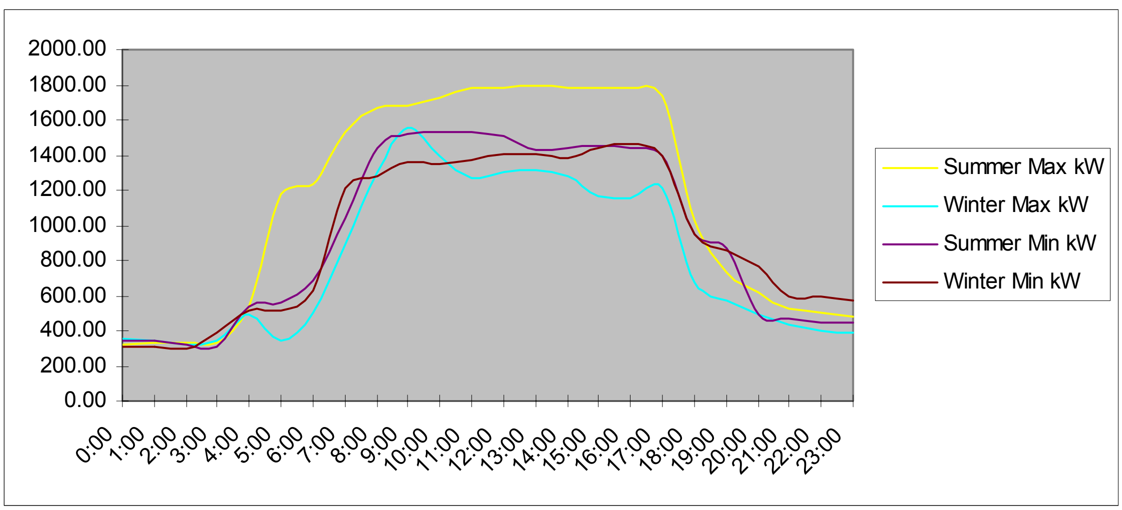

Figure 6-5. SC1 weekday minimum/maximum building loads (kW)

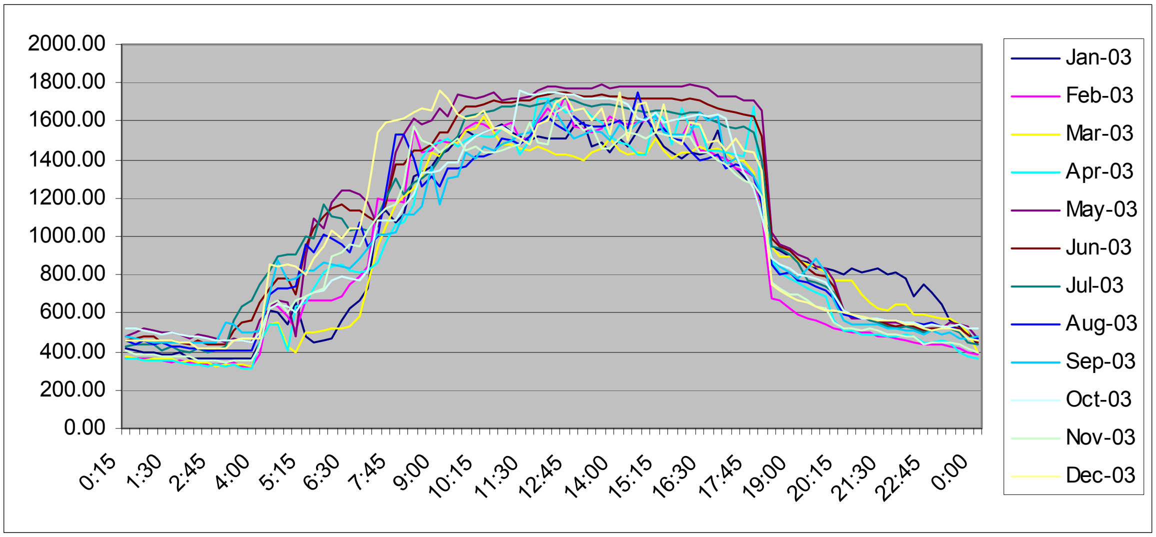

Figure 6-6. SC1 maximum kilowatts by month

6.3.3.2 Site Chiller Information

The building had an existing electric chiller with a poor efficiency of 0.35 kW/ton-hour. RE expected to displace 48% of the operation of this chiller by capturing waste heat to feed an absorption chiller. RE would serve more of this load, but it is limited by the hot water it can serve the absorption chiller from the captured waste heat coming from the engine jacket water and exhaust from the three engines.

6.3.3.3 Performance Expectations

The following figures summarize RE's pro forma performance expectations. Figure 6-7 shows the pro forma ratio of RE-generated kilowatt-hours to utility-supplied kilowatt-hours during the three tariff periods.

Figure 6-8 shows the pro forma division of RE-generated kilowatt-hours among the three tariff periods and generator use as a percentage of total generation capacity. Although the on- and mid-peak RE-utility ratios are about the same as in SD1, note that RE expected to generate 58% of off-peak power. The result is lower generator use and a higher unused percentage of 40%. This plan was necessitated by the economics of the site.

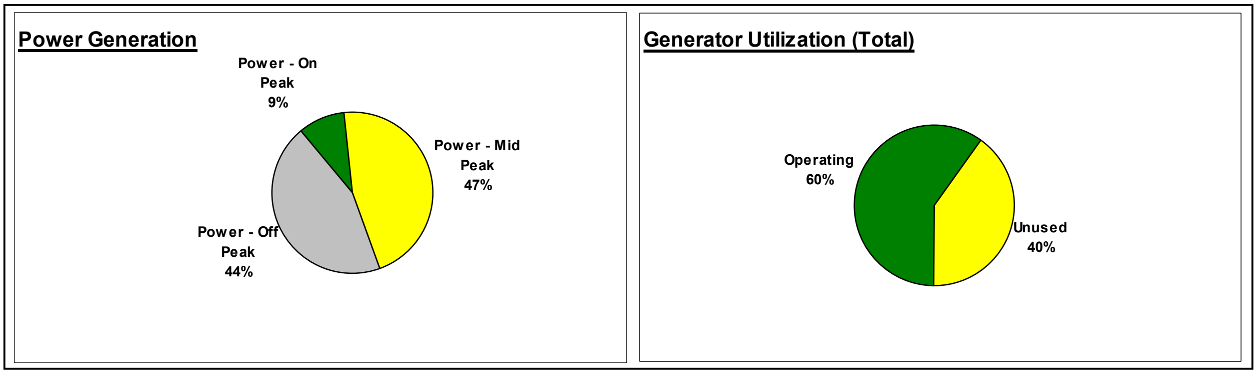

Figure 6-7. SC1 pro forma utility versus RE power generation by tariff period

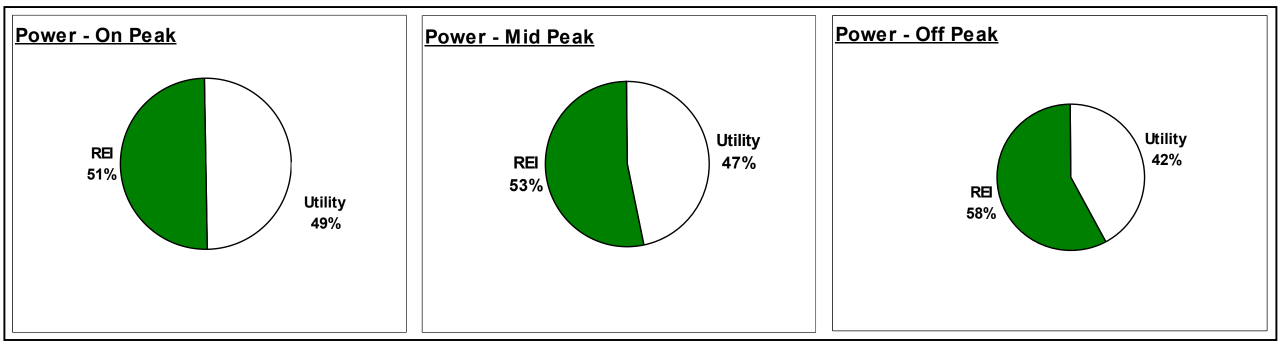

Figure 6-8. SC1 pro forma generator utilization by tariff period

6.3.4 Project SD2

SD2, like the facilities already presented, is a large commercial office building of more than 200,000 ft^2. It is located in San Diego. In its pro forma estimation, RE expected to generate electricity during 98% of on-peak hours, or 1,159 hours a year. In the mid-peak, RE expected to generate electricity 98% of the time, or about 2,808 hours a year. In the off-peak, RE expected to generate electricity 42% of the time, or about 1,991 hours. It expected to sell 100% of the captured thermal energy (net of system inefficiencies) by running a 100-ton absorption chiller. Capacity, availability, and reliability are summarized in Table 6-10.

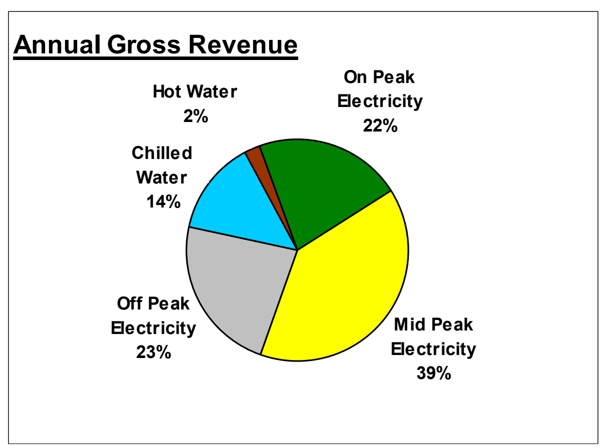

Figure 6-9. SD1 expected revenue sources

Table 6-10. SD2 Pro Forma Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	440,549	1,159	98%
Power – Mid-Peak	1,066,926	2,808	98%
Power – Off-Peak	756,480	1,991	42%
Total	2,263,955		
ICEs		2	
Total Availability (hours/year)		5,958	68%
Total Net Capacity (kW)		380	95%
Total Reliability (kWh)		2,263,955	65%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	45,584		100%
Chilled Water – Mid-Peak	109,648		100%
Chilled Water – Off-Peak	11,243		100%
Total	166,475		

6.3.4.1 Site Electric Load

In the pro forma base year, SD2 had an annual peak demand of 914 kW and an average of 617 kW on-peak, 504 kW mid-peak, and 233 kW off-peak. In 2003, the site averaged 677 kW on-peak, 458 kW mid-peak, and 254 kW off-peak in the summer. Peaks were 890 kW in summer and 776 kW in winter. In the pro forma, there were 730,035 kWh on-peak (about 65,000 more than 2003 actuals), 1,435,019 kWh mid-peak (about 68,000 more than 2003 actuals), and 1,102,267 kWh off-peak (about 63,000 less than 2003 actuals).

The following figures detail 2003 SD2 building loads.

Table 6-11. SD2 Site Electric Load Summary

Project SD2	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	1,445,765	502,653	437,334	502,086
Winter kWh	1,747,974	162,293	928,882	663,377
Total kWh	3,193,739	664,946	1,366,217	1,165,462
Summer Maximum kW	890.50			
Winter Maximum kW	776.50			
Summer Weekday Minimum kW	492.63			
Winter Weekday Minimum kW	504.50			
Summer Average kW		677	458	254
Winter Average kW		371	489	243

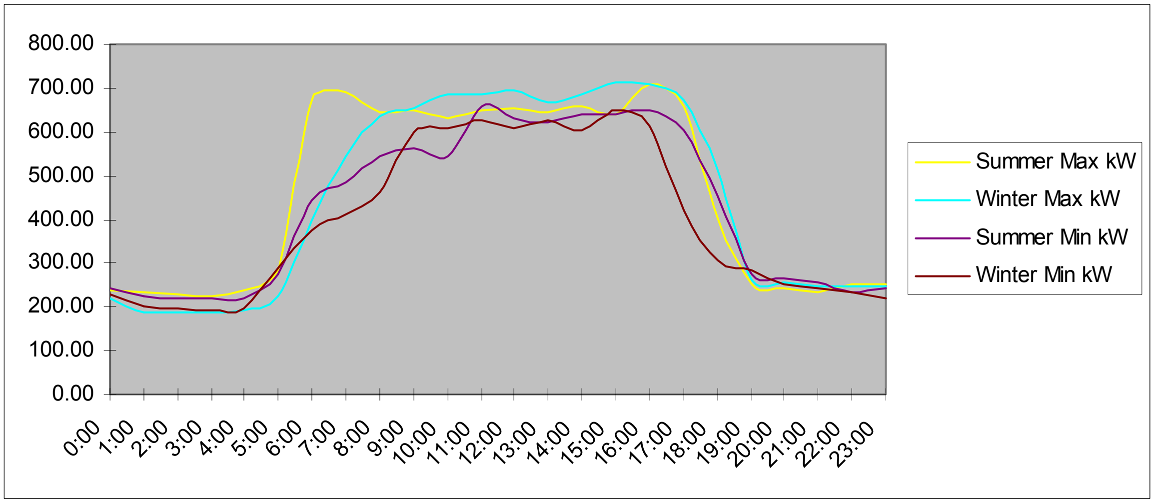

Figure 6-10. SD2 weekday minimum/maximum building loads (kW)

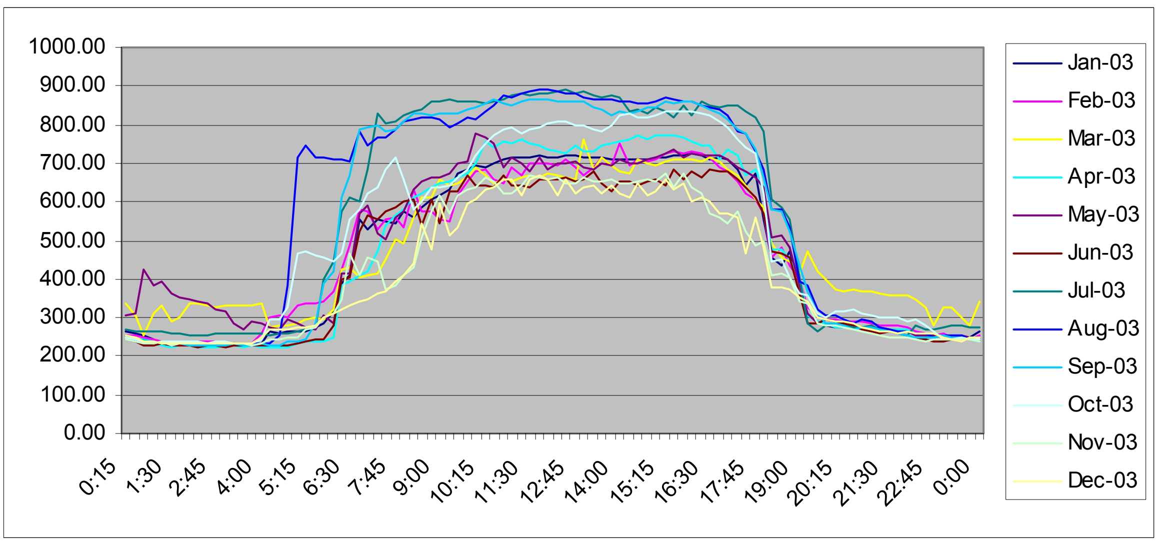

Figure 6-11. SD2 maximum kilowatts by month

6.3.4.2 Site Chiller Information

The building had an existing 300-ton electric chiller of unknown efficiency. RE expected to displace 63% of the operation of the chiller by capturing waste heat to feed an absorption chiller.

6.3.4.3 Performance Expectations

The following figures summarize RE's pro forma generation performance expectations. Once again, RE planned to produce a high percentage of the host facility's electricity. It expected to generate 73% of total power.

The pro forma expectation for revenue from hot water was dropped from the project when it was determined to be uneconomical. This was true of all four of the sample projects.

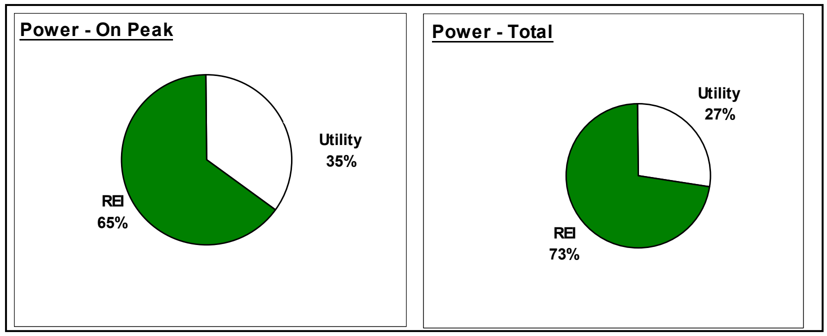

Figure 6-12. SD2 utility versus RE power generation by tariff period

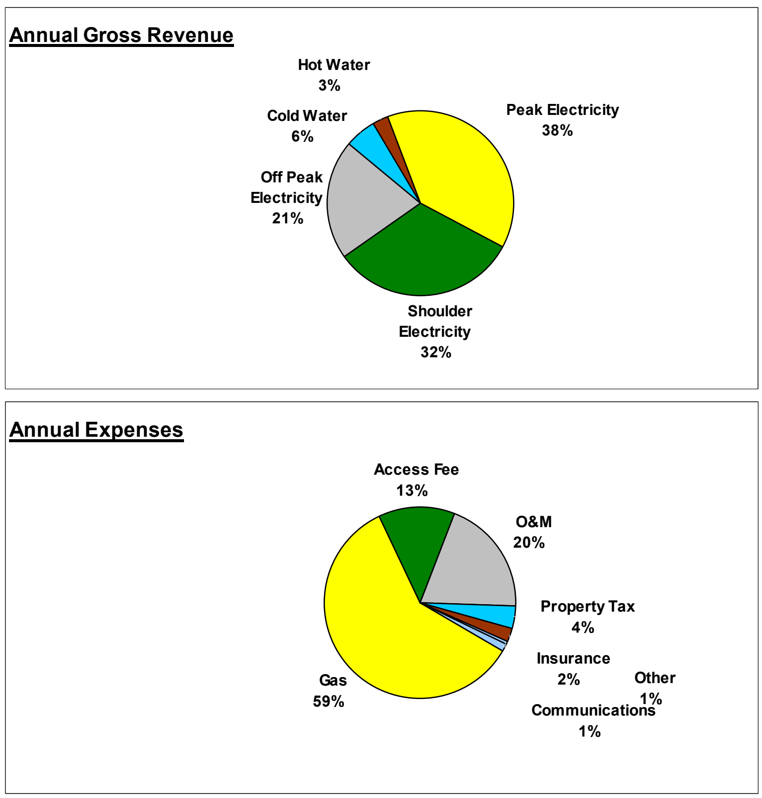

Figure 6-13. SD2 pro forma expected revenue and expense sources

6.3.5 Project SC2

SC2 is a commercial office building in the South Coast with more than 710,000 ft^2. In its pro forma estimation, RE expected to generate 98% of the on-, mid-, and off-peak hours, i.e., the maximum pro formed availability. RE expected to sell 100% of the captured thermal energy (net of system inefficiencies). Capacity was pro formed at the maximum, less parasitic loads (95%), 950 kW for the 5 ICEs. RE expected maximum reliability of 93%, running maximum hours at maximum capacity, as shown in Table 6-12.

Table 6-12. SC2 Pro Forma Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	491,568	517	98%
Power – Mid-Peak	2,744,588	2,889	98%
Power – Off-Peak	4,919,404	5,178	98%
Total	8,155,560		
ICEs		5	
Total Availability (hours/year)		8,585	98%
Total Net Capacity (kW)		950	95%
Total Reliability (kWh)		8,155,560	93%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	153,896		100%
Chilled Water – Mid-Peak	846,734		100%
Chilled Water – Off-Peak	869,370		100%
Total	1,870,000		

6.3.5.1 Site Electric Load

RE estimated that SC2 site load would be 1,947 kW on-peak, 1,580 kW mid-peak, and 1,159 kW off-peak. In 2003, the site averaged 1,857 kW on-peak, 1,462 kW mid-peak, and 1,042 kW off-peak in the summer. Peak kilowatts were 2,609 in summer and 2,288 in winter. So the pro forma building load is higher than the 2003 average but lower than the 2003 peak—although RE reported a 2,946-kW peak (from utility bills) in the pro forma year.

The following figures detail 2003 SC2 site operations.

Table 6-13. SC2 Site Electric Load Summary

Project SC2	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	4,831,508	1,377,641	1,395,196	2,058,671
Winter kWh	6,091,515	617,319	2,996,915	2,477,281
Total kWh	10,923,023	1,994,960	4,392,111	4,535,952
Summer Maximum kW	2609.00			
Winter Maximum kW	2288.00			
Summer Weekday Minimum kW	1726.00			
Winter Weekday Minimum kW	1492.00			
Summer Average kW		1,857	1,462	1,042
Winter Average kW		1,409	1,579	908

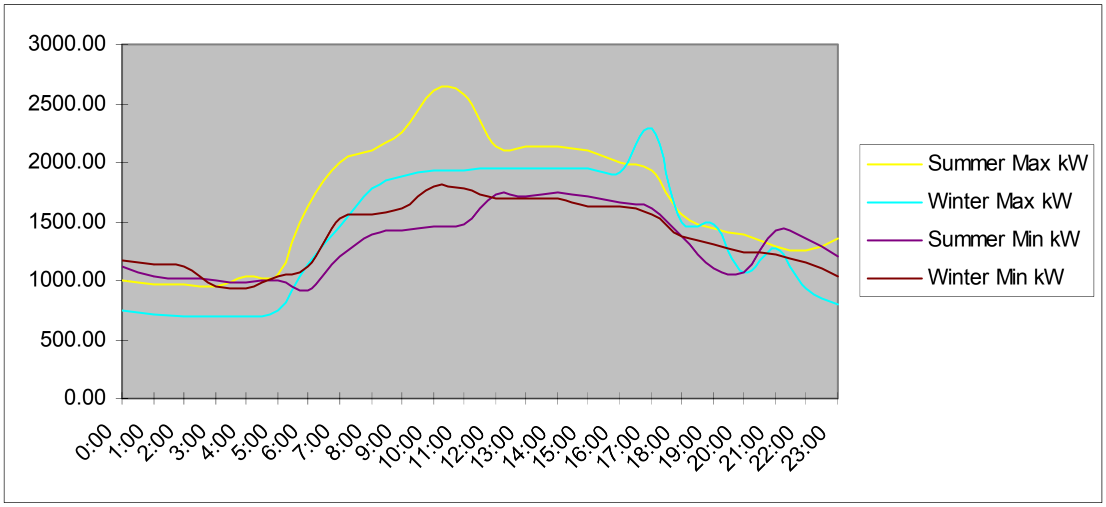

Figure 6-14. SC2 weekday minimum/maximum building loads (kW)

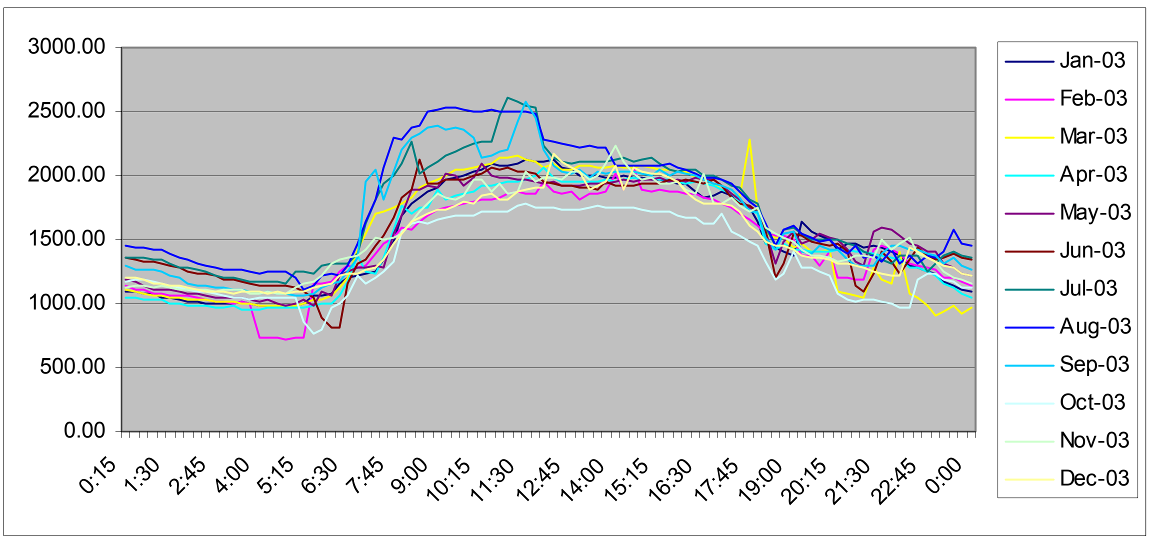

Figure 6-15. SC2 maximum kilowatts by month

6.3.5.2 Site Chiller Information

The building had two existing electric chillers, 700 tons and 300 tons, with efficiencies of 0.80 kW/ton-hour. RE expected to displace 59% of the operation of these chillers by capturing waste heat to feed an absorption chiller.

6.3.5.3 Performance Expectations

The following figures summarize RE's pro forma performance expectations.

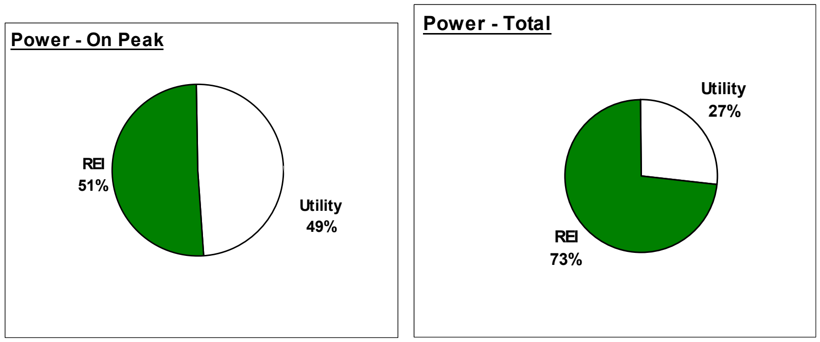

Figure 6-16. SC2 pro forma utility versus RE power generation by tariff period

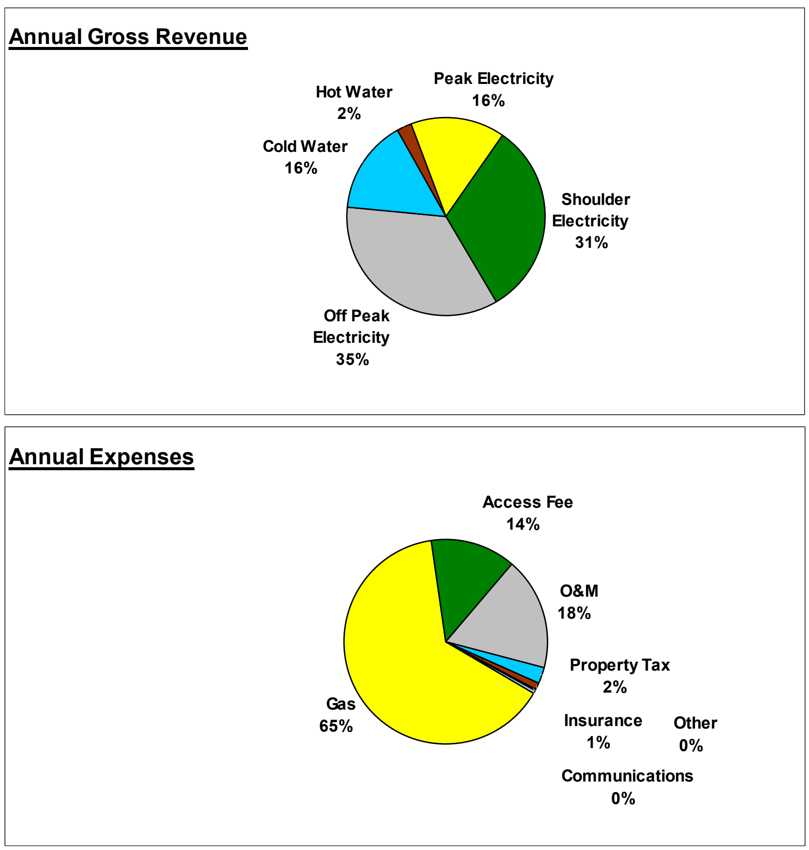

Figure 6-17. SC2 pro forma expected revenue sources and expenses

6.4 Actual Combined Heat and Power Trends

6.4.1 Non-Trended Causes of Non-Operation

RE's paper "Tariff Risk and DER Market Development" showed how spark spread became negative in 2003 during off-peak.[137] The two biggest causes of this change in the California CHP market were natural gas prices and utility tariffs. As noted above, neither of these causes is captured by RE's information system; they are non-trended. The trend data will show, however, the effect of these changes in the market. If the engines are shut off during off-peak, it can be assumed that the reason is spark spread at that time is negative.

Figure 2-10 detailed rising natural gas prices in 2003. The current TOU-8 SCE tariff modeled in "Tariff Risk and DER Market Development" showed the following electric time-of-use rate tariffs:[138]

Table 6-14. SCE Current TOU-8 Electric Tariff Rates

SCE TOU-8 (New)	Period	Summer	Winter
Energy	On-Peak	$0.14701	N/A
	Mid-Peak	$0.06890	$0.07996
	Off-Peak	$0.05004	$0.05108
Demand	On-Peak	$17.95	N/A
	Mid-Peak	$2.70	$0.00
	Off-Peak	$0.00	$0.00
	Non-Coincident	$6.60	

Because the pro formas of the projects in SCE territory assume higher rates in all tariff periods—and therefore better spark spreads (see Table 6-7, Table 6-9, Table 6-11, and Table 6-13)—the precipitous fall into unprofitability in the off-peak in 2003 must have been even more surprising. This effect is noted in the trend data.

6.4.2 Project SD1

Electricity generation did not meet the expectations of the pro forma in capacity, availability, or reliability. Actual on-peak and mid-peak generation in 2003 were only 60% of pro forma. Off-peak generation was 34%. The off-peak and some mid-peak hours may have been reduced because of economics. But analysis of on-peak performance shows performance degradation in availability and capacity when all units should be operating at maximum. Availability was 88% of pro forma; capacity was only 68% of pro forma. Overall reliability was 61%.

Thermal capture was also disappointing, though not as much as might be expected from the generation levels. Actual on-peak thermal capture in 2003 was 65% of pro forma, mid-peak thermal capture was 42% of pro forma, and off-peak thermal capture was 56% of pro forma. Total thermal capture was 50% of the expected level.

[137] See Figure 3.1 of the report.
[138] See Table 4.2 of the report.

Table 6-15. SD1 Actual Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	396,429		60%
Power – Mid-Peak	938,094		60%
Power – Off-Peak	681,617		34%
Total	2,016,139		
Summer Peak Performance			
Availability (hours/year)		655	88%
Average Capacity (kW)		386	68%
Reliability (kWh)		252,978	61%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	84,865		65%
Chilled Water – Mid-Peak	120,792		42%
Chilled Water – Off-Peak	24,589		56%
Total	230,246		50%

6.4.2.1 Electricity Generation

The following table summarizes actual generation totals, in terms of kilowatts and kilowatt-hours, by utility tariff period. Summer and winter maximum and minimum kilowatt days, with the addition of maximum kilowatt-hour days, are given in Table 6-16. Negative generation (when the generator is off) is due to parasitic loads on site. Figure 6-19 shows average seasonal changes in electricity generation with monthly totals.

Table 6-16. SD1 Site Electric Load Summary

Project SD1	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	924,701	252,978	275,280	396,443
Winter kWh	1,091,438	143,451	662,814	285,173
Total kWh	2,016,139	396,429	938,094	681,617
Summer Maximum kW	506.72			
Winter Maximum kW	571.75			
Summer Weekday Minimum kW	210.53			
Winter Weekday Minimum kW	-9.50			
Summer Average kW		341	289	204
Winter Average kW		323	358	97

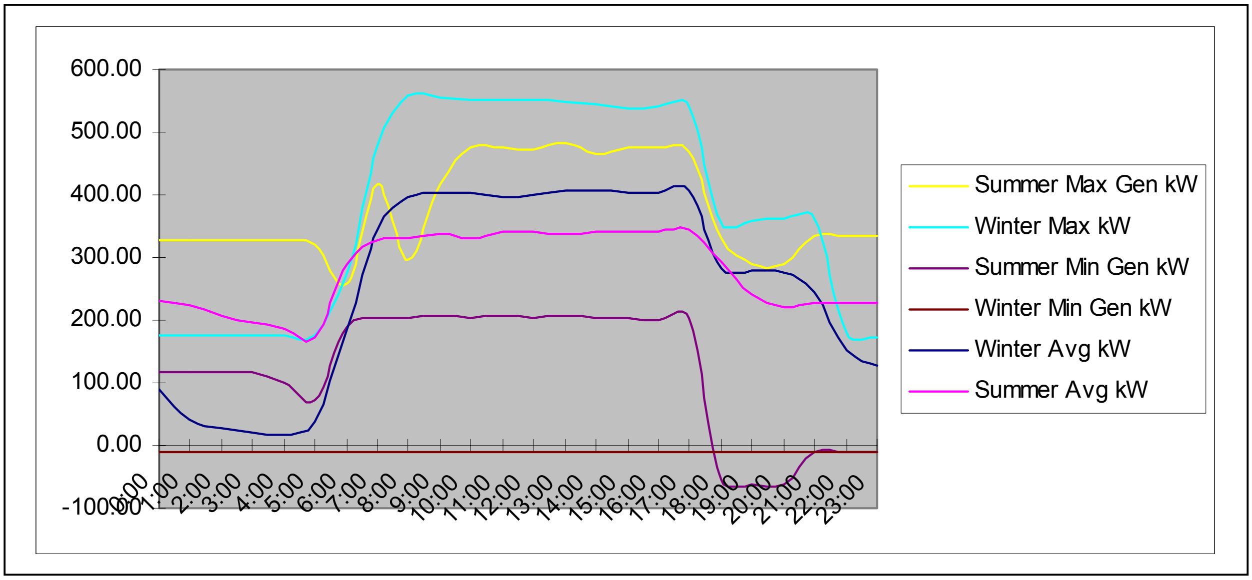

Figure 6-18. SD1 weekday minimum/maximum electric generation (kW/kWh)

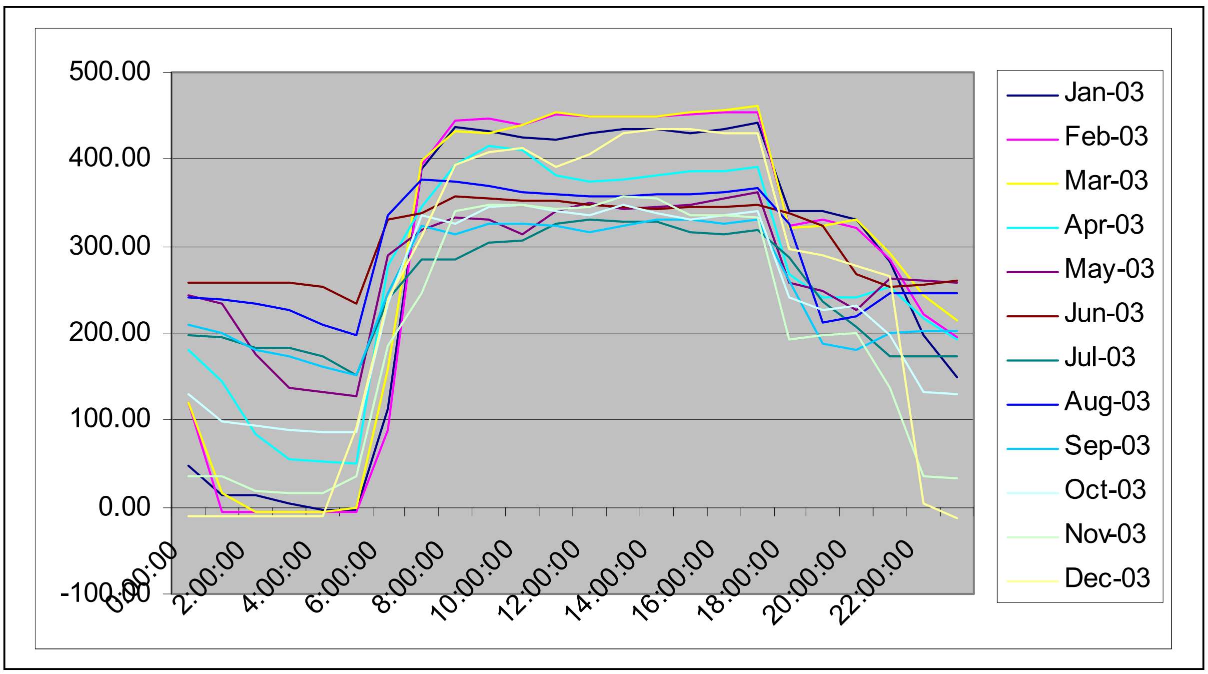

Figure 6-19. SD1 average generator load kilowatt output by month

6.4.2.2 Thermal Byproduct

Table 6-17 summarizes thermal capture totals in tons and ton-hours by utility tariff period. Summer and winter maximum and minimum ton-output days, with the addition of maximum ton-hour days, are graphed in Figure 6-20. The winter maximum tons figure is likely a monitoring error because it is about twice as much as any other value for the season.

