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ENERGY & ENVIRONMENT DIVISION

Evaluation of Public Service Electric & Gas Company's Standard Offer Program Volume I

C.A. Goldman, M.S. Kito, and M.M. Moezzi

July 1995

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Contents

Tables

Figures

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Acronyms and Abbreviations

B/C	Benefit/Cost
BPU	Board of Public Utilities
C/I	Commercial & Industrial
CPUC	California Public Utilities Commission
DSM	Demand-Side Management
EEPS	Energy Efficiency Products and Services
EMCS	Energy Management Control Systems
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESCO	Energy Service Company
ESN	Energy Services Network
FC	Foot Candle
HVAC	Heating, Ventilation, and Air Conditioning
LBNL	Lawrence Berkeley National Laboratory
M&V	Measurement & Verification
NJAC	New Jersey Administrative Code
NPV	Net Present Value
O&M	Operation & Maintenance
PG&E	Pacific Gas & Electric Company
PSCRC	Public Service Conservation Resource Corporation
PSE&G	Public Service Electric & Gas Company
PUC	Public Utility Commission
RFP	Request for Proposal
SPPADR	Summer Prime Period Average Demand Reduction
TRC	Total Resource Cost
VAV	Variable Air Volume
VSD	Variable Speed Drive

Glossary

Core Demand Side Management Programs	Conservation programs required to be performed by the utilities and which are not subject to the incentive provisions established by the New Jersey Board of Public Utilities. Core programs typically involve the dissemination of energy efficiency information to the public as well as to accomplish certain socially desirable or other public benefit goals.
Customer Sponsors	Customers who reduce the summer prime period demand by 100 kW, submit a proposal to PSE&G for approval conforming to the terms and conditions of the Standard Offer Agreement, and sign a contract for 5; 10, or 15 years with PSE&G.
"Deferred" Free Rider	A program participant who installs the energy efficient equipment sooner than originally planned.
Eligible Measures	Includes any equipment, system or material that improves the efficiency of a new or existing end use and provides savings that can be measured and verified. Load shifting (e.g., cool storage) or fuel switching (e.g., conversion to gas a/c) equipment also qualifies.
Energy Service Company (ESCO)	A third-party company which provides energy efficiency and load management equipment and/or services to end user customers.
Host Customers	All entities and/or premises located within PSE&G's electric service territory at which Standard Offer projects are located.
"Performance-Based" DSM Programs	Utility demand side management programs for which utilities in New Jersey receive an incentive, either through a shared-savings program or a standard pricing offer.
Pre-Implementation Audits	Audits conducted by PSE&G at host facilities, consisting of an on-site detailed inspection to establish a base usage against which energy savings are measured.
Post-Implementation Audits	Audits conducted by PSE&G at host facilities, consisting of a series (up to 15) on-site, detailed inspections, which include a visual inspection of all areas and systems associated with the project and measurement of the power of a representative sample of circuits.

"Pure" Free Rider	A program participant who would have installed identical energy efficiency equipment without the program.
Project Sponsor	Either a customer or ESCO who reduces the summer prime period demand by 100 kW, submits a proposal to PSE&G for approval conforming to the terms and conditions of the Standard Offer Agreement, and signs a contract for 5, 10, or 15 years with PSE&G.
Statewide M&V Protocol	The measurement and verification protocols adopted by the New Jersey Board of Public Utilities based on a consensus process involving key stakeholders.
Summer Prime Period Average Demand Reduction (SPPADR)	The total kWh saved during the summer prime period divided by the total number of hours (430) in the summer prime period. The summer prime period includes the weekday hours between noon and 5 p.m. from June 1 to September 30, except holidays.
Utility Sampling Plan	The statewide measurement and verification protocol specifies that utilities develop individual M&V and sampling plans for performance-based programs.

Executive Summary

Background

In May 1993, Public Service Electric and Gas (PSE&G), the largest investor-owned utility in New Jersey, initiated the Standard Offer program, an innovative approach to acquiring demand-side management (DSM) resources. In this program, PSE&G offers long-term contracts with standard terms and conditions to project sponsors, either customers or third-party energy service companies (ESCOs), on a first-come, first-serve basis to fill a resource block. The design includes posted, time-differentiated prices which are paid for energy savings that will be verified over the contract term (5, 10, or 15 years) based on a statewide measurement and verification (M&V) protocol. The design of the Standard Offer differs significantly from DSM bidding programs in several respects. The eligibility requirements and posted prices allow ESCOs and other energy service providers to market and develop projects among customers with few constraints on acceptable end use efficiency technologies. In contrast, in DSM bidding, ESCOs typically submit bids without final commitments from customers and the utility selects a limited number of winning bidders who often agree to deliver a pre-specified mix of savings from various end uses in targeted markets. In the Standard Offer, competition for projects among ESCOs occurs at the customer level, while in DSM bidding, competition among ESCOs occurs during the utility's bid evaluation process and at the customer level, depending on the market overlap among winning bidders.

From a policy perspective, the program is interesting for several reasons: (1) its potential size (150 MW) is significantly larger than any current utility program that relies primarily on ESCOs and contractors to market and deliver energy services, (2) the program's scope is quite broad and includes new construction and retrofits in existing commercial, industrial, and residential buildings, and (3) participation by PSE&G's subsidiary, Public Service Conservation Resources Corporation (PSCRC), raises important competition policy issues in emerging energy services markets. The relationship between program design and regulatory incentive treatment is crucial to understanding the development of the Standard Offer program. The DSM incentive regulations adopted by the New Jersey Board of Public Utilities (BPU) in 1992 allow PSE&G to operate in its own service territory through an energy services subsidiary in a Standard Offer-type program.

As part of the Stipulation of Settlement that approved the Standard Offer pilot, the New Jersey BPU asked PSE&G to conduct an independent evaluation of the program. Lawrence Berkeley National Laboratory (LBNL), with co-funding from the Department of Energy, was retained to perform a process and impact evaluation. The major objectives of the LBNL evaluation were to assess market response and customer satisfaction; analyze program costs and cost-effectiveness; review and evaluate the utility's administration and delivery of the program; examine the role of PSE&G's energy services subsidiary (PSCRC) in the program and the effect of its involvement on the development of the energy services industry in New Jersey; and discuss the potential applicability of the Standard Offer concept given current trends in the electricity industry (i.e., increasing competition and the prospect of industry restructuring). Based on our findings, we also suggest options to improve the design and implementation of PSE&G's next Standard Offer and related DSM programs.

Evaluation Approach

We reviewed all program materials, regulatory filings, and a sample of proposals submitted by project sponsors, made site visits to several facilities in various stages of development, and interviewed key program participants. These included in-person interviews with utility and regulatory staff and telephone surveys with project sponsors (both customers and ESCOs), host customers that used ESCOs as project sponsors, and ESCOs that are not active in the program. We attempted to interview all project sponsors and a sample of host customers that had worked with each participating ESCO.

We also reviewed and analyzed data in PSE&G's program tracking database for the first 18 months of field operation (June 1993-December 1994). The database includes descriptive information on each facility, a detailed inventory of individual measures installed, baseline and proposed equipment efficiencies, estimated hours of operation and savings by time period, actual savings based on end-use and equipment metering and monitoring of hours of operation, and various types of program costs. This information was used in our analysis of market penetration, market shares for various participants, and program costs and cost-effectiveness.

Program Evolution

Table ES-1 provides a brief chronology of the Standard Offer from design through various phases of implementation in three areas - regulatory, utility, and market activities. We highlight significant decisions and milestones in the program's evolution to provide context for understanding key issues that arose in our evaluation:

- The program design and rules were the product of a consensus settlement involving major stakeholders, which was approved by the New Jersey BPU. Key issues included the allowed scope of PSE&G's DSM marketing activities to promote the Standard Offer, the role of the utility's energy services subsidiary, and the development of M&V protocols.

Table ES-1. Program Chronology

	Program Design ('92 -Early '93)	Initial Implementation (June '93 -Mar '94)	Program Implementation (Apr '94 - Dec '94)	Program Implementation (Jan '95 -)
Regulatory	Negotiated Settlement	Initial M&V Protocols Approved	Minor Program Changes	"Stay the Course on DSM"
Utility	PSCRC Formed	Utility Adopts "Hands-Off" Attitude	Field Marketing Staff Hired	Utility Re-Organization
Market	PSCRC Promotes ESN	ESCOs Marketing Std Offer & '89 Bid	Problems w/ESN PSCRC Offers "Bright Investment" Program	Increasing Momentum

- During the initial implementation period, the utility's subsidiary, PSCRC, aggressively entered the energy services market. PSCRC financed projects sponsored by other ESCOs or host customers and organized an Energy Services Network (ESN) in which it acted as a project facilitator attempting to guide customers towards other qualified third parties that were members of the ESN. Major problems arose in implementing the ESN and many of the original ESCO members dropped out after disagreements with PSCRC.

- Several winning ESCOs from PSE&G's 1989 competitive bidding solicitation were marketing this earlier program as well as the Standard Offer. The competing offers created some confusion among large commercial/industrial (C/I) customers.