Figure 6-21 shows average seasonal changes in thermal capture with monthly totals.

Table 6-17. SD1 Thermal Capture Summary

Project SD1	Total	On-Peak	Mid-Peak	Off-Peak
Summer ton-hours	147,857	78,694	50,619	18,544
Winter ton-hours	82,389	6,171	70,173	6,045
Total ton-hours	230,246	84,865	120,792	24,589
Summer Maximum tons	166.75			
Winter Maximum tons	433.25			
Summer Weekday Minimum tons	0.00			
Winter Weekday Minimum tons	0.00			
Summer Average tons		106	53	9
Winter Average tons		14	37	2

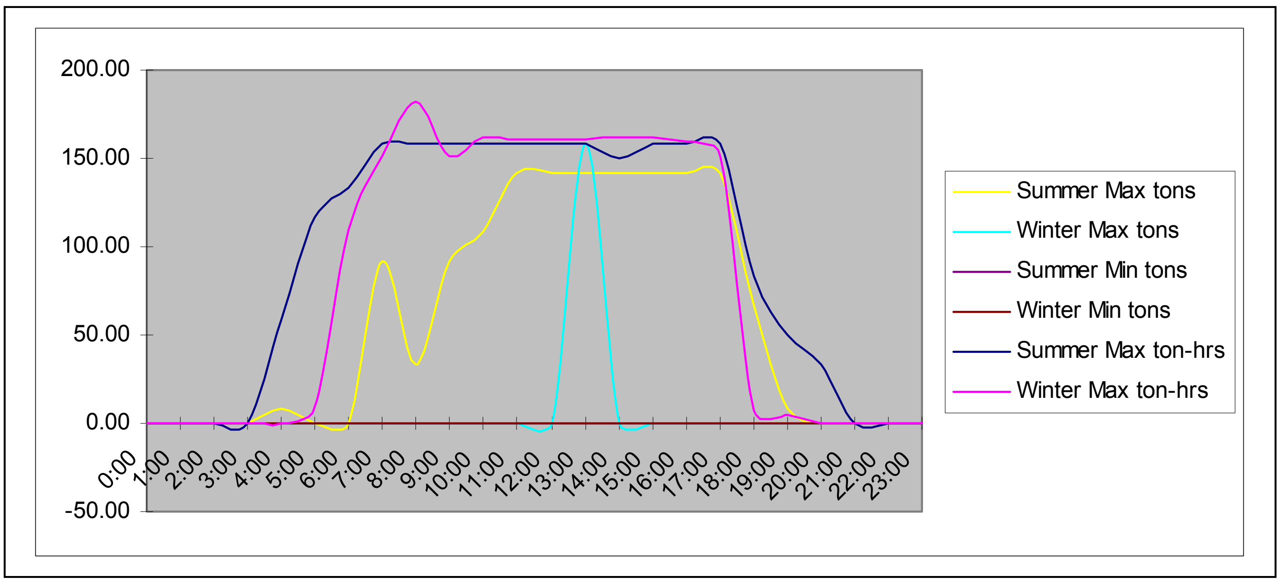

Figure 6-20. SD1 weekday minimum/maximum thermal capture (tons/ton-hours)

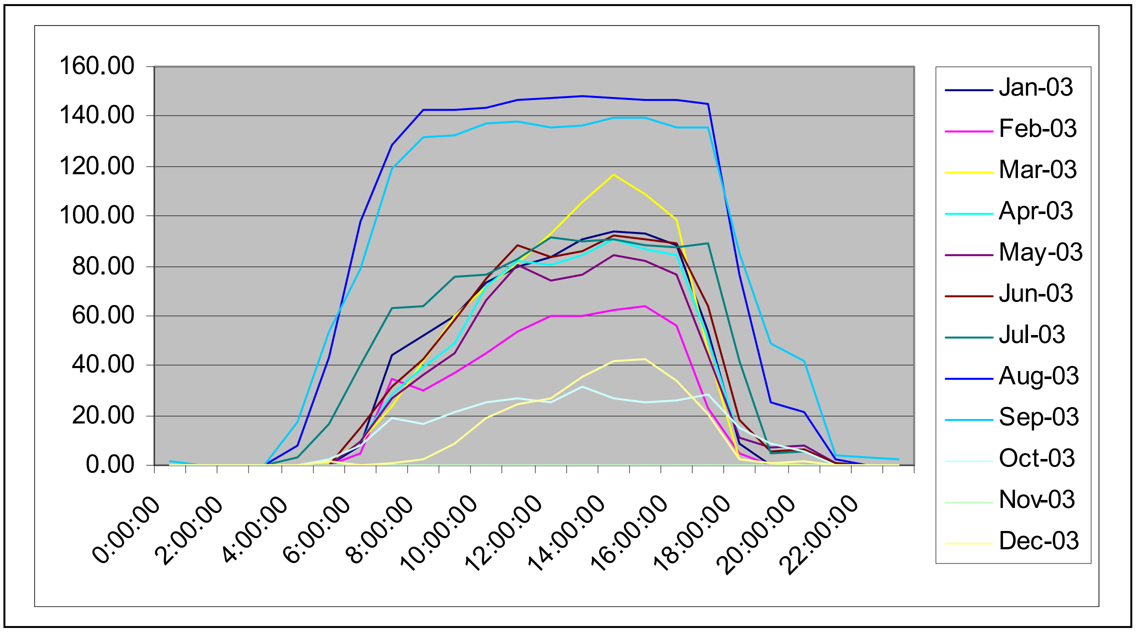

Figure 6-21. SD1 average thermal capture by month (tons)

6.4.3 Project SC1

SC1 performance suffered in comparison with the pro forma. Economic issues such as reductions in utility tariffs and increased gas prices caused a significant reduction in off-peak hours, which are only 9% of the pro forma. Mid-peak hours were reduced by 42% by economic factors. Availability during summer on-peak was 92%, though capacity was only 85% of what RE expected. Overall reliability for on-peak hours was 80%. Chilled water production was down to 38% and 19% of pro forma levels for on- and mid-peak.

Table 6-18. SC1 Actual Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	235,689		80%
Power – Mid-Peak	616,673		42%
Power – Off-Peak	120,279		9%
Total	972,641		
Summer Peak Performance			
Availability (hours/year)		486	92%
Average Capacity (kW)		485	85%
Reliability (kWh)		235,689	80%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	27,853		38%
Chilled Water – Mid-Peak	44,142		19%
Chilled Water – Off-Peak	630		–
Total	72,624		24%

6.4.3.1 Electricity Generation

Table 6-19 summarizes actual generation for SC1 in kilowatts and kilowatt-hours by utility tariff period. Summer and winter maximum and minimum kilowatt days are graphed in Figure 6-22. Negative generation (when the generator is off) is due to parasitic loads on site. Figure 6-23 shows average seasonal changes in electricity generation with monthly totals.

Table 6-19. SC1 Site Electric Load Summary

Project SC1	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	600,909	282,751	223,490	95,942
Winter kWh	418,793	0	393,182	24,336
Total kWh	1,019,702	282,751	616,673	120,279
Summer Maximum kW	525.13			
Winter Maximum kW	625.86			
Summer Weekday Minimum kW	312.06			
Winter Weekday Minimum kW	-15.73			
Summer Average kW		435	199	44
Winter Average kW		99	191	5

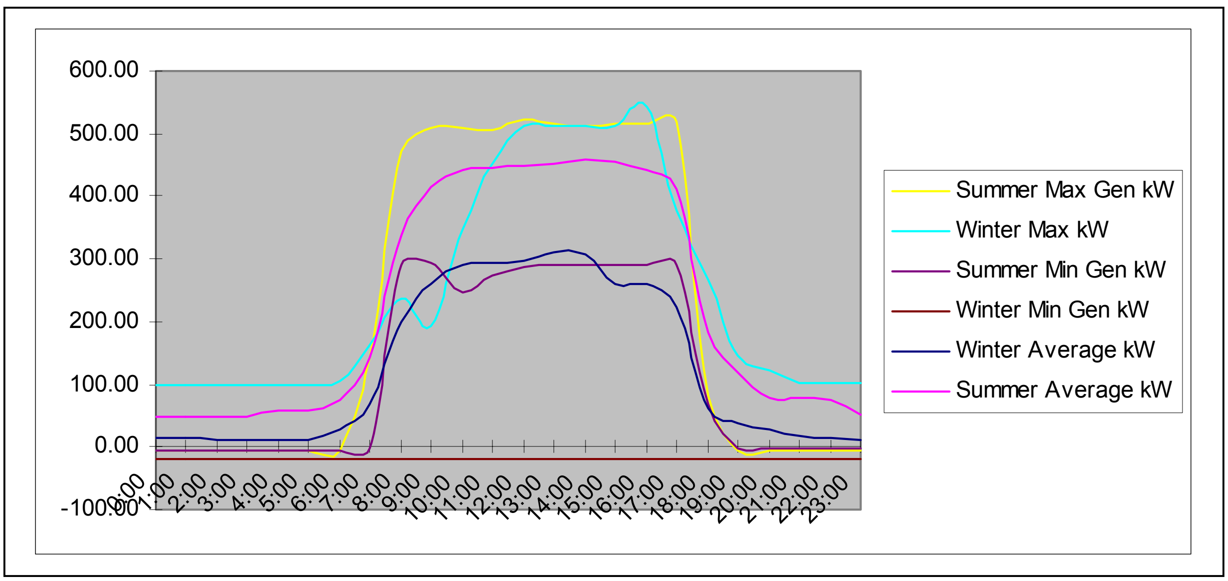

Figure 6-22. SC1 weekday minimum/maximum electric generation (kW/kWh)

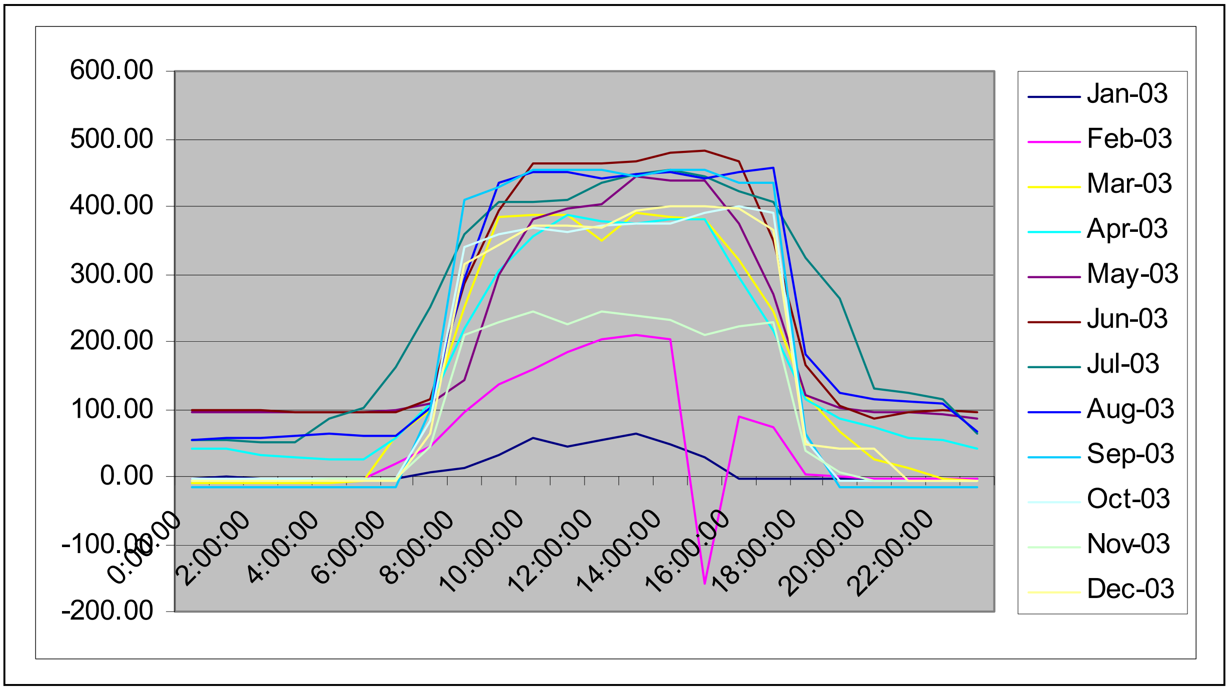

Figure 6-23. SC1 average generator load kilowatt output by month

November, January, and February show especially poor capacities. Trend data are used to discover whether low months are caused by weather, reduced occupancy, equipment malfunction, or metering/monitoring error. Once the cause is known, management action can improve performance.

6.4.3.2 Thermal Byproduct

Table 6-20 summarizes thermal capture totals in tons and ton-hours by utility tariff period. Summer and winter maximum and minimum ton output days, with the addition of maximum ton-hour days, are graphed in Figure 6-24. The winter maximum tons figure is likely a monitoring error because it is about twice as much as any other value for the season. Figure 6-24 shows average seasonal changes in thermal capture with monthly totals.

Table 6-20. SC1 Thermal Capture Summary

Project SC1	Total	On-Peak	Mid-Peak	Off-Peak
Summer ton-hours	45,182	27,853	18,233	627
Winter ton-hours	27,442	0	25,908	3
Total ton-hours	72,624	27,853	44,142	630
Summer Maximum tons	143.34			
Winter Maximum tons	143.34			
Summer Weekday Minimum tons	0.00			
Winter Weekday Minimum tons	0.00			
Summer Average tons		41	15	0
Winter Average tons		6	13	0

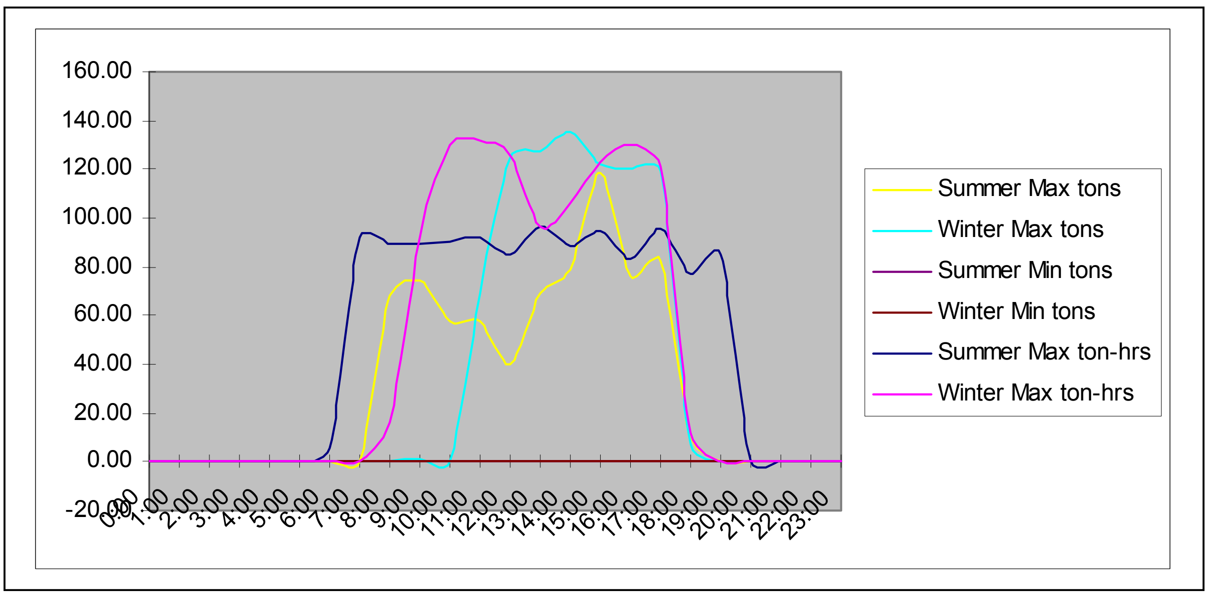

Figure 6-24. SC1 weekday minimum/maximum thermal capture (tons/ton-hours)

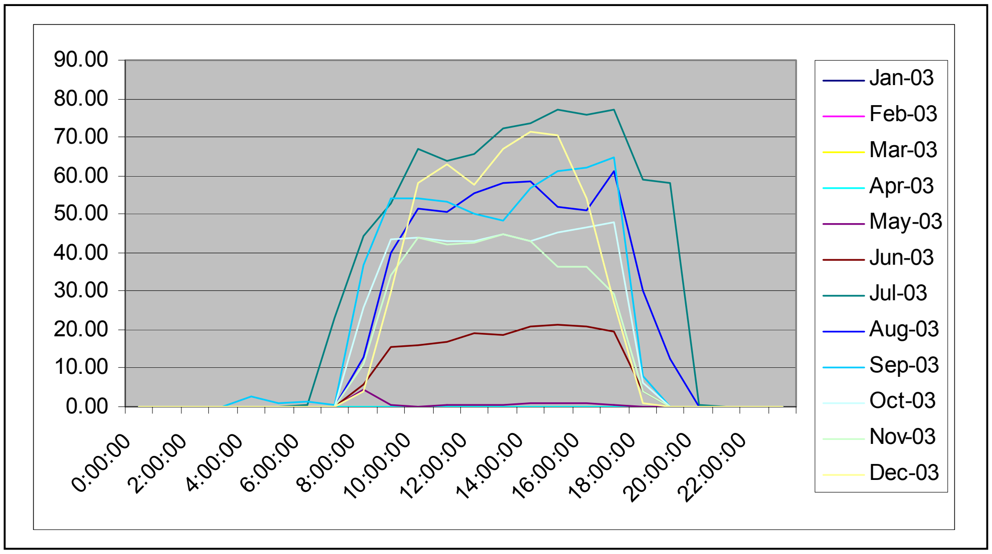

Figure 6-25. SC1 average thermal capture by month (tons)

6.4.4 Project SD2

Like the other sites, SD2 performed worse than expected. Reliability for on-peak, mid-peak, and off-peak was 60%, 54%, and 40% of pro forma, respectively. Summer on-peak was slightly better at 70% reliability.[139] Summer on-peak availability was 94%, but net capacity was only 279 kW—less than 140 kW per ICE.[140]

Results are shown in Table 6-21.

[139] The reason for the discrepancy between on-peak and summer on-peak is that SDG&E (unlike SCE) has a winter on-peak period. Performance during winter on-peak brought total on-peak reliability down.

[140] Net capacity is a calculation of engine kilowatt output after adjusting for availability. Recall that availability is a measure of an engine that is able to produce at least 50% of its nameplate capacity. If availability were considered to be the ability to turn on and produce greater than 0 kW, the resulting kilowatts would be gross capacity.

Table 6-21. SD2 Actual Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	263,158		60%
Power – Mid-Peak	573,926		54%
Power – Off-Peak	301,142		40%
Total	1,138,226		
Summer Peak Performance			
Availability (hours/year)		696	94%
Average Capacity (kW)		279	74%
Reliability (kWh)		194,538	70%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	36,467		80%
Chilled Water – Mid-Peak	67,803		62%
Chilled Water – Off-Peak	38,033		338%
Total	142,303		85%

6.4.4.1 Electricity Generation

Table 6-22 summarizes actual generation for SD2 in kilowatts and kilowatt-hours by utility tariff period. In Figure 6-26, summer and winter maximum and minimum kilowatt days are graphed. The winter minimum generation is negative because of parasitic loads on site. Figure 6-27 shows average seasonal changes in electricity generation with monthly totals.

Table 6-22. SD2 Site Electric Load Summary

Project SD	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	529,278	194,538	192,942	141,797
Winter kWh	608,948	68,620	380,983	159,345
Total kWh	1,138,226	263,158	573,926	301,142
Summer Maximum kW	349.50			
Winter Maximum kW	363.00			
Summer Weekday Minimum kW	119.88			
Winter Weekday Minimum kW	-14.50			
Summer Average kW		262	202	76
Winter Average kW		155	206	52

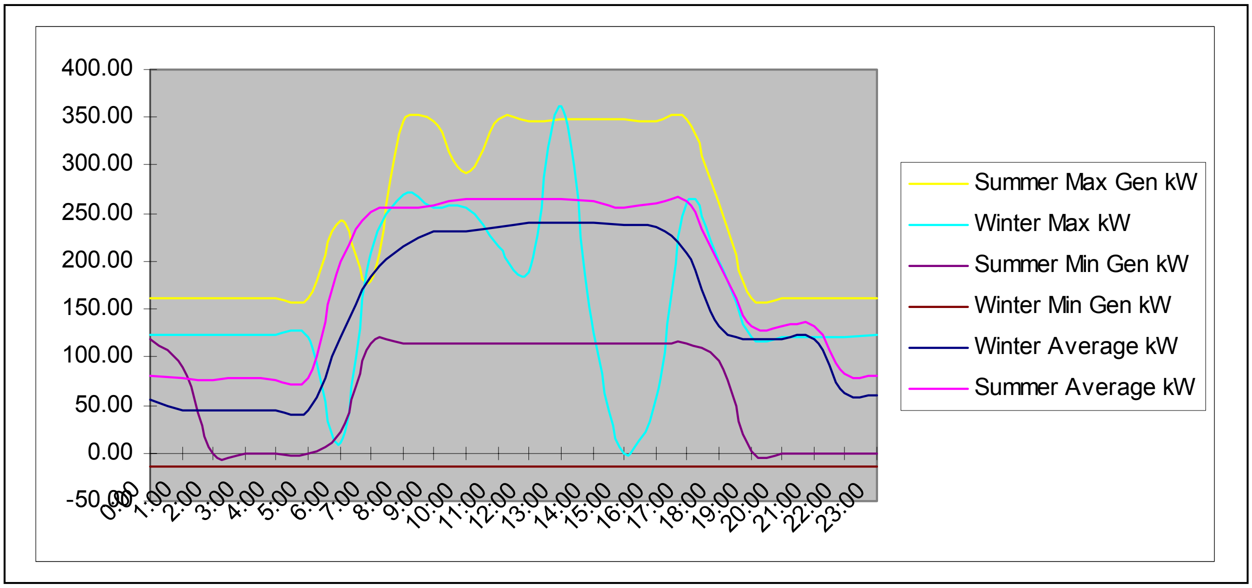

Figure 6-26. SD2 weekday minimum/maximum electric generation (kW/kWh)

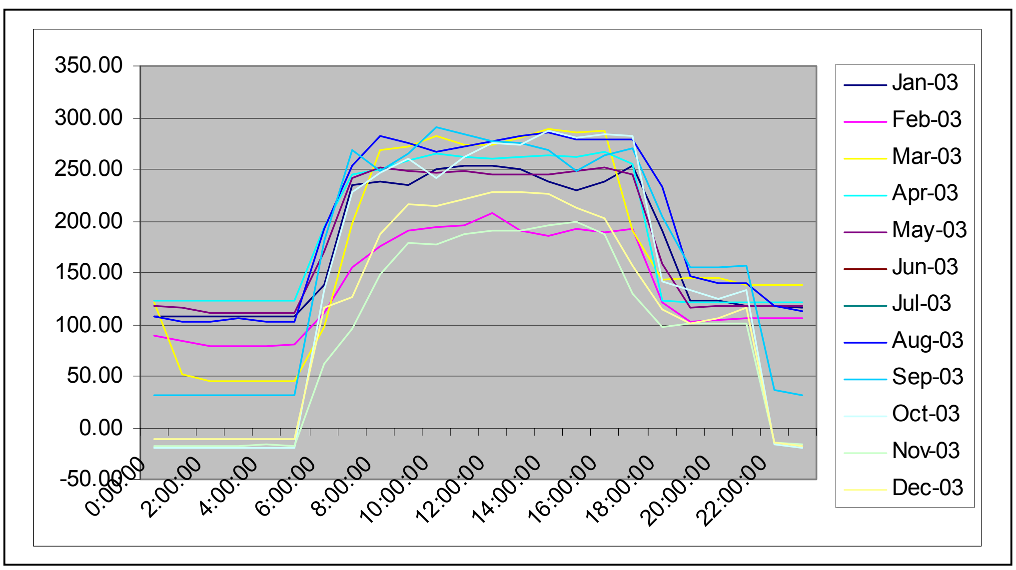

Figure 6-27. SD2 average generator load kilowatt output by month

6.4.4.2 Thermal Byproduct

Table 6-23 summarizes thermal capture totals in tons and ton-hours by SDG&E tariff period. In Figure 6-28, summer and winter maximum and minimum ton output days, with the addition of maximum ton-hour days, are graphed. Figure 6-28 shows average seasonal changes in thermal capture with monthly totals.

Table 6-23. SD2 Thermal Capture Summary

Project SD2	Total	On-Peak	Mid-Peak	Off-Peak
Summer ton-hrs	71,302	31,667	20,098	19,537
Winter ton-hrs	71,002	4,801	47,705	18,496
Total ton-hrs	142,303	36,467	67,803	38,033
Summer Maximum tons	116.66			
Winter Maximum tons	113.33			
Summer Weekday Minimum tons	0.00			
Winter Weekday Minimum tons	0.00			
Summer Average tons		43	21	10
Winter Average tons		11	25	7

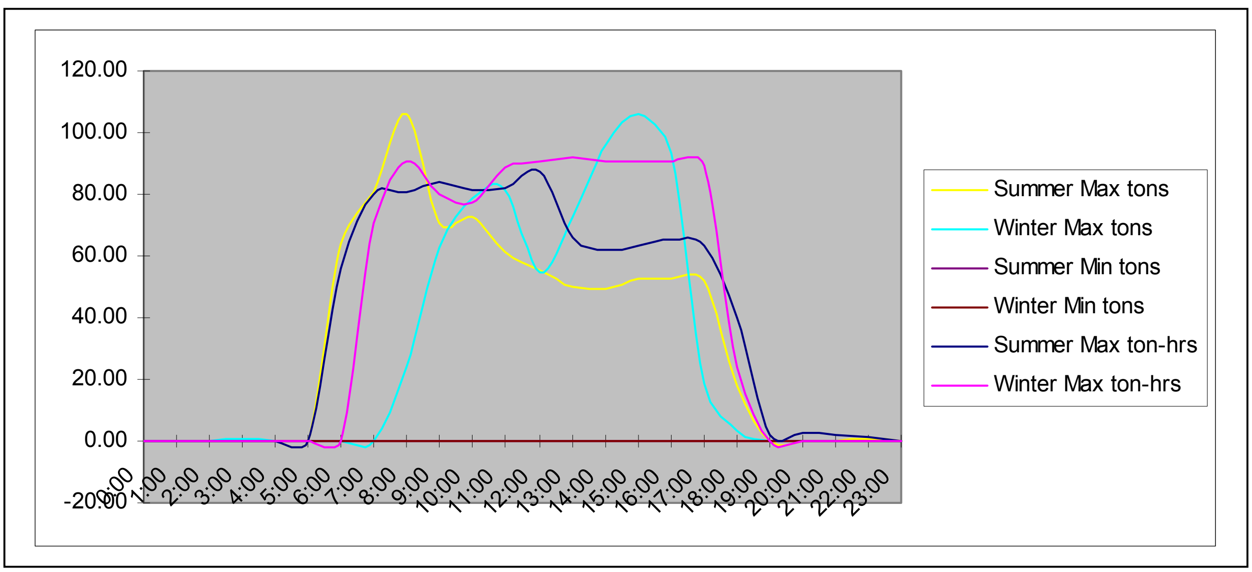

Figure 6-28. SD2 weekday minimum/maximum thermal capture (tons/ton-hours)

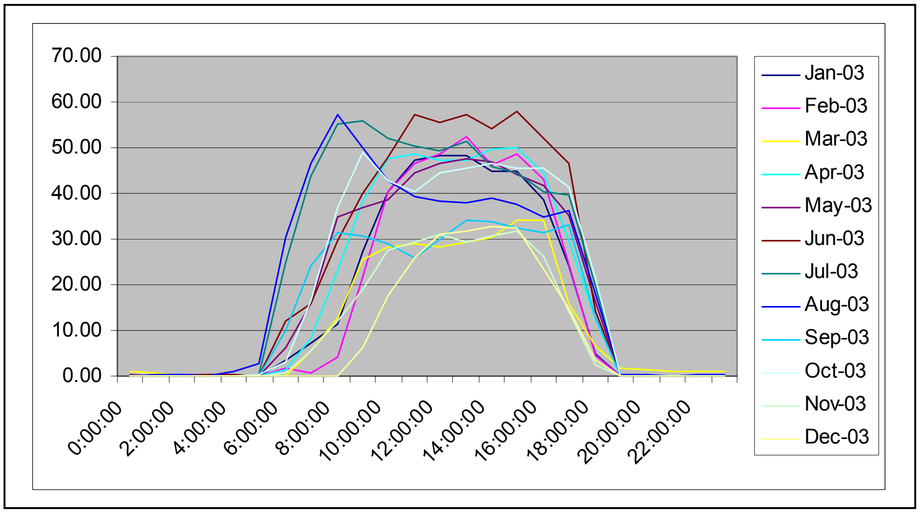

Figure 6-29. SD2 average thermal capture by month (tons)

6.4.5 Project SC2

SC2 is probably the best-performing of the sites reviewed here. It achieved 86%, 71%, and 39% of its expected generation in the on-peak, mid-peak, and off-peak periods, respectively. Recall that off-peak generation was rolled back, especially in SCE territory, because of utility tariff decreases and, in all utility territories, because of higher-than-expected gas prices. Availability in on-peak was relatively good at 94%. Net capacity was 849 kW for five engines—170 kW each on average. This is certainly the best performance of the sites reviewed. Overall on-peak reliability was 86%.

Results appear in Table 6-24.

Table 6-24. SC2 Actual Electric and Thermal Productivity

	Net Generation	Performance Data	Performance Factors
Energy – Electric (kWh)			
Power – On-Peak	421,550		86%
Power – Mid-Peak	1,949,392		71%
Power – Off-Peak	1,924,384		39%
Total			
Summer Peak Performance			
Availability (hours/year)		497	94%
Average Capacity (kW)		849	89%
Reliability (kWh)		421,550	86%
Energy – Thermal (ton-hour)			
Chilled Water – On-Peak	71,908		47%
Chilled Water – Mid-Peak	354,233		42%
Chilled Water – Off-Peak	1,924,384		221%
Total	2,350,526		126%

6.4.5.1 Electricity Generation

Table 6-25 summarizes actual generation for SC1 in kilowatts and kilowatt-hours by utility tariff period. Summer and winter maximum and minimum kilowatt days are graphed in Figure 6-30. Negative generation (when the generator is off) is due to parasitic loads on site. Figure 6-31 shows average seasonal changes in electricity generation with monthly totals.