- Initially, in strict accordance with the settlement agreement, PSE&G program staff consciously limited their program marketing activities because of concern about influencing customers' access to and selection among competing ESCOs. In response to the market's initial slow response and confusion among customers, PSE&G made significant mid-course corrections in April 1994. PSE&G assigned specialists in regional offices to provide customers with assistance on specific program issues and PSE&G field representatives began to market and promote the program more aggressively. ESCOs also revised their marketing strategies; as one example, PSCRC began promoting its "Bright Investment" program offering lighting efficiency improvements to smaller C/I customers.

- In late 1994, the BPU extended the pilot program to December 1995 as part of an explicit strategy to "stay the course on DSM" while it considers broader issues related to industry restructuring. There is also evidence that the program is gaining increasing customer and market acceptance.

Market Response

- Through December 1994, PSE&G received commitments from 35 project sponsors (16 ESCOs and 19 customer sponsors) for a total of about 40 MW of Summer Prime Period Average Demand Reduction (SPPADR)[1] from more than 1,050 facilities. About 9 MW were operational (see Table ES-2). The market response is significantly less than the original program target of 150 MW in two years but compares favorably with most DSM bidding programs, assuming that most of the committed projects eventually come on-line.

Table ES-2. Distribution of Projects by Sponsor Type

Sponsor Type	Number of Facilities	Committed Projects: SPPADR (MW)	Commercial Operation: SPPADR (MW)
ESCOs (excluding PSCRC) (14)	94	15.1	1.8
PSCRC	146	10.7	4.9
PSCRC -- Bright Investments	782	7.1	2.4
Customer Sponsors (19)	34	7.2	0.2
TOTAL	1,056	40.1	9.3

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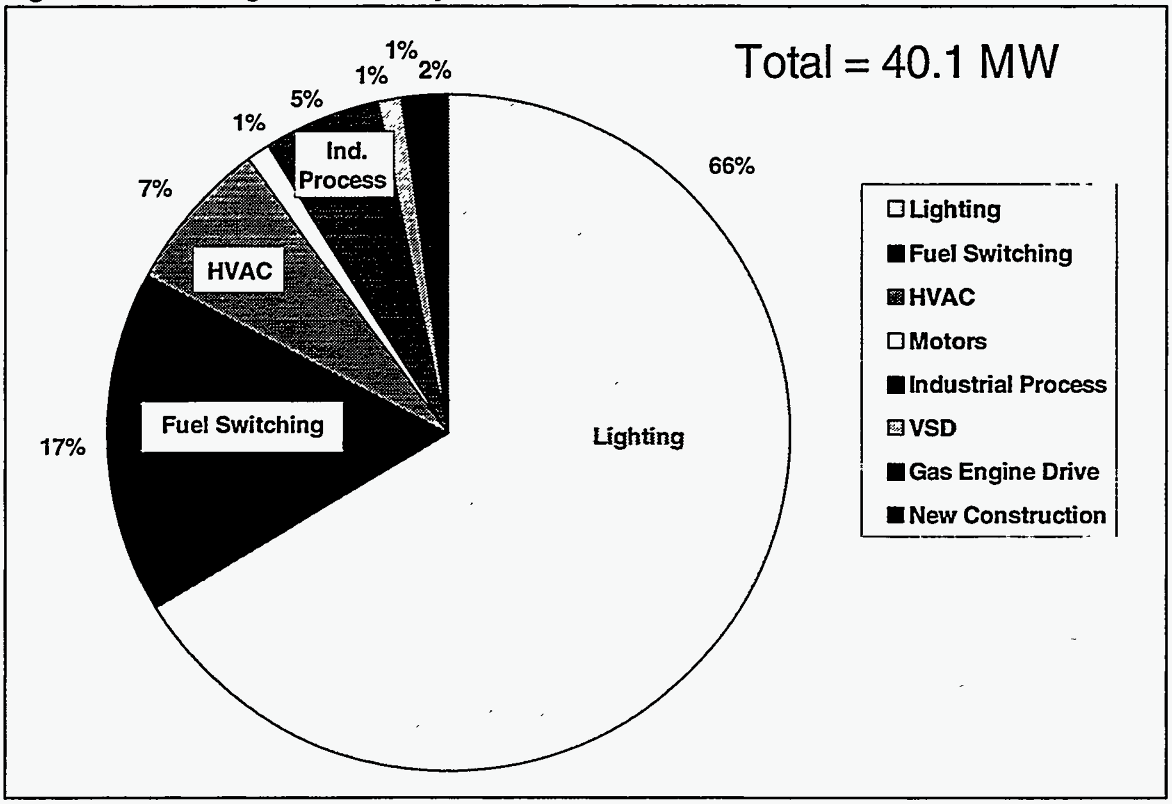
1 Summer Prime Period Average Demand Reduction is defined as the total kWh saved during the summer prime period divided by the total number of hours (430) in the Summer Prime Period. The Summer Prime Period includes the weekday hours between 12 noon and 5 p.m. from June 1 to September 30, except holidays.

- Various types of lighting measures (66%) and electric-to-gas conversions of space and water heating equipment and industrial processes (17%) are the most popular measures (see Figure ES-1). Non-lighting measures represent 75% of the savings from customer-sponsored projects, while lighting measures represent 75% of the savings from projects sponsored by ESCOs.

- Compared to the economic potential for DSM, the market response to the Standard Offer appears to be small in most C/I target markets and end uses (<5%) with a few notable exceptions. In some sectors (e.g., large commercial office buildings), ESCOs report that certain program design features discourage participation (e.g., lengthy contract terms, penalties for non-performance), particularly in non-owner occupied buildings.

- The Standard Offer program has succeeded in creating a high level of interest and support among various types of energy service providers (e.g., ESCOs, lighting service contractors, energy engineering firms and consultants, and firms that specialize in measurement and verification of savings). The program has also been relatively

Figure ES-1. Saving Breakdown by Measure



successful in reaching industrial customers; some industrials have chosen to be customer sponsors and they have also been heavily marketed by ESCOs.

- Many ESCOs also note that the program has been a "harder sell" than anticipated to customers. They report long sales cycles and low proposal to closing ratios (see Section 5.5), which suggests that ESCOs are incurring substantial up-front marketing and project development costs.[2] According to ESCOs, factors that adversely affected participation included poor or uncertain economic conditions in New Jersey, customer perceptions that the program is too complex and risky, stringent contract provisions, and the time and costs involved in developing acceptable M&V protocols for DSM measures that were not covered in the statewide M&V protocols.

- The extent of competition among ESCOs and other service providers varies by market sector. Competition appears quite intense among firms seeking to develop projects for large C/I customers. The typical large C/I customers reported that they received proposals from four ESCOs. In contrast, among small C/I customers interviewed, it was not uncommon for customers to have been approached by only one firm.

Customer Satisfaction

- Overall, customer sponsors and host customers were very satisfied with the Standard Offer program, driven in large part by their perception that the financial incentives offered by PSE&G were quite attractive.[3]

- The group of 11 customer sponsors surveyed had very strong reactions to the program with seven stating that they were very satisfied, while the two dissatisfied customer sponsors complained about the program's complexity and difficulty in developing and gaining approval for their M&V plans.

- Among the sample of 17 host customers in the large C/I market, only one was dissatisfied. Among the sample of participants in PSCRC's Bright Investment program, customer satisfaction was very high, with 16 of 25 customers indicating that they were "very satisfied."

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2 Proposal to closing ratio refers to the number of proposals made to customers compared to number of accepted proposals that produce a project.

3 Customer sponsors are those who directly sponsor a project in the Standard Offer, while host customers are customers whose projects are developed by ESCOs.

Program Costs and Cost-Effectiveness

- Total resource costs for the Standard Offer program, levelized over the contract term of each facility, average 6.8 ¢/kWh overall, which is about 74% of the utility's then avoided supply costs. Total resource costs vary somewhat by market segment, averaging 6.6 ¢/kWh for ESCO- and customer-sponsored projects in the large C/I market and about 8 ¢/kWh for PSCRC's Bright Investment projects, which are targeted at smaller C/I customers.

- Total resource costs also varied by types of measures installed: lighting-only projects averaged about 5.9 ¢/kWh for 217 facilities in the large C/I market, while the 27 projects that involved both fuel switching and other measures averaged about 7.3 ¢/kWh (see Table ES-3)

Table ES-3. Summary of Program Costs

	Number of Facilities	Total Resource Costs (¢/kWh)	TRC as % of Avoided Costs
Overall Program	1,041	6.8	74%
Type of Project Sponsor			
ESCOs	239	6.6	74%
Bright Investment	768	8.0	85%
Customer Sponsors	34	6.6	71%
Market Sector			
New Construction	10	5.8	58%
Existing Large C/I[a]	263	6.6	73%
***Type of Measure** (Large C/I: Existing Buildings)*			
Lighting Projects	217	5.9	67%
Fuel Switching, plus other measures	27	7.3	81%
Lighting, plus other measures	7	7.8	89%

[a] Includes all measures for both customer sponsors & ESCOs.

- Costs incurred by the utility average about 6.1 ¢/kWh for the program overall. Payments from host customers account for less than 10% of the total resource costs in large C/I facilities and average about 26% for small C/I customers that are participating in PSCRC's Bright Investment projects.