Table 6-25. SC2 Site Electric Load Summary

Project SC2	Total	On-Peak	Mid-Peak	Off-Peak
Summer kWh	1,893,844	504,663	662,960	739,510
Winter kWh	2,484,595	0	1,286,432	1,184,874
Total kWh	4,378,439	504,663	1,949,392	1,924,384
Summer Maximum kW	868.94			
Winter Maximum kW	881.06			
Summer Weekday Minimum kW	671.00			
Winter Weekday Minimum kW	-5.00			
Summer Average kW		788	658	355
Winter Average kW		644	623	366

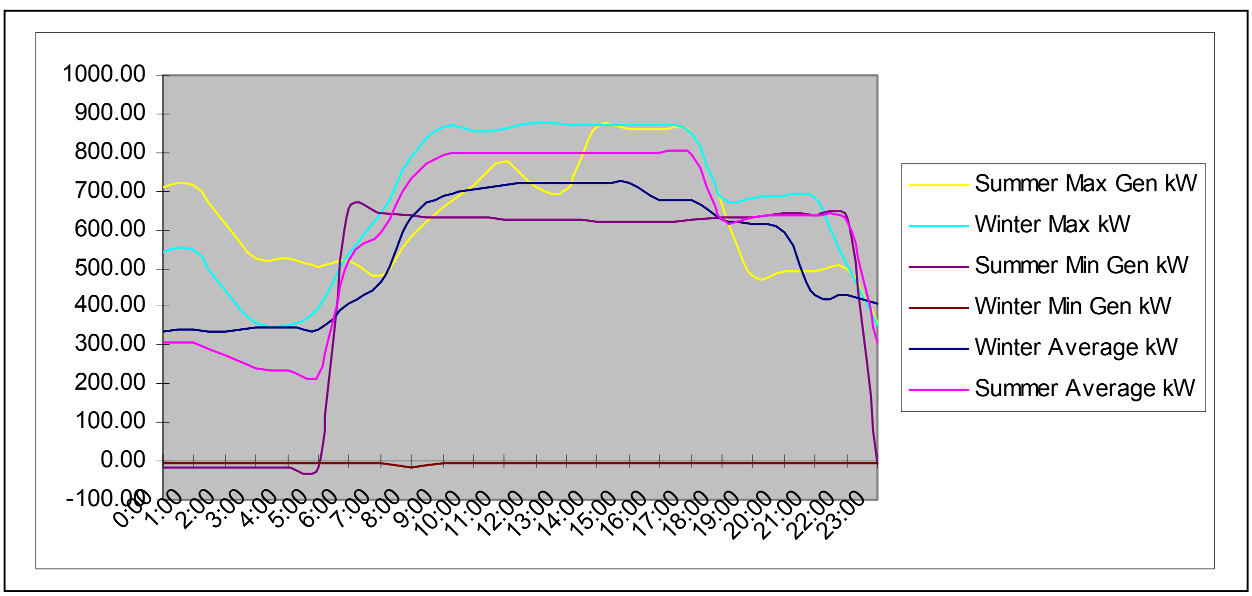

Figure 6-30. SC2 weekday minimum/maximum electric generation (kW)

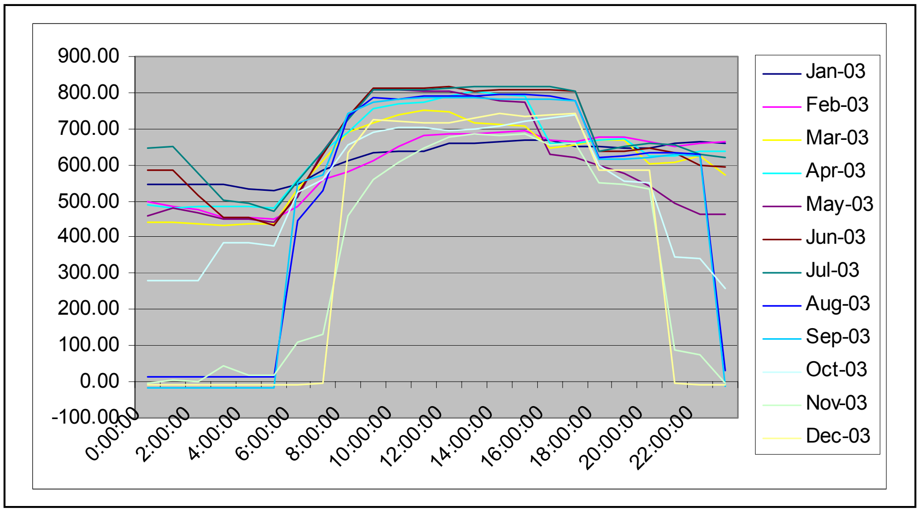

Figure 6-31. SC2 average generator load kilowatt output by month

6.4.5.2 Thermal Byproduct

Table 6-26 summarizes thermal capture totals in tons and ton-hours by utility tariff period. Summer and winter maximum and minimum ton output days, with the addition of maximum ton-hour days, are graphed in Figure 6-32. Figure 6-33 shows average seasonal changes in thermal capture with monthly totals.

Table 6-26. SC2 Thermal Capture Summary

Project SC2	Total	On-Peak	Mid-Peak	Off-Peak
Summer ton-hrs	243,667	71,908	119,141	56,300
Winter ton-hrs	373,042	0	235,092	134,267
Total ton-hrs	616,708	71,908	354,233	190,567
Summer Maximum tons	233.31			
Winter Maximum tons	233.38			
Summer Weekday Minimum tons	166.67			
Winter Weekday Minimum tons	0.00			
Summer Average tons		117	117	24
Winter Average tons		97	117	39

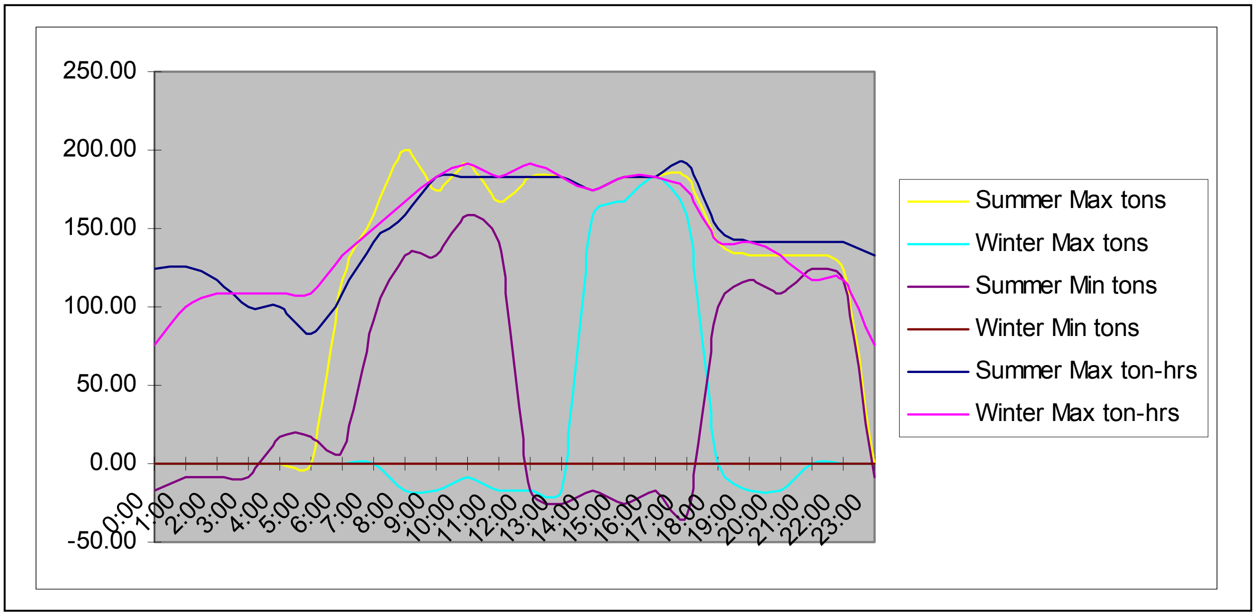

Figure 6-32. SC2 weekday minimum/maximum thermal capture (tons/ton-hours)

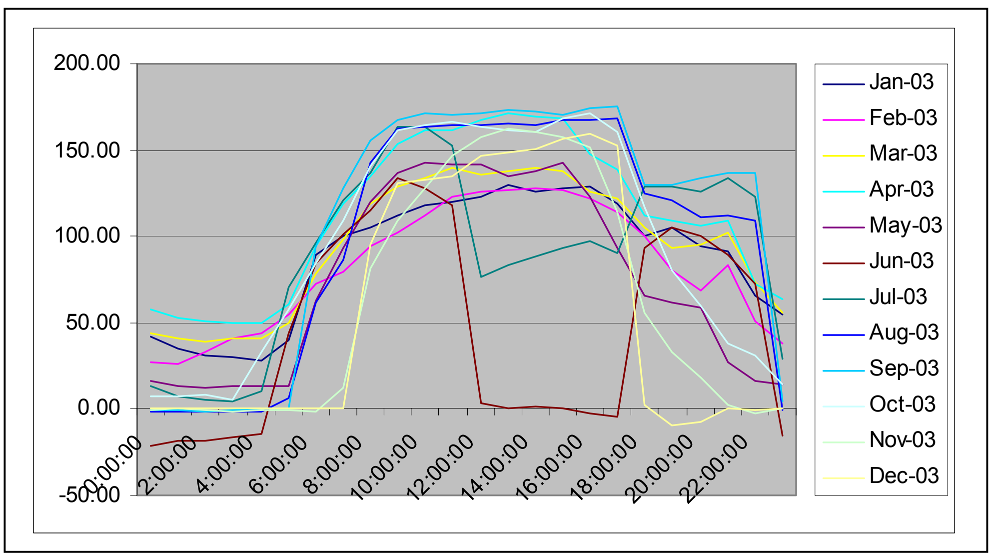

Figure 6-33. SC2 average thermal capture by month (tons)

6.4.6 Common Performance Issues

6.4.6.1 Prices and Tariffs

Electric utility tariffs are going down as California utilities in the post-"energy crisis" pay off accounts. Although the pro forma expectations extended the utility tariff extant in 2001 or 2002 out 15 years, those tariff rates after only 2–3 years are already quite inaccurate. Gas rates (also mentioned) have fluctuated and recently gone up. The combination of gas hikes and utility rate decreases has put a serious squeeze on spark spreads and made off-peak operation uneconomic.

6.4.6.2 The Internal Combustion Engines

Poor off-peak generation totals can be attributed to negative spark spread. But how can poor on-peak and mid-peak generation totals be accounted for? The cogeneration systems should be running throughout these periods to make up for lost revenues. But that is not what the data show. In fact, all on-peak and mid-peak operations average just 64% and run at fractions from 37% to 96% of pro forma expectations. A close look at the trend data shows two causes:

- The cogeneration systems are not performing at nameplate-rated kilowatt outputs.
- The cogeneration systems often fail and are unavailable to run at any output level.

There are two primary causes of poor cogeneration system performance: the engine gensets are malfunctioning or building operating conditions are such that the engine gensets cannot run or are running at reduced output. The trend data in this report do not differentiate between the two. There is additional trend data available in RE's energy information and management system; however, this data was not analyzed for this report. The important point is that RE can analyze the data to identify causes of failure and take corrective action.

The following tables show that cogenerations systems run between 44% and 88% reliability. The engines not only failed to run at their full 200-kW capacity, but in the peak period in 2003, they also never reached a constant output of 180 kW in a 15-minute period. That is, the engines were not able to run at 90% of their rated output *ever*. Overall availability of all systems sampled was only 61%. Overall unavailability was pro formed at 2%; actual unavailability ran 6%–12%. Additional performance metrics are shown in Table 6-27.

Table 6-27. On-Peak Engine Performance – All Sites

SD1 – On-Peak Engine Performance		% of Time	# of Periods	
Pro Forma Net kWh	414,481	0%	0	# of times 3 engines ran at least 180 kW
Actual kWh	252,978	3%	84	# of times 3 engines ran at least 150 kW
Overall Reliability	61.0%	47%	1405	# of times 2 engines ran at least 180 kW
		79%	2359	# of times 2 engines ran at least 150 kW

SC1 – On-Peak Engine Performance				
Pro Forma Net kWh	293,066	0%	0	# of times 3 engines ran at least 180 kW
Actual kWh	235,689	73%	1549	# of times 3 engines ran at least 150 kW
Overall Reliability	80.4%	85%	1800	# of times 2 engines ran at least 180 kW
		93%	1969	# of times 2 engines ran at least 150 kW

SD2 - Summer On-Peak Engine Performance				
Pro Forma Net kWh	276,321			
Actual kWh	194,538	0%	0	# of times 2 engines ran at least 180 kW
Overall Reliability	70.4%	15%	431	# of times 2 engines ran at least 150 kW
		88%	2611	# of times 1 engines ran at least 180 kW
		96%	2840	# of times 1 engine ran at least 150 kW

SC2 - On Peak Engine Performance				
Pro Forma Net kWh	491,568	0%	0	# of times 5 engines ran at least 180 kW
Actual kWh	421,550	89%	1872	# of times 5 engines ran at least 150 kW
Overall Reliability	85.8%	89%	1874	# of times 4 engines ran at least 180 kW
		94%	1975	# of times 4 engines ran at least 150 kW

The cogeneration system at SD2 performed so poorly that the engines had to be derated to run at 150 kW tops rather than the (twice-derated) level of 185 kW. Their operation at just less than 300 kW (for two engines) is shown in Figure 6-34 before and after the depicted failures.

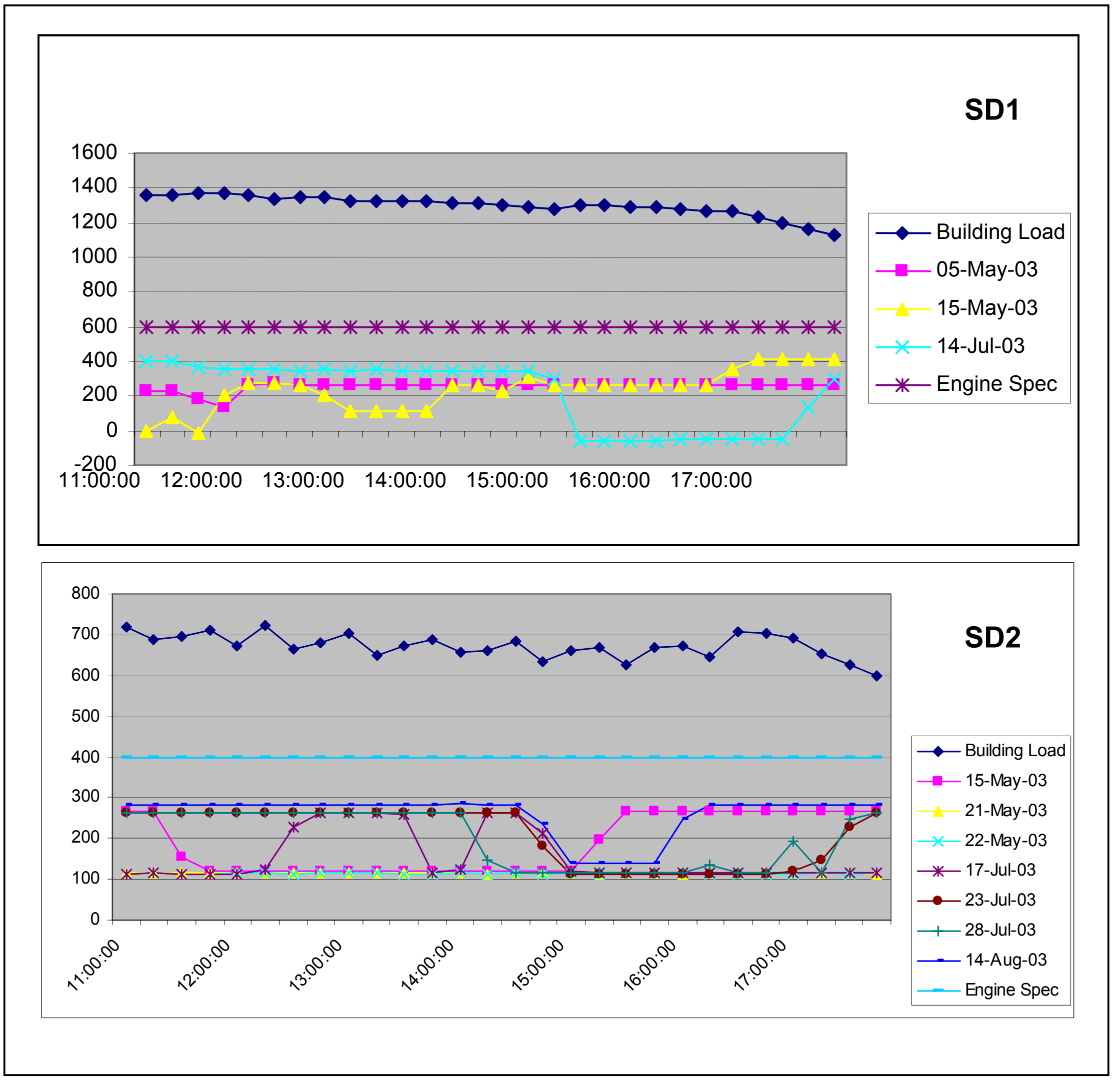

Figure 6-34. San Diego sites poor cogeneration performance days

It appears that on Sept. 5 and 8, shown in SC1 in Figure 6-35, that the third engine was unavailable during the peak period—a not-uncommon situation, particularly at SD1, SD2, and SC1.

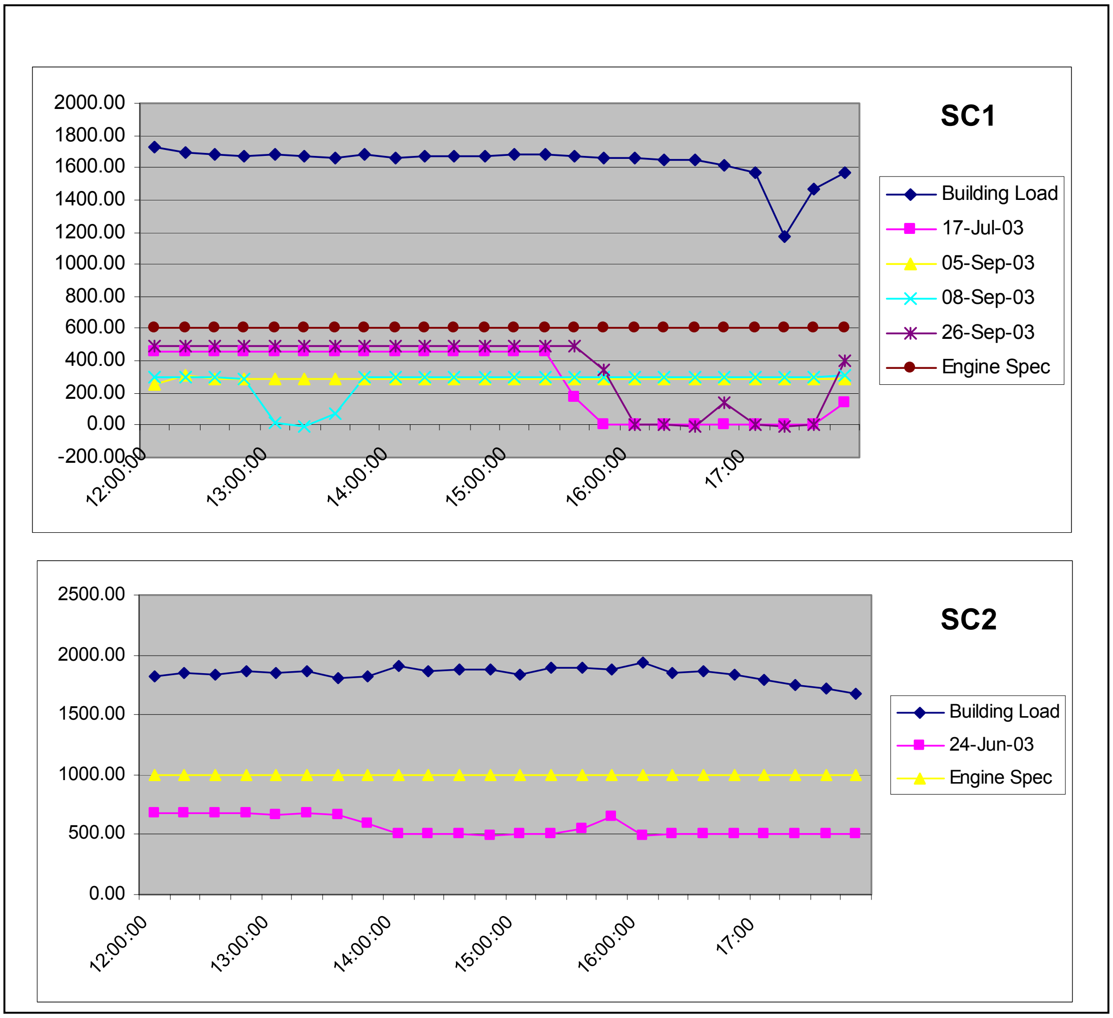

Figure 6-35. Southern California sites poor cogeneration performance days

6.4.6.3 The Absorption Chillers

One would expect thermal capture to suffer from lack of engine reliability, and that has been the case. Figure 6-36 tracks chiller performance on the "poor cogeneration days"—the same days tracked in Figure 6-34 and Figure 6-35. It is worth noting that the absorption chillers—although they did not perform as well as could be desired—at least performed within manufacturer specifications and delivered 42° chilled water when they received an adequate supply of 205° cogeneration water as input.

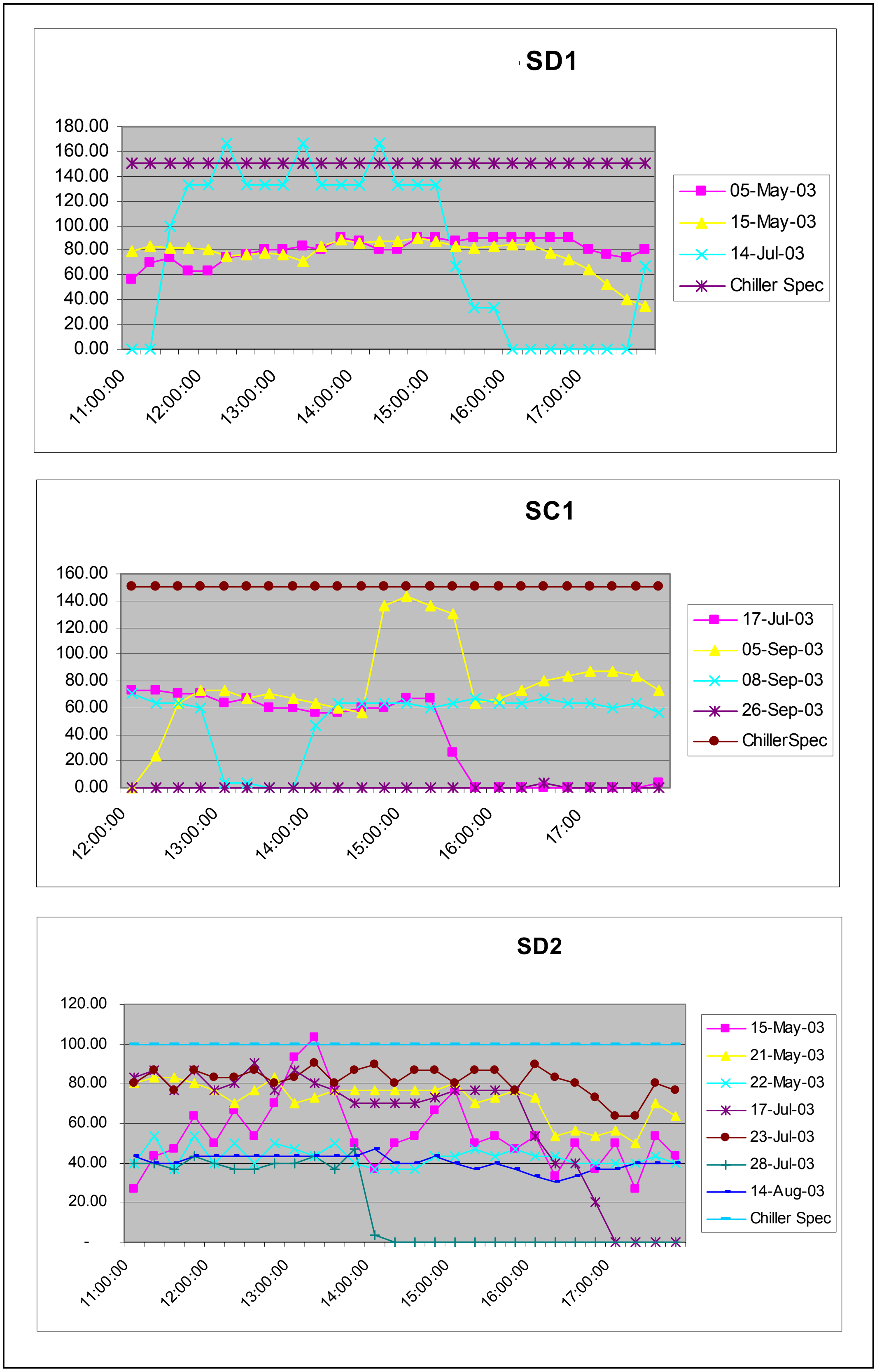

Figure 6-36. Poor chiller performance days – three sites

6.5 Conclusions

It may have been supposed at the outset that trend analysis would lead to minor tweaking of performance operations for slight efficiency gain. However, the results of trend analysis show a gross lack of performance that requires major efforts to restore performance to the expectation of the pro forma. Recall that, in the pro forma, RE was going to generate most of the electricity for each of the four sites. Instead, because of shrinking spark spreads, changed building operations, and unreliable engine operation, RE generated less than half of total building load and, in most cases, less than half the pro forma amounts.

Results are shown in Table 6-28.

Table 6-28. All Sites Summary of ICE Performance

Summary of Performance	kWh	
SD1 – Building Load	5,770,331	100%
SD1 – Pro Forma	4,215,422	73%
SD1 – Actual Generation	2,016,139	35%
SC1 – Building Load	6,251,254	100%
SC1 – Pro Forma	3,146,383	50%
SC1 – Actual Generation	972,641	16%
SD2 – Building Load	3,193,739	100%
SD2 – Pro Forma	2,263,955	71%
SD2 – Actual Generation	1,138,226	36%
SC2 – Building Load	10,923,023	100%
SC2 – Pro Forma	8,155,560	75%
SC2 – Actual Generation	4,295,327	39%

If we assume that non-operation in off-peak periods in 2003 was caused by economic factors (negative spark spread) and that non-operation or partial operation during mid- and on-peak periods was caused by degraded engine performance or engine failure, it is possible to apportion responsibility for the actual results to the factors of economics or DG technology. This may be useful for future DG research, development, demonstration, and commercialization efforts as well as for RE's strategic planning and fleet deployment. The result is that 100% of total lost revenue is attributable to all causes; 64% of that is attributable to spark spread, and 36% is attributable to reduced engine reliability.

7 Performance of Dispatch Systems (D-2.09)

7.1 Executive Summary

The issues associated with dispatch can be divided into three categories:

- Communications and control issues
- Engine/generator issues
- Interconnection issues.

RE has been through four generations of control systems while working toward optimal dispatch and remote load following. Each system had its strengths and weaknesses.

- First generation: Hess ICE with CView and Woodward controller

  Strengths
  - Woodward was reliable.

  Weaknesses
  - The Cartwright engine valve limited controllable load to 20% of total output because of emissions issues.
  - PML monitors could not communicate with the Woodward.
  - CView required a dial-up modem.
  - CView had proprietary data vocabulary.
  - Hess engines could not meet rated output and had a high failure rate.

- Second generation: Hess ICE with CView and Murphymatic controller

  Strengths
  - The Murphymatic had three variable-kilowatt output settings.

  Weaknesses
  - Heat and vibration of the CHP caused the Murphymatic to fail.
  - The Cartwright engine valve limited controllable load to 20% of total output because of emissions issues.
  - PML monitors could not communicate with the Woodward.
  - CView required a dial-up modem.
  - CView had proprietary data vocabulary.
  - Hess engines could not meet rated output and had a high failure rate.

- Third generation: Hess ICE with NextGen controller

  Strengths
  - NextGen eliminated the need for the Woodward.
  - It was readable over the Internet.
  - It was capable of load following across the full range of engine capacity.

  Weaknesses
  - The Cartwright engine valve limited controllable load to 20% of total output because of emissions issues.
  - NextGen had proprietary data vocabulary.
  - Hess engines could not meet rated output and had a high failure rate.

- Fourth generation: Caterpillar ICE with Encorp controller

  Strengths
  - Caterpillar engine was capable of rated output and was highly reliable.
  - Encorp system was capable of load following across the full range of engine output.
  - The engine valve (emissions) issue was resolved with the Caterpillar valve.

  Weaknesses
  - The Encorp system runs on a personal computer at the site. If the personal computer operating system crashes (a common occurrence), someone must reset the system manually.
  - Personal computers are not rugged against extremes of temperature or humidity.
  - The Encorp software Virtual Maintenance Monitor cannot be accessed remotely unless RE uses third-party remote access software, so its actual data and screen are not otherwise available for operation through the Internet.

Since its inception, RE has worked toward optimal dispatch. RE has arrived at the following dispatch conclusions and recommendations:

- Remote monitoring, control, and load following are important in optimizing economic dispatch.
- Some considerations are more important than load following. These include:
  - Positive spark spread
  - Making engines run consistently
  - Maintaining emission limits
  - Meeting interconnection requirements.
- A DG developer should try for integration at the outset rather than trying to retrofit.
- Retrofits are expensive and time-consuming.

- Choosing good technology the first time is key.
- Connectivity is still an issue;
- Legacy hardware and software are an issue.
- Open systems avoid stranding legacy investments.

7.2 Introduction

The purpose of this task was to report progress toward optimal dispatch through remote generator control and load following. Specifically, RE evaluated each of the systems it used for load following and auto-dispatch of generators and noted changes from early systems to the present state of the art. RE also assessed the need for further operational testing, identified issues remaining to portfolio-wide deployment, and identified critical parameters for improvement.

RE has made tremendous progress in the area of dispatch control. Along the way, it has had to contend with technological and regulatory issues that have increased the difficulty of achieving real-time dispatch.

This section reviews system components to provide a context for understanding the difficulties of achieving real-time dispatch. Section 7.3 deals with historical systems from roughly 2001–2003. Section 7.4 discusses the fourth-generation system.

Figure 7-1 shows the components of a dispatch system.

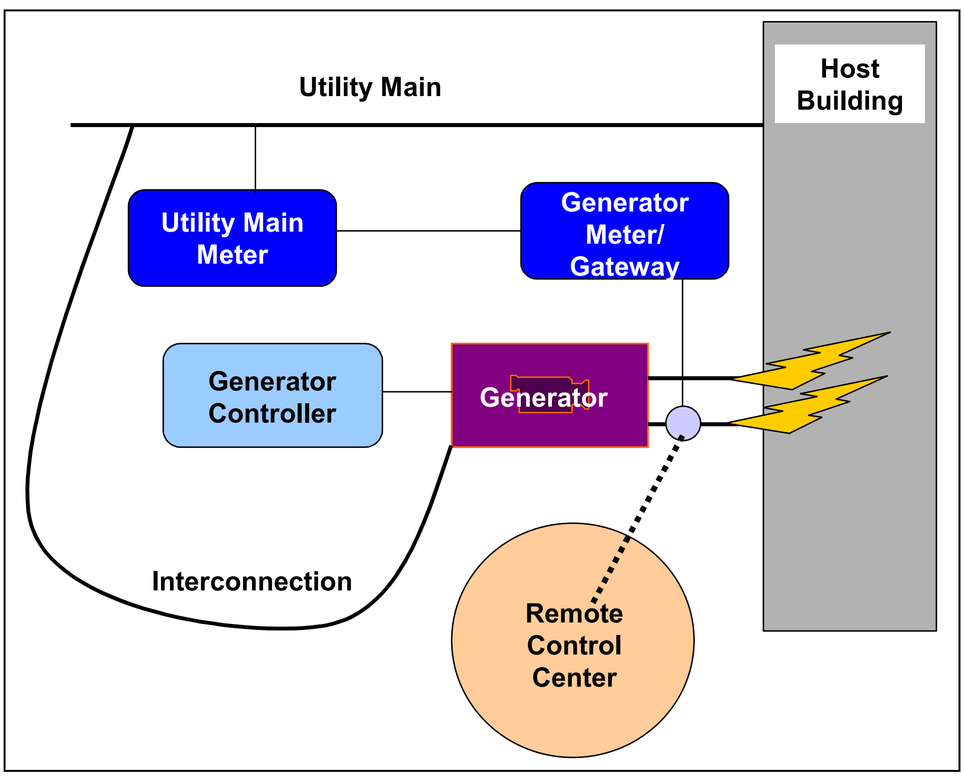

Figure 7-1. Components of a generator dispatch system

The issues associated with dispatch can be divided into three categories:

- Communications and control issues
- Engine/generator issues
- Interconnection issues.

7.2.1 Communications and Control Issues

Because of interconnection requirements, the generator meter and generator controller cannot be the same unit. The generator manufacturer supplies the prime mover, generator, and generator controller. The generator meter and the utility meter are discrete components. The generator control unit does not provide adequate metering capability, and the meter is not wired to control the generator. This forced redundancy adds costs and can be a source of communications problems if the components do not share compatible communications protocols. Although the industry is working on standards protocols, they are probably several years away.

Questions that must be considered include:

- Does the controller have the ability to receive control input from the meter?
- Can the components communicate?
- Is there a need for additional communication links and conversion devices?

Other issues arise from the manufacturer-supplied controller. Considerations in this area include the controller's ability to respond to external signals and the rate of signal update, the ability of the emissions control system to communicate and coordinate with the control signal while maintaining regulatory emission limits, and the need and ability to bias the signal in response to facility load conditions and utility interconnection requirements. Underlying all is the requirement of implementing in a cost-effective manner.

7.2.2 Engine/Generator Issues

In the base year of this effort, RE looked at the role engine efficiency plays in automated dispatch. It found that an economically driven load-following system is limited at the lower threshold by engine efficiency. As engine throttling moves down the load curve, the engine requires more fuel per kilowatt of output. At a certain level (called the "throttle-down threshold"), operating the engine becomes uneconomic because fuel costs consume the revenue streams from electric and thermal energy production.

The worse the efficiency of the engine at 100%, the less load following that engine will be capable of. The heat rate of RE's primary engine in operation has varied at times and locations from the manufacturer specification and RE's initial estimates. Also, an engine that has failed cannot be controlled remotely or on site. The loss from non-granular loading of engines (Task 4 of the base year) is dwarfed by the cost of engine failure. Optimal dispatch, then, starts with a fully functional engine that can produce its specified output at 100%.

7.2.3 Interconnection Issues
Finally, there is a regulatory issue of interconnection to be considered: inadvertent export of power. If building load decreases faster than the generator's ability to follow, there will be inadvertent export (sometimes called incidental export)—i.e., some electric power will go to the grid inadvertently (incidentally).

Utilities expect that non-exporting distributed generators (such as those in RE's fleet) will not export under any conditions. The usual solution is an interconnection protection technology (usually bundled with other interconnection functions in a "multifunction relay" to prevent export) called Device-32[141]. A control signal from the generator meter turns off the generator if building load drops below 105% of generator output. For example, if a generator is producing 100 kW of power and the load is 105 kW, all is well. If the load drops to 104 kW for more than 2 seconds, the Device 32 shuts off the generator to prevent export. Of course, no export will occur if the load is 104 kW and the generator is producing 100 kW of power. But the extra 5 kW (actually, 5%) is a safety margin called a "design margin."

Whether the utility's non-export concern is legitimate—there is evidence that, in some situations, nothing happens when export occurs on the distribution system except the utility gets a bit of power without paying for it—is beyond the present scope. The utilities do allow for an inadvertent export interconnection in California;[142] however, this type of interconnection requires additional protection equipment and potential upgrades to the distribution system. In many cases, the costs of the additional requirements are prohibitive.

As a practical matter, then, the real question is what RE must do in its dispatch automation to comply with the utility non-export rules and California's allowance for generator inadvertent export under Rule 21.

7.3 Historical Approaches to Generator Dispatch

7.3.1 Manual Dispatch

7.3.1.1 Modifying On/Off Dispatch
In actual practice, an "egg timer" or purely automated form of on-off dispatch has never been feasible for the RE fleet. The approach has to be modified to prevent export, follow operational best practices, and increase revenues when possible.

[141] Device 32 is the designation for directional power by the American National Standards Institute.
[142] At this time, SCE and SDG&E have inadvertent export agreements; PG&E does not.

RE's sizing criteria calls for as much generation as can operate profitably—usually 40%–80% of building peak load, depending on the load profile, expected occupancy, utility tariffs, gas prices, and other factors. All of RE's early projects used 200-kW engines from a single manufacturer. The models were called "220"—indicating the manufacturer's belief that the engines could produce 220 kW at the top end. A sample of 13 of these engines at four sites proved that in operation they were incapable of maintaining more than 180 kW output at any time during the peak hours of 2003. Before it had this operational feedback, RE believed it was slightly under-sizing its systems.