- The Standard Offer program has a benefit/cost (B/C) ratio of about 1.6 from a societal cost perspective.[4] About 25% of the individual facilities (59 out of 234) in the large C/I market have TRC B/C ratios less than one, with twenty facilities having B/C ratios less than 0.8. This result is possible because project sponsors are allowed to bundle together facilities for individual customers that would fail the TRC test on a stand alone basis if the project proposal passes the TRC for the entire set of facilities.

- We also compared program costs in the Standard Offer with a sample of nine DSM bidding programs where the performance risks and measure mix are comparable. Total resource costs in the Standard Offer are in the mid- to high-range compared to other utilities (5.2-8.1 ¢/kWh). We also found that costs incurred by the utility (i.e., financial incentives and administrative costs) are higher in the Standard Offer (about 6 ¢/kWh) compared to several recent DSM bidding programs (2.5-3.0 ¢/kWh).

PSE&G's Measurement and Verification Procedures

The statewide M&V protocols as well as the M&V procedures and sampling plans developed by PSE&G are a distinctive feature of the Standard Offer program. As part of our evaluation, we examined both policy-related and technical issues related to M&V (see Chapter 7).

- We believe that the New Jersey M&V protocols represent an important step forward in improving the credibility of DSM as a reliable resource compared to "typical" practice among utilities at the time they were adopted. Our preliminary analysis suggests that M&V costs in the Standard Offer represent a slightly higher share of total project costs compared to typical evaluation budgets for utility DSM programs.[5] The incremental benefits or value of the M&V protocols, specifically improved accuracy and reduced bias of savings estimates, appear to be cost-effective compared

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4 In New Jersey, the BPU requires that utilities include environmental externality costs of about 2 ¢/kWh in the total resource cost test calculation.

5 M&V costs accounted for about 7% of total project costs in customer-sponsored projects, which were mostly non-lighting measures. ESCOs reported M&V costs ranging from about 5-10%, depending on the types of measures and the project size. Raab and Violette (1994) estimate that utilities in 12 states spent an average of 6% of their DSM budgets on evaluation, ranging from 3-10%.

to these costs. However, we urge the parties in New Jersey to consider a number of major changes to the current M&V protocols to reflect implementation experience in New Jersey, advances in impact evaluation techniques, and appropriate standards for assessing the adequacy of DSM savings estimates (e.g., confidence and precision levels).

- Our technical review identified a number of areas in which the M&V protocols could be improved either in terms of improved accuracy or reduced cost. These include establishing more appropriate baseline conditions (e.g., planned replacement situations or new construction), using building simulation models to develop more accurate estimates of savings from lighting measures that account for HVAC-lighting interactive effects, relying on field audit acceptance techniques to verify certain parameters, and most importantly, changing the Sampling Plan to provide better accuracy for an equivalent or reduced cost. Because of statistical problems with the current Sampling Plan, we conclude that there is no direct evidence to suggest that savings measured under this protocol meet the stated objectives of the statewide M&V protocol (i.e., 90% confidence that savings equal or exceed the value measured). We also recommend that PSE&G change the experimental sampling design from stratification based on hours of operation to usage areas, with simple random sampling within each of these usage area strata.

Role of PSCRC

- We evaluated PSCRC's role and performance in the Standard Offer program primarily in terms of regulatory guidelines and intent. The New Jersey BPU's DSM policies were intended to expand the energy efficiency product and services (EEPS) market by incenting utilities financially. In approving the formation of PSCRC and allowing it to operate in PSE&G's service territory, the BPU was well aware of possible conflicts of interest and the potential for abuses, which it sought to limit through various policies and regulatory oversight. In the Stipulation of Settlement, PSCRC agreed to provide financing to other ESCOs and customers, to offer project facilitation services to customers and other energy service providers, and to develop a corporate structure that relied on third parties to directly install and service projects.

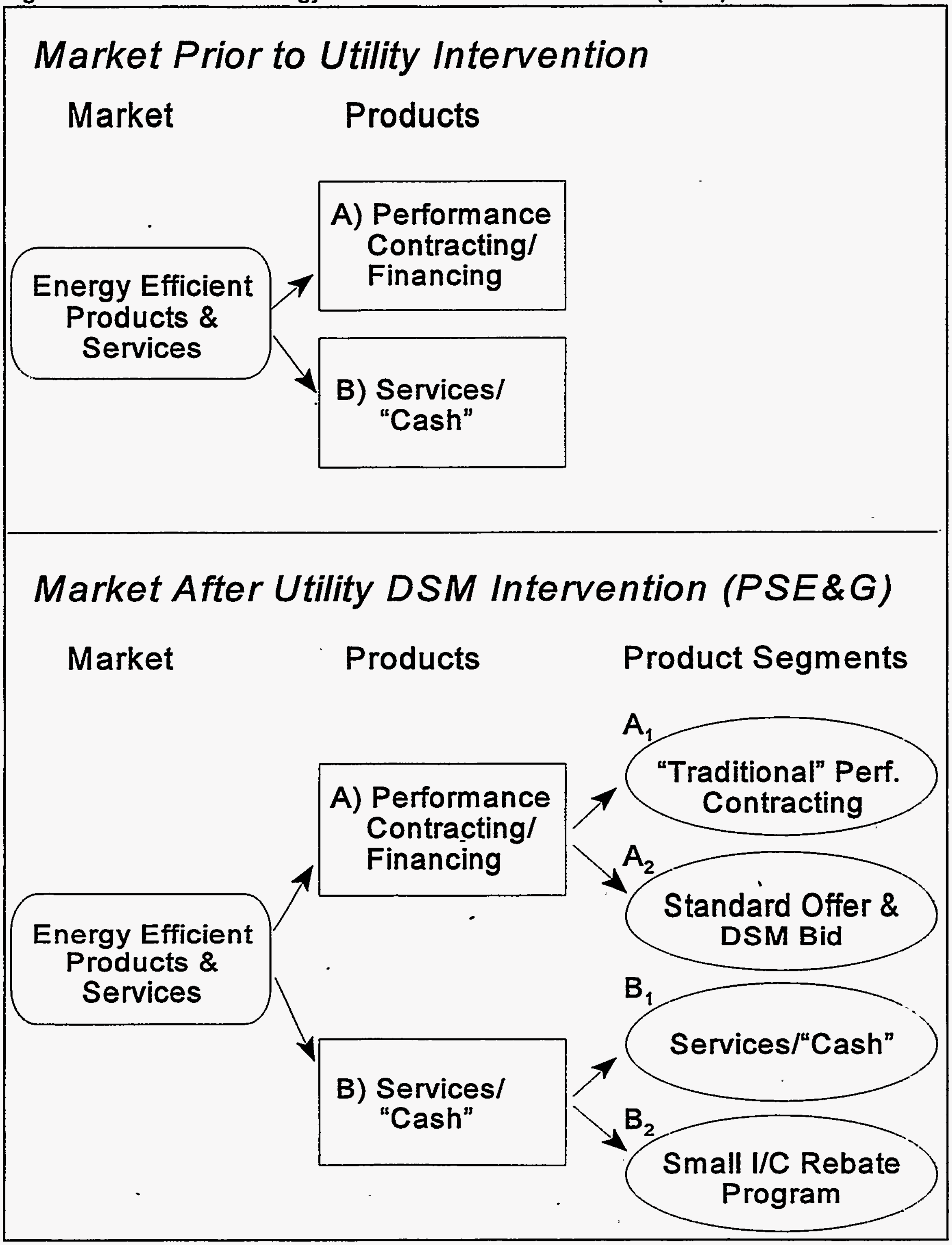
- In a relatively short time (i.e., less than three years), PSCRC has become a significant player in the local energy services market, active in both the large and small C/I sectors. PSCRC-sponsored projects account for about 43% of the program's committed savings. PSCRC has also provided construction and permanent financing to many projects sponsored by other ESCOs and customers.

- Overall, PSCRC appears to have been successful in its role of providing capital investment services to other ESCOs and customers. PSCRC's financial support and backing has provided an important stimulus to the energy services infrastructure in New Jersey as a number of new ESCOs and other types of service providers have entered the market. However, PSCRC's efforts to facilitate projects sponsored by other ESCOs have been less successful. Many ESCOs were disappointed with their experiences in PSCRC's Energy Service Network and many dropped out after disagreements with PSCRC (see Section 5.6.1). Since then, PSCRC has relied more heavily on alliances with several lighting service contractors and engineering/construction firms who bring jobs to PSCRC that it sponsors.

- There has been a significant shake-out in the local energy services market during the last several years. Several ESCOs that were winners in PSE&G's 1989 DSM bid have significantly downsized their marketing efforts. Some ESCOs have moved on to other areas of the U.S. where opportunities are perceived to be greater and they don't face a well-capitalized, utility-affiliated ESCO. Other "full-service" ESCOs have adapted to PSCRC's presence in the market by consciously focusing on market segments and niches where PSCRC and its trade allies are less active.

- In order to address the competition policy issues raised by PSCRC's role, we examined the extent to which the local EEPS market has expanded because of the utility's DSM programs (which was a key objective of New Jersey's regulators) and whether PSCRC's market share in an appropriately-defined product market provided evidence of the potential for market power. Figure ES-2 provides a conceptual illustration of the market for EEPS among C/I customers in PSE&G's service territory prior to and after DSM interventions by the utility. Based on available information, we conclude that PSE&G's DSM programs, and particularly the Standard Offer, have expanded the local EEPS market significantly. We also estimate that PSCRC's market share is about 25% in the local performance contracting/financing market (based on project sponsorship); but that their market share is significantly higher (50-60%) if we include projects where PSCRC has provided construction and permanent financing.

Figure ES-2. Market for Energy Efficient Products and Services (EEPS)



- We calculated Herfindahl-Hirschman Index (HHI) values which provide an index of market concentration by accounting for both the number and relative size of firms in an industry. We estimate HHI index values of about ~1,270 for the Standard Offer and DSM bidding program; HHI index values may range between 910-1,010 for the entire performance contracting market including "traditional" performance contracting done by ESCOs outside of utility DSM programs. Using the Department of Justice merger guidelines, the HHI values provides prima facie evidence for some, but not overwhelming, concern over the potential for market power. Barriers to entry are also particularly important in analyzing market competitiveness and structure. In this regard, we find that there are no formal entry barriers to becoming a "project sponsor" in the Standard Offer for customers of a certain minimum size and that ESCOs too face few eligibility restrictions. Thus, overall, ease of entry for firms (and customers) in this product market tends to mitigate some of our long-run concerns regarding PSCRC's market power.

- On balance and in light of the low barriers to entry in the Standard Offer, we believe that the existence of PSCRC has done more to increase the viability of a local energy services industry that promotes performance contracting/financing services rather than impede it. However, we also believe that a significant regulatory oversight and monitoring role will be required to ensure the development of a robust and competitive energy services industry and to ensure that ratepayer investments in DSM continue to be prudently managed by PSE&G. We believe that this is one of the costs that regulators and utilities must bear if they decide that public policy is best served by allowing a utility buyer to purchase from a seller affiliated with the host utility in their own service territory.

Recommendations for the Next Standard Offer

Our proposed changes to the program's design are guided by two overall goals:

- Program design changes should position DSM and the energy services industry to function more effectively in an increasingly competitive electricity industry. This means that the turnkey costs of DSM projects must be significantly reduced in order to respond effectively to the prospect of lower avoided supply-side costs. Participating customers also need to bear an increasing share of total project costs in order to minimize adverse rate impacts.

- The Standard Offer should be performance-based, but the program should better accommodate the distinctive characteristics of DSM resources rather than attempt to make DSM look like supply-side resources.

Table ES-4 summarizes our recommendations in various program areas (target market, design, implementation and delivery, and M&V protocols).

Table ES-4. LBNL Recommendations for Standard Offer #2

Program Area	Recommendations
Target Market	Limit program scope to C/I retrofit and planned replacement market
	For commercial new construction and major remodel market: develop program based on designs that have proven effective at other utilities
	Develop utility-sponsored pilot programs that target other potential lost opportunities (e.g., failed equipment/emergency replacement situations) in order to improve cost-effectiveness
	For the residential market: evaluate performance of the one ESCO-sponsored project that targets residential customers; develop additional "performance-based" programs in this sector, if cost effective
	For small C/I customers (<50 kW monthly peak demand): consider alternative program designs for very small C/I customers and changes to M&V and sampling procedures in order to improve cost-effectiveness
Program Design	Adopt two-tiered payment scheme with lower payments for lighting-only projects and higher payments for projects that achieve a specified percentage of their savings (25-30%) from non-lighting measures
	Establish minimum TRC B/C ratio for individual facilities (e.g., 0.9) that are submitted as part of larger projects in order to limit situations in which ratepayers support the installation of measures that are not cost effective from a societal perspective
Program Delivery & Administration	Ensure adequate staffing
	"Re-engineer" administrative procedures to reduce costs and ensure quality control
	Streamline program material and Standard Offer contract
	Work more closely with those customers that want to be project sponsors
Measurement & Verification	Develop additional M&V protocols for measures not covered (e.g., lighting controls)
	Modify Sampling Plan for control circuits
	Use audit acceptance techniques to verify key inputs
	Re-assess target confidence and precision levels for accuracy of DSM savings

Target Market

- A major finding from our evaluation is that the Standard Offer concept is most appropriate for the C/I retrofit market. The program design is not particularly amenable to capturing many of the technical opportunities in commercial new construction or in situations where there are limited windows of opportunity to influence investment decisions (e.g., failed equipment/emergency replacement). In these situations, as well as planned replacement, the societal cost of acquiring high-efficiency equipment is only the incremental cost of improved efficiency. These types of energy-efficiency opportunities may be particularly cost-effective for PSE&G to pursue, depending on the administrative costs and savings potential. Based on experience at other utilities, programs that are targeted to overcome the specific market barriers in these situations are required. For example, in emergency replacement situations, stocking practices, and thus the existing vendor structure, are key to equipment availability and delivery.

- In the residential sector, the limited number of energy service companies that currently target residential customers tends to undermine a key premise of the Standard Offer: that competition among service providers will ensure that customers have meaningful choices regarding energy efficiency. If payments under the next Standard Offer are significantly lower than current levels, this problem will likely be exacerbated. We recommend that PSE&G assess whether ESCOs can effectively target residential customers by evaluating the performance of the one ESCO that has proposed a project. In the commercial new construction market, the Standard Offer has only been able to generate a limited response. Our primary concerns are that the current program design is not attractive to certain types of developers (e.g., speculative, build-to-rent), that marketing in new construction often involves a different set of contacts and sales approaches than the retrofit market in which ESCOs typically operate, and that the M&V requirements will eliminate many cost-effective measures in new construction (e.g., daylighting, EMCS).

Program Design

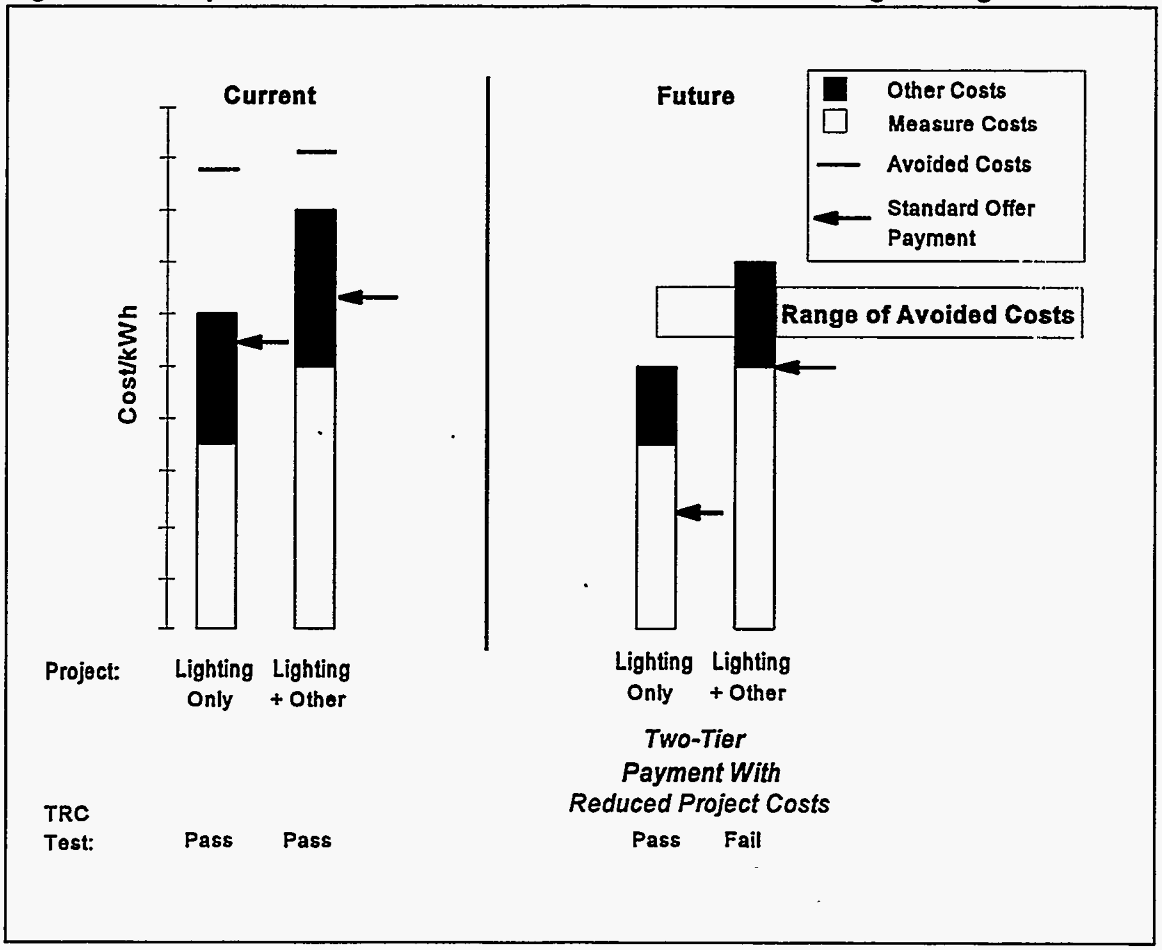
- We recommend that PSE&G consider a two-tiered Standard Offer payment. Projects that install only lighting measures would receive lower payments, while projects that involve significant savings from other end uses (e.g., HVAC, refrigeration, industrial process) would receive payment at the higher price.[6] A two-tiered payment scheme could lower the cost to ratepayers of acquiring savings from lighting-only projects,

6 Both payment levels would be less than the utility's avoided cost of supply.

while increasing the costs borne by participants. This approach may also allow "full-service" ESCOs that offer comprehensive packages of measures to compete more effectively against competitors that promote lighting-only projects.