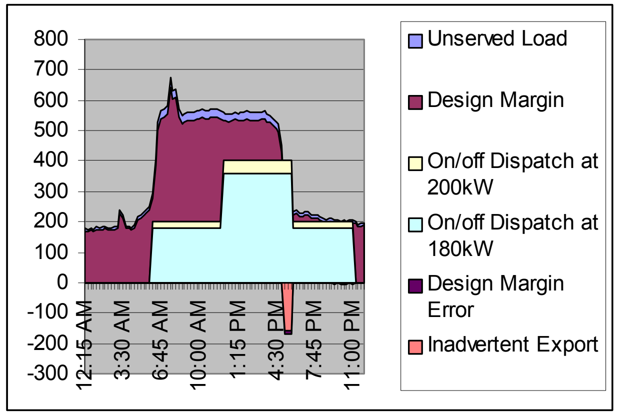

Figure 7-2. Dispatch according to time clock

The addition of another engine would usually result in an under-utilized asset. Consider an example building with a peak kilowatt load for the year of 675 kW. Figure 7-2 shows the peak kilowatt day for an actual RE installation. To meet its criteria, RE sized its generation at two 200-kW ICE and assumed 400 kW output—59% of peak. If the time clock were set to shut off the engines in off-peak, run one in mid-peak, and run both in on-peak, the expected generation and building load shapes (on the maximum-load weekday) would look like Figure 7-3 and Figure 7-4.

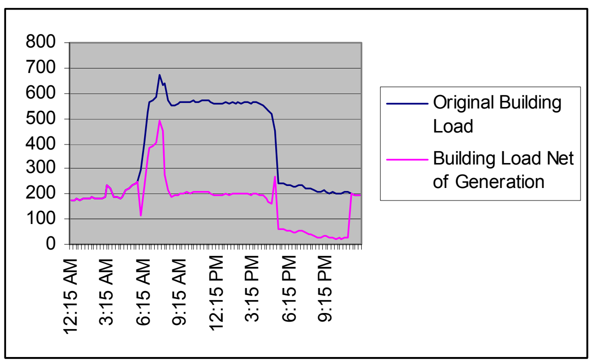

Figure 7-3. Revised time clock dispatch

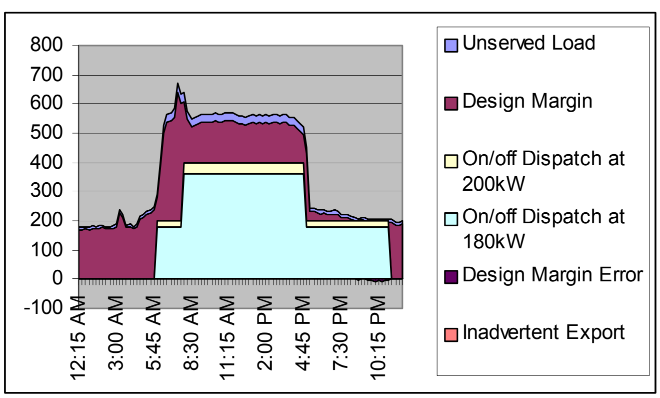

Figure 7-4. Better fit reduces peak kilowatts

Figure 7-5 shows the expected 200 kW output and the actual 180 kW output. The difference is the capacity loss from under-performance. Running both engines for the full on-peak period causes inadvertent export from 7:30 a.m. to 4:30 p.m. with a maximum magnitude of more than 100 kW. Dispatch at this level must be automated by time clock, based on tariff schedule, and modified by non-export device implementation. In practice, the non-export device would shut off the engine after 2 seconds of export.

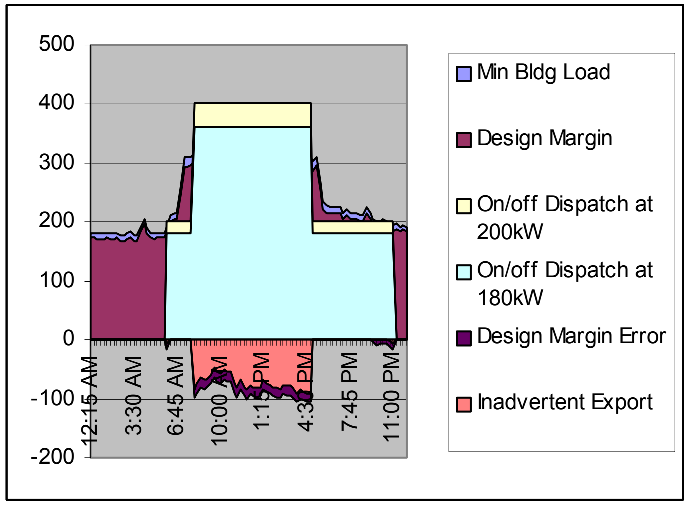

Figure 7-5. Inadvertent export on a minimum load day

Clearly, this on/off timer approach needs to be adjusted to prevent export and capture more mid-peak load. The revised dispatch in Figure 7-3 accomplishes this. It also reduces the peak load for the year from 675 kW to 495 kW—a significant savings in demand charges, as shown in Figure 7-4.

What happens on a minimum load weekday? Without automated control based on load feedback, there could be significant export. However, the non-export device prevents this from happening. If the building load drops below 378 kW (assuming 360 kW maximum generation) for more than 2 seconds, the non-export device will trip the lag (or marginal) engine—provided each engine is configured with its own relay device. Each decision to upgrade the CHP plant's ability to respond means additional cost and must be weighed against the economic benefit. Figure 7-5 shows what export would be on the minimum day absent the non-export device.[143] That export represents free power to the utility. So the question is whether the net life-cycle cost of inadvertent export is less than the increased area in the curve that is captured by preventing the shutdown of the marginal engine.

Is there a weekday dispatch shape that fits the load closely enough to allow the operator to "set it and forget it"? The answer is yes, of course, but how much revenue do you have to give up to get this operational simplicity?

In the example in Figure 7-5, non-export would prevent the marginal engine from running at all because the load peaks that day at 352 kW—26 kW below the design margin for both engines to run. To avoid conditions of the minimum load day, it is sensible to size overall generation at closer to 50% of peak load or even smaller given on/off dispatch. But this operational consideration leads to lost revenue on days of higher building load.

[143] RE's export agreements do not allow incidental export. If the design margin (between generation and building load) drops to less than 5%, the marginal ICE will trip in less than 2 seconds.

This is one of the strongest reasons for implementing optimal dispatch with load-following capabilities. In fact, what RE did in its early days was modify the on/off timer approach by using manual control—placing an experienced operator in the field that could make adjustments at the sites depending on loads and engine performance. That was a part of the learning curve, no doubt, but RE recognizes it is not cost-effective as a regular practice. The answer lies in remote load control.

7.3.2 Remote Load Control

The economic reasons for optimized load following and load control have already been discussed.[144] It is useful at this point, in light of recent advances, to recapitulate RE's quest for remote load control and optimal dispatch and how hardware and software have been limiting factors.

7.3.2.1 First Generation: C-View and the Woodward Controller

RE's first-generation control was provided by Hess Microgen, the engine genset packager. The company provided different control hardware depending on the generator. Induction machines needed only the built-in engine controller manufactured by Hess called "C-View." Synchronous generators also needed throttle control provided by a Woodward controller because C-View could not provide the subtle control necessary to achieve synchronous operation.

The additional controller on the synchronous machines helped them remain synchronized to the grid when operating in parallel with it. C-View did scheduling and provided engine diagnostics, including temperature and pressure, engines safety, and alarms. The Woodward EGCP-2 is a microprocessor-based engine generator control and energy management device. Its key functions were engine control, synchronizing, real kilowatt load control, reactive kilovolt-ampere control, generator sequencing, engine protection, generator protection, and communications. The Woodward and the C-View were networked together by Hess and shipped as part of a synchronous genset.

C-View alone does not have the capability for load following, so this was a limitation for sites with induction generating facilities. The Woodward theoretically provided the capability for load following, but RE was unable to use it for that purpose because of issues of latency and ramp rates. There was also a limit on the percentage of engine load that could be controlled while allowing the engine to stay under its emission threshold. For these reasons, solving the problems that prevented load following with this particular genset was prohibitive.

In addition, Hess was already migrating to a new engine controller and was not willing to fund the engineering required to make load following with C-View possible. RE was also having difficulty connecting the PML generator monitor (RE's site-monitoring, control, communications, and revenue billing device) to the C-View engine control. The PML system was not able to communicate with the Woodward. It could communicate only with the C-View—and even then was only capable of providing read-only engine diagnostics.

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[144] See Task 4 of: RealEnergy. "Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report." NREL/SR-560-33581. Golden, CO: National Renewable Energy Laboratory. April 2003.

Furthermore, obtaining diagnostic information required communications through a dial-up modem. Depending on the malfunction, either the C-View or the Woodward might trip the engine. If the C-View tripped the engine, RE could reset the engine remotely; but if the Woodward tripped the engine, it was not possible to reset the engine without sending someone to the site. Because of difficulties in tying the PML system to the engine control, RE could not discern through its PML-fed trend data which controller tripped the engine.

C-View did not have Internet access; it had to be accessed through a dial-up modem. The communicating device on a voltage regulator would sometimes flood the C-View with requests, so the modem would not answer when RE personnel dialed. For all these reasons, RE abandoned the attempt to achieve load following and optimal control with the first-generation control setup.

In addition to lost revenue in overall sizing and during daily operations, on/off dispatch has another serious limitation: The engines may stop and start frequently. At 4:30 a.m. and again at 7:30 a.m. on the day depicted in Figure 7-6, the marginal engine shut off because the load dipped below the threshold for only one or two periods.[145] This can happen multiple times per day on days of frequent load fluctuation. The result is costly because site operations must restart the engine, it is non-optimal for engine maintenance, and it causes lost revenue.

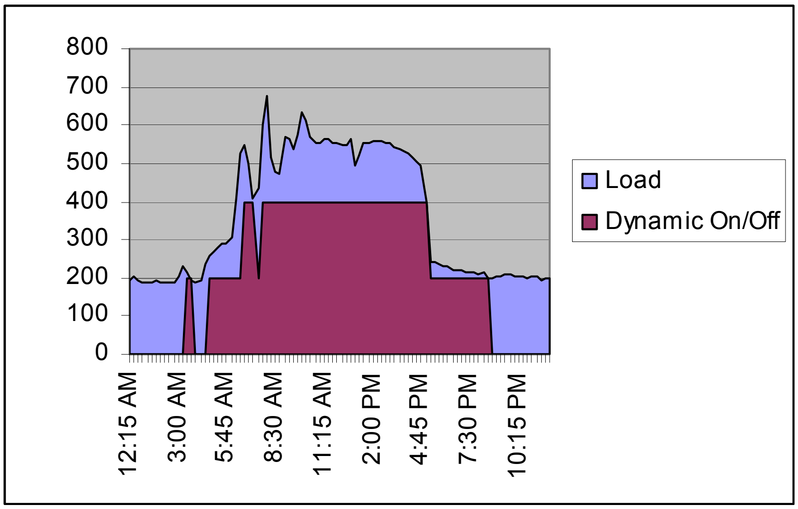

Figure 7-6. Tripping because of load fluctuation

7.3.2.2 Second Generation: Murphymatic Controller

In a bid to eliminate non-export tripping of its generators and increase revenue at the shoulders, RE tested a dynamic multi-setting form of dispatch. On-peak, the system was to produce a 5% improvement in profitability (according to base-year estimates)and avoid incidental export and nuisance tripping. In the pro-forma example shown in Figure 7-7, the system was estimated to run the generator all night (assuming profitability in the off-peak).

[145] A period is one-quarter of an hour, or 15 minutes.

To achieve this form of dispatch, RE selected the Murphymatic controller AT-67207 24 VDC. It was reputed to have reliability equal to the Woodward controller and greater operational flexibility. Three kilowatt output levels were offered in addition to on and off. The Murphymatic did not promise optimal dispatch but offered greater flexibility than RE could achieve cost-effectively using first-generation hardware/software. RE hoped some limited load following would be possible.

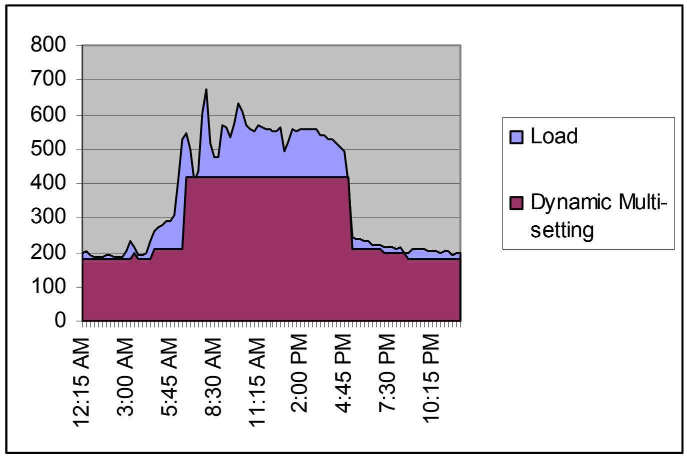

Figure 7-7. Dynamic on/off dispatch

However, the Murphymatic proved less reliable than the Woodward and had mechanical issues that prevented even limited three-way dispatch. The manufacturer has not disclosed failure quantities, but it has admitted that failures are traceable to heat and vibration. The solution proposed by the manufacturer was to better isolate the controllers. Modifications were made, and the controller was redeployed. Unfortunately, RE never was able to get the Murphymatic to operate properly. RE deemed the mechanical problems of the controller to be insurmountable within its cost horizon. The Murphymatic hardware test was replaced with the first-generation control system.

7.3.2.3 Third Generation: NextGen Controller

Hess developed a controller for its synchronous units to replace the problematic Woodward/C-View approach. This controller, NextGen, has diagnostic and control features of the C-View as well as throttle control capabilities of the Woodward in an integrated computer board and software system. The C-View modem is replaced with Ethernet local area network capabilities and Internet connectivity. Because it is an improvement for all Hess gensets, NextGen also ships with new induction systems.

Although several of RE's newer sites have NextGen technology, RE has not retrofitted its other installations with NextGen because it would not be cost-effective. Part of the problem with using NextGen for load following and flexible dispatch is that the engine itself has yet to prove its reliability (as discussed in D-2.10, "Trend Analysis for On-site Generation"). Also, NextGen is built on proprietary data vocabulary—the opposite of an open industry standard and, therefore, probably the wrong direction for RE.

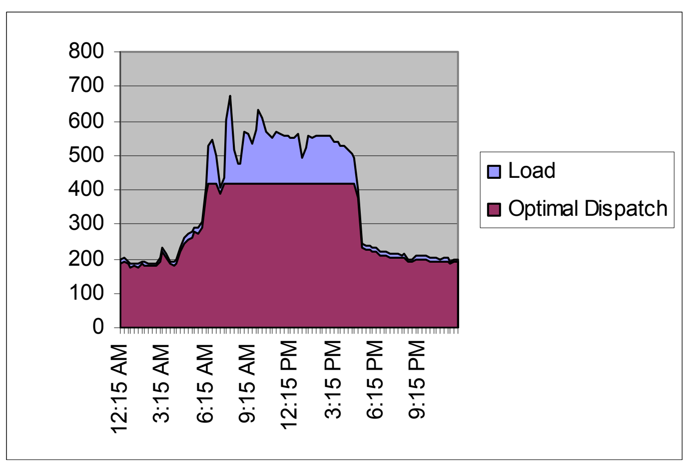

Figure 7-8. Optimal dispatch

The shortcomings of NextGen as an overall solution to RE dispatch needs are also linked to limits associated with prime mover efficiency and emissions.

7.3.2.4 Limits to Optimal Control

Optimal control means the system is free to provide energy services unconstrained within the operating range provided by the generating facility. Optimal control approaches the point of zero lost revenue. It cannot actually arrive at zero lost revenue because of generator limitations and the relative uncertainty of building load fluctuation.

Besides the technological limitations on optimal dispatch already discussed, two other issues have prevented RE from wholly embracing it: overall CHP system efficiency and emission limits on the prime mover.

To maintain its status as a qualifying facility and meet related California requirements, a CHP system must maintain an overall thermal and electrical efficiency of more than 42.5% after reducing the useful thermal output by half. As the engine-genset runs farther down the load curve, its overall efficiency decreases. It is possible that if a particular engine-genset ran at part load during off-peak hours, for example, its overall efficiency could decline to less than 42.5%, and it could lose its status as a qualifying facility. RE relies on the qualifying facility status of its generators to get SGIP money and qualify for other favorable regulatory treatment.

A second problem with RE's first- and second-generation gensets is the interaction of their Cartwright valve (the emissions controller) and three-way catalyst caused emission limits to exceed permitted levels when the kilowatt output was raised or lowered more than 20% (plus or minus 10%). Therefore, no matter what control system they had, they could not load follow outside this 20% band without violating the site air quality permit. RE experimented with retrofitting an engine with a Continental valve that allows full span of control (the total range of the engine) without affecting overall emissions. The retrofit was successful. Because of other difficulties of load following that were already preventing dispatch flexibility, as discussed above, RE has not retrofit its other engines with the Continental valve.

7.4 RealEnergy's Fourth-Generation Dispatch System

In its quest for cost reduction and fleet uniformity, until 2003, RE used gensets, engine software, generator controls, and metering devices from the same manufacturers for every project (as detailed in the base year final report).[146] But as the company expanded, and as it got performance feedback from its trending data, a significant research effort was undertaken to find a more reliable, flexible solution to the challenges of owning, operating, and remotely deploying a fleet of on-site CHP installations. As a result, a decision was made to change from the old prime mover manufacturer to a multi-engine platform based on Caterpillar and Waukesha and consolidate metering and control functions, using Encorp's controller as a single point of integration for metering and control functions.

[146] RealEnergy. "Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report." NREL/SR-560-33581. Golden, CO: National Renewable Energy Laboratory. April 2003.

This approach led to a step forward in load following and remote fleet dispatch. Before those results are described, it is useful to look at the underlying hardware and software in the new dispatchable CHP platform.

7.4.1 Generator and Prime Mover

Figure 7-9. Caterpillar natural gas engine

In the example project, the first of a new generation of RE projects, the company selected a Caterpillar G3516 gas engine generator rated to produce 810 kW at full load,[147] not including parasitic loads.[148] Nominal engine efficiency is 38.1% at full load, 36.9% at 75% load, and 34.9% at 51% load (where engine efficiency tolerance is +0, -5% of full load percent efficiency value, and nominal engine efficiency tolerance is ±3% of full load percent efficiency value). Nominal thermal efficiency is 39.2% at 100% load, 40.6% at 75% load, and 43.6% at 51% load, where thermal efficiency includes jacket heat plus lube oil heat plus exhaust heat to 120°C. Total nominal efficiency is 77.4% at 100% load, 77.5% at 75% load, and 78.5% at 51% load, where total efficiency equals engine efficiency plus thermal efficiency and tolerance is ±10% of full load data.

If engine efficiency holds up in the field (after accounting for parasitic loads and actual operating conditions), the engine would consume less than 10,000 Btu/kWh at full load[149] and better at 51% load than its current engine is at 100% load: 10,750 Btu/kWh versus 11,500 Btu/kWh. Primarily, though, RE looks to its new Caterpillar engine to improve on-peak engine capacity and availability, which have been below an acceptable level. That will depend on whether the new genset can produce its specified kilowatt output, maintain its thermal efficiency, and operate consistently with a minimum of unscheduled maintenance. A full year of trend data in 2004 will answer these questions conclusively and give RE a look at whether its new generating facility outperforms its old one.

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[147] Assumes two engine-driven water pumps with a tolerance of ±3% full load. Generator power is determined with an assumed generator efficiency of 97% and power factor of 0.8 [generator power = engine power x generator efficiency].
[148] In RE experience, these range 5%–10%.
[149] This assumes 10% parasitic load.

7.4.2 Generator Control and Related Functions

When it started, RE's business niche of operating a fleet of distributed generators was relatively new. As the DG industry matured, hardware/software solutions tailored specifically to the DG marketplace began to emerge. At first, these were untried and untested. After significant research and solutions testing, RE determined that none of the hardware or software solutions provided the full spectrum of functionality required for reliable commercial operations.

RE decided to develop its own solution. This approach forced RE to serve as a hardware/software integrator of DG systems information, which was not its core business. Although it chose best-of-breed manufacturers of power control and metering equipment, each manufacturer and device was meant to serve some other market. RE was left to cobble products together to serve its unique need.

The following functions were served by devices from different manufacturers:

- Engine diagnostics
- Generator control
- Generator and utility main metering (all power quality monitoring functions included)
- Communications
- Data housing
- Grid protection
- Revenue metering and billing.

As noted, RE was not able to load follow or optimize generator control.

By 2003, however, the picture had changed. Integrated, field-tested solutions were becoming available. RE reassessed its approach and attempted to improve its dispatch optimization by using a comprehensive hardware/software platform. After more product research, it chose the DG controls family from Encorp.

7.4.2.1 Multifunctional Control Hardware

RE is using three pieces of Encorp control hardware in its new generation:

- Generator power control (GPC) – one per unit
- Utility power control – one per site
- Communications processor module – one per site.

In its new generation of installations, RE is controlling its generators with Encorp's GPC, a multi-function hardware control device. It includes an embedded programmable logic controller with software module, communication through Modbus (RS-232/485), power quality monitoring, kilowatt load sharing control with soft loading and unloading, and base load control. The unit is a utility-grade device capable of remote control, remote metering and monitoring, and remote data logging using a variety of communication methods. Switch inputs and relay outputs are separately programmable and separately isolated using a personal computer. The GPC provides interconnection protection functions for safe, reliable transfer of power between a single generator and the utility grid. Standard options include a variety of traditional control modules and open-communication protocols integrated into a single unit. When outfitted with "kilowatt-sharing control," all of the above functions are available to multiple generators—a necessity for the RE fleet. Combined with Encorp's software, it can synchronize and parallel multiple generators with the utility grid. Encorp's integrated solution was put together in the factory and delivered to the site complete, which provides easier and faster installation than RE had experienced previously.

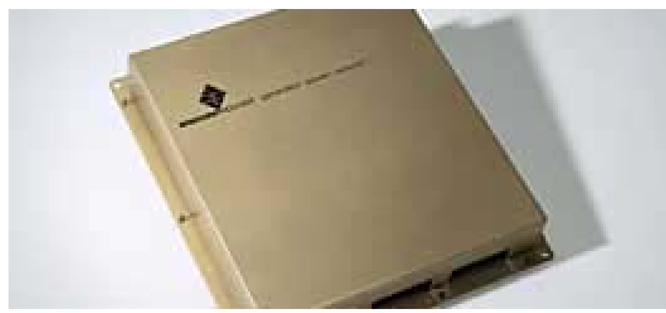

Figure 7-10. Encorp's GPC

Sites include one GPC control box per ICE, one utility power control for mastering multiple GPCs (where there are multiple ICEs), and one industrial computer called the communications processor module gateway. The Encorp GPC is responsible for starting, stopping, and controlling the generating facilities. The controls also command the circuit breakers that connect the facility, gensets, and utility feed. The communications processor module communicates with Encorp power controls by Ethernet local area network. Server software running on the communications processor module exchanges data with the Encorp power controls and makes this data available to the Encorp primary software module called the VMM.

7.4.2.2 Multifunctional Control Software

One of the problems RE ran into while integrating its distributed energy information system was the enterprise monitoring software provided with the metering hardware. This software had a proprietary database that was a step down in size and speed from the industrial-strength database RE needed for its fleet-wide data collection effort.

To solve this problem, RE had to program around the proprietary database to get the information into a Microsoft Sequel Server database. This has become RE's legacy back-office data collection and distribution system. Although Encorp planned its software for a fleet-wide data collection effort, RE would incur significant cost to change to its system for back-office functions. This does not mean RE could not make the change in the future.

Rather than supplying a poor proprietary database, Encorp has focused on supporting information technology data standards,[150] such as the open database connectivity specification, and OPC servers[151] so RE can use any database compliant with those standards.

Encorp's VMM is a complete energy information management solution. It can be used for control, monitoring, trending analysis, and alarm notification to help managers achieve optimal dispatch. VMM allows managers to monitor and control Encorp GPC or other hardware, analyze data, and observe a site's big picture or drill down for more detail. The VMM allows system managers to operate and maintain generating facilities from RE's headquarters. VMM is connected with distributed energy sites via TCP/IP. RE uses broadband connectivity between offices and sites, it uses a local area network within offices, and it uses a virtual private network between offices for backup.

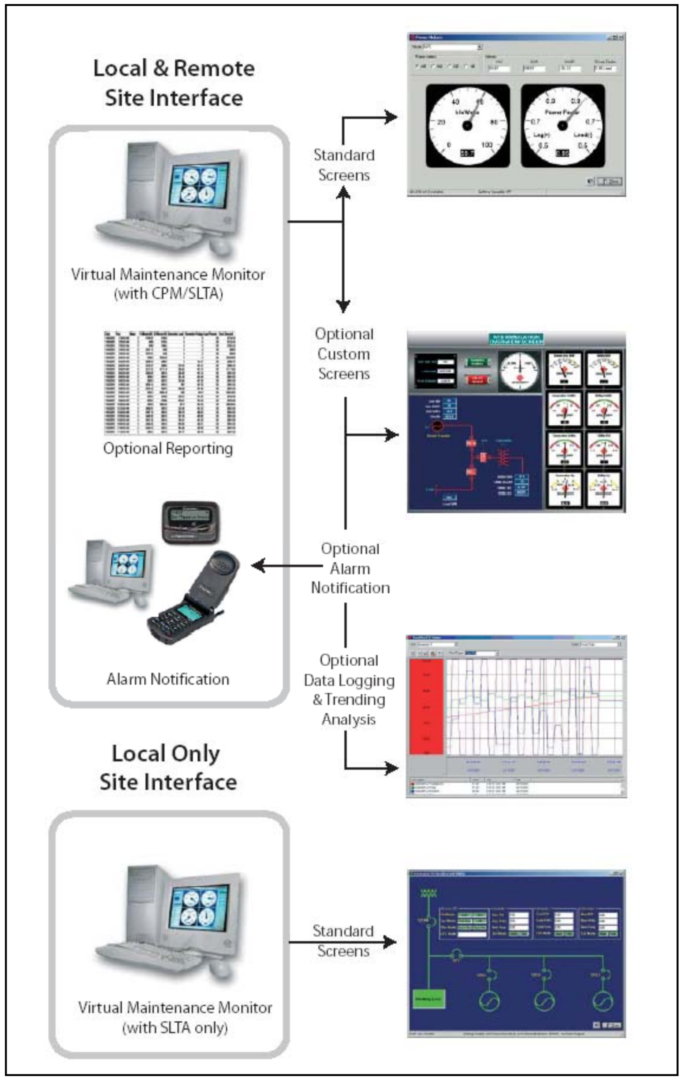

Figure 7-11. Encorp hardware/software handles information requirements

VMM works in conjunction with Encorp hardware and a broadband connection to allow real-time remote access. VMM employs real-time and historic trending tools to allow managers to track virtually any engine or power parameter. The flexibility of VMM extends beyond interfacing with Encorp controls by integrating with Encorp's gateway servers, which is made possible through the OPC standard. The Encorp gateway servers include configurations for aggregating large amounts of data on more complex projects. The combination of utility power control, GPC, communications processor module, and VMM allows RE to poll sites and integrate site data to produce information system requirements except billing, metering, and electric monitoring.

[150] These are technically specifications, not standards, because they have not been voted on by a standards-making body.
[151] Deliverable D2.12, "Information Design Hierarchy for Combined Heat and Power," contains a lengthy discussion of DG-related information protocols and standards and mentions OPC Foundation specifications. Since 1996, OPC specs, developed by leading automation and hardware suppliers working in cooperation with Microsoft, have been the standard client/server specification.

The system handles engine data integration, engine data communications, engine monitoring, alarms, and controls.[152]

The system accommodates multiple graphical, custom screens with software access points so usage patterns and operating parameters can be monitored across the RE portfolio. VMM interfaces with third-party hardware and software through Modbus and OPC protocols. Although VMM does perform data logging and trending analysis, RE does not use it for electrical analysis, monitoring, metering, or billing. VMM only holds engine data at this point. Much of the technology that makes it possible to manage generating facilities from a central location resides on-site, near the generators. RE plant operators can also use VMM on-site to operate and maintain gensets. Service personnel can gain access remotely if it is necessary to reconfigure variables based on operating history. All data for a site can be aggregated to appear on a single screen that graphically represents the site. Alarm notification is available for any variable via phone, fax, e-mail, pager, pop-up Web page, or software scrolling marquees.

7.4.2.3 Drawbacks of the New System

Electric metering, monitoring, and billing is not integrated into the new RE sites—not because Encorp cannot handle it but because changing to Encorp for monitoring would require RE to change its back-office billing system to adapt to the new software. Therefore, RE uses PML for its electric metering. Thus, the current state of system integration is two parallel systems: one for engines and one for the electrical data. This is a legacy system issue, not a technological one. Until hardware and software vendors use common standards and protocols, legacy data systems will continue to strand information assets.

The main drawback to the Encorp VMM is that is runs on a personal computer at the individual site. This is not a rugged design and is a poor platform for remote operation. The drawback is worsened by the requirement of using PC-Anywhere or GotoMyPC to have access to VMM. In other words, the program cannot run simultaneously on two computers over the Internet.

7.4.3 New System Performance

7.4.3.1 Sample Site Load

There are now 3 months of trend data on the performance of the Caterpillar/Encorp system in a commercial office facility in New Jersey. The facility looks like a typical office building. It peaks on weekdays during normal business hours and is flatter on Saturday and Sunday. Closer examination, however, shows facility load drops off after noon and approaches 800 kW by 3 p.m. This has a significant effect on dispatch. Figure 7-12 shows a typical five-peak week (Jan. 11 is a Sunday, and Jan. 17 is a Saturday). Figure 7-13 shows the drop-off in daily load.

[152] See Section 1.3 of: RealEnergy. “Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System: Phase 1 Report.” NREL/SR-560-33581. Golden, CO: National Renewable Energy Laboratory. April 2003.

7.4.3.2 Engine and Generator Issues

The 810-kW engine has performed at or above its rated kilowatt output, assuming about a 5% parasitic load—i.e., at about 780–790 kW quite consistently. A spot-check of the heat rate at the site puts it at 10,252 Btu/kWh higher heating value. That is higher than manufacture specifications because it is quoted net of parasitic loads.

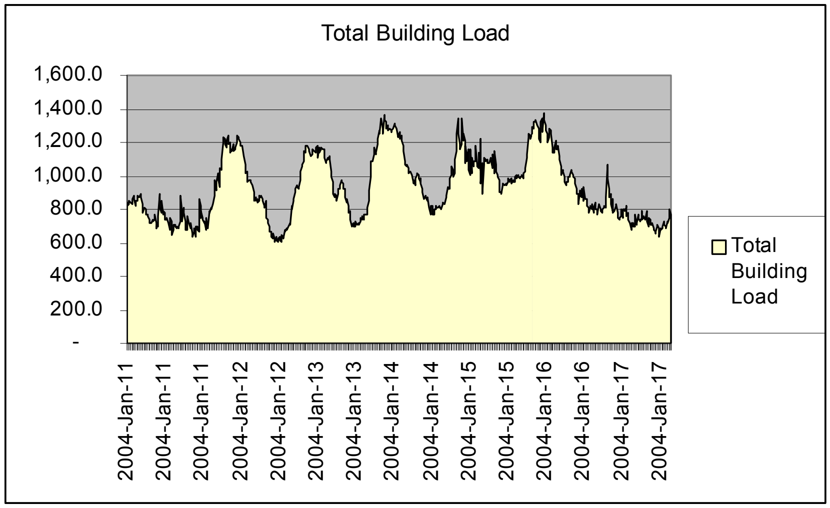

Figure 7-12. Weekly load data for RE's fourth-generation control site

The site has not used extensive load following during its initial operations. The reason is natural gas prices are more than $8/mcf and, at these prices, RE's spark spread is negative in the mid- and off-peak periods. This will likely improve in the summer as on-peak electric rates increase and natural gas is no longer needed for heating in the Northeast. Technologically, it is operating very well.

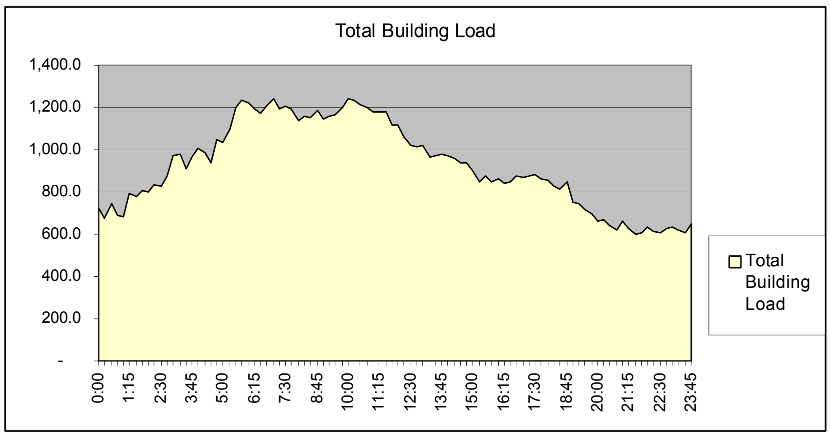

Figure 7-13. One-day load data for sample site

The fourth-generation system is ideally suited to load following because of its good efficiency and emission control across a band of operating load levels. Because of the Caterpillar prime mover efficiency, not only at 100% but as low as 50% of nameplate kilowatts, maintaining qualifying facility status is less of a concern. If it were profitable, RE could afford more load following down the load curve. The Caterpillar emissions system is built to maintain low emissions at various operating levels in its load curve, so emissions considerations do not restrict load following along the entire controllable range of the prime mover.

7.4.3.3 Communications, Control, and Interconnection Issues

Non-export is a concern to utilities, and most interconnection rules require non-export devices be used in generating facility protection packages.

At the fourth-generation site, the official import limit Device 32-reverse power relay protection setpoint is 123 kW, and RE is controlling to an import setpoint of 180 kW using the Encorp controller. The difference is a safety margin that prevents inadvertent trips because of rapid changes in load that drop below 123 kW before the engine can respond. It is an example of interconnection requirements and the reality of how RE has to operate to meet them. If the site were under an "inadvertent export" interconnection in which the utility would allow small amounts of export for a short period of time, this 57 kW (between 123 kW and 180 kW) would not have to be left on the table. California utilities offer inadvertent export agreements as an option, but the required utility review takes more rigorous testing, and there is a chance the generator may have to pay for local distribution system upgrades to make it work. The non-export approach taken by RE in its New Jersey example site was deemed to be the most cost-effective available at the time and for the foreseeable future.