- The prospect of lower avoided costs is likely to impact significantly the economics of certain projects. Figure ES-3 illustrates the implications for two prototypical types of projects: a lighting-only project and a project that involves installation of both lighting and non-lighting measures, which we refer to as a "comprehensive retrofit." Assuming that future avoided costs are 30-40% lower than current levels, most lighting projects would still pass a TRC test, although projects with low hours of operation or those that targeted small C/I customers are more likely to be marginally uneconomic. Many "comprehensive retrofit" projects would fail the TRC test. ESCO and customer sponsors interested in pursuing these projects may respond by installing fewer and/or lower cost measures, implementing certain "high-cost" measures outside

Figure ES-3. Implications of Lower Avoided Costs and Possible Design Changes



of the program, or by finding ways to reduce other, non-measure costs (e.g., up-front marketing and project development, M&V).

Program Delivery and Implementation

- It is critical that PSE&G management devote sufficient resources to administering this type of program effectively, both in terms of staffing levels and technical expertise. The utility must maintain a particularly high standard of performance to avoid even the appearance of impropriety or favoritism, given the active participation by their energy services affiliate. In this regard, we offer several suggestions to improve internal administration procedures (see Section 9.6.2). We also believe that there are significant opportunities to reduce the turnkey costs of projects through a combination of changes to the program's design and administration as well as opportunities that ESCOs have to improve operating efficiencies and reduce costs. We suggest a number of ways that administrative and M&V costs can be reduced because this is the area where PSE&G (and state regulators) can directly influence potential outcomes. Many of these involve minor changes but cumulatively they may be significant (see Sections 7.5 and 9.4.3) To be successful in the future, ESCOs will also have to find additional ways to reduce up-front marketing costs, lower the cost of financing, and creatively manage project risks. We also encourage PSE&G to revise the Standard Offer software proposal package and marketing materials, given the mixed reviews given by project sponsors.

Transferability of the Standard Offer to Other Utilities

In discussing the transferability of the Standard Offer to other utilities, it is important to distinguish between the underlying concept and the PSE&G program, because the pilot has been shaped by policy and design choices made by PSE&G, New Jersey's regulators, and interested parties. The most important of these were the broad market scope of the program (e.g., new and existing C/I buildings and residences), the decision to allow an ESCO affiliated with the host utility to participate directly, and the approach to savings verification.

As noted previously, the initial results in New Jersey suggest that the "one size fits all" approach for various market segments is not appropriate. The Standard Offer concept appears to work best in C/I markets in either retrofit or planned replacement situations. Direct participation by an ESCO that is affiliated with the host utility also created additional program implementation and monitoring challenges for PSE&G and the New Jersey BPU. Over the long term, incentive mechanisms that place the utility on both sides of the transaction (i.e., buyer and seller) necessitate additional regulatory scrutiny to minimize problems that inevitably arise from perceived or actual conflicts of interest. If other states adopt the Standard Offer concept, regulators should seriously consider alternative approaches that offer opportunities for financial incentives to utility shareholders (e.g., sharing of net resource benefits produced by a program) or institutional arrangements and requirements that minimize potential conflicts of interest. These include the option of having an independent agency administer the program if the host utility's energy services affiliate participates directly or establishing additional conditions that limit market power (e.g., initially limiting the potential market share of the utility's energy services subsidiary).

The terms and conditions in PSE&G's Standard Offer contract appear to draw heavily from their experience with independent power producers. Similarly, the design philosophy underlying the statewide M&V protocol is that DSM impacts should be measured with the same standard of accuracy as the output from supply-side resources to the extent feasible. This led to such requirements as continuous metering of hours of operation of lighting control circuits over the 10-15 year contract term and exclusion of certain types of efficiency measures whose savings could not be measured "reliably" (e.g., lighting and HVAC controls). While we support the design goal of linking payments for energy savings to long-term performance, we believe that alternative approaches to M&V can also achieve this objective (see Chapter 7).

Potential Role for Standard Offer as Part of a DSM Transition Strategy

Many analysts have argued that the reality (or even the threat) of electric utility industry restructuring presents a fundamental challenge to the continuation of large-scale, ratepayer-funded utility DSM programs. One attractive aspect of the Standard Offer concept is that it could be managed by a statewide agency or consortium empowered to acquire various types of DSM resources in pursuit of societal objectives. The statewide consortium could define standard terms and conditions for entities that wish to provide verified energy savings; costs of administering and delivering the program, including incentive payments to project sponsors, could come from a variety of sources, including, for example, a broad-based fee or system benefits charge. The Standard Offer concept is attractive to ESCOs because it provides a natural fit with the way they market and develop projects. The concept is also compatible with notions of "customer choice" because it maximizes customers' choice of service providers and theoretically places fewer constraints on their choice of acceptable end use efficient technologies. For those state PUCs and utilities looking to preserve and/or stimulate the energy efficiency services industry during a period of electricity industry restructuring and regulatory reform, the Standard Offer concept (and other competitive resource acquisition strategies) merits consideration in certain market segments.

Introduction

U.S. utilities continue to experiment with innovative approaches to acquiring demand-side management (DSM) resources. The design of DSM resource acquisition programs is shaped by both the state regulatory environment and the major policy objectives of the utilities and other parties (Goldman et al. 1994). New Jersey offers an important case study of this phenomenon. In October 1991, the New Jersey Board of Public Utilities (BPU) adopted regulations that provided guidelines for the state's investor-owned electric and gas utilities on DSM planning and acquisition (NJAC 1991). The rules reflected a compromise and consensus among the parties on the following DSM policy framework: (1) increased energy efficiency is regarded as a viable alternative to the construction or procurement of new electric generation resources, (2) utilities are uniquely positioned to foster increased energy efficiency, (3) utility shareholders are given the opportunity to earn financial incentives on investments in energy efficiency, and (4) significantly increased opportunities are provided for the sale and delivery of DSM measures and energy efficiency services by independent, non-utility energy service companies, contractors, and suppliers to encourage the development of energy services markets that are not dominated by utilities.

In 1992, in response to the new regulations, Public Service Electric and Gas (PSE&G), the state's largest investor-owned utility, filed its DSM resource plan and, in May 1993, initiated a large-scale DSM pilot -- the Standard Offer program. The program's design is innovative in that the utility offers long-term contracts with standard terms and conditions to project sponsors, either customers or third-party energy service companies (ESCOs) on a first-come, first-served basis. The design includes posted, time-differentiated prices which are paid for energy savings that are verified over the contract term based on a statewide measurement and verification (M&V) protocol. The program's scope is quite broad and includes new construction and retrofits in existing commercial, industrial, and residential buildings. However, the Standard Offer is PSE&G's primary DSM program for large commercial and industrial (C/I) customers. From a policy perspective, the program is interesting for several reasons: (1) its potential size (150 MW) is significantly larger than any current utility program that relies primarily on third-party energy service providers to market and deliver a performance-based program (e.g., DSM bidding), and (2) participation in the Standard Offer by PSE&G's regulated subsidiary, the Public Service Conservation Resources Corporation (PSCRC), represents a practical test of the BPU's DSM incentive regulations. In contrast to other states in which DSM incentive mechanisms typically provide utility shareholders with the opportunity to earn profits on DSM through retaining a share of the net societal benefits, the New Jersey BPU provided an additional option, which PSE&G chose, involving direct participation by the host utility's energy services subsidiary in a Standard Offer-type program. PSCRC's direct participation also raises important competitive issues with respect to PSE&G's role in the development of the energy services market.

This study presents results from a process and impact evaluation of the Standard Offer program. As part of the Stipulation of Settlement that approved the pilot program, the New Jersey BPU asked PSE&G to conduct an independent evaluation of the program. Lawrence Berkeley National Laboratory (LBNL), with co-funding from the U.S. Department of Energy (DOE), was retained to perform the evaluation. Based on discussions with PSE&G, the New Jersey BPU staff, and DOE, five major objectives were established defining the scope of the LBNL evaluation: (1) to assess market response and customer satisfaction, (2) to analyze program costs and cost-effectiveness, (3) to review and evaluate the utility's administration and delivery of the program, (4) to examine the role of PSE&G's energy services subsidiary (PSCRC) in the program and the effect of its involvement on the development of the energy services industry in New Jersey, and (5) to discuss the applicability and transferability of the Standard Offer concept to utilities in other states in light of the competitive pressures facing electric utilities. Based on our findings, we also provide recommendations and options to improve the design and implementation of PSE&G's program in the future.

1.1 Evaluation Approach

We reviewed all program materials, regulatory filings, and a sample of proposals submitted by project sponsors, made site visits to several facilities in various stages of development, and interviewed key program participants. These included in-person interviews with utility and regulatory staff and telephone surveys with project sponsors (both customers and ESCOs), host customers that used ESCOs as project sponsors, and ESCOs that are not active in the program. We attempted to interview all project sponsors and a sample of host customers that had worked with each participating ESCO. As is typical in process evaluations, all respondents were informed that their responses would be treated as confidential with no attribution.

We also reviewed and analyzed data in the utility's program tracking database for the first 18 months of field operation (June 1993-December 1994). The tracking database includes descriptive information on each facility (floor space, SIC code), a detailed inventory of individual measures installed, baseline and proposed equipment efficiencies, estimated hours of operation and savings by time period, actual savings based on end-use and equipment metering and monitoring of hours of operation, and various types of program costs. The data in the program tracking database was used in our analysis of market penetration, market shares for various participants, and program costs and cost-effectiveness. We also reviewed studies on the DSM potential in the utility's service territory (Xenergy 1994) and the design of PSE&G's current programs in the commercial/industrial sector (Gordon et al. 1994) that were provided by PSE&G. To address confidentiality and proprietary concerns, LBNL agreed that market penetration and cost information would either be masked or aggregated into broader categories (e.g., ESCOs and all customer sponsors) with one exception. For PSCRC, this information is broken out separately in order to address one of the central issues in the evaluation: the role of the utility's affiliate in the energy services market.

1.2 Report Organization

The remainder of the report is organized as follows. In Chapter 2, we provide a brief overview of PSE&G's current DSM programs, trace the evolution of the Standard Offer program from design through various implementation stages, and describe its key design features. In Chapter 3, we examine the market response to the Standard Offer program through December 1994. We report on the activity levels of various market participants (e.g., ESCOs, customer sponsors), savings and market penetration in selected target markets and the types of measures installed. We also assess program experience in light of recent estimates of the economic potential for DSM in PSE&G's service territory. In Chapter 4, we analyze the utility and societal costs of the Standard Offer program and compare the program's costs with the experience of other utilities as well as PSE&G's estimated avoided cost of supply. In Chapter 5, we report the results of our interviews with ESCOs and customers that have participated in the program as project sponsors, host customers that participated through ESCOs, and ESCOs that are currently not active in the program (see Appendix A for list of utility staff and ESCOs interviewed). We discuss participants' experiences and satisfaction with the program, their assessment of the utility's administration and marketing of the program, their views on key program design features, and their suggestions for improvement. The interview protocols used for each group are included as technical appendices (Appendices B-H). In Chapter 6, we discuss issues related to measuring net savings from the Standard Offer program, including analysis of free rider, free driver, and program spillover effects based on our interviews with customer sponsors and a sample of host customers. In Chapter 7, we review and critique the measurement and savings verification procedures used by PSE&G in the Standard Offer. In Chapter 8, we examine the role of PSCRC in the Standard Offer program and the effect of its involvement on the development of the energy services industry in New Jersey. In Chapter 9, we summarize the major findings from our process and impact evaluation with reference to the five study objectives and discuss the relative merits of the Standard Offer concept compared to alternative program designs. We also present recommendations and options for PSE&G to consider as it revises the program, which address some areas of concern identified in this study.

PSE&G DSM Programs and the Standard Offer

2.1 Overview

This chapter briefly describes the range of PSE&G's current DSM activities, noting their relationship to the current regulatory incentives for DSM that have been adopted in New Jersey. This relationship between program design and regulatory incentive treatment is crucial to understanding the development of the Standard Offer program. The opportunity for PSCRC to operate in PSE&G's service territory effectively provides utility shareholders with a powerful DSM incentive mechanism.

We then discuss the evolution of the Standard Offer program, from the initial design process through various stages of implementation. We show how the origins of the Standard Offer program are rooted in PSE&G's and the energy services industry's dissatisfaction with the "all-source" competitive bidding process that PSE&G conducted in 1989. We then summarize key features of the Standard Offer program, including pricing and contract provisions and measurement and verification (M&V) requirements. Finally, we compare the Standard Offer design concept to alternative program designs, such as customized rebate and DSM bidding programs, that are often targeted at large C/I customers. This overview of PSE&G's current DSM programs and the Standard Offer is intended to provide background and context for our discussion of program impacts (Chapters 3 and 4), survey responses by project sponsors and host customers (Chapter 5), and review of PSE&G's M&V protocols (Chapter 7).

2.2 PSE&G's Current DSM Programs

The DSM regulations adopted by the New Jersey BPU define two types of DSM programs, "core" and "performance-based," which differ in terms of their primary objectives and financial treatment. The BPU requires each utility to offer a specified set of "core" programs which are intended to disseminate information to the public on energy efficiency and achieve certain socially desirable or other public policy goals (e.g., low-income programs offered to address equity concerns).[7] Many of these core programs were initiated in the mid-1980s and

[7] The core programs were approved by all parties on the basis of the following transition process. PSE&G was to conduct a cost-benefit analysis for each core program by the next DSM resource plan filing and either recommend discontinuing the program if it was not cost-effective and did not otherwise offer countervailing societal benefits or offering the program under the performance-based program guidelines.

have evolved over the years. Utilities are allowed to expense costs incurred in operating these core programs, but do not receive any additional financial incentive.

"Performance-based" programs are intended to provide measurable net resource benefits to utility ratepayers. Utilities have two options to earn profits on DSM, either through direct participation in a Standard Offer program or through retaining a percentage of the net benefits achieved by performance-based programs. Utilities are also allowed to recover program costs and can propose a revenue adjustment mechanism to address undercollection of authorized fixed costs.

Table 2-1 lists the current programs offered by PSE&G, broken down by target market (e.g., residential or commercial) and primary objective (e.g., information-only programs) (The Results Center 1994). All of these programs are "core" programs with the exception of the Standard Offer and winning DSM bids from the 1989 integrated, all-source bidding solicitation. The Standard Offer is performance-based and the 1989 DSM bids were awarded prior to the DSM incentive regulations.

PSE&G spent roughly $38 million on its core programs in 1994. About 84% was spent on the residential programs, 7% on core programs targeted at commercial customers, and 9% on informational programs and other expenditures (e.g., research studies). The Residential A/C Cycling, the Compact Fluorescent Bulbs, and the Residential Rebates programs, in total, accounted for 52% of PSE&G's core program expenditures (Table 2-2).

Table 2-1. PSE&G's Current DSM Programs

Residential
Home Energy Savings
Low Income Seal-Ups
Low Income Direct Grant
Low Income Attic Insulation
Residential Loans
ETH -- Energy for Tomorrow's Homes
Energy Profile
Air Conditioning Rebates
Heat Pump Rebates
Heating Equipment Rebates
Water Heater Replacement Rebates
Compact Fluorescent
Residential Air Conditioning Cycling
SERP -- Super-Efficient Refrigerator Program
Commercial/Industrial
Commercial and Apartment Building Conservation
Small I&C Rebates
DSM Bids from 1989 RFP
Green Lights
C.A.S.H. Rebates
Information
Energy Conservation Center
Conservation Van/Displays/Presentation
Low Income Workshops/Kits
DSM Seniors
Large I&C Custom Audits
DSM Information Programs
Youth Conservation

Table 2-2. PSE&G 1994 Expenditures and Savings

Program	1994 Expenditures $ (Millions)	Estimated Impact 1994 (MW)	Cumulative (MW)	1994 (GWh)	Cumulative (GWh)
Core Programs					
Residential					
A/C Cycling	10.61	21.56	74.50	N/A	N/A
Residential Rebates	6.85	6.43	73.82	5.46	59.50
Compact Fluorescents	2.39	7.84	15.59	15.52	21.55
Other	12.24				
Commerical/Industrial					
Small I&C Rebates	1.49	2.63	3.96	9.96	11.27
Other	1.06				
Information & Other	3.54				
Core Program Total	*38.18*	*38.46*	*167.87*	*30.94*	*92.31*
Performance-Based Programs					
DSM Standard Offer	0.97	8.62	8.62	14.01	14.01
Other DSM Bidding	6.15	8.51	28.55	99.38	166.35
TOTAL	**45.30**	**55.59**	**205.05**	**144.34**	**272.67**

PSE&G's DSM bids refers to those ESCOs that were selected in a 1989 all-source bidding solicitation. PSE&G received and accepted bids from eight ESCOs for slightly more than 50 MW. After accepting the bids, PSE&G entered into negotiations with the winning ESCOs and signed detailed contracts specifying timelines for the installation of the energy efficiency measures, penalty provisions for failure to install the measures, payments for the energy savings, measurement and verification protocols, etc. To date, PSE&G has received almost 29 MW of capacity reduction from the 1989 bidding program. So as to not disadvantage ESCOs that were participating in the bidding program, the Stipulation of Settlement approved by the New Jersey BPU allowed the winning ESCOs to abandon or transfer all or a portion of their uncommitted bid contract amount to the Standard Offer program (New Jersey BPU 1992). Several ESCOs exercised the option to terminate their contracts without penalty and are now participating in the Standard Offer program.