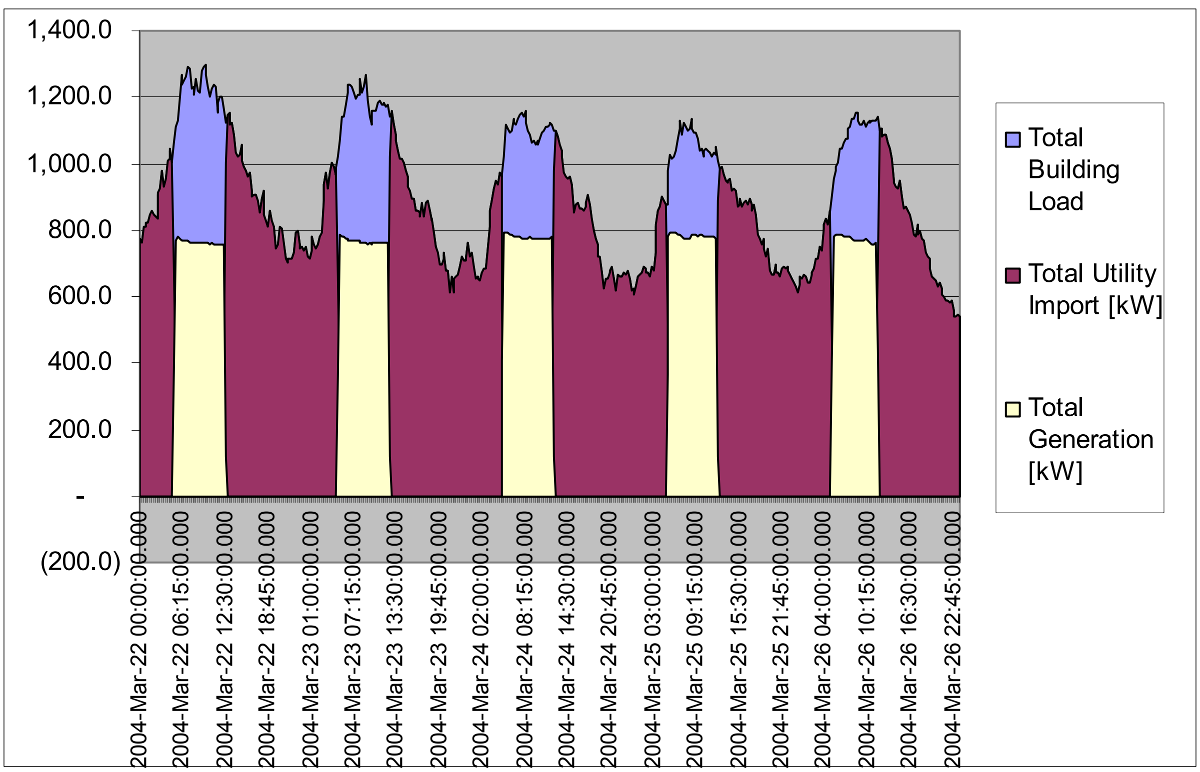

Figure 7-14. Sample operating week for RE's fourth-generation control system

Figure 7-14 shows that RE's dispatch in the test period, though automated, is essentially an on/off system that turns on at 5 a.m., runs until noon, and then shuts off. However, this operating procedure is driven by negative economics. Spark spread is negative during the winter, even on weekday afternoons. It remains to be seen whether this changes in the summer months.

However, RE has tested the new system for its ability to load follow, and the system has performed remarkably. The test was to see if the system could maintain constant net building import. (Although the interconnection agreement specifies 180 kW, the system test was set at 238 kW.) Figure 7-15 shows the results.

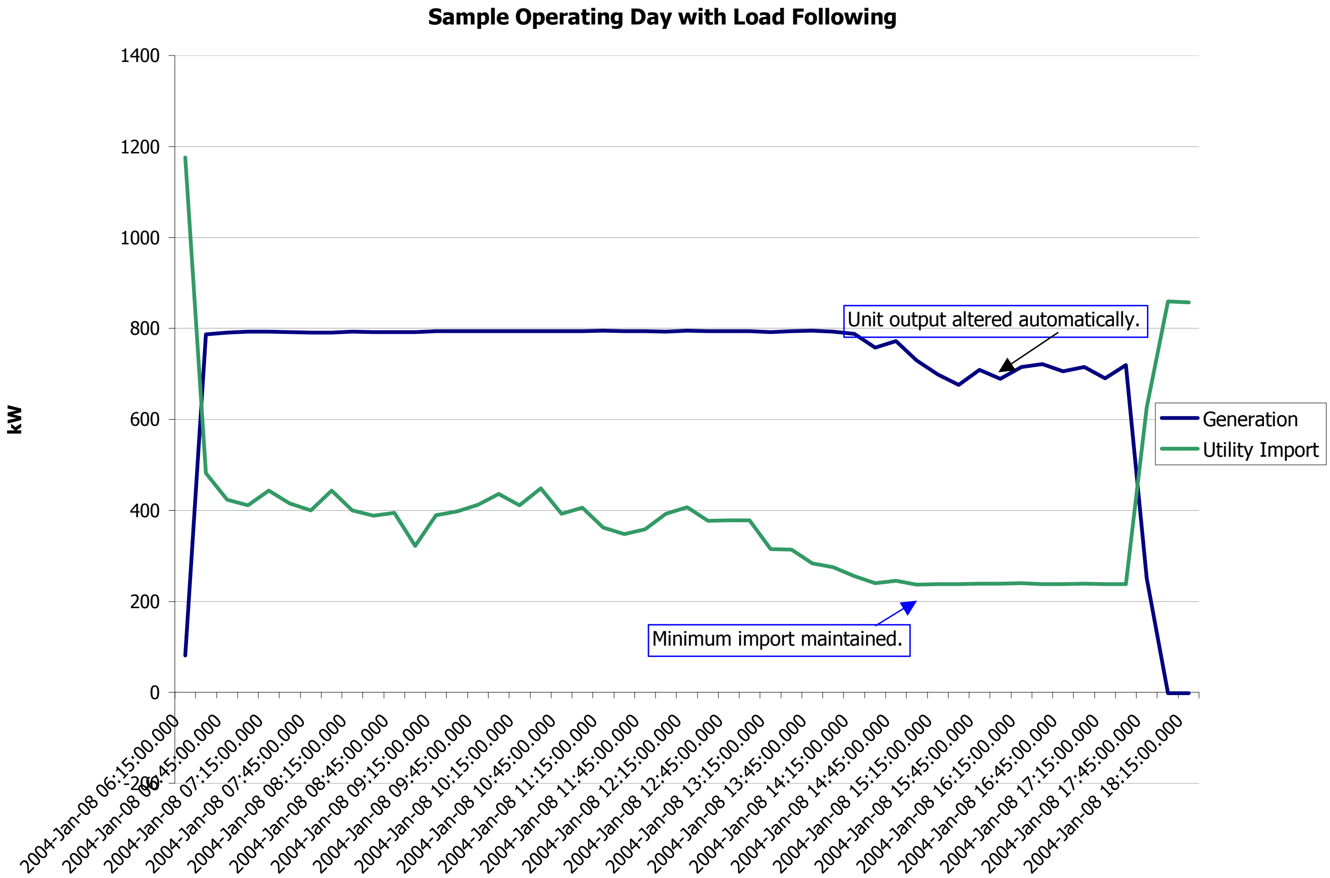

Figure 7-15. Optimal dispatch achieved by the RE fourth-generation test site

The unit altered its output to maintain minimum utility import. This approach maximizes profitability (or minimizes loss with negative spark spread) while upholding the utility interconnection agreement. If total building load were to dip below 800 kW, the system could reduce its output to less than 620 kW, thereby maximizing profitability (within the limits set by the interconnection agreement) and maintaining minimum import.

7.5 Conclusions and Recommendations

From its early attempts to automate dispatch capabilities, comply with interconnection requirements, and operate profitably (as reported in the base year) to its very latest installations, RE has been working toward achieving optimal dispatch. Of course, load following is often upstaged by operational issues—such as making engines run—and financial issues—such as shutting down when spark spread is negative. Through all these adversities, RE has learned, and from its many experiences can extract, the following conclusions and recommendations:

- Remote monitoring, control, and load following are primary objectives in optimizing economic dispatch.
- Some considerations are more important than load following, including:
  - Achieving positive spark spread
  - Maintaining emission limits
  - Meeting interconnection requirements.
- A DG developer should go for integration at the outset instead of trying to retrofit.
- Retrofits are expensive and time-consuming.
- Choosing good technology the first time is key.
- Connectivity is still an issue.
- Legacy hardware and software is still an issue.
- Open systems are the way to go to avoid stranding legacy investments.

8 Information Design Hierarchy for Combined Heat and Power (D-2.11)

8.1 Executive Summary

The IEC is working with EPRI to build software models of DER. These models are supposed to fit within the overall frame of IEC work on distribution automation that has been ongoing for a decade and captured in a series of standards called IEC 61850. A related effort at IEC called 61400-25 has built a complete model for wind energy generation in conformance with the 61850 family of standards.

This section focuses on the use of the worldwide standard for data integration, called XML (for eXtensible Markup Language), to trace a path through the tortuous standards of 61850 and the FERC, NERC (North American Electric Reliability Council), and CAISO electricity tracking systems. Despite many disagreements, XML is one specification all seem to agree on—except 61400-25, which uses a different standard for real-time data. Whether that is necessary remains to be seen. Meanwhile, the following observations, pro and con, can be made of the IEC 61850/EPRI model approach for a data standard for CHP:

Pros

- IEC 61850 and IEC 61400 are an excellent foundation for customer-side DER.
- Advanced Distribution Automation for Distributed Energy Resources (ADA-DER) extensions make a near-complete CHP model.
- Adding to the model appears to be relatively simple.
- ADA-DER is inclusive and futuristic.
- IEC 61850 and IEC 61400 object orientation and use of XML makes standardization benefits—such as interoperability, relevance to the Internet, extensibility, code re-use, and wide adoption—more likely.
- Building the CHP model has been relatively easy.

Cons

- IEC 61850, IEC 61400, and ADA-DER are utility-centric and could be used to shut out customer involvement in grid automation.
- The IEC 61850 naming convention is obscure and arcane, and it has no ready semantic (it is scattered through IEC documents).

- IEC 61850 path names are unnecessarily space constricted. There is an anachronistic 64-byte path name limit that constrains all node, data object, and data attribute names. This does not make sense in a broadband world.
- The cost of standards documents and user-unfriendliness of the IEC Web site limit distribution of IEC documents and retard the spread of standards to the DER market. The World Wide Web Consortium (W3C), by contrast, gives free and open access to all specifications.

The primary conclusion here is that more work needs to be done on object modeling for CHP. This study is intended to be a useful draft to further a working group effort. It cannot supplant the work involved in hammering out a standard. Once that work is done, devices used in implementing customer-side CHP should be easier and less expensive to integrate. It is possible that remote translators will no longer be needed and expensive custom programming will not be necessary to translate one data vocabulary into another.

Yet the case of IEC 61850 and IEC 61400 for use with customer-side (as opposed to utility-side) DER is not so simple. Here, there are conflicting advantages and disadvantages from the customer's point of view.

8.2 Introduction

8.2.1 Purpose

The purpose of this task is to develop an information design hierarchy that describes the operations of a DER fleet that supplies the thermal and electric needs of its customers. There is an "intranet" and "Internet" problem in distributed energy markets that arises from the use of proprietary data vocabularies. On the "intranet" (communications internal to the company), equipment manufacturers' control systems (including the host building controls, the engine/prime mover controls, and the absorption chiller controls) must be tied together despite their proprietary data formats. The ad hoc solution is to use programmable protocol converters (a species of remote terminal unit) for each device in every installation. On the "Internet" (communications external to the company), there is no DER data exchange vocabulary for communications with ISOs, utilities, or other outside entities. A global solution would require the creation of a data vocabulary for distributed energy—based on existing and developing standards to the extent that they exist—that includes data necessary in CHP projects.

This paper presents a straw proposal,[153] based on analysis of a working CHP system from base year Task 3, for an information design hierarchy for distributed energy—a beginning XML data vocabulary for CHP codenamed DCHP.

[153] The development of an industry specification for communication is inherently collaborative and requires input from all interested stakeholders working for consensus on a system that all parties will use. A paper such as this can only hope to provide useful input to a consensus discussion.

8.2.2 Existing Resources

A tremendous amount of work has laid the groundwork for the possibility of a distributed energy (CHP) standard data vocabulary. This includes:

- A W3C specification for data on the Internet called XML
- ISOs' open access same-time information systems (OASIS) using XML
- The IEC family of standards for distribution system automation, IEC 61850, especially:
    - 61850-6:[154] Configuration description language for communication in electrical substations, an XML schema
    - 61400-25: Wind Power Plant Communications Model
- EPRI's ADA-DER project.

8.3 Background of the XCHP Design Hierarchy

This section provides a brief description of the precursors to the XCHP data vocabulary mentioned above. These include:

- XML
- OASIS
- IEC standards
- ADA-DER.

Because each of these specifications and standards is national or international in scope, involves hundreds of people working together in multiyear working group efforts, and results in technically complex and difficult work products, and because the present effort is limited, it will be necessary to summarize and simplify the complexity by focusing on key components. One simplifying perspective notes how XML is used in other standards and specifications. In fact, it is the only technology—besides those too far down in the communication infrastructure to mention (such as TCP/IP and HTTP)—that is essential to each of the XCHP precursors.[155]

XML has found its way into the forefront of core data standards in developing electricity markets. It is like Ariadne's thread, leading through a maze of information technologies, standards, and specifications in the energy business.

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[154] Communication Networks and Systems in Substations – Part 6.

[155] This paper will not discuss physical, data link, network, or transport layers (layers 1–4) of the ISO open system interconnection reference model; it will only cover session, presentation, and application layers (5–7). Universally accepted standards, such as TCP and IP, are already in place for the lower layers. The only remaining question of relevance to this discussion is the bandwidth of the physical layer.

8.3.1 The De Facto Internet Data Standard, Extensible Markup Language

8.3.1.1 What is Extensible Markup Language?

Extensible markup language, or XML, is a simple yet powerful way of representing the structure of information using intuitive language. It is built on the notion that most information is structured in a hierarchy. For example, you could use XML to represent the structure of an essay like this:

```
<essay>
	<name/>
	<title/>
	<date/>
	<body/>
</essay>
```

An opening tag (<essay>) requires a closing tag (</essay>) unless it is self-enclosed (<name/>).

It is easy to elaborate on this simple structure to allow more complex representation of the data hierarchy. For example:

```
<essay>
	<name>
		<firstname/>
		<lastname/>
	</name>
	<title/>
	<date/>
	<body>
		<introduction/>
		<thesis/>
		<conclusion/>
	</body>
</essay>
```

This process of elaboration could continue to any level of detail to cover any essay or essay type. Suppose the writer of the essay wanted to keep track of the date so that the date element[156] was updated daily. She could simply structure the date element (and sub-elements) in the same way the date was provided.

[156] Each pair of angle brackets is called a tag. Beginning tags have no slash mark (/); ending tags start with a slash mark. Each pair of tags (or a tag with a slash mark at the end) makes an "element," which in database terminology is called a "field." In fact, databases often interact with XML files by filling XML elements with the contents of database fields.

For example:

```
<date>
	< year>2004</year>
	<month>April</month>
	<day>1</day>
	<hour>19</hour>
	<minute>33</minute>
	<second>21</second>
</date>
```

Alternatively, the "children" (year, month, day, etc.) of the date element could be XML attributes[157] of the date element:

```
<date year = "2004" month = "April" day = "1" hour = "19" minute = "33" second = "21"/>
```

Then the user would need to use a programming language (because XML is not a programming language, only a way of structuring data) to go out and fetch the date from the computer system itself, the Internet atomic clock, or somewhere else.

Notice that XML does not say how the data should be presented on the screen, page, or device. That is one reason XML works well with hypertext markup language (HTML) for Web documents or Adobe's portable document format (PDF) for print documents. XML is for structuring data, not presenting it.

The W3C says:

> Extensible Markup Language (XML) is a simple, very flexible text format derived from [standard generalized markup language] (ISO 8879).[158] Originally designed to meet the challenges of large-scale electronic publishing, XML is also playing an increasingly important role in the exchange of a wide variety of data on the Web and elsewhere.[159]

Charles Goldfarb, inventor of the standard generalized markup language standard, says:

> Many of the most influential companies in the software industry are promoting XML as the next step in the Web's evolution. How can they be so confident about something so new? More important: how can you be sure that ... time invested in ... XML will be profitable? ... We can all safely bet on XML now because the central ideas in this technology are in fact very old and have been proven correct across several decades and thousands of projects. ... For the amazing truth about XML is that with it, data processing and document processing are the same thing! If you understand where ... [XML] comes from, [i.e., from standard generalized markup language] you understand where it—and the Web—are going.[160]

[157] XML attributes are different from IEC 61850 data attributes.
[158] http://www.iso.org/iso/en/CatalogueDetailPage.CatalogueDetail?CSNUMBER=16387
[159] http://www.w3.org/XML/
[160] Goldfarb, C. "The XML Handbook." Second Edition, Prentice Hall. 2000; p. 5.

There are a number of reasons XML is favored as a way of passing data over the Internet:

- It is a small, simple subset of standard generalized markup language.
- It is a language that can encode any hierarchical structure easily.
- It is human-readable, can be used to "markup" human-readable texts, and can be edited with a simple text editor.
- When it is used for other documents (e.g., databases, technical reports, and vector graphics) it has little overhead.
- It integrates easily with spreadsheets and databases.

Perhaps most important in terms of its use on the Internet, XML integrates easily with HTML, the language in which Web pages are written. This is important because HTML has no way of separating data from text. When used in combination with HTML:

- XML can keep data separated from HTML.
  HTML pages are used to display text and data, indiscriminately. With XML, data can be stored in a separate XML file. This way, users can concentrate on using HTML for formatting and display and be sure that changes in the underlying data will not force changes to HTML code.

- XML can store data inside HTML documents.
  XML data can be stored inside HTML pages as "data islands," if the browser supports it—as Internet Explorer does.

- XML can be used as a format to exchange information.
  Computer systems and databases contain data in incompatible formats. One of the most time-consuming challenges for developers has been exchanging data among such systems over the Internet. Converting the data to XML can greatly reduce this complexity and create data that can be read by different types of applications.

- XML can store data in files or databases.[161]
  Because XML can be used to store data in files or in databases, applications can be written to store and retrieve information from the store, and generic applications can be used to display the data.

[161] These points and their descriptions are from: Refsnes, E. "How Can XML Be Used?" http://www.xmlfiles.com/xml/xml_usedfor.asp.

8.3.1.2 How Are Industries Using Extensible Markup Language?

The Web site www.xml.org[162] lists 63 industry segments developing XML standards, with 1,163 XML industry data vocabulary standards under development. It should be noted that these are not official standards[163] but specifications for common industry transactions. Interestingly, only three of the specifications listed on the xml.org site are focused on electricity. This would seem to indicate that XML is not being used in the electricity business. However, most of the wholesale electricity transactions in America today are being, or soon will be, identified, logged, and communicated via XML.

8.3.2 Open Access Same-Time Information Systems

8.3.2.1 The Federal Energy Regulatory Commission

In its final rule under Order Number 888, issued April 24, 1996, FERC:

> ... requires all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce:
>
> - To file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service;
> - To take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs;
> - To develop and maintain a same-time information system that will give existing and potential transmission users the same access to transmission information that the public utility enjoys, and further requires public utilities to separate transmission from generation marketing functions and communications.[164]

The same-time information systems required are known nationally as OASIS. OASIS is "an Internet-based electronic posting and reservation system for transmission access data and ancillary services which [sic] allows prospective transmission customers to simultaneously view service offerings and submit reservations for those services."[165] The FERC order created and exacerbated some interesting challenges for participants in wholesale electricity markets and required an organizing entity to help implement a system-wide solution.

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[162] This Web site was formerly managed by the Organization for Advancement of Structured Information Systems (OASIS), not to be confused with the Open Access Same-Time Information Systems (also OASIS) developed by ISOs of electrical systems under order from FERC.
[163] The W3C itself does not promulgate standards but consensus *specifications*. In an area of such rapid technical progress as the Internet, industry consensus and de facto standards are usually preferable to the slow, monolithic nature of official standards-making.
[164] FERC Order 888. http://www.ferc.gov/legal/ferc-regs/land-docs/rm95-8-00w.txt.
[165] This OASIS definition is from: "Tagging Essentials For Etag 1.7." Feb. 18, 2002. http://reg.tsin.com/Tagging/e-tag/Tagging%20Essentials.pdf.

8.3.2.2 The North American Electric Reliability Council

Prior to FERC order 888, wholesale market participants were aware of a difference between the path of economic agreements and the physical flow of electricity through transmission lines: Some electricity flowed through systems that were not involved in the transaction. This problem of "parallel flow" was within acceptable limits then because the transactions were smaller and more infrequent. The FERC order and the wholesale market it fostered promised to increase parallel flow and the economic and physical capacity problems it causes.

NERC, tasked with solving this problem and making OASIS work, said,
" ... control areas [have] lost the ability to know even the transactions that were within their own control area." In describing the issues before it, NERC said:

> Parallel flows are still not accounted for. The determination of available transfer capability ... will never be made with any degree of certainty because transactions are based on contract path commitments, not actual usage. Many of the concerns raised over the operation of the OASIS and its interaction with transaction scheduling can be traced to the fact that it is, in most areas, a contract path-based system and cannot therefore accurately reflect real world conditions.
>
> The use of the contract path approach has resulted in economic distortions through over/under compensation relative to system use and in system reliability problems due to parallel flows. A further economic impact is the unnecessary curtailment of energy schedules. When an overload on a transmission line occurs due to parallel flows, the primary relief available to the system operator is the curtailment of energy schedules. Unfortunately, the operator generally does not have full knowledge of all schedules impacting the line. Those known to the operator, and those which are likely to be curtailed, are generally the ones that are paying for the use of the system. The identity of the parallel flows generally is not known. This problem is particularly severe in the highly networked Eastern Interconnection.[166]

NERC began taking steps to solve this problem by implementing a transaction information system to identify the source of parallel flows. The system works by identifying each transaction with a "tag." The first tag system was implemented using a spreadsheet tag entry and retrieval system and faxes and e-mail to transport tags between parties in a transaction. This system was replaced in October 1998 by "NERCtag," a Visual Basic program. It was easier to use but still relied on e-mail and manual operation. However, e-mail was not always timely and was subject to corruption or change. Tag specification was not rigorous and therefore open to interpretation. Seeing that it needed an automated electronic system to ensure tags were sent, received, and approved in a timely and allowed a manner, NERC directed the development of a specification for electronic tagging, or ETAG. NERC recognized that for ETAG to work, all parties to potential transactions had to agree on a way of passing data back and forth, so it adopted "Policy 3." This required wholesale electricity market participants to have full-time ETAG monitoring:

[166] See Note 165.

> To be effective, ETAG requires full support by all market participants. Although etagging has been operational for the past 2 years, there are significant improvements that will make it more useful. Version 1.7 includes those additional features. Version 1.7 also moves etagging to he latest electronic data exchange standard (XML) and aligns the system more closely with the market business practices and the latest NERC policies.[167]

With the implementation of this policy, e-tagging "is [now] an integral part of the wholesale [electricity] marketplace in North America."[168]

8.3.2.3 The California Independent System Operator

CAISO released a prototype of OASIS in July 2000. Over the next 8 months, the prototype was implemented by the CAISO XML Working Group in stages. It released a new prototype every few months until March 2001, when the final prototype version was released.

CAISO explains its implementation choice in a presentation available on its Web site. This indicates it intends to implement ETAG, OASIS, electronic scheduling, and many other ISO functions in XML:

> Why is the ISO Migrating to XML?
>
> **XML Benefits**
>
> - eXtensible Markup Language (XML) is the international standardized protocol for data interchange
> - Supports download of dynamic data requests
> - Supports data validation
> - Supports downloads via HTTP requests
> - Uses schemas and style sheets
>
> **Future XML Migration Plans**
>
> - CaISO
> - OASIS/PMI
> - Pre-dispatching system
> - Logging system
> - Scheduling interface
> - Power industry
> - E-tag
> - Electronic scheduling
> - OASIS.[169]

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[167] See Note 165.
[168] http://reg.tsin.com/Tagging/e-tag/etag1_7Training_FINAL4.ppt
[169] http://www.caiso.com/docs/2001/04/20/2001042011551026196.pdf

8.3.3 International Electrotechnical Commission Standards

EPRI has worked closely with IEEE and the IEC for many years to develop a series of standards to aid in electricity distribution system automation. Because the IEC standards are bound up with older standards from the 1980s and 1990s, they tend to be complex and, in some ways, out of date. Rather than a critique of the standards, this paper will give a brief history of their development and an overview of those parts that seem useful to the purpose of fashioning a data standard for CHP.

8.3.3.1 Complexity From the Outset[170]

EPRI first published the Utility Communication Architecture (UCA) for the purpose of defining data communications in a way that could be used throughout the utility enterprise. The technology underlying UCA was the Manufacturing Message Specification, an information technology Standard ISO 9506. MMS was based on binary code, rather than text files, so it was only machine-readable but very compact—good for real-time information exchange, particularly in speed-critical applications and where bandwidth was a limiting factor. MMS has made its way into contemporary standards for utility communications.

Next, in the early 1990s, EPRI defined a protocol for communications between utilities called Inter-Control Center Communications Protocol (ICCP). The protocol allows a utility to publish a "points view" of devices in its network operations and include only non-proprietary points for other utilities to see and interact with. ICCP was considered the solution to an urgent industry need and was offered as input to an international standard. ICCP was published as IEC Standard 870-6 (TASE.2). EPRI considers ICCP to be part of UCA.

EPRI then began work on UCA 2.0, an upgrade to UCA that would use object-oriented programming technology to describe each device in software as an object. The purpose was to model the state (data) and behavior (functions or methods) of all devices in the electrical network. The power of object-oriented programming is in building hierarchical classes of real-world objects that can be elaborated over time. Also, interfaces can be built that allow access only to data members and methods that are appropriate for the entity requesting access. UCA 2.0 was supposed to capture intelligent electronic device state and behavior in objects that could be communicated across the utility internal network from one intelligent electronic device to another.

[170] Parts of this history draw on: Holstein, D.K. “Competing Solutions: Communications for Utility Enterprise Operations.” June 1999. http://www.opusss.com/competing_approaches.htm.

Unfortunately, UCA 2.0 is not fully compatible with ICCP or the international TASE.2 standard.[171] The UCA Forum, which was supposed to solve this problem, went out of business in 1997 prior to solving it. It has been reconstituted as the UCA International Users Group, a nonprofit organization whose members are utilities, vendors, and users of communications for utility automation and whose mission is to enable utility integration through the deployment of open standards.[172] UCA 2.0, for better or for worse, has made its way into the IEC 61850 family of standards.

EPRI and IEC efforts leading up to and including IEC 61850 are summarized below.

Table 8-1. Antecedents of IEC Standard 61850

Timeframe	Who	Standard	Technology
Late 1980s	EPRI	UCA	ISO 9506 MMS
Early 1990s	EPRI	ICCP	Point List View
Early 1990s	IEC	870-6 (TASE.2)	International version of ICCP
Mid 1990s	EPRI	UCA 2.0	Object-oriented programming, unified modeling language, MMS
Late 1990s	IEC TC57 WG 13, 14	IEC 61970 and IEC 61968	Unified modeling language, XML, interface reference model, and interface definition language
Late 1990s	IEC TC57 WG 10,11,12	IEC 61850	UCA 2.0 device view, Abstract Syntax Notation One (ASN.1--IEC Std 8824), UML, MMS
2004	IEC TC57 WG 10,11,12	IEC 61850	UCA 2.0, UML, MMS, XML, simple object access protocol, Common Information Model – IEC 61970

Comparing the last two entries on IEC 61850 shows how the technologies underlying the standard have evolved over the past 5–6 years: The working groups have added XML, simple object access protocol, and the 61970 Common Information Model to the repertoire. Although it is obvious that the IEC working groups are trying to keep up with the latest Internet data vocabularies and Web services, it is clear that the 61850 working groups are swimming in an alphabet soup of technologies that make establishment and implementation of working systems difficult if not impossible.

[171] Holstein says: " ... only for special cases would the two implementations interoperate. This is best described by considering the following two situations. In a client-server environment, if the client implemented Generic Object Models for Substation and Feeder Equipment … and the server implemented ICCP, the two could sometimes communicate—but not always. If the implementation is reversed, ICCP in the client and [Generic Object Models for Substation and Feeder Equipment] in the server, most communications will *not* inter-operate. From a utility integration point of view, this can get real ugly!" See Note 170 for reference information.

[172] See http://www.ucausersgroup.org/

From the end-user perspective, the following difficulties of using IEC 61850 as the basis for a CHP data vocabulary remain:

- Data is represented in 61850 both in binary (MMS) and text (XML) formats, under the assumption that "XML will not work for real-time applications."[173]
- Distribution automation at this time is conceived as an entirely utility-centric process that assumes central station generation, extensive transmission and distribution lines, and a few utility-controlled distributed generators here and there on the end the line.
- IEC 61850 "does not yet have the ability for interoperability with DER."[174]
- No regulatory or market barriers are acknowledged—though in California today they make end-user participation in an automated distribution system a practical and economic impossibility.
- The many competing standards and specifications, far from making the job of creating a CHP data vocabulary easier, have made it more difficult by requiring conceptual translation from one system to another and assessment of which is most efficient and effective for the job.

8.3.3.2 Supervisory Control and Data Acquisition Protocols

8.3.3.2.1 What Is Supervisory Control and Data Acquisition?

Supervisory Control and Data Acquisition (SCADA) is an industrial measurement and control system that consists of a central host or master (usually called a master station or master terminal unit), one or more field data-gathering and control units or remote stations, and a collection of standard or custom software used to monitor and control remote data collection devices. Contemporary SCADA systems usually use long distance communications.[175]

[173] See Note 170. XML may not work in all real-time situations, but NERC's OASIS systems disprove this general proposition.
[174] Consortium for Electrical Infrastructure to Support a Digital Society/E2i. "Open Communication Architecture for Distributed Energy Resources in Advanced Distribution Automation (The DER/ADA Project)." Dec. 25, 2003.
[175] http://members.iinet.net.au/~ianw/primer.html

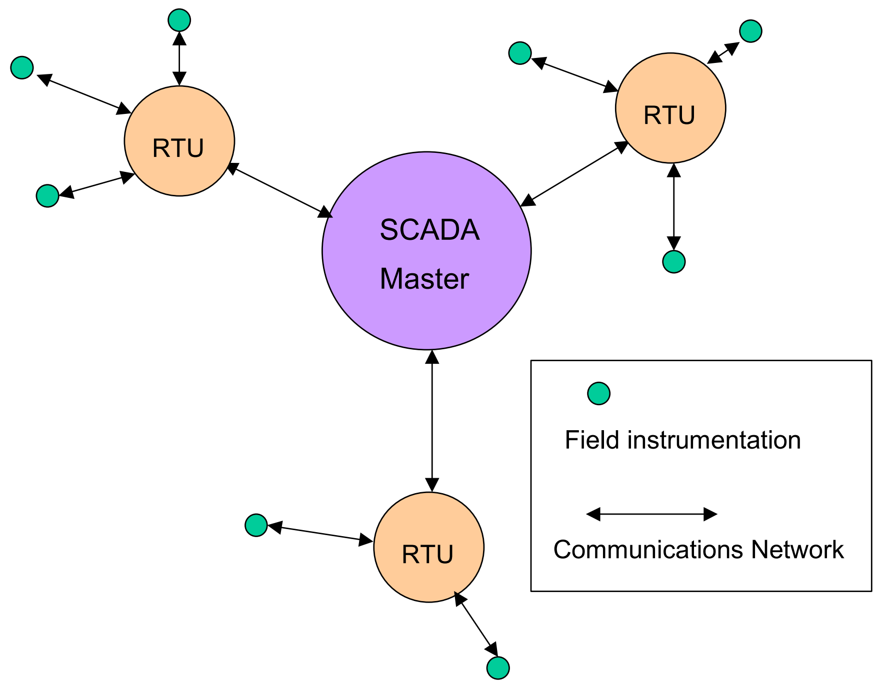

Figure 8-1. SCADA system components

The SCADA remote terminal units are small rugged computers (programmable logic controllers) that provide intelligence in the field and allow the central SCADA master to communicate with field instruments. They are standalone data acquisition and control units. Their function is to control process equipment at remote sites, acquire data from the equipment, and transfer the data back to the central SCADA system.[176]

8.3.3.2.2 Comparing IEC 61850 and Other SCADA Protocols

IEC and the SCADA industry have developed six SCADA protocols:

- IEC 60870-5-101 – Companion standard for basic telecontrol tasks
- IEC 60870-5-103 – Companion standard for the informative interface of protection equipment
- IEC 60870-5-104 – Network access for IEC 60870-5-101 using standard transport profiles
- DNP3 – Distributed network protocol, widely used in the SCADA industry
- IEC 60870-6 – Telecontrol equipment and systems – TASE.2 (synonymous with ICCP)
- IEC 61850 – Communication networks and systems and substations (UCA).

[176] http://members.iinet.net.au/~ianw/rtu.html

Karlheinz Schwarz, who has been very active in the development of IEC 61850, IEC 61400-25, and the current ADA-DER workshops, wrote a paper that compared these SCADA protocols.[177] Table 8-2 and Table 8-3 are excerpted from his more comprehensive comparison, although several parts of it are updated here to capture changes since 2002.