The origins of the Standard Offer program are rooted in PSE&G's dissatisfaction and the ESCOs concern with the 1989 all-source solicitation. Both the utility and ESCOs found that bid evaluation and contract negotiations were time-consuming and costly. The utility also found itself paying different amounts to ESCOs for energy savings, in some cases at prices that were very near its avoided supply cost. The utility was also concerned about the financial impacts of the DSM bids because, under the rules that were in place at the time the all source solicitation was issued, the utility was not allowed to earn financial incentive on the DSM resource savings or to recover net lost revenues. In May 1993, PSE&G issued the Standard Offer and has received nearly 9 MW in demand reductions that are in commercial operation through December 1994. As Table 2-2 shows, thus far, payments to project sponsors under the Standard Offer program have not been significant (<$1 million), primarily because payments are made over lengthy contract terms and because most projects are still under development. Assuming that currently approved projects actually develop, the annual financial payments to project sponsors for saved energy would be in excess of $7 million over a ten year period for the 40 MW of committed projects.

2.3 Program Evolution

Table 2-3 provides an overview of the evolution of the Standard Offer from design through various phases of implementation in three areas - regulatory, utility, and market activities - based on our analysis of significant events and milestones.

2.3.1 Program Design Process and Regulatory Approval

The program design and rules were the product of a consensus settlement involving major stakeholders, which was approved by the BPU and which of necessity involved compromises among the parties on several key issues: the role of the utility's energy services subsidiary, the allowed scope of utility program marketing, and the M&V protocols. In this section, we review the settlement agreement on the first two issues because of their relevance to the objectives of this evaluation; the M&V protocols are discussed in Section 2.4.

Role of Public Service Conservation Resources Corporation

Under the Stipulation of Settlement, PSE&G was allowed to participate directly in the Standard Offer program through a wholly owned subsidiary, PSCRC, which it incorporated and organized. The settlement agreement included an explicit statement of PSCRC's mission, objectives, and intended services. PSCRC's general mission "is to facilitate a viable and enduring performance based DSM marketplace in New Jersey" and its corporate objective is to increase "the efficiency of the service delivery system through standardization of contract terms and conditions" and performance standards for all aspects of projects (New Jersey BPU 1992). PSCRC agreed to develop a corporate structure that relies on third party firms to

Table 2-3. Program Chronology

	Regulatory	Utility	Market
(1) Program Design/Approval: (1992 - Early 1993)	• Negotiated settlement among parties approved by BRC (12/92) • Work on M&V protocols	• Utility forms PSCRC (1992) • Informational meetings for customers (early 1993)	• ESCOs that won 1989 RFP marketing to large C/I customers • PSCRC promotes Energy Service Network (ESN)
(2) Initial Program Implementation: (June 1993 - March 1994)	• BRC provides list of ESCOs to interested customers • Initial M&V protocols approved (6/93)	• Utility program managers provide only general information ("hands off" attitude)	• Several ESCOs marketing Standard Offer and '89 Bid • PSCRC as facilitator and financier
(3) Program Implementation: (April 1994 - December 1994)	• Minor program changes and clarifications approved by BRC • Pilot program extended	• Establish program specialists in 6 field offices • Provide customers with more specific assistance	• Energy Service Network problems cause several ESCOs to leave • PSCRC offers "Bright Investment" program for small C/I customers (5/94)
(4) Program Implementation: (January 1995 -)	• "Stay the course on DSM" while considering industry restructuring	• Utility re-organization and departure of key program staff • Planning for Standard Offer II; "re-engineering" of administrative process	• Increasing momentum and customer acceptance

directly implement the installation and service requirements of end-use equipment installed under the Standard Offer. PSCRC envisioned providing the following services:

- Capital investment services - purchase future electricity savings from PSE&G customers when they have developed projects under the Standard Offer using equity from PSE&G shareholders and debt acquired from outside lenders.

- Customer and DSM industry project facilitation - assist host customers in the identification and procurement of engineering design and construction management services from the DSM industry.[8]

PSE&G Marketing Activities under Standard Offer

The settlement agreement also discussed the scope of PSE&G's DSM marketing activities under the Standard Offer. PSE&G field marketing personnel were directed to promote general conservation awareness and were to forward the names of interested customer leads to the National Association of Energy Service Companies (NAESCO) who would make this information available to interested ESCOs for a fee. In response to customer inquiries regarding ESCOs, PSE&G field marketing personnel were to be instructed to direct customers to call the offices of the BPU in order to obtain a list of ESCOs (New Jersey BPU 1992).

2.3.2 Program Implementation

Based on our discussions with utility and regulatory staff and program participants, we can define three rather distinctive implementation phases of this pilot: (1) an initial ramp-up phase, which encompasses the period from June 1993 - March 1994, (2) a second phase from about April - December 1994 during which PSE&G made some changes to program marketing to overcome some initial problems and gained regulatory approval for minor program revisions; similarly, many ESCOs adjusted their marketing approaches and strategic alliances based on their initial experience promoting the program, and (3) the period since December 1994, during which marketing of the current program and planning for Standard Offer II are occurring in the midst of increasing competitive pressures within the electricity industry (as manifested by an internal re-organization within the utility and new regulatory initiatives) (New Jersey Energy Master Plan Committee 1994).

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8 PSCRC agreed to purchase any services from PSE&G at a fully loaded cost of service rate using standard cross charge accounting practices, which had to be reported to the BPU on an annual basis and were subject to independent audit.

- Throughout much of the implementation period, several winning ESCOs from PSE&G's 1989 competitive bidding solicitation were marketing this earlier program as well as the Standard Offer. The competing offers created some confusion among large C/I customers, which adversely affected market response to the Standard Offer.

- From June 1993 through about March 1994, in strict accordance with the settlement agreement, PSE&G program staff consciously limited their program marketing activities because of concern about influencing customers' access to and selection among competing ESCOs. During this initial period, PSCRC aggressively entered the energy services market. PSCRC provided financing for projects sponsored by other ESCOs or host customers and organized an Energy Services Network (ESN) in which it acted as a project facilitator attempting to guide customers towards other qualified third parties that were members of the ESN. Major problems arose in implementing the ESN and many of the original members dropped out after disagreements with PSCRC.

- In response to the market's initial slow response and confusion among customers, PSE&G made significant mid-course corrections in April 1994. PSE&G specialists in regional offices began to provide assistance to customers on specific program issues. PSE&G field representatives also began to market and promote the program more aggressively. ESCOs also revised their marketing strategies; as one example, PSCRC began promoting its "Bright Investment" program offering lighting efficiency improvements to smaller C/I customers.

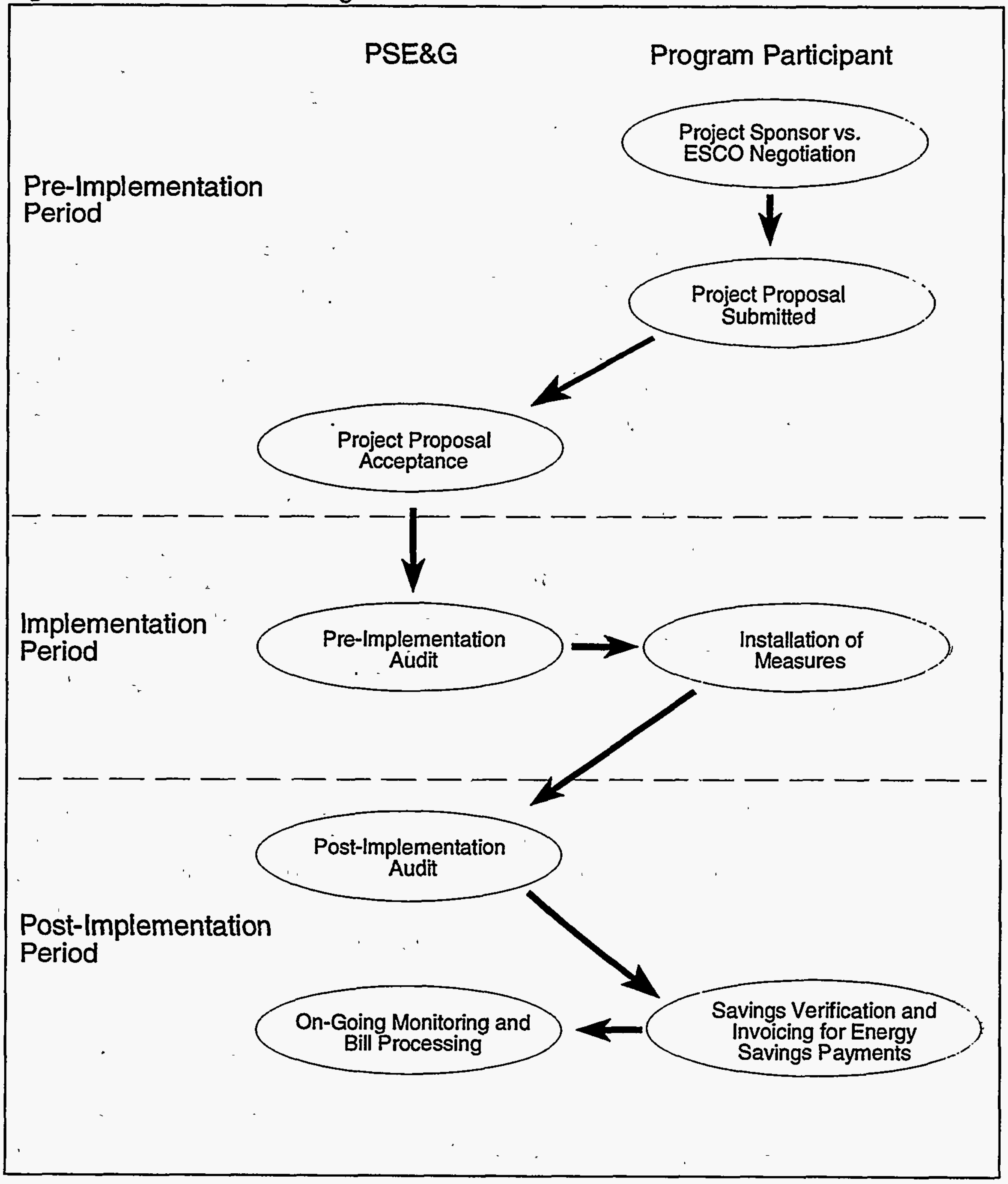
- By the end of 1994, there is evidence that the program is gaining increasing customer and market acceptance.[9] In late 1994, the BPU extended the pilot program to December 1995 while it considers broader issues related to industry restructuring. PSE&G completed an internal re-organization in early 1995, during which several key program staff left the utility. As part of its planning for Standard Offer II, PSE&G is reviewing and "re-engineering" its administrative processes.