It is clear from this analysis that the fundamental difference among the SCADA protocols is that 61850 employs the latest information technologies, including objects, Web services, and XML. 61850 also uses a mishmash of earlier work on utility communication, especially UCA 2.0 and MMS. But one should not pass lightly over the significance of 61850's use of current information technologies. Last year, it was announced that OPC Foundation, the industrial controls trade organization that supports "open connectivity via open standards," was shifting its own standard specifications and technologies in this same direction:

> OPC Foundation underlines its intent to transition away from "component-based" architecture to a more unified architecture by using Web services and XML. ... Moving away from component-based architectures will allow OPC to provide a richer user experience through the use of vendor products that will now be totally inter-operable with full Internet conductivity and unlimited scalability across platforms of the end-user's choice.[178]

OPC Foundation currently has seven standards specifications completed or in development. Its latest specifications are "OPC XML-DA – providing flexible, consistent rules and formats for exposing plant floor data using XML, leveraging ... [Simple Object Access Protocol] and Web Services" and "OPC Complex Data – a companion specification to Data Access and XML-DA that allows servers to expose and describe more complicated data types such as binary structures and XML documents."[179]

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[177] Schwarz, K. "Comparison of IEC 60870-5-101/-103/-104, DNP3, and IEC 60870-6-TASE.2 With IEC 61850." Feb. 2, 2002.
[178] From a news announcement of Control Engineering. OPC Foundation, ISA Show, Houston, Texas. October 2003.
[179] http://www.opcfoundation.org/01_about/01_whatis.asp

Table 8-2. Comparison of SCADA Protocols: Application, Coverage, and Standards

Feature	*60870-5-101*	*60870-by-104*	*60870-5-103*	*DNP 3*	*60870-6-TASE.2*	*61850*
Application domain	Telecontrol (SCADA)	Telecontrol (SCADA), intra-substation and control-center to substation	Protection	Telecontrol (SCADA), intra-substation and control-center to substation	Control-Center to control-center	Substation and feeder automation (open for other domains)
Main coverage	Application Layer (Services and Protocol)	Application Layer (Services and Protocol)	Application Layer (Services and Protocol) and basic Application Semantic	Application Layer (Services and Protocol)	Application Layer (Services and Protocol) and basic Application Semantic	Application Layer (Services and Protocol), Application Semantic (models of devices and applications), and Substation configuration language
Standardization	IEC Standard (1995)	IEC Standard (2000)	IEC Standard (1997)	Open Industry Specification (1993), IEEE 1379 Recommended Practice (2000)	IEC Standard (1997)	Some parts are IEC Standard, Others are in final draft.(as of March 2004)
Standardization Organization	IEC TC 57 WG 03	IEC TC 57 WG 03	IEC TC 57 WG 03	DNP Users Group (from IEEE specification)	IEC TC 57 WG 07	IEC TC 57 WG 10, 11, and 12
Use in other organizations as based standard				Considered for standardization by Australian water utility industry		Project 25 of IEC TC 88 (Wind Turbine Systems)
Crucial design rule used for the development process of the standard	Optimize use of bandwidth and hardware	Optimize use of bandwidth and hardware	Optimize use of bandwidth and hardware	Optimize use of bandwidth and hardware	Simplify device (data) engineering and integration	Simplify device (data) engineering and integration

Table 8-3. Comparison of SCADA Protocols: Object Orientation and XML

Feature	*60870-5-101*	*60870-by-104*	*60870-5-103*	*DNP 3*	*60870-6-TASE.2*	*61850*
Crucial Paradigm	Exchange of numbered lists of simple data points	Exchange of numbered lists of simple data points	Exchange of numbered lists of simple data points	Exchange of numbered lists of simple data points	Exchange of numbered lists of simple and complex data points	Modeling of application objects and exchange of I/O and metadata
Object-oriented modeling	None	None	None	Under development	Permits object-oriented naming	Supports inheritance, encapsulation, hierarchical models,...
Semantic of data (i.e., what the data mean in a specific domain)	None	None	Some (Protection)	None	None	2000 Object Classes
Complete description of device configuration	Paper Document Only	Paper Document Only	Paper Document Only	Paper Document Only; Online document under development	Paper Document Only	XML / XML DTD (Document Type Definition) Specifies the semantic of devices, logical devices, logical nodes, data
Location of configuration	Configuration of RT you and/or IED, configuration of databases, and configuration of applications	Configuration of RT you and/or IED, configuration of databases, and configuration of applications	Configuration of RT you and/or IED, configuration of databases, and configuration of applications	Configuration of RT you and/or IED, configuration of databases, and configuration of applications	Configuration of RT you and/or IED, configuration of databases, and configuration of applications	The complete configuration is in the IED, therefore is always consistent; additionally in the XML file of the configuration.
Automatic verification of online and off-line configuration	None	None	None	None	None	Validation of online XML file with offline DTD/Schema
Open for other encoding solutions (example: XML)	None	None	None	Under development for DNP3	None	Some products provide XML coded messages
Web services through HTTP, CORBA, SOAP...)	None	None	None	None	None	Some

8.3.3.3 Parts of IEC 61850

IEC Standard 61850, "Communication Networks and Systems in Substations," is nearly complete as an international standard. In a March 22 e-mail announcing a seminar and implementation workshop, a consulting firm in the area of distribution automation announced:

> ... 13 of the 14 parts of the standard series IEC 61850 (Communication networks and systems in substations) have been published/approved as International Standards. All crucial parts to implement and apply this standard series are stable and available.[180]

The only part of the standard that is not complete is Part 10 (61850-10: Conformance Testing),[181] and the addendum to Part 7-4.

Table 8-4. IEC 61850 Status List of Parts[182]

Standard Reference #	*Publish Date*	*Part#: Title*
IEC/TR 61850-1	(2003-04)	Part 1: Introduction and overview
IEC/TS 61850-2	(2003-08)	Part 2: Glossary
IEC 61850-3	(2002-01)	Part 3: General requirements
IEC 61850-4	(2002-01)	Part 4: System and project management
IEC 61850-5	(2003-07)	Part 5: Communication requirements for functions and device models
IEC 61850-6	BPUB*	Part 6: Configuration description language for communication in electrical substations related to IEDs
IEC 61850-7-1	(2003-07)	Part 7-1: Basic communication structure for substation and feeder equipment - Principles and models
IEC 61850-7-2	(2003-05)	Part 7-2: Basic communication structure for substation and feeder equipment - Abstract communication service interface (ACSI)
IEC 61850-7-3	(2003-05)	Part 7-3: Basic communication structure for substation and feeder equipment - Common data classes
IEC 61850-7-4	(2003-05)	Part 7-4: Basic communication structure for substation and feeder equipment - Compatible logical node classes and data classes
IEC 61850-7-401	ANW**	Part 7-401: Power Quality Monitoring Addendum
IEC 61850-8-1	BPUB*	Part 8-1: Specific communication service mapping (SCSM) - Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3
IEC 61850-9-1	(2003-05)	Part 9-1: Specific Communication Service Mapping (SCSM) - Sampled values over serial unidirectional multidrop point to point link
IEC 61850-9-2	BPUB*	Part 9-2: Specific communication service mapping (SCSM) - Sampled values over ISO/IEC 8802-3
IEC 61850-10	CCDV***	Part 10: Conformance testing

*BPUB = Publication being printed
**ANW = Approved new work
***CCDV = Circulated committee draft for vote

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180 "Standard IEC 61850: Get Started With a Seminar/Workshop." March 21, 2004, 2:31 p.m. seminars@nettedautomation.com.
181 Draft circulated as committee draft with vote.
182 http://www.iec.ch/cgi-bin/procgi.pl/www/iecwww.p?wwwlang=E&wwwprog=sea22. p&search= iecnumber&header=IEC&pubno=61850&part=&se=&submit=Submit#projs

8.3.3.4 Information Model of IEC 61850

Although IEC 61850 is a standard designed for substations, not DER, its information model is general enough to be useful for DER communications. The information model consists of a class inherited from the logical node class defined in IEC 61850-7-2. The abstract class logical node is the "parent" of all other logical nodes—it gives its characteristics to the nodes below. This is the nature of object-oriented programming: Begin with the most general and primitive characteristics and add complexity and specificity in succeeding "generations."

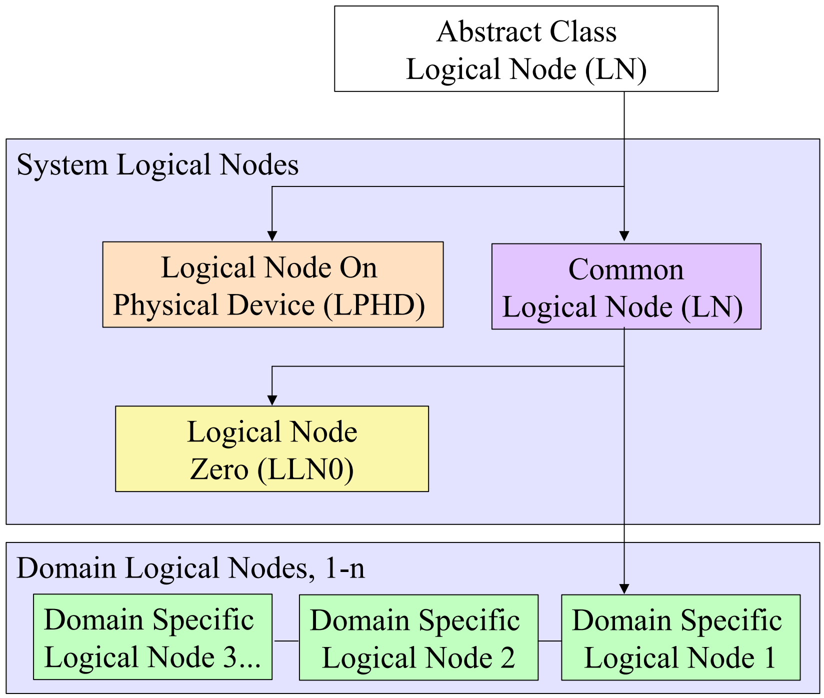

Figure 8-2. IEC 61850 information model

If we imagine the system logical nodes, also known as the logical device, implemented in the domain of a device server—i.e., a piece of software connected to a controller and a generator to be controlled—there are essentially three functions to be performed:

1. Control and monitor the generator
2. Monitor the controller
3. Monitor the server.

Logical nodes that are derived from the system logical nodes perform these functions:

1. LN (1-n) = controls and monitors the system (generator, absorption chiller, etc.)
2. LPHD = controls and monitors the physical controller device
3. LLN0 = monitors the logical device.

In this information model, the system logical nodes never actually occur in a real system; they simply pass on their characteristics—i.e., their data members and class functions—to the domain logical nodes.

8.3.3.5 Model Application to Wind in IEC 61400-25

IEC 61400-25 is a design hierarchy for a wind power plant (called WPP) for electricity generation and, as such, is instructive for our purposes.[183] At the top level, the WPP hierarchy consists of the single root element <Device>,[184] inside of which are <VMD> (identification information), <Meteor> (meteorological monitoring nodes), and <Sigvards> (the name of the wind farm, with all status and control elements nested inside).

```
- <Device>
  + <VMD>
  + <Meteor>
  + <Sigvards>
  </Device>
```

Figure 8-3. WPP hierarchy top view

<VMD> contains a single element, <DI>, which contains two elements with children, <VndID> and <CommID> (vendor and communication identification elements, respectively—not elaborated further in this paper), and five childless elements: <Name>, <Class>, <d> (description), <Own> (owner name), and <Loc> (location). Notice that each element has an attribute "mmstype" that tells what kind of data the element contains and its maximum length in bytes (for character strings) or bits (for numerical data types). Recall from Table 8-4 that IEC 61850-8-1 is concerned with mapping to and from ISO 9506, the MMS; the mmstype attribute appears to be a data typing into the MMS standard.

```
- <Device>
  - <VMD>
    - <DI>
        <Name mmstype="visibleString[-
          32]">"Wind Power Plant
          Demo"</Name>
        <Class mmstype="visibleString[-
          32]">"WPP"</Class>
        <d mmstype="visibleString[-32]">"Demo
          to test device model."</d>
        <Own mmstype="visibleString[-
          32]">"Vattenfall Utveckling AB"</Own>
        <Loc mmstype="visibleString[-
          128]">"Gotland Nas$Sigvards2"</Loc>
      + <VndID>
      + <CommID>
      </DI>
    </VMD>
  + <Meteor>
  + <Sigvards>
  </Device>
```

Figure 8-4. VMD node

Notice how the entire XML file is arranged hierarchically, with an indentation displaying a lower level of hierarchy, a minus sign indicating that the hierarchy is expanded at this element, a plus sign indicating that an element has additional sub-elements beneath it, and no plus or minus sign indicating that the element is at the bottom of this branch of the hierarchy.[185]

The <Meteor> element contains the single sub-element <WMet> (wind meteorological information), which has three sub-elements beneath it.

```
- <Device>
  + <VMD>
  - <Meteor>
    - <WMet>
      + <MX>
      + <CF>
      + <RP>
      </WMet>
    </Meteor>
  + <Sigvards>
  </Device>
```

Figure 8-5. Meteor node

---

[183] References to the wind design hierarchy are from a file called "root.xml," available for download as part of a demonstration from NettedAutomation at http://www.nettedautomation.com/index.html.

[184] A rule of XML is that there must be a root element that encapsulates all other XML elements in the file.

[185] This hierarchical display is a convention built into Microsoft's Internet Explorer for viewing XML files. The “+” and “-” symbols are not part of the actual XML.

In the parlance of IEC 61850, these are functional constraints. MX is for measurement objects, i.e., numbers that change in real time due to external processes; CF is for configuration information, the value of which may be written or read; and RP is for unsolicited reporting data that arrive when an event such as an error or other exception occurs. The kind of meteorological information captured under MX includes multiple measurements of wind speed, wind direction, and temperature and single measurements of air pressure and rain.

The Sigvards logical device contains all the logical nodes necessary for monitoring and controlling the wind generator. The logical node names (represented in XML as elements) are listed below:

Name	**Description**
CustRP	Custom report
WBrake	Wind brake information
WEnv	Wind environmental information
WGear	Wind gear information
WGen	Wind generator information
WGrid	Wind grid information
WNace	Wind nacelle (generator housing) information
WRotor	Wind rotor information
WTurb	Wind turbine information
WYaw	Wind yaw (yaw motor and drive) information.

```
- <Device>
  + <VMD>
  + <Meteor>
  - <Sigvards>
    + <CustRP>
    + <WBrake>
    + <WEnv>
    + <WGear>
    + <WGen>
    + <WGrid>
    + <WNace>
    + <WRotor>
    + <WTurb>
    + <WYaw>
    </Sigvards>
  </Device>
```

Figure 8-6. Sigvards logical device

Although most of the implementation details of WPP are not relevant to XCHP, it is useful to look at several examples to get a better idea of how data and data attributes are handled. For example, the logical node <WRotor> contains functional constraints MX (measurement), ST (status), CF (configuration), RP (unsolicited reporting), and LG (logging time-stamped data). Within MX, there are two elements (called data class names in IEC 61850), <RotSpd> and <RotPos>, which correspond not to decayed potatoes and flowers, respectively, but to rotor speed and rotor position. Both of these rotary elements contain identical sub-elements (called data attributes in IEC 61850): a 16-bit integer called "mVali," a 16-bit bitstring "q," and a time element "t." All common data classes in WPP have these three data attributes at a minimum (because they are mandatory in IEC 61850).

```
- <WRotor>
  - <MX>
    - <RotSpd>
        <mVali mmstype="integer
          [16]">1829</mVali>
        <q mmstype="bitString[16]">
          [0000001000000010]</q>
        <t mmstype="binaryTime
          [6]">03/03/2004_20:23:12.968</t>
      </RotSpd>
    - <RotPos>
        <mVali mmstype="integer
          [16]">1830</mVali>
        <q mmstype="bitString[16]">
          [0000001000000010]</q>
        <t mmstype="binaryTime
          [6]">03/03/2004_20:23:12.968</t>
      </RotPos>
    </MX>
  + <ST>
  + <CF>
  + <RP>
  + <LG>
  </WRotor>
```

Figure 8-7. Rotor measurement objects

Data attribute mVali is an analog measured value, an integer, that represents the rotational speed (for <RotSpd>) or rotational position (for <RotPos>) of the rotor. Data attribute t is a timestamp that represents the time of the measurement to a thousandth of a second. Data attribute q is a convention in SCADA protocols that allows each bit of a 16-bit number to have a different meaning (called a "packed list"), as follows in Table 8-5.[186]

Table 8-5. The Meaning of Attribute Q

Quality Type Definition			
Attribute Name	**Attribute Type**	**Value / Value Range**	**M/O/C**
	PACKED LIST		
validity	CODED ENUM	good | invalid | reserved | questionable	M
detailQual	PACKED LIST		M
overflow	BOOLEAN		M
outOfRange	BOOLEAN		M
badReference	BOOLEAN		M
oscillatory	BOOLEAN		M
failure	BOOLEAN		M
oldData	BOOLEAN		M
inconsistent	BOOLEAN		M
inaccurate	BOOLEAN		M
source	CODED ENUM	process | substituted DEFAULT process	M
test	BOOLEAN	DEFAULT FALSE	M
operatorBlocked	BOOLEAN	DEFAULT FALSE	M

It is conventional in IEC 61850 (and elsewhere) that 1 = true and 0 = false. Given the value of q = 0000001000000010 and the table above, one can see that all q values are false except for badReference and test. Given that the data values in root.xml are not real, this makes sense.

One excellent result of the hierarchical organization of WPP, which it inherits by design of IEC 61850, is the ability to precisely address items of information on the lowest level of the hierarchy. Thus, a command to:

Get "Sigvards/WRotor.MX.Rotspd.mVali" would return the value 1829. In the IEC 61850 hierarchy nomenclature:

- Sigvards is the logical device.
- WRotor is the logical node.
- MX is the functional constraint.
- RotSpd is the data object.
- mVali is the data object attribute.

[186] See IEC 61850-3.

8.3.4 Advanced Distribution Automation for Distributed Energy Resources

8.3.4.1 Overview

ADA-DER is part of the Consortium for Electric Infrastructure to Support a Digital Society, a multimillion-dollar project managed by EPRI subsidiary E2I. The aim is to facilitate seamless integration of DER into the control system of the electric power system. Because of the variety of DER technologies—and the variety of ways DER may be used, owned, and operated—the ADA-DER project believes: "the most effective way to integrate DER into the power system control infrastructure is by using an open communication architecture, as opposed to a multiplicity of proprietary architectures. The principal open (non-proprietary) architecture is IEC 61850."[187]

To bring about this end, ADA-DER has two goals:

1. To develop DER object models (information_exchange templates) that are of suitable quality to be part of the body of standards associated with IEC 61850 and with appropriate IEEE standards; and
2. To proceed with the standardization by working in concert with IEC and IEEE from the outset.[188]

Although IEC 61400-25 (WPP) is a step in the right direction, IEC 61850 does not yet have the ability for interoperability with other forms of DER besides wind generation. Establishing this capability will require the development and field validation of an object model for each type of DER device. An object model is a detailed data template for the information exchange needed for monitoring and controlling the DER device within the architecture of a power distribution system. The object model makes the DER device recognizable and controllable to (i.e., interoperable with) the power system.[189]

---

[187] Consortium for Electric Infrastructure to Support a Digital Society ADA-DER. "Executive Summary of Multiyear Project Plan." Dec. 25, 2003.

[188] "Utility Communications Architecture (UCA) Object Models for Distributed Energy Resources (UCA-DER) Final Report." Dec. 2003. Pp. 1–3.

[189] Goodman, F.; Markushevich, N. "Framework for Preparation and Conducting Laboratory and Field Tests of DER in Distribution Operation Environment Interim Document." February 2004.

8.3.4.2 Possible Benefits of Advanced Distribution Automation for Distributed Energy Resources

According to Frank Goodman, chairman of the ADA-DER project, the drivers for automated distribution and integration with DER technologies are to:

- Improve reliability and performance of distribution systems
- Reduce operating costs
- Enhance contingency response capability
- Improve power quality
- Increase customer service options
- Prevent and mitigate outages
- Aid outage recovery operations and reduce restoration times
- Support DER integration into distribution operations
- Make customer systems part of the system performance equation.[190]

The effect and benefits of the successful completion of ADA-DER would be to:

- Provide one international standard that would define the communication and control interfaces for all DER devices
- Simplify DER implementation
- Encourage and facilitate more widespread use of DER and ADA
- Increase the value of DER functionality (capabilities) in utility distribution system operations
- Reduce DER installation and maintenance costs
- Improve reliability and economics of power system operations
- Enable new system-level ADA options.[191]

The progress and accomplishments of the ADA-DER working group include:

- Two draft object models
    - Diesel generators
    - Fuel cells
- First phase of studies of distribution operations with DER.[192]

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[190] Goodman, F. "Project Overview and Highlights of 2003 Accomplishments." Feb. 16, 2004.
[191] Ibid.
[192] Ibid.

8.3.4.3 DER Logical Nodes

Recall from Section 8.3.3 that within the logical device, the next level of hierarchy is filled with domain-specific logical nodes. In the case of the wind power plant, the logical nodes are WBrake, WEnv, WGear, WGen, WGrid, WNace, WRotor,WTurb, and WYaw, each of which describes an aspect of the WPP. The first step of building the object models was for the ADA-DER working group to lay out which logical nodes were already constructed and which should be added. The new nodes are shown in the table below with a gray background; the existing nodes (from IEC 61850) are shown with a white background. The group spent most of its time building object models for a diesel engine (DIES below) and a fuel cell (DFCL below).

Table 8-6. Logical Nodes for DER Devices[193]

Logical Node	Description
	DER Device Characteristics
DRCT	*DER Controller*
DRGN{n}	*DER Generator Characteristics and Control (units 0 – n)*
DSYN{n}	*DER Synchronization: GSYN0-n = Generator Unit*
{Multiple LNs} Prime Mover or Storage	*DER Prime Mover or Storage Device Characteristics and Control (e.g. DIES, DFCL). This LN varies, depending upon the DER technology*
DCOV{n}	*DER Converter/Inverter Characteristics: CONV0-n = Converter/Inverter Unit. This LN varies, depending upon the need for a converter/inverter*
DFUL	*Fuel Systems*
DBAT	*Battery Systems*
	Electrical Power System Measurements
MMSU{n}	DER voltage, current, frequency, & var measurements: e.g. MMSU0 = DER Alternator; MMSU1 = local power; MMSU2 = utility power. This LN is similar to MMXU, but contains additional attributes related to statistics
MMXU{n}	DER voltage, current, frequency, & var measurements without statistical information. Alternative to MMSU. (MMXN if single phase)
MHAI{n}	Power System Harmonics (MHAN if single phase)
MMTR{n}	DER Energy Meters: MMTR0 = Total generation; MMTR1 = Net generation; MMTR2 = Transferred to power system; MMTR{m} = submetering
	Circuit Breakers
XCBR{n}	DER Circuit Breakers: XCBR0 = Load Breaker; XCBR1 = Common Coupling Breaker; XCBR2 = Interface Point Breaker; XCBR3-n = DER Generator Unit Breakers
	Protection Function
PBRO{n}	DER Protective Relaying base logical node: for PUVR, POVR, PTOC, PDPR, PFRQ
PBTC{n}	DER Protective Relaying timing logical node: for PUVR, POVR, PTOC
RREC{n}	Reclosing relay for circuit breakers
PRCF{n}	*DER Rate of Change of Frequency Relaying*
Pxxx {n}	*Other protection functions (TBD)*
	Automatic Transfer Switch
ATSC{n}	DER Automatic Transfer Switch Characteristics
SWIT{n}	DER Automatic Transfer Switch (ATS) status
SDRV{n}	DER ATS Control
AUTO{n}	DER ATS Automatic Control Logic
FIND{n}	DER ATS Fault Indicator
	Administrative Function
DMIB{n}	SNMP Management Information Base for DER Installations

It is useful to see how these nodes are situated in an actual distribution system.

193 Ibid.

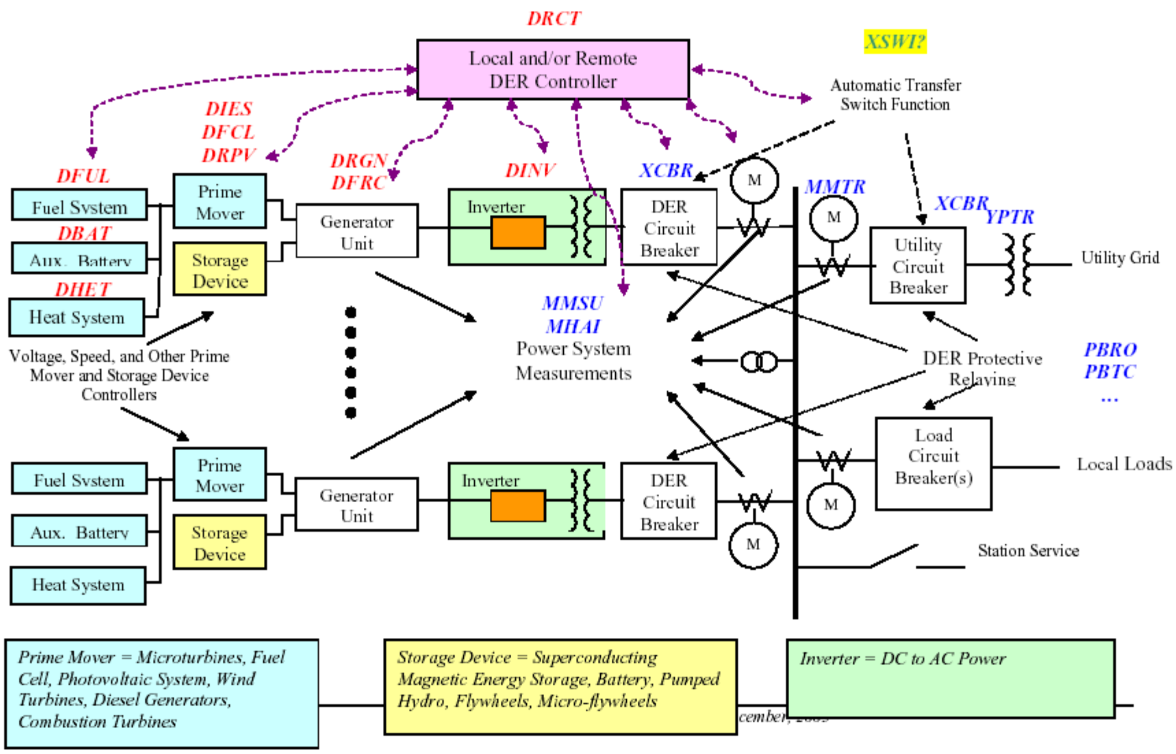

Figure 8-8. DER logical nodes imposed on power system diagram[194]

It is clear from Figure 8-8 which of the nodes will be useful for a CHP design hierarchy and which should be excluded. Specifically, it will be useful to include:

- DRCT – Distributed resources controller
- DRGN – Distributed resources generator
- DIES – Diesel engine
- DFUL – Distributed resources fuel
- ENVR– Environmental metrics (not shown in the above figure but useful)
- DHET – Heat recovery system.

The ADA-DER project has made information model charts (upon the model of IEC 61850) for each of these nodes. The charts represent a methodical listing of each element needed to build the design hierarchy and include:

- Logical node names
- Functional constraints
- Common data classes
- Data object names
- Data object attributes.

[194] "Utility Communications Architecture (UCA) Object Models for Distributed Energy Resources (UCA-DER) Final Report." December 2003. Pp. 1–3. Nodes in red are new; nodes in blue are existing in IEC 61850.

Information model charts for the DER logical nodes are shown in the same order as listed above. As shown in the WPP hierarchy, this is all one needs to know to build the XML file.

8.3.5 The Diesel Engine Logical Node

The question remains how much of the DIES logical node, serving emergency building loads, will be useful for a base-loaded natural gas ICE. To make this assessment, this section will look at each functional constraint individually.

8.3.5.1 Configuration Settings

Table 8-7. DIES Configuration Settings

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Configuration Settings				
DiesOwner	DOO	Owner and operator of device	See Section 5.1.1	O
DERLoc	GPS	GPS location of device		O
DiesFuel	ING	Type of fuel		O
DiesAvgCalFuel	ASG	Average calorie content of fuel		O
DiesMaxTurPres	ASG	Max turb pressure		O
DiesMaxInletTemp	ASG	Max inlet temperature		O
Dies MaxOutTemp	ASG	Max outlet temperature		O
DiesMinSpeed	ASG	Min speed		O
DiesMaxSpeed	ASG	Max speed		O
DiesHeatRtCurves	CSD	Heat rate curves	From IEC61850-7-3 Clause 7.9.4	O
DiesFuel	ING	Type of fuel used by diesel engine		O

It is evident that all configuration data attributes are relevant to a natural gas engine prime mover for a CHP application. The data attribute types also do not need to be changed. However, the attribute names need to be changed to reflect the fact that it is not a diesel engine. So, “Dies” is replaced with “Ngic” for all attribute names:

- NgicOwner
- DERLoc (no change)
- NgicFuel
- NgicAvgCalFuel
- NgicMaxTurPres
- NgicMaxInletTemp
- Ngic MaxOutTemp
- NgicMinSpeed
- NgicMaxSpeed
- NgicHeatRtCurves
- NgicFuel.

8.3.5.2 Status Information

Table 8-8. DIES Status Information

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Status Information				
DiesOnOff	SPS	Diesel is on or is off	Off; On	M
DiesMode	INS	Operational or in test/off-line mode,	1 = in test 2 = off-line 3 = available	O
SpdDroop	SPS	Speed droop status	Disabled; enabled	O
OilPresSt	SPS	Oil pressure status	Normal; Abnormal	O
CoolPresSt	SPS	Coolant pressure status	Normal; Abnormal	O
CustSw1	SPS	Status of customer switch 1	Off; On	
CustSw2	SPS	Status of customer switch 2	Off; On	
DiesAlm	ALM	Diesel engine alarms	TBD	O

All DIES status attributes are relevant to “Ngic,” but several attribute names need to be changed. DiesOnOff should be changed to NgicOnOff, DiesMode should be changed to NgicMode, and DiesAlm should be changed to NgicAlm.

8.3.5.3 *Measured Values*

Table 8-9. DIES Measured Values

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Measured Values				
OilPres	MV	Oil pressure	Pressure, in Pascals	O
DiesTemp	MV	Engine temperature	Temperature in degrees K	O
DiesRPM	ANV	Diesel engine speed	Speed in revolutions per minute	O
GenFrq	MV	Diesel engine gen frequency	Hz	O
EngTrq	MV	Engine torque	Metric equivalent to ft-lbs	O
EngTim	MV	Engine timing	Degrees BTDC?	O
EngFuel	MV	Engine fuelling ??Set or MV?	Mm3s ???	O
AirPres	MV	Air pressure	Metric equivalent to InHg	O
CoolPres	MV	Coolant pressure	Metric equivalent to psi	O
CoolTemp	MV	Coolant temperature	Deg C	O
ManiPres	MV	Intake manifold pressure	Metric equivalent to psi	O
ManiTemp	MV	Intake manifold temperature	Deg C	O
WaterTemp	MV	Aftercooler water temperature	Deg C	O
BlowFlow	MV	Blowby flow	CFM ??	O
BatVolt	MV	Battery voltage	volts	O
FuelPres	MV	Fuel Rail pressure	Metric equivalent to psi	O
TimPres	MV	Timing Rail pressue	Metric equivalent to psi	O
FuelTemp	MV	Fuel temperature	Deg C	O
FuelAmp	MV	Fuel Rail actuator current	amps	O
TimAmp1	MV	Timing rail actuator current	amps	O
TimAmp2	MV	Timing rail actuator current	amps	O
PumpAmp	MV	Fuel pump actuator current	amps	O
BatVolt	MV	Battery charger alt flash volts	volts	O
TotCumFuel	MV	Cumulative fuel consumption	Fuel in liters	O
CumFuel	MV	Cumulative fuel since reset	Fuel in liters	O
EngRunTim	TMS	Engine running time	Hours	O
FuelRate	MV	Fuel usage rate	Fuel usage rate liters/hr	
FuelCal	MV	Calorie content of fuel	Calorie content of fuel	O
FuelLvl1	MV	Fuel level in tank #1	Fuel level in one tank	O
FuelLvl2	MV	Fuel level in tank #2	Fuel level in second tank	O

Again, all DIES data attributes are useful for “Ngic,” and only names need to be changed: DiesTemp to NgicTemp and DiesRPM to NgicRPM.

8.3.5.4 Controls and Control Setpoints

Table 8-10. DIES Controls and Control Setpoints

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
Controls				
DiesCtl	DPC	Start / stop diesel engine	Stop; Start	M
Crank	DPC	Crank relay driver command	Off; On	O
FuelShut	DPC	Fuel shutoff valve driver command	False; True	
Emerg Ctl	DPC	Emergency start / stop diesel engine	Stop; Start	O
DiagEna	DPC	Diagnostic mode enable	Fault flashout	O
Control Setpoints				
TrgSpd	SPV	Final target engine speed	rpm	O
DiesFreq	APC	Diesel generator frequency	Hz	O
EngTrqSet	APC	Desired engine torque	Metric equivalent to ft-lbs	O
DrpAdj	APC	Droop adjustment	%	O

Again, there is no attribute that does not also work for “Ngic.” Name changes are DiesCtl to NgicCtl and DiesFreq to NgicFreq.

This is a surprising result. The ADA-DER modeling team did not make any distinctions between diesel engines (for emergency backup) and natural gas engines (for CHP). If this is indeed the final model, it should be broadened to cover both types of ICEs. Alternatively, if the modeling team desires to capture the differences between diesel engines and spark engines, then it has some additional modeling to do.

With this analysis complete, it is possible to build the CHP design hierarchy, based on IEC 61850, IEC 61400-25, and the ADA-DER object models.

8.4 The Combined Heat and Power Design Hierarchy

8.4.1 Unspecified and Undefined Data Attributes

DIES is one of the logical nodes that make up the complete set of object models included in the work by the ADA-DER working group. Each logical node is made up of data attributes, such as DERLoc and EngTrqSet. These data attribute names mean something, and their meaning is not always clear because of the abbreviation or a lack of technical understanding. For this reason, it is useful in the XML implementation to invent an XML attribute[195] that tells what the semantic is for the name. This is implemented in the CHP design hierarchy whenever possible.

[195] Section 8.3.1.1 explains what XML attributes are. IEC 61850 data attributes are implemented in XML as the lowest level elements in hierarchy. IEC 61400 declares data types for the IEC data attributes as XML attributes as follows: <IECDataAttribute mmstype= "datatype"/>.

It is not possible in two cases to define the semantic:

- When the meaning of the attribute name is not defined in any of the documents consulted in this study (called "unknown")
- When the meaning of the attribute name is not determined yet by the ADA-DER working group (called "unspecified").

An example in which many attributes are unspecified is the logical node DHET, which is the attribute dealing with thermal energy. Most of the additions in this study to the ADA-DER object models are made to specify the unspecified DHET thermal attribute names. The functional constraint "Configuration Settings" is left blank and unspecified, the functional constraint "Status" is left blank and unspecified, and there are only three measured values and one control data attribute. See Table 8-11.

Some of the common data classes referred to in the work of ADA-DER were not available in the version of IEC 61850-7-3 consulted in the writing of this report. An example is the common data class "ALM," which means alarm:

```
<DgicAlm CommonDataClass="ALM" Semantic="IC engine alarms To Be Determined">
    <!-- Unknown Common Data Class ALM -->
</DgicAlm>
```

Figure 8-9. Alarm data class

The example above shows how some attribute names have been revised to reflect the change from a diesel ICE to a natural gas ICE.

All additions and changes to the ADA-DER object models, made here to extend their work into the realm of CHP, need to be reviewed and vetted in a working group by engineers active in the field of cogeneration and trigeneration. Their inclusion here builds on what has already been done and, hopefully, serves as draft input to a working group process.

Table 8-11. The Thermal Energy Logical Node

Attribute Name	Attr. Type	Explanation	SI Units and Meanings	M/O
LNName		Shall be inherited from Logical-Node Class		
Data				
Logical Node Mandatory Data		*LN shall inherit all Mandatory Logical Node Information from Common Logical Node Class*	*Mod, Beh, Health, NamPlt)*	M
EEHealth	INS	External equipment health (health of generator)	See IEC61850-7-4, Clause 6 (Health)	M
EEName	DPL	Battery/UPS nameplate information	Vendor and Device nameplate	M
Configuration Settings		Unspecified!		
Status Information		Unspecified!		
Measured Values		Not Much Here!		
InWatTemp	MV	Inlet water temperature	Degrees C	O
OutWatTemp	MV	Outlet water temperature	Degrees C	O
WatFlowRate	MV	Water flow rate	Meters per second	O
Controls		Not Much Here!		
PumpOnOff	DPC	Start / stop pumps	Stop; Start	M

8.4.2 Combined Heat and Power Extensions to the Advanced Distribution Automation for Distributed Energy Resources Object Model

Recall the surprising result from the foregoing analysis that all the work done on the diesel engine object model applies also to a natural gas ICE, despite the differences between those prime mover technologies and the different ways they are typically used.[196] Because of this, it was possible to use all the DIES logical nodes by simply renaming them. To complete the analysis of what should remain in the existing object model, what should be left out, and what should be added, it was necessary to return to the information model built in the report "Develop Codes and Modules for Optimal Dispatch Algorithms."[197] This analysis fortifies the notion that what is missing is the capability to handle a thermal load. More specifically, for RE installations, this means additional modeling to cover an absorption chiller and an absorption chiller controller. The model could also be extended to include building use of hot water to displace existing building boiler capacity.

Functions covered and not covered by the existing object model are shown in Figure 8-10.

[196] Could this mean that the DIES object model is incomplete?
[197] RealEnergy. "Develop Codes and Modules for Optimal Dispatch Algorithms." January 2002; p. 3.

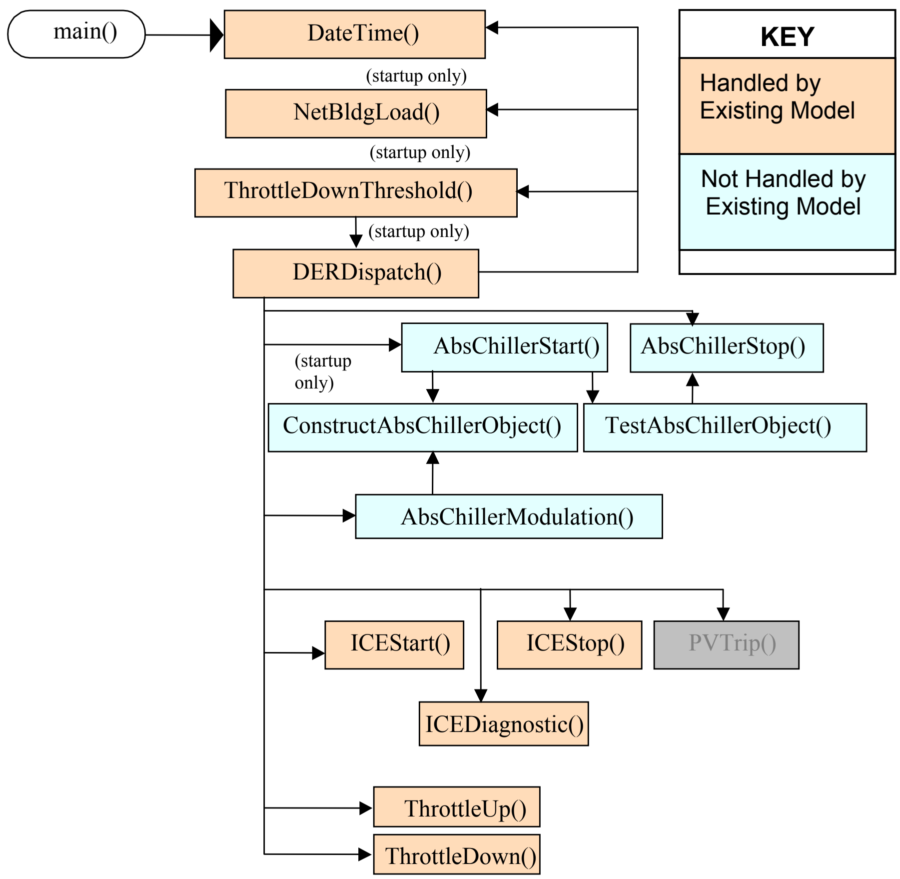

Figure 8-10. CHP information flow diagram

Functions covered include most of those involving the generator/prime mover; likewise, functions not covered concern the thermal capture component of CHP.

Upon further analysis, it becomes evident that the absorption chiller controller and the ICE controller share many of the same data attributes. Some of the configuration settings are also the same. It is possible then to re-use these portions of the design hierarchy and move them from DRCT to DHET, as shown below.

Configuration Settings
DRCT.CF.DERType ➔ DHET.CF.DERType
DRCT.CF.DEROwn ➔ DHET.CF.DEROwn
DRCT.CF.DERLoc ➔ DHET.CF.DERLoc

Control
DRCT.CO.GenMode ➔ DHET.CO.ChillerMode
DRCT.CO.GenConn ➔ DHET.CO.ChillerConn
DRCT.CO.GenSync ➔ DHET.CO.ChillerSync
DRCT.CO.EPSConn ➔ DHET.CO.TESConn.

All other DRCT.CO attributes become DHET.CO attributes without name changes.
With these additions to the CHP design hierarchy, the following absorption chiller control functions are now accounted for in data attributes:

- AbsChillerStart()
- AbsChillerStop()
- TestAbsChillerObject()
- AbsChillerModulation().

The only function left unaddressed is "ConstructAbsChillerObject()." Pseudocode for this function serves to (1) check status and (2) get temperature values as shown below.

To Construct Abs Chiller Object (cogen only):
Output: Request Cogeneration Supply Water pump amps
AbsChillerObject.CogenSupplyPumpAmps = Cogeneration Supply Wate
1) Check Status
Output: Request Condenser water pump amps
AbsChillerObject.CondenserPumpAmps = Return Condenser water pump amps;
Output: Request Chilled water pump amps
AbsChillerObject.ChilledWaterPumpAmps = Chilled water pump amps;
Output: Request Absorption Chiller Enabled flag status
AbsChillerObject.AbsChillerEnabledFlag = Absorption Chiller Enabled flag status;
Output: Request building chilled water demand.
AbsChillerObject.BldgChilledWaterDemand = Building chilled water demand;
Output: Request chiller capacity control valve open percentage
AbsChillerObject.ChillerCapacityControlValvePct = Chiller capacity control valve open percentage
AbsChillerObject.CoolingTowerBypassValvePct = Cooling tower bypass valve open percentage

Output: Request Cogeneration Supply Water Temperature
AbsChillerObject.CogenSupplyTemp = Cogeneration Supply Water Temp
2) Get Values
Output: Request Cogeneration Return Water Temperature
AbsChillerObject.CogenReturnTemp = Cogeneration Return Water Temperature;
Output: Request Condenser Water return temperature
AbsChillerObject.CondenserWaterReturnTemp = Condenser Water return temperature;
Output: Request Condenser Water supply temperature
AbsChillerObject.CondenserWaterSupplyTemp = Condenser Water return temperature;

Output: Request Chilled water return temperature
AbsChillerObject.ChilledWaterReturnTemp = Chilled water return temperature;
Output: Request Chilled water supply temperature
AbsChillerObject.ChilledWaterSupplyTemp = Chilled water supply temperature;

AbsChillerObject.ChilledWaterTempDifference = AbsChillerObject.ChilledWaterReturn – AbsChillerObject.ChilledWaterSupply;

Output: Request MMBtu of cooling delivered to user
AbsChillerObject.DeliveredCooling = MMBtu of cooling delivered to user;

Figure 8-11. Checking thermal status and values pseudocode

The temperature values in Box 2 (Get Values) may be completed by extending the measured values functional constraint in the ADA-DER DHET logical node so that temperatures are taking at inlets and outlets of all three loops in a complete CHP system, as used by RE.

```xml
<MX>
    <BldgInWatTemp CommonDataClass="MV" Semantic="Building Inlet water temperature Degrees C"></BldgInWatTemp>
    <BldgOutWatTemp CommonDataClass="MV" Semantic="Building Outlet water temperature Degrees C"></BldgOutWatTemp>
    <BldgWatFlowRate CommonDataClass="MV" Semantic="Building Water flow rate Meters per second"></BldgWatFlowRate>
    <DgicInWatTemp CommonDataClass="MV" Semantic="IC Engine Inlet water temperature Degrees C"></DgicInWatTemp>
    <DgicOutWatTemp CommonDataClass="MV" Semantic="IC Engine Outlet water temperature Degrees C"></DgicOutWatTemp>
    <TowerInWatTemp CommonDataClass="MV" Semantic="Cooling Tower Inlet water temperature Degrees C"></TowerInWatTemp>
    <TowerOutWatTemp CommonDataClass="MV" Semantic="Cooling Tower Outlet water temperature Degrees C"></TowerOutWatTemp>
</MX>
```

Figure 8-12. Checking thermal status and values XML code

The flow rate is taken only at the building chilled water loop for the purpose of billing the host client for delivered therms of chilled water.

Box 1 (Check Status) values turn out to be similar to status variables in the DRCT logical node and can be attained through the addition of data attributes to the DHET status functional constraint:

DRCT.ST.EPSConn ➔ DHET.ST.TESConn
DRCT.ST.GenConn ➔ DHET.ST.ChillerConn
DRCT.ST.AutoMan ➔ DHET.ST.AutoMan
DRCT.ST.GenMode ➔ DHET.ST.ChillerMode
DRCT.ST.GenReady ➔ DHET.ST.ChillerReady
DRCT.ST.LoadMode ➔ DHET.ST.LoadMode

The complete detail of the CHP design hierarchy in XML (including all mandatory and optional common data classes) is included in the appendix.

```xml
<?xml version="1.0" encoding="UTF-8" ?>
- <Device>
  - <VMD>
    + <DI Semantic="Descriptive Information">
    </VMD>
  - <CHPSite>
    + <DRCT Semantic="Distributed Resources Controller">
    + <DRGN Semantic="Distributed Resources Generator">
    + <DGIC Semantic="Distributed Natural Gas-fired Internal Combustion Engine">
    + <DFUL Semantic="Distributed Resources Fuel">
    + <ENVR Semantic="Environmental Metrics">
    + <DHET Semantic="Heat Recovery System">
    </CHPSite>
  </Device>
```

Figure 8-13. CHP design hierarchy logical nodes

9 Conclusions

CHP rises and falls with "spark spread." This is a variable number and one not subject to control, particularly not by relatively small energy market players. Gas price is a huge unknown in the future of CHP. According to many industry sources, most U.S. wells have peaked and are in decline, and few new sources remain. At the same time, demand, not only for electricity generation but also for a host of other uses, has expanded. The net result is what we see today: rising gas prices. That factor alone could make CHP unprofitable in years to come—despite meeting every other challenge in this very complex business.

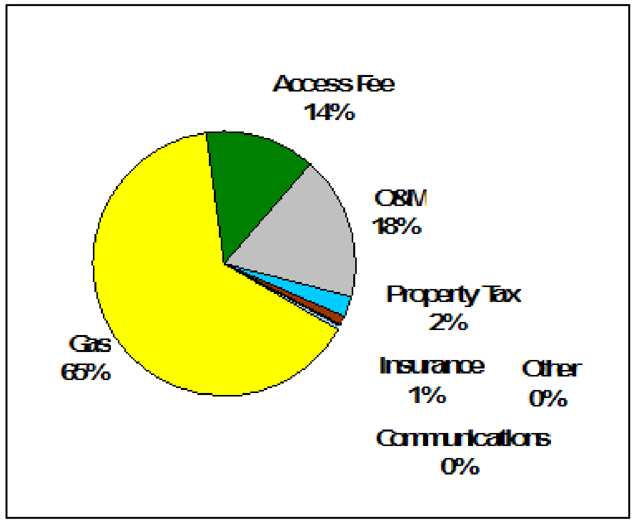

Figure 9-1. RE pro forma CHP operational costs

Of course, gas prices are likely to make electricity prices go up, too—at least wholesale prices. But as shown in California, rising wholesale prices do not always translate into rising retail prices in a way consumers can respond to. California is trying to pay for its $40 billion dollar electricity tag for the energy crisis through declining government services and higher taxes. If it had corresponding higher retail electricity prices, consumers would become creative about reducing energy prices—through thermal and electric efficiency.

As a result, California energy consumers are likely to experience systemic problems for years, if not decades, to come. And, for now, spark spreads are in serious decline.

At the same time, CHP faces many challenges from "cogen killer" utility tariffs. In California, proposed SCE GRC-2 rates, standby charges, BCAP transportation cost increases, and departing load fees all took a bite out of project profitability until a project that had shown a $70,000 annual profit showed a $130,000 loss. Monopoly power appears to be retrenching with the full backing of federal and state jurisdictions. At a time when CHP could be a great part of the solution, it is being ignored in the face of tariff changes that threaten its future viability. The Department of Energy announced in its annual review that it intends to back the return to coal and nuclear power as primary fuels for meeting future energy needs.

Although the incentives for CHP have been high in California especially, the incentives come from public goods charges that have recently come under increasing pressure for diversion elsewhere because of the state's fiscal crisis.

There has been progress, too, on interconnection in California, but much of the benefit has yet to trickle down to rotating equipment—most of which is still subject to supplemental review. There is a process in place (interconnection certification) that can remedy the situation. If the market for their products is strong enough, more manufacturers are likely to certify their products for interconnection in the state. If so, there is a fairly good chance RE will be able to interconnect certified gensets in the future, though it is not able to do so now. The question remains whether that will qualify it for simplified interconnection without corresponding progress in developing tools for estimating and handling the 15% line section screen, which threatens to make even certified units face supplemental review. In regard to interconnection cost, it is safe to say that the costs the marketplace should expect to pay are becoming more certain. Whether costs to fulfill the requirements represent a real reduction from the interconnection cost of projects prior to 2001 remains open.

One of RE's primary concerns about interconnection in California is the significant differences in Rule 21 implementation that still exist among utilities. Despite the best efforts of the framers of Rule 21, each utility still can exercise its discretion in the field to effectively block interconnection or make any requirements it deems necessary and prudent to its business practices. It is really the willingness of the utilities to cooperate that has allowed the revised Rule 21 the level of success it enjoys today. Beyond a certain level of technical detail, there is little in the rule to guarantee a generator a right to interconnect. If this could be addressed, it should be—but it is not clear whether it is possible to specify the level of detail necessary to cover the realm of possible interconnection configurations in the field.

RE has made tremendous progress solving operational problems in the field through its use of best practices and its reliance on trend data for financial and operational feedback. It has also come a long way in its quest for remote optimal dispatch. It is important to bear in mind that all of this comes to naught unless there is a positive spark spread—only then can we expect the current marginal industry, and RE, to thrive.

Appendix: CHP Design Hierarchy

```
<?xml version="1.0" encoding="UTF-8" ?>
- <Device>
  - <VMD>
    - <DI Semantic="Descriptive Information">
        <Name mmstype="visibleString[32]">CHP Design Hierarchy</Name>
        <Class mmstype="visibleString[32]">CHP</Class>
        <d Semantic="Description" mmstype="visibleString[32]">Combined Heat
          and Power XML Model</d>
        <Own Semantic="Owner" mmstype="visibleString
          [32]">RealEnergy</Own>
        <Loc Semantic="Location" mmstype="visibleString[128]">Woodland Hills,
          CA</Loc>
      - <VndID Semantic="Vendor ID">
          <Vnd mmstype="visibleString[32]">Overdomain, LLC</Vnd>
          <Mdl mmstype="visibleString[32]" />
          <DevMdls mmstype="visibleString[128]">XML CHP design</DevMdls>
          <SerNum mmstype="visibleString[32]">D-1.11-v2m</SerNum>
          <HwRev mmstype="visibleString[8]" />
          <SftRev mmstype="visibleString[8]" />
        </VndID>
      </DI>
    </VMD>
  - <CHPSite>
    - <DRCT Semantic="Distributed Resources Controller">
      - <EEHealth CommonDataClass="INS" Semantic="External Equipment
          Health">
          <stVal Semantic="status value" mmstype="integer[32]" />
          <q Semantic="quality" mmstype="bitString[16]" />
          <t Semantic="timestamp" mmstype="binaryTime[6]" />
          <subEna Semantic="?" mmstype="boolean" />
          <subVal Semantic="?" mmstype="integer[32]" />
          <subQ Semantic="Quality" mmstype="bitString[16]" />
          <subID Semantic="?" mmstype="visibleString[64]" />
          <d Semantic="description" mmstype="visibleString[255]" />
          <cdcNs Semantic="Common Data Class Namespace"
            mmstype="visibleString[255]" />
          <cdcName Semantic="Common Data Class Name"
            mmstype="visibleString[255]" />
          <dataNs Semantic="Common Data Class Namespace"
            mmstype="visibleString[255]" />
        </EEHealth>
      - <EEName CommonDataClass="DPL" Semantic="External Equipment
          Health">
          <vendor Semantic="vendor" mmstype="visibleString[255]" />
          <hwRev Semantic="Hardware Revision" mmstype="visibleString
            [255]" />
          <swRev Semantic="Software Revision" mmstype="visibleString
            [255]" />
          <serNum Semantic="Serial Number" mmstype="visibleString[255]" />
          <model Semantic="?" mmstype="visibleString[255]" />
          <location Semantic="?" mmstype="visibleString[255]" />
          <cdcNs Semantic="Common Data Class Namespace"
            mmstype="visibleString[255]" />
```

```
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </EEName>
- <CF>
  - <DERType CommonDataClass="INS" Semantic="Type of DER device">
      <stVal Semantic="status value" mmstype="integer[32]" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </DERType>
  - <DEROwn CommonDataClass="DOO" Semantic="Owner and operator of
    device">
      <!--  UndefinedCommon Data Class  DOO   -->
    </DEROwn>
  - <DERLoc CommonDataClass="GPS" Semantic="GPS location of device">
      <!--  Undefined Common Data Class GPS    -->
    </DERLoc>
  - <CktID CommonDataClass="ING" Semantic="Circuit Id">
      <setVal mmstype="integer[32]" />
      <setVal mmstype="integer[32]" />
      <minVal mmstype="integer[32]" />
      <maxVal mmstype="integer[32]" />
      <stepSize mmstype="unsigned[32]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </CktID>
  - <CktPhs CommonDataClass="ING" Semantic="Circuit phases">
      <setVal mmstype="integer[32]" />
      <setVal mmstype="integer[32]" />
      <minVal mmstype="integer[32]" />
      <maxVal mmstype="integer[32]" />
      <stepSize mmstype="unsigned[32]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
```

```
    </CktPhs>
  - <EPSConn CommonDataClass="ING" Semantic="Interconnection with
      Area EPS">
      <setVal mmstype="integer[32]" />
      <setVal mmstype="integer[32]" />
      <minVal mmstype="integer[32]" />
      <maxVal mmstype="integer[32]" />
      <stepSize mmstype="unsigned[32]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </EPSConn>
  </CF>
- <ST>
  - <EPSConn CommonDataClass="SPS" Semantic="DER is connected to
      Utility EPS, or to Local EPS">
      <stVal Semantic="status value changed True-False"
        mmstype="boolean" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </EPSConn>
  - <GenConn CommonDataClass="SPS" Semantic="DER is connected to or
      disconnected from load">
      <stVal Semantic="status value changed True-False"
        mmstype="boolean" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </GenConn>
  - <LocEPSSw CommonDataClass="SPS" Semantic="Status of disconnect
      switch for starting device in Local EPS only Contact open">
```

<stVal Semantic="status value changed True-False"
mmstype="boolean" />
<q Semantic="quality" mmstype="bitString[16]" />
<t Semantic="timestamp" mmstype="binaryTime[6]" />
<subEna Semantic="?" mmstype="boolean" />
<subVal Semantic="?" mmstype="integer[32]" />
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</LocEPSSw>
- <AutoMan CommonDataClass="SPS" Semantic="Automatic or Manual
mode Automatic">
<stVal Semantic="status value changed True-False"
mmstype="boolean" />
<q Semantic="quality" mmstype="bitString[16]" />
<t Semantic="timestamp" mmstype="binaryTime[6]" />
<subEna Semantic="?" mmstype="boolean" />
<subVal Semantic="?" mmstype="integer[32]" />
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</AutoMan>
- <GenMode CommonDataClass="INS" Semantic="Operational or in
test/off-line mode,1 = in test; 2 = off-line; 3 = available">
<stVal Semantic="status value" mmstype="integer[32]" />
<q Semantic="quality" mmstype="bitString[16]" />
<t Semantic="timestamp" mmstype="binaryTime[6]" />
<subEna Semantic="?" mmstype="boolean" />
<subVal Semantic="?" mmstype="integer[32]" />
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</GenMode>
- <GenReady CommonDataClass="SPS" Semantic="Generator is ready to
be connected to load">
<stVal Semantic="status value changed True-False"
mmstype="boolean" />
<q Semantic="quality" mmstype="bitString[16]" />

```
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </GenReady>
  - <LoadMode CommonDataClass="SPS" Semantic="Base load or load
      following Possible modes: Base load; Load following; Available
      energy, Fixed export">
      <stVal Semantic="status value changed True-False"
        mmstype="boolean" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </LoadMode>
  - <DCPowStat CommonDataClass="SPS" Semantic="DC Power Status">
      <stVal Semantic="status value changed True-False"
        mmstype="boolean" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </DCPowStat>
  </ST>
- <MX>
  - <ContTime CommonDataClass="TMS">
      <!-- Note...Unknown data object type TMS (timestamp)   -->
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
    </ContTime>
  </MX>
```

```
- <CO Semantic="Controls">
  - <AutoManCtl CommonDataClass="SPC" Semantic="Sets operations mode
      to automatic or manual">
      <ctlVal Semantic="Control Value Off or On" mmstype="boolean" />
      <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <origin Semantic="Originator" mmstype="" />
      <!--  unknown Attribute Type - Originator   -->
      <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
      <stVal Semantic="Status Value change False-True"
        mmstype="boolean" />
      <q Semantic="Quality" mmstype="bitString[16]" />
      <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <!--  unknown Attribute Type - TimeStamp   -->
      <stSeld Semantic="?" mmstype="boolean" />
    </AutoManCtl>
  - <GenMode CommonDataClass="SPC" Semantic="Sets generator into test
      mode or operational mode">
      <ctlVal Semantic="Control Value Off or On" mmstype="boolean" />
      <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <origin Semantic="Originator" mmstype="" />
      <!--  unknown Attribute Type - Originator   -->
      <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
      <stVal Semantic="Status Value change False-True"
        mmstype="boolean" />
      <q Semantic="Quality" mmstype="bitString[16]" />
      <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <!--  unknown Attribute Type - TimeStamp   -->
      <stSeld Semantic="?" mmstype="boolean" />
    </GenMode>
  - <GenConn CommonDataClass="DPC" Semantic="Connects generator to
      load, or disconnects generator from load">
      <ctlVal Semantic="Control Value off (FALSE) | on (TRUE)"
        mmstype="boolean" />
      <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <origin Semantic="Originator" mmstype="" />
      <!--  unknown Attribute Type - Originator   -->
      <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
      <stVal Semantic="Status Value change intermediate-state | off |
        on | bad-state" mmstype="bitString[4]" />
      <q Semantic="Quality" mmstype="bitString[16]" />
      <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <!--  unknown Attribute Type - TimeStamp   -->
      <stSeld Semantic="?" mmstype="boolean" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="Status Value change intermediate-state | off |
        on | bad-state" mmstype="bitString[4]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <pulseConfig Semantic="?" mmstype="" />
      <!--  unknown Attribute Type - PulseConfig   -->
      <ctlModel Semantic="Control Model ENUMERATED CF status-only |
        direct-with-normal-security | sbo-with-normal-security |
        direct-withenhanced-security | sbo-with-enhancedsecurity"
```

```
 mmstype="bitString[5]" />
   <sboTimeout Semantic="Time out" mmstype="unsigned[8]" />
   <sboClass Semantic="ENUMERATED CF operate-once | operate-
     many" mmstype="boolean" />
   <d Semantic="description" mmstype="visibleString[255]" />
   <cdcNs Semantic="Common Data Class Namespace"
     mmstype="visibleString[255]" />
   <cdcName Semantic="Common Data Class Name"
     mmstype="visibleString[255]" />
   <dataNs Semantic="Common Data Class Namespace" />
 </GenConn>
- <LoadMode CommonDataClass="SPC" Semantic="Sets generator mode
   as base load or as load following Base load">
   <ctlVal Semantic="Control Value Off or On" mmstype="boolean" />
   <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <origin Semantic="Originator" mmstype="" />
   <!--  unknown Attribute Type - Originator   -->
   <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
   <stVal Semantic="Status Value change False-True"
     mmstype="boolean" />
   <q Semantic="Quality" mmstype="bitString[16]" />
   <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <!--  unknown Attribute Type - TimeStamp   -->
   <stSeld Semantic="?" mmstype="boolean" />
 </LoadMode>
- <GenSync CommonDataClass="SPC" Semantic="Starts synchronizing
   generator to EPS True = start synchronization">
   <ctlVal Semantic="Control Value Off or On" mmstype="boolean" />
   <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <origin Semantic="Originator" mmstype="" />
   <!--  unknown Attribute Type - Originator   -->
   <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
   <stVal Semantic="Status Value change False-True"
     mmstype="boolean" />
   <q Semantic="Quality" mmstype="bitString[16]" />
   <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <!--  unknown Attribute Type - TimeStamp   -->
   <stSeld Semantic="?" mmstype="boolean" />
 </GenSync>
- <EmgStop CommonDataClass="DPC" Semantic="Remote emergency
   stop">
   <ctlVal Semantic="Control Value off (FALSE) | on (TRUE)"
     mmstype="boolean" />
   <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <origin Semantic="Originator" mmstype="" />
   <!--  unknown Attribute Type - Originator   -->
   <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
   <stVal Semantic="Status Value change intermediate-state | off |
     on | bad-state" mmstype="bitString[4]" />
   <q Semantic="Quality" mmstype="bitString[16]" />
   <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <!--  unknown Attribute Type - TimeStamp   -->
   <stSeld Semantic="?" mmstype="boolean" />
```

```
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="Status Value change intermediate-state | off |
      on | bad-state" mmstype="bitString[4]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <pulseConfig Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - PulseConfig   -->
    <ctlModel Semantic="Control Model ENUMERATED CF status-only |
      direct-with-normal-security | sbo-with-normal-security |
      direct-withenhanced-security | sbo-with-enhancedsecurity"
      mmstype="bitString[5]" />
    <sboTimeout Semantic="Time out" mmstype="unsigned[8]" />
    <sboClass Semantic="ENUMERATED CF operate-once | operate-
      many" mmstype="boolean" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </EmgStop>
- <FaultAck CommonDataClass="SPC" Semantic="Acknowledge fault
    clearing True = Reset">
    <ctlVal Semantic="Control Value Off or On" mmstype="boolean" />
    <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <origin Semantic="Originator" mmstype="" />
    <!--  unknown Attribute Type - Originator   -->
    <ctlNum Semantic="Control Number" mmstype="unsigned[32]" />
    <stVal Semantic="Status Value change False-True"
      mmstype="boolean" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <stSeld Semantic="?" mmstype="boolean" />
  </FaultAck>
- <EPSConn CommonDataClass="DPC" Semantic="Connects generator to
    the EPS, or disconnects generator from the EPS">
    <ctlVal Semantic="Control Value off (FALSE) | on (TRUE)"
      mmstype="boolean" />
    <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <origin Semantic="Originator" mmstype="" />
    <!--  unknown Attribute Type - Originator   -->
    <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
    <stVal Semantic="Status Value change intermediate-state | off |
      on | bad-state" mmstype="bitString[4]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <stSeld Semantic="?" mmstype="boolean" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="Status Value change intermediate-state | off |
      on | bad-state" mmstype="bitString[4]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
```

```
      <subID Semantic="?" mmstype="visibleString[64]" />
      <pulseConfig Semantic="?" mmstype="" />
      <!--  unknown Attribute Type - PulseConfig    -->
      <ctlModel Semantic="Control Model ENUMERATED CF status-only |
        direct-with-normal-security | sbo-with-normal-security |
        direct-withenhanced-security | sbo-with-enhancedsecurity"
        mmstype="bitString[5]" />
      <sboTimeout Semantic="Time out" mmstype="unsigned[8]" />
      <sboClass Semantic="ENUMERATED CF operate-once | operate-
        many" mmstype="boolean" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </EPSConn>
  </CO>
- <CS CommonDataClass="ASG" Semantic="Control Settings">
    <!-- Note...Unknown Functional Constraint - Control Settings
    (CS??)   -->
  - <DerateTar Semantic="Derated load target">
      <setMag Semantic="set AnalogueValue" mmstype="" />
      <!--  unknown Attribute Type - AnalogueValue   -->
      <setMag Semantic="set AnalogueValue" mmstype="" />
      <units Semantic="?" mmstype="" />
      <!--  unknown Attribute Type - Unit   -->
      <sVC Semantic="ScaledValueConfig" mmstype="" />
      <!--  unknown Attribute Type - ScaledValueConfig  -->
      <minVal Semantic="Minimum AnalogueValue" mmstype="" />
      <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
      <stepSize Semantic="AnalogueValue CF 1 … (maxVal – minVal)"
        mmstype="" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </DerateTar>
  - <LdGovW CommonDataClass="ASG" Semantic="Load kW target">
      <setMag Semantic="set AnalogueValue" mmstype="" />
      <!--  unknown Attribute Type - AnalogueValue   -->
      <setMag Semantic="set AnalogueValue" mmstype="" />
      <units Semantic="?" mmstype="" />
      <!--  unknown Attribute Type - Unit   -->
      <sVC Semantic="ScaledValueConfig" mmstype="" />
      <!--  unknown Attribute Type - ScaledValueConfig  -->
      <minVal Semantic="Minimum AnalogueValue" mmstype="" />
      <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
      <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
        mmstype="" />
      <d Semantic="description" mmstype="visibleString[255]" />
```

```
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </LdGovW>
- <LdGovVar CommonDataClass="ASG" Semantic="Load kVar target">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!--  unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </LdGovVar>
- <LdGovVarMx CommonDataClass="ASG" Semantic="Max load kVar">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!--  unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </LdGovVarMx>
- <RampLd CommonDataClass="ASG" Semantic="Ramp Load or Unload
    rate">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!--  unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
```

```
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </RampLd>
– <LdShutDown CommonDataClass="ASG" Semantic="Load Shut Down:
    Stop/Don't Stop O">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!-- unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!-- unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!-- unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </LdShutDown>
– <LdShareRamp CommonDataClass="ASG" Semantic="Load Share/Don't
    share">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!-- unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!-- unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!-- unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </LdShareRamp>
– <AltAppkW CommonDataClass="ASG" Semantic="% load kW">
    <setMag Semantic="set AnalogueValue" mmstype="" />
```

```
    &lt;!-- unknown Attribute Type - AnalogueValue --&gt;
    &lt;setMag Semantic="set AnalogueValue" mmstype="" /&gt;
    &lt;units Semantic="?" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - Unit --&gt;
    &lt;sVC Semantic="ScaledValueConfig" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - ScaledValueConfig --&gt;
    &lt;minVal Semantic="Minimum AnalogueValue" mmstype="" /&gt;
    &lt;maxVal Semantic="Maximum AnalogueValue" mmstype="" /&gt;
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    &lt;d Semantic="description" mmstype="visibleString[255]" /&gt;
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    &lt;dataNs Semantic="Common Data Class Namespace" /&gt;
  &lt;/AltAppkW&gt;
- <ImExLev CommonDataClass="ASG" Semantic="The setpoint for
    maintaining constant import/export to EPS kW value at the EPS
    connection">
    &lt;setMag Semantic="set AnalogueValue" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - AnalogueValue --&gt;
    &lt;setMag Semantic="set AnalogueValue" mmstype="" /&gt;
    &lt;units Semantic="?" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - Unit --&gt;
    &lt;sVC Semantic="ScaledValueConfig" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - ScaledValueConfig --&gt;
    &lt;minVal Semantic="Minimum AnalogueValue" mmstype="" /&gt;
    &lt;maxVal Semantic="Maximum AnalogueValue" mmstype="" /&gt;
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    &lt;d Semantic="description" mmstype="visibleString[255]" /&gt;
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    &lt;dataNs Semantic="Common Data Class Namespace" /&gt;
  &lt;/ImExLev&gt;
- <PowerFact CommonDataClass="ASG" Semantic="The setpoint for
    maintaining fixed power factor Power factor value">
    &lt;setMag Semantic="set AnalogueValue" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - AnalogueValue --&gt;
    &lt;setMag Semantic="set AnalogueValue" mmstype="" /&gt;
    &lt;units Semantic="?" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - Unit --&gt;
    &lt;sVC Semantic="ScaledValueConfig" mmstype="" /&gt;
    &lt;!-- unknown Attribute Type - ScaledValueConfig --&gt;
    &lt;minVal Semantic="Minimum AnalogueValue" mmstype="" /&gt;
    &lt;maxVal Semantic="Maximum AnalogueValue" mmstype="" /&gt;
    <stepSize Semantic="AnalogueValue CF 1 … (maxVal - minVal)"
      mmstype="" />
    &lt;d Semantic="description" mmstype="visibleString[255]" /&gt;
    <cdcNs Semantic="Common Data Class Namespace"
```

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  mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </PowerFact>
– <FreqLvl CommonDataClass="ASG" Semantic="The setpoint for
    maintaining fixed frequency Frequency value (offset?)">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!--  unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 ... (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </FreqLvl>
– <VoltLvl CommonDataClass="ASG" Semantic="The voltage setpoint for
    maintaining fixed voltage level Voltage value {% offset?}">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!--  unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
    <stepSize Semantic="AnalogueValue CF 1 ... (maxVal - minVal)"
      mmstype="" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </VoltLvl>
– <StartCnt CommonDataClass="ASG" Semantic="Time before starting
    Seconds">
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <!--  unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="" />
    <units Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="" />
```

```
      <!--  unknown Attribute Type - ScaledValueConfig  -->
      <minVal Semantic="Minimum AnalogueValue" mmstype="" />
      <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
      <stepSize Semantic="AnalogueValue CF 1 ... (maxVal - minVal)"
        mmstype="" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </StartCnt>
  - <StopDly CommonDataClass="ASG" Semantic="Time delay before
      stopping Seconds">
      <setMag Semantic="set AnalogueValue" mmstype="" />
      <!--  unknown Attribute Type - AnalogueValue   -->
      <setMag Semantic="set AnalogueValue" mmstype="" />
      <units Semantic="?" mmstype="" />
      <!--  unknown Attribute Type - Unit   -->
      <sVC Semantic="ScaledValueConfig" mmstype="" />
      <!--  unknown Attribute Type - ScaledValueConfig  -->
      <minVal Semantic="Minimum AnalogueValue" mmstype="" />
      <maxVal Semantic="Maximum AnalogueValue" mmstype="" />
      <stepSize Semantic="AnalogueValue CF 1 ... (maxVal - minVal)"
        mmstype="" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </StopDly>
  </CS>
</DRCT>
- <DRGN Semantic="Distributed Resources Generator">
  - <EEHealth CommonDataClass="INS" Semantic="External Equipment
      Health">
      <stVal Semantic="status value" mmstype="integer[32]" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
      <subVal Semantic="?" mmstype="integer[32]" />
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
    </EEHealth>
  - <EEName CommonDataClass="DPL" Semantic="External Equipment
```

```
Health">
    <vendor Semantic="vendor" mmstype="visibleString[255]" />
    <hwRev Semantic="Hardware Revision" mmstype="visibleString
      [255]" />
    <swRev Semantic="Software Revision" mmstype="visibleString
      [255]" />
    <serNum Semantic="Serial Number" mmstype="visibleString[255]" />
    <model Semantic="model" mmstype="visibleString[255]" />
    <location Semantic="location" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </EEName>
- <CF>
  - <DEROwn CommonDataClass="DOO" Semantic="Owner and operator of
    device">
      <!-- UndefinedCommon Data Class  DOO   -->
    </DEROwn>
  - <DERLoc CommonDataClass="GPS" Semantic="GPS location of device">
      <!-- UndefinedCommon Data Class  GPS   -->
    </DERLoc>
  - <ConnectType CommonDataClass="INS" Semantic="Type of connection
      3-phase or single phase, Delta, Wye M">
      <stVal semantic="status value" mmstype="integer[32]" />
      <q semantic="quality" mmstype="bitString[16]" />
      <t semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna semantic="" mmstype="boolean" />
      <subVal semantic="" mmstype="integer[32]" />
      <subQ semantic="Quality" mmstype="bitString[16]" />
      <subID semantic="" mmstype="visibleString[64]" />
      <d semantic="description" mmstype="visibleString[255]" />
      <cdcNs semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs semantic="Common Data Class Namespace" />
    </ConnectType>
  - <VoltRt CommonDataClass="MV" Semantic="Voltage level rating
      Voltage in volts">
      <instMag Semantic="AnalogueValue" mmstype="?" />
      <!-- Unknown Attribute Type - AnalogueValue   -->
      <mag Semantic="AnalogueValue" mmstype="?" />
      <!-- Unknown Attribute Type - AnalogueValue   -->
      <range Semantic="Measured Range - normal | high | low | high-
        high | low-low" mmstype="bitString[5]" />
      <q Semantic="Quality" mmstype="bitString[16]" />
      <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <!-- unknown Attribute Type - TimeStamp   -->
      <subEna Semantic="?" mmstype="boolean" />
      <submag Semantic="AnalogueValue" mmstype="?" />
      <!-- Unknown Attribute Type - AnalogueValue   -->
```

```
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </VoltRt>
- <AmpRt CommonDataClass="MV" Semantic="Continuous current rating
    Current in amps">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </AmpRt>
```

```
- <HzRt CommonDataClass="MV" Semantic="Nominal frequency
   Frequency in Hz">
   <instMag Semantic="AnalogueValue" mmstype="?" />
   <!-- Unknown Attribute Type - AnalogueValue  -->
   <mag Semantic="AnalogueValue" mmstype="?" />
   <!-- Unknown Attribute Type - AnalogueValue  -->
   <range Semantic="Measured Range - normal | high | low | high-
     high | low-low" mmstype="bitString[5]" />
   <q Semantic="Quality" mmstype="bitString[16]" />
   <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <!-- unknown Attribute Type - TimeStamp  -->
   <subEna Semantic="?" mmstype="boolean" />
   <submag Semantic="AnalogueValue" mmstype="?" />
   <!-- Unknown Attribute Type - AnalogueValue  -->
   <subQ Semantic="Quality" mmstype="bitString[16]" />
   <subID Semantic="?" mmstype="visibleString[64]" />
   <units Semantic="?" mmstype="?" />
   <!-- unknown Attribute Type - Unit  -->
   <db Semantic="deadband value" mmstype="unsigned[32]" />
   <zeroDb Semantic="zero deadband value" mmstype="Unsigned
     [32]" />
   <sVC Semantic="ScaledValueConfig" mmstype="?" />
   <!-- Unknown Attribute Type - ScaledValueConfig  -->
   <rangeC Semantic="RangeConfig" mmstype="?" />
   <!-- Unknown Attribute Type - RangeConfig  -->
   <smpRate Semantic="?" mmstype="unsigned[32]" />
   <d Semantic="description" mmstype="visibleString[255]" />
   <cdcNs Semantic="Common Data Class Namespace"
     mmstype="visibleString[255]" />
   <cdcName Semantic="Common Data Class Name"
     mmstype="visibleString[255]" />
   <dataNs Semantic="Common Data Class Namespace" />
  </HzRt>
- <TempRt CommonDataClass="MV" Semantic="Max temperature rating
   Temperature in Centigrade">
   <instMag Semantic="AnalogueValue" mmstype="?" />
   <!-- Unknown Attribute Type - AnalogueValue  -->
   <mag Semantic="AnalogueValue" mmstype="?" />
   <!-- Unknown Attribute Type - AnalogueValue  -->
   <range Semantic="Measured Range - normal | high | low | high-
     high | low-low" mmstype="bitString[5]" />
   <q Semantic="Quality" mmstype="bitString[16]" />
   <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
   <!-- unknown Attribute Type - TimeStamp  -->
   <subEna Semantic="?" mmstype="boolean" />
   <submag Semantic="AnalogueValue" mmstype="?" />
   <!-- Unknown Attribute Type - AnalogueValue  -->
   <subQ Semantic="Quality" mmstype="bitString[16]" />
   <subID Semantic="?" mmstype="visibleString[64]" />
   <units Semantic="?" mmstype="?" />
   <!-- unknown Attribute Type - Unit  -->
   <db Semantic="deadband value" mmstype="unsigned[32]" />
```

```
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!--  Unknown Attribute Type - ScaledValueConfig   -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!--  Unknown Attribute Type - RangeConfig   -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</TempRt>
- <FltCurRt CommonDataClass="MV" Semantic="Max fault current rating
  Amps">
<instMag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!--  unknown Attribute Type - TimeStamp   -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!--  unknown Attribute Type - Unit   -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!--  Unknown Attribute Type - ScaledValueConfig   -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!--  Unknown Attribute Type - RangeConfig   -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</FltCurRt>
- <FltDurRt CommonDataClass="INS" Semantic="Max fault duration
  rating Seconds">
<stVal Semantic="status value" mmstype="integer[32]" />
<q Semantic="quality" mmstype="bitString[16]" />
<t Semantic="timestamp" mmstype="binaryTime[6]" />
<subEna Semantic="?" mmstype="boolean" />
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```
<subVal Semantic="?" mmstype="integer[32]" />
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<d Semantic="description" mmstype="visibleString[255]" />
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  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</FltDurRt>
- <VolAmpRt CommonDataClass="MV" Semantic="Max volt-amps rating
  Volt-Amps">
<instMag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!-- unknown Attribute Type - TimeStamp -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!-- unknown Attribute Type - Unit -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!-- Unknown Attribute Type - ScaledValueConfig -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!-- Unknown Attribute Type - RangeConfig -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</VolAmpRt>
- <VolAmprRt CommonDataClass="MV" Semantic="Max var rating VArs">
<instMag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
```

```
<!-- unknown Attribute Type - TimeStamp -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!-- unknown Attribute Type - Unit -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!-- Unknown Attribute Type - ScaledValueConfig -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!-- Unknown Attribute Type - RangeConfig -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</VolAmprRt>
- <PwrFactRt CommonDataClass="MV" Semantic="Power factor rating
  Cos?">
<instMag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!-- unknown Attribute Type - TimeStamp -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!-- unknown Attribute Type - Unit -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!-- Unknown Attribute Type - ScaledValueConfig -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!-- Unknown Attribute Type - RangeConfig -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
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<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</PwrFactRt>
– <VTPhs CommonDataClass="ING" Semantic="Voltage transformer
phases A, B, C, Delta, Wye in volts">
<setVal mmstype="integer[32]" />
<setVal mmstype="integer[32]" />
<minVal mmstype="integer[32]" />
<maxVal mmstype="integer[32]" />
<stepSize mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</VTPhs>
– <CTPhs CommonDataClass="ING" Semantic="Current transformer
phases Amps">
<setVal mmstype="integer[32]" />
<setVal mmstype="integer[32]" />
<minVal mmstype="integer[32]" />
<maxVal mmstype="integer[32]" />
<stepSize mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</CTPhs>
– <MaxLodRampRt CommonDataClass="INS" Semantic="Max load ramp
rate Watts per second">
<stVal Semantic="status value" mmstype="integer[32]" />
<q Semantic="quality" mmstype="bitString[16]" />
<t Semantic="timestamp" mmstype="binaryTime[6]" />
<subEna Semantic="?" mmstype="boolean" />
<subVal Semantic="?" mmstype="integer[32]" />
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</MaxLodRampRt>
– <MaxUnlodRampRt CommonDataClass="INS" Semantic="Max unload
ramp rate Watts per second">
<stVal Semantic="status value" mmstype="integer[32]" />
<q Semantic="quality" mmstype="bitString[16]" />
<t Semantic="timestamp" mmstype="binaryTime[6]" />

```
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </MaxUnlodRampRt>
- <EmgRampRt CommonDataClass="INS" Semantic="Emergency ramp
    rate Watts per second">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </EmgRampRt>
- <MaxWattOut CommonDataClass="MV" Semantic="Max Watt output
    Watts">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
```

```
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </MaxWattOut>
- <RtdWatt CommonDataClass="MV" Semantic="Rated Watts Watts">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </RtdWatt>
- <MinWattOut CommonDataClass="MV" Semantic="Min Watt output
    Watts">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
```

```
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </MinWattOut>
- <MaxVarOut CommonDataClass="MV" Semantic="Max VAr output VArs">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
```

```
  </MaxVarOut>
– <RotDir CommonDataClass="INS" Semantic="Rotation direction ABC or
    CBA">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </RotDir>
– <GenDisconLvl CommonDataClass="INS" Semantic="Generator
    disconnect level Watts">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenDisconLvl>
– <GenLodDrpSet CommonDataClass="INS" Semantic="Generator load
    droop setting Volts per amp (ohms) or Hz per Watt">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenLodDrpSet>
– <RaiseLodSetRt CommonDataClass="INS" Semantic="Raise baseload
    setpoint rate Watts">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
```

```
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </RaiseLodSetRt>
- <LowerLodSetRt CommonDataClass="INS" Semantic="Lower baseload
    setpoint rate Watts">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </LowerLodSetRt>
- <CostRamp CommonDataClass="MV" Semantic="$ for ramping Cost">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
```

```
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </CostRamp>
- <CostStart CommonDataClass="MV" Semantic="$ for starting generator
    Cost">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </CostStart>
- <CostStop CommonDataClass="MV" Semantic="$ for stopping generator
    Cost">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
```

```
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </CostStop>
- <CostOper CommonDataClass="MV" Semantic="$ for operating Cost">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
```

```
</CostOper>
- <GenPID CommonDataClass="PID" Semantic="Proportional, integral,
  and derivative gain parameters for automatic voltage regulator
  (AVR)">
    <!-- Unknown Common Data Class  PID  -->
  </GenPID>
- <GenPQV CommonDataClass="?" Semantic="Real Power-Reactive
  Power-Voltage dependency curve">
    <!-- Unspecified CommonDataClass  -->
  </GenPQV>
</CF>
- <ST>
- <GenSt CommonDataClass="SPS" Semantic="Generator is on or is off">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenSt>
- <GenOpSt CommonDataClass="INS" Semantic="Generation operational
    state: 1 = Starting up, 2 = Shutting down, 3 = At disconnect level,
    4 = kW ramping, 5 = kVar ramping">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenOpSt>
- <GenSync CommonDataClass="SPS" Semantic="Generator is
    synchronized to EPS, or not Not synched">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
```

```
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenSync>
- <GenExcit CommonDataClass="SPS" Semantic="Excitation state
    Excitation off / on">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenExcit>
- <ParlSt CommonDataClass="SPS" Semantic="Paralleling status
    Standby">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </ParlSt>
- <GenAlarm CommonDataClass="ALM" Semantic="Generation alarms: 1
  = High voltage alarm, 2 = Low voltage alarm, 3 = High current
  alarm, 4 = Low current alarm, 5 = High frequency alarm, 6 = Low
  frequency alarm, 7 = Emergency trip alarm">
    <!--  Unknown Common Data Class ALM   -->
  </GenAlarm>
- <VoltDroop CommonDataClass="SPS" Semantic="Voltage droop status
    Droop enabled/not enabled">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
```

```
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </VoltDroop>
- <RampLdSw CommonDataClass="SPS" Semantic="Ramp Load/Unload
    Switch">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </RampLdSw>
- <DCPowStat CommonDataClass="SPS" Semantic="DC Power Status
    Power on / not on">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DCPowStat>
- <OperTim CommonDataClass="INS" Semantic="Total time in seconds
    generator has operated">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
```

```
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </OperTim>
- <GenOnCnt CommonDataClass="INS" Semantic="The number of times
    that the generator has been turned on">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenOnCnt>
</ST>
- <MX>
- <TotkWh CommonDataClass="MV" Semantic="Total kWh delivered
    Value = kWh">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
```

```
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </TotkWh>
- <PerkWh CommonDataClass="MV" Semantic="kWh in period since last
    reset">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </PerkWh>
- <TotStarts CommonDataClass="CTE" Semantic="Count of total number
  of starts">
    <!--  Unknown Common Data Class CTE   -->
  </TotStarts>
- <PerStarts CommonDataClass="CTE" Semantic="Count of starts since
  reset">
    <!--  Unknown Common Data Class CTE   -->
  </PerStarts>
- <GenOprTim CommonDataClass="MV" Semantic="Time in msec after the
    GenOnOff command was issued; max = maximum time before
    issuing a start-failure alarm">
```

```
<instMag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!--  unknown Attribute Type - TimeStamp   -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!--  unknown Attribute Type - Unit   -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!--  Unknown Attribute Type - ScaledValueConfig   -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!--  Unknown Attribute Type - RangeConfig   -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</GenOprTim>
- <GenStbTmr CommonDataClass="MV" Semantic="Stabilization time in
  msec; max = maximum time before issuing a stabilization-failure
  alarm">
<instMag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!--  unknown Attribute Type - TimeStamp   -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!--  unknown Attribute Type - Unit   -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
```

```
[32]" />
  <sVC Semantic="ScaledValueConfig" mmstype="?" />
  <!-- Unknown Attribute Type - ScaledValueConfig   -->
  <rangeC Semantic="RangeConfig" mmstype="?" />
  <!-- Unknown Attribute Type - RangeConfig   -->
  <smpRate Semantic="?" mmstype="unsigned[32]" />
  <d Semantic="description" mmstype="visibleString[255]" />
  <cdcNs Semantic="Common Data Class Namespace"
    mmstype="visibleString[255]" />
  <cdcName Semantic="Common Data Class Name"
    mmstype="visibleString[255]" />
  <dataNs Semantic="Common Data Class Namespace" />
</GenStbTmr>
- <GenCoolDn CommonDataClass="MV" Semantic="Timer for generator to
  cool down in msec; min = minimum time for cool down">
  <instMag Semantic="AnalogueValue" mmstype="?" />
  <!-- Unknown Attribute Type - AnalogueValue   -->
  <mag Semantic="AnalogueValue" mmstype="?" />
  <!-- Unknown Attribute Type - AnalogueValue   -->
  <range Semantic="Measured Range - normal | high | low | high-
    high | low-low" mmstype="bitString[5]" />
  <q Semantic="Quality" mmstype="bitString[16]" />
  <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
  <!-- unknown Attribute Type - TimeStamp   -->
  <subEna Semantic="?" mmstype="boolean" />
  <submag Semantic="AnalogueValue" mmstype="?" />
  <!-- Unknown Attribute Type - AnalogueValue   -->
  <subQ Semantic="Quality" mmstype="bitString[16]" />
  <subID Semantic="?" mmstype="visibleString[64]" />
  <units Semantic="?" mmstype="?" />
  <!-- unknown Attribute Type - Unit   -->
  <db Semantic="deadband value" mmstype="unsigned[32]" />
  <zeroDb Semantic="zero deadband value" mmstype="Unsigned
    [32]" />
  <sVC Semantic="ScaledValueConfig" mmstype="?" />
  <!-- Unknown Attribute Type - ScaledValueConfig   -->
  <rangeC Semantic="RangeConfig" mmstype="?" />
  <!-- Unknown Attribute Type - RangeConfig   -->
  <smpRate Semantic="?" mmstype="unsigned[32]" />
  <d Semantic="description" mmstype="visibleString[255]" />
  <cdcNs Semantic="Common Data Class Namespace"
    mmstype="visibleString[255]" />
  <cdcName Semantic="Common Data Class Name"
    mmstype="visibleString[255]" />
  <dataNs Semantic="Common Data Class Namespace" />
</GenCoolDn>
- <AVR CommonDataClass="MV" Semantic="% Duty Cycle Value">
  <instMag Semantic="AnalogueValue" mmstype="?" />
  <!-- Unknown Attribute Type - AnalogueValue   -->
  <mag Semantic="AnalogueValue" mmstype="?" />
  <!-- Unknown Attribute Type - AnalogueValue   -->
  <range Semantic="Measured Range - normal | high | low | high-
    high | low-low" mmstype="bitString[5]" />
```

```
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!--  unknown Attribute Type - TimeStamp   -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!--  Unknown Attribute Type - AnalogueValue   -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!--  unknown Attribute Type - Unit   -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!--  Unknown Attribute Type - ScaledValueConfig   -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!--  Unknown Attribute Type - RangeConfig   -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</AVR>
</MX>
- <CO>
- <GenCtl CommonDataClass="DPC" Semantic="Starts or stops the
  generator">
<ctlVal Semantic="Control Value off (FALSE) | on (TRUE)"
  mmstype="boolean" />
<operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
<origin Semantic="Originator" mmstype="" />
<!--  unknown Attribute Type - Originator   -->
<ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
<stVal Semantic="Status Value change intermediate-state | off |
  on | bad-state" mmstype="bitString[4]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!--  unknown Attribute Type - TimeStamp   -->
<stSeld Semantic="?" mmstype="boolean" />
<subEna Semantic="?" mmstype="boolean" />
<subVal Semantic="Status Value change intermediate-state | off |
  on | bad-state" mmstype="bitString[4]" />
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<pulseConfig Semantic="?" mmstype="" />
<!--  unknown Attribute Type - PulseConfig   -->
<ctlModel Semantic="Control Model ENUMERATED CF status-only |
  direct-with-normal-security | sbo-with-normal-security |
  direct-withenhanced-security | sbo-with-enhancedsecurity"
  mmstype="bitString[5]" />
<sboTimeout Semantic="Time out" mmstype="unsigned[8]" />
```

```
    <sboClass Semantic="ENUMERATED CF operate-once | operate-
      many" mmstype="boolean" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenCtl>
- <GenRL CommonDataClass="DPC" Semantic="Raises or lowers the
    generation level">
    <ctlVal Semantic="Control Value off (FALSE) | on (TRUE)"
      mmstype="boolean" />
    <operTim Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <origin Semantic="Originator" mmstype="" />
    <!--  unknown Attribute Type - Originator   -->
    <ctlNum Semantic="Control Number" mmstype="unsigned[8]" />
    <stVal Semantic="Status Value change intermediate-state | off |
      on | bad-state" mmstype="bitString[4]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <stSeld Semantic="?" mmstype="boolean" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="Status Value change intermediate-state | off |
      on | bad-state" mmstype="bitString[4]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <pulseConfig Semantic="?" mmstype="" />
    <!--  unknown Attribute Type - PulseConfig    -->
    <ctlModel Semantic="Control Model ENUMERATED CF status-only |
      direct-with-normal-security | sbo-with-normal-security |
      direct-withenhanced-security | sbo-with-enhancedsecurity"
      mmstype="bitString[5]" />
    <sboTimeout Semantic="Time out" mmstype="unsigned[8]" />
    <sboClass Semantic="ENUMERATED CF operate-once | operate-
      many" mmstype="boolean" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenRL>
</CO>
</DRGN>
- <DGIC Semantic="Distributed Natural Gas-fired Internal Combustion
    Engine">
- <CF>
  - <DgicOwner CommonDataClass="DOO" Semantic="Owner and operator
    of device">
    <!--  Unknown Common Data Class  DOO   -->
  </DgicOwner>
```

```
- <DERLoc CommonDataClass="GPS" Semantic="GPS location of device">
    <!--  Unknown Common Data Class  GPS   -->
  </DERLoc>
- <DgicFuel CommonDataClass="ING" Semantic="Type of fuel">
    <setVal mmstype="integer[32]" />
    <setVal mmstype="integer[32]" />
    <minVal mmstype="integer[32]" />
    <maxVal mmstype="integer[32]" />
    <stepSize mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DgicFuel>
- <DgicAvgCalFuel CommonDataClass="ASG" Semantic="Average calorie
    content of fuel">
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="?" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="?" />
    <stepSize Semantic="AnalogueValue (maxVal - minVal)"
      mmstype="?" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DgicAvgCalFuel>
- <DgicMaxTurPres CommonDataClass="ASG" Semantic="Max turb
    pressure">
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  unknown Attribute Type - ScaledValueConfig  -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="?" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="?" />
    <stepSize Semantic="AnalogueValue (maxVal - minVal)"
      mmstype="?" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
```

```
  mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DgicMaxTurPres>
- <DgicMaxInletTemp CommonDataClass="ASG" Semantic="Max inlet
    temperature">
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue  -->
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit  -->
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- unknown Attribute Type - ScaledValueConfig -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="?" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="?" />
    <stepSize Semantic="AnalogueValue (maxVal - minVal)"
      mmstype="?" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DgicMaxInletTemp>
- <DgicMaxOutTemp CommonDataClass="ASG" Semantic="Max outlet
    temperature">
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue  -->
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit  -->
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- unknown Attribute Type - ScaledValueConfig -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="?" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="?" />
    <stepSize Semantic="AnalogueValue (maxVal - minVal)"
      mmstype="?" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DgicMaxOutTemp>
- <DgicMinSpeed CommonDataClass="ASG" Semantic="Min speed">
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue  -->
    <setMag Semantic="set AnalogueValue" mmstype="?" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit  -->
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- unknown Attribute Type - ScaledValueConfig -->
    <minVal Semantic="Minimum AnalogueValue" mmstype="?" />
    <maxVal Semantic="Maximum AnalogueValue" mmstype="?" />
```

```
      <stepSize Semantic="AnalogueValue (maxVal - minVal)"
        mmstype="?" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </DgicMinSpeed>
  - <DgicMaxSpeed CommonDataClass="ASG" Semantic="Max speed">
      <setMag Semantic="set AnalogueValue" mmstype="?" />
      <!--  Unknown Attribute Type - AnalogueValue   -->
      <setMag Semantic="set AnalogueValue" mmstype="?" />
      <units Semantic="?" mmstype="?" />
      <!--  unknown Attribute Type - Unit   -->
      <sVC Semantic="ScaledValueConfig" mmstype="?" />
      <!--  unknown Attribute Type - ScaledValueConfig  -->
      <minVal Semantic="Minimum AnalogueValue" mmstype="?" />
      <maxVal Semantic="Maximum AnalogueValue" mmstype="?" />
      <stepSize Semantic="AnalogueValue (maxVal - minVal)"
        mmstype="?" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </DgicMaxSpeed>
    <DgicHeatRtCurves CommonDataClass="CSD" Semantic="Heat rate
      curves From IEC61850-7-3 Clause 7.9.4" />
  - <DgicFuel CommonDataClass="ING" Semantic="Type of fuel used by IC
      engine">
      <setVal mmstype="integer[32]" />
      <setVal mmstype="integer[32]" />
      <minVal mmstype="integer[32]" />
      <maxVal mmstype="integer[32]" />
      <stepSize mmstype="unsigned[32]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </DgicFuel>
  </CF>
- <ST>
  - <DiesOnOff CommonDataClass="SPS" Semantic="IC Engine is on or is
      off">
      <stVal Semantic="status value changed True-False"
        mmstype="boolean" />
      <q Semantic="quality" mmstype="bitString[16]" />
      <t Semantic="timestamp" mmstype="binaryTime[6]" />
      <subEna Semantic="?" mmstype="boolean" />
```

```
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DiesOnOff>
- <DiesMode CommonDataClass="INS" Semantic="Operational mode: 1 =
    in test, 2 = off-line, 3 = available">
    <stVal Semantic="status value" mmstype="integer[32]" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DiesMode>
- <SpdDroop CommonDataClass="SPS" Semantic="Speed droop status
    Disabled">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </SpdDroop>
- <OilPresSt CommonDataClass="SPS" Semantic="Oil pressure status">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
```

```
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </OilPresSt>
- <CoolPresSt CommonDataClass="SPS" Semantic="Coolant pressure
    status">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </CoolPresSt>
- <CustSw1 CommonDataClass="SPS" Semantic="Status of customer
    switch 1">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </CustSw1>
- <CustSw2 CommonDataClass="SPS" Semantic="Status of customer
    switch 2">
    <stVal Semantic="status value changed True-False"
      mmstype="boolean" />
    <q Semantic="quality" mmstype="bitString[16]" />
    <t Semantic="timestamp" mmstype="binaryTime[6]" />
    <subEna Semantic="?" mmstype="boolean" />
    <subVal Semantic="?" mmstype="integer[32]" />
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
```

```
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </CustSw2>
  - <DgicAlm CommonDataClass="ALM" Semantic="IC engine alarms To Be
    Determined">
      <!--  Unknown Common Data Class ALM   -->
    </DgicAlm>
  </ST>
- <MX>
  - <OilPres CommonDataClass="MV" Semantic="Oil pressure Pressure, in
      Pascals">
      <instMag Semantic="AnalogueValue" mmstype="?" />
      <!--  Unknown Attribute Type - AnalogueValue   -->
      <mag Semantic="AnalogueValue" mmstype="?" />
      <!--  Unknown Attribute Type - AnalogueValue   -->
      <range Semantic="Measured Range - normal | high | low | high-
        high | low-low" mmstype="bitString[5]" />
      <q Semantic="Quality" mmstype="bitString[16]" />
      <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
      <!--  unknown Attribute Type - TimeStamp   -->
      <subEna Semantic="?" mmstype="boolean" />
      <submag Semantic="AnalogueValue" mmstype="?" />
      <!--  Unknown Attribute Type - AnalogueValue   -->
      <subQ Semantic="Quality" mmstype="bitString[16]" />
      <subID Semantic="?" mmstype="visibleString[64]" />
      <units Semantic="?" mmstype="?" />
      <!--  unknown Attribute Type - Unit   -->
      <db Semantic="deadband value" mmstype="unsigned[32]" />
      <zeroDb Semantic="zero deadband value" mmstype="Unsigned
        [32]" />
      <sVC Semantic="ScaledValueConfig" mmstype="?" />
      <!--  Unknown Attribute Type - ScaledValueConfig   -->
      <rangeC Semantic="RangeConfig" mmstype="?" />
      <!--  Unknown Attribute Type - RangeConfig   -->
      <smpRate Semantic="?" mmstype="unsigned[32]" />
      <d Semantic="description" mmstype="visibleString[255]" />
      <cdcNs Semantic="Common Data Class Namespace"
        mmstype="visibleString[255]" />
      <cdcName Semantic="Common Data Class Name"
        mmstype="visibleString[255]" />
      <dataNs Semantic="Common Data Class Namespace" />
    </OilPres>
  - <DgicTemp CommonDataClass="MV" Semantic="Engine temperature in
      degrees K">
      <instMag Semantic="AnalogueValue" mmstype="?" />
      <!--  Unknown Attribute Type - AnalogueValue   -->
      <mag Semantic="AnalogueValue" mmstype="?" />
      <!--  Unknown Attribute Type - AnalogueValue   -->
      <range Semantic="Measured Range - normal | high | low | high-
        high | low-low" mmstype="bitString[5]" />
      <q Semantic="Quality" mmstype="bitString[16]" />
      <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
```

```
<!-- unknown Attribute Type - TimeStamp -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!-- unknown Attribute Type - Unit -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!-- Unknown Attribute Type - ScaledValueConfig -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!-- Unknown Attribute Type - RangeConfig -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
<cdcName Semantic="Common Data Class Name"
  mmstype="visibleString[255]" />
<dataNs Semantic="Common Data Class Namespace" />
</DgicTemp>
- <DgicRPM CommonDataClass="ANV" Semantic="IC Engine engine speed
  in revolutions per minute">
<instMag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<mag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<range Semantic="Measured Range - normal | high | low | high-
  high | low-low" mmstype="bitString[5]" />
<q Semantic="Quality" mmstype="bitString[16]" />
<t Semantic="TimeStamp" mmstype="binaryTime[6]" />
<!-- unknown Attribute Type - TimeStamp -->
<subEna Semantic="?" mmstype="boolean" />
<submag Semantic="AnalogueValue" mmstype="?" />
<!-- Unknown Attribute Type - AnalogueValue -->
<subQ Semantic="Quality" mmstype="bitString[16]" />
<subID Semantic="?" mmstype="visibleString[64]" />
<units Semantic="?" mmstype="?" />
<!-- unknown Attribute Type - Unit -->
<db Semantic="deadband value" mmstype="unsigned[32]" />
<zeroDb Semantic="zero deadband value" mmstype="Unsigned
  [32]" />
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!-- Unknown Attribute Type - ScaledValueConfig -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!-- Unknown Attribute Type - RangeConfig -->
<smpRate Semantic="?" mmstype="unsigned[32]" />
<d Semantic="description" mmstype="visibleString[255]" />
<cdcNs Semantic="Common Data Class Namespace"
  mmstype="visibleString[255]" />
```

```
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </DgicRPM>
- <GenFrq CommonDataClass="MV" Semantic="IC engine gen frequency
    Hz">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </GenFrq>
- <EngTrq CommonDataClass="MV" Semantic="Engine torque Metric
    equivalent to ft-lbs">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
```

```
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </EngTrq>
- <EngTim CommonDataClass="MV" Semantic="Engine timing Degrees
    BTDC?">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
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- <EngFuel CommonDataClass="MV" Semantic="Engine fuelling ??Set or
    MV? Mm3s ??? O">
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- <CoolPres CommonDataClass="MV" Semantic="Coolant pressure Metric
    equivalent to psi">
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- <CoolTemp CommonDataClass="MV" Semantic="Coolant temperature
    Deg C">
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- <ManiPres CommonDataClass="MV" Semantic="Intake manifold
  pressure Metric equivalent to psi">
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- <ManiTemp CommonDataClass="MV" Semantic="Intake manifold
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- <WaterTemp CommonDataClass="MV" Semantic="Aftercooler water
    temperature Deg C">
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    <rangeC Semantic="RangeConfig" mmstype="?" />
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  mmstype="visibleString[255]" />
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</FuelPres>
- <TimPres CommonDataClass="MV" Semantic="Timing Rail pressue
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  <rangeC Semantic="RangeConfig" mmstype="?" />
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    mmstype="visibleString[255]" />
  <cdcName Semantic="Common Data Class Name"
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- <FuelTemp CommonDataClass="MV" Semantic="Fuel temperature Deg
  C">
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    <cdcName Semantic="Common Data Class Name"
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  </FuelTemp>
- <FuelAmp CommonDataClass="MV" Semantic="Fuel Rail actuator
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    <rangeC Semantic="RangeConfig" mmstype="?" />
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    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
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      mmstype="visibleString[255]" />
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- <TimAmp1 CommonDataClass="MV" Semantic="Timing rail actuator
    current amps">
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    <mag Semantic="AnalogueValue" mmstype="?" />
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    <smpRate Semantic="?" mmstype="unsigned[32]" />
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      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
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  </TimAmp1>
- <TimAmp2 CommonDataClass="MV" Semantic="Timing rail actuator
    current amps">
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    <mag Semantic="AnalogueValue" mmstype="?" />
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    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
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```
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    <rangeC Semantic="RangeConfig" mmstype="?" />
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    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </TimAmp2>
- <PumpAmp CommonDataClass="MV" Semantic="Fuel pump actuator
    current amps">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </PumpAmp>
```

```
– <BatVolt CommonDataClass="MV" Semantic="Battery charger alt flash
    volts volts">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!-- Unknown Attribute Type - ScaledValueConfig -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!-- Unknown Attribute Type - RangeConfig -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </BatVolt>
– <TotCumFuel CommonDataClass="MV" Semantic="Cumulative fuel
    consumption Fuel in liters">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!-- unknown Attribute Type - TimeStamp -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!-- Unknown Attribute Type - AnalogueValue -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!-- unknown Attribute Type - Unit -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
```

```
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </TotCumFuel>
- <CumFuel CommonDataClass="MV" Semantic="Cumulative fuel since
    reset Fuel in liters">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </CumFuel>
- <EngRunTim CommonDataClass="TMS" Semantic="Engine running time
  Hours">
    <!-- Note...Unknown data object type TMS (timestamp)   -->
  </EngRunTim>
- <FuelRate CommonDataClass="MV" Semantic="Fuel usage rate Fuel
    usage rate liters/hr">
```

```
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
    <sVC Semantic="ScaledValueConfig" mmstype="?" />
    <!--  Unknown Attribute Type - ScaledValueConfig   -->
    <rangeC Semantic="RangeConfig" mmstype="?" />
    <!--  Unknown Attribute Type - RangeConfig   -->
    <smpRate Semantic="?" mmstype="unsigned[32]" />
    <d Semantic="description" mmstype="visibleString[255]" />
    <cdcNs Semantic="Common Data Class Namespace"
      mmstype="visibleString[255]" />
    <cdcName Semantic="Common Data Class Name"
      mmstype="visibleString[255]" />
    <dataNs Semantic="Common Data Class Namespace" />
  </FuelRate>
- <FuelCal CommonDataClass="MV" Semantic="Calorie content of fuel
    Calorie content of fuel">
    <instMag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <mag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <range Semantic="Measured Range - normal | high | low | high-
      high | low-low" mmstype="bitString[5]" />
    <q Semantic="Quality" mmstype="bitString[16]" />
    <t Semantic="TimeStamp" mmstype="binaryTime[6]" />
    <!--  unknown Attribute Type - TimeStamp   -->
    <subEna Semantic="?" mmstype="boolean" />
    <submag Semantic="AnalogueValue" mmstype="?" />
    <!--  Unknown Attribute Type - AnalogueValue   -->
    <subQ Semantic="Quality" mmstype="bitString[16]" />
    <subID Semantic="?" mmstype="visibleString[64]" />
    <units Semantic="?" mmstype="?" />
    <!--  unknown Attribute Type - Unit   -->
    <db Semantic="deadband value" mmstype="unsigned[32]" />
    <zeroDb Semantic="zero deadband value" mmstype="Unsigned
      [32]" />
```

```xml
<sVC Semantic="ScaledValueConfig" mmstype="?" />
<!--  Unknown Attribute Type - ScaledValueConfig   -->
<rangeC Semantic="RangeConfig" mmstype="?" />
<!--  Unknown Attribute Type - RangeConfig   -->
```

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14. ABSTRACT *(Maximum 200 Words)*
This report details progress on subcontract NAD-1-30605-1 between the National Renewable Energy Laboratory and RealEnergy (RE), the purpose of which is to describe RE's approach to the challenges it faces in the implementation of a nationwide fleet of clean cogeneration systems to serve contemporary energy markets. The Phase 2 report covers: utility tariff risk and its impact on market development; the effect on incentives on distributed energy markets; the regulatory effectiveness of interconnection in California; a survey of practical field interconnection issues; trend analysis for on-site generation; performance of dispatch systems; and information design hierarchy for combined heat and power.

For more information about this body of research, see the report describing the first phase of this work, NREL/SR-560-33581, "Development, Demonstration, and Field Testing of Enterprise-Wide Distributed Generation Energy Management System."

15. SUBJECT TERMS
RealEnergy; combined heat and power; CHP; deregulation; distributed energy information system; DEIS; distributed energy resources; DER; energy management; National Renewable Energy Laboratory; NREL

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