2.4 Program Design: Key Features

During the various stages of development, program participants interact with PSE&G program staff on various issues (see Figure 2-1). Prior to participating in the Standard Offer program, customers must first decide whether to submit their project directly and accept the responsibilities, risks, and potential benefits of becoming a project sponsor or to work with an ESCO and negotiate an energy services agreement. The next step is for either the

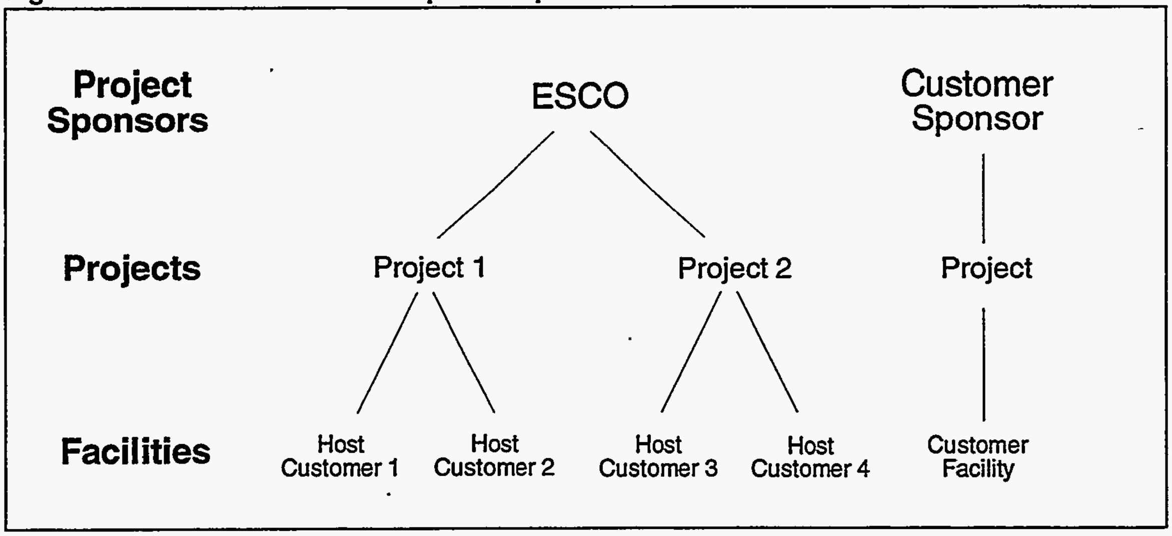
[9] Based on the monthly program reports, we observe significant increases in the number of new projects submitted and the associated demand reductions.

Figure 2-1. Standard Offer Program Process



customer sponsor or ESCO to submit a project proposal to PSE&G, which details the project technologies; estimated energy savings; operation and maintenance (O&M) plan; various types of costs associated with the project; and information on the life of the energy saving measures. After receiving approval from PSE&G, the project sponsor is then responsible for installing and maintaining the measures, implementing the agreed-upon M&V plan, verifying

Figure 2-2. Standard Offer Participation Options



the savings associated with the project over the contract term, and submitting bills to PSE&G for payment under the program.

Utility program staff review proposals submitted by project sponsors, perform an initial cost-effectiveness analysis to ensure that projects pass the Total Resource Cost test, negotiate savings verification agreements based on the standard protocols, verify key factors that influence estimates of energy savings by conducting pre- and post-implementation audits (e.g., verify fixture count, check baseline and post-retrofit equipment efficiency, test for changes in lighting levels), and approve payments for delivered savings.

Figure 2-2 shows the nomenclature and relationships between project sponsors and host customers and their facilities in the program. Project sponsors, either ESCOs or customers, propose projects to PSE&G that meet minimum size requirements (e.g., 100 kW for existing buildings) and can propose additional projects as long as the program remains open and the 150 MW block size is not filled. An ESCO-sponsored project will typically involve multiple host customer facilities.

2.4.1 Standard Contract and Payment Options

PSE&G offers a standard contract that includes time-differentiated payments for electricity savings, which are directly tied to their value to the utility. Program participants have the option of receiving unlevelized or levelized prices for their energy savings (see Table 2-4). For example, for a ten-year project coming on-line in 1994, levelized payments would be about 17.8 cents/kWh during the summer prime period, 4.8 - 5.4 ¢/kWh during the on-peak periods of each season, and 2.9 - 3.5 ¢/kWh during the off-peak periods of each season. By

Table 2-4. PSE&G Standard Offer Pricing Provisions

Unlevelized Prices for the Standard Offer Program							
Year	Summer Prime (¢/kWh)	Summer Peak (¢/kWh)	Summer Off-Peak (¢/kWh)	Spring/ Fall Peak (¢/kWh)	Spring/Fall Off-Peak (¢/kWh)	Winter Peak (¢/kWh)	Winter Off-Peak (¢/kWh)
1993	12.10	3.16	1.64	2.43	1.76	2.66	1.85
1994	12.82	3.63	1.80	3.13	2.14	3.59	2.34
1995	15.13	3.98	2.01	3.40	2.26	3.71	2.41
2000	20.68	6.59	3.74	6.00	4.24	5.81	4.30
2005	27.64	9.97	6.06	9.32	6.92	9.07	6.96
2010	33.97	12.19	8.83	10.96	9.40	10.65	9.62
2015	44.97	17.68	13.32	15.85	13.67	15.34	14.02
Levelized Prices for the Standard Offer Program (for projects beginning in 1994)							
Contract Term	Summer Prime (¢/kWh)	Summer Peak (¢/kWh)	Summer Off-Peak (¢/kWh)	Spring/ Fall Peak (¢/kWh)	Spring/Fall Off-Peak (¢/kWh)	Winter Peak (¢/kWh)	Winter Off-Peak (¢/kWh)
5-Year	15.58	4.36	2.28	3.80	2.61	4.06	2.75
10-Year	17.86	5.37	2.94	4.83	3.37	4.95	3.50
15-Year	19.77	6.24	3.58	5.66	4.05	5.69	4.18

contrast, if a project sponsor chose the unlevelized payment option, payments would escalate over the term of the contract, although the net present value of the two payment streams would be comparable (using the utility's discount rate of 11.2%). Project sponsors sign 5-, 10-, or 15-year contracts with the utility.

When ESCOs market the Standard Offer program to customers, the pre-specified, fixed payments effectively serve to reduce the payback time for any retrofit project under consideration that can meet established M&V requirements. The program concept also assumes that ESCOs will bundle the incentive offered by utilities with other services that customers either value or require in order to overcome barriers that inhibit investments in energy efficient equipment (e.g., upfront financing for project, performance guarantees, technical expertise and information on the most appropriate technologies and design). For customer sponsors, the program concept implicitly assumes that the failure of a project to meet a customer's financial hurdle rate is the dominant factor inhibiting the investment.

2.4.2 Target Market, Program Size, and Eligibility Requirements

The program block size was set at 150 MW of summer prime period average demand reduction (SPPADR) to be delivered by December 31, 1995.[10] The Standard Offer program has relatively few eligibility requirements compared to most DSM bidding programs (see Table 2-5). The program allows project sponsors to propose a wide variety of DSM measures, including strategic conservation, load shifting, and fuel-switching options, subject to the condition that the economic lifetime of the measures must be at least five years and that the savings can be satisfactorily measured under the program's M&V requirements. The program is open to commercial, industrial, and residential customers, but has a minimum size requirement for projects of 100 and 50 kW of SPPADR for existing and new buildings, respectively. Thus, as a practical matter, only large commercial and industrial (C/I) customers have the option of directly sponsoring projects, while smaller C/I and residential customers must work with a third party sponsor that aggregates jobs from individual facilities.

2.4.3 Contract Provisions and Performance Requirements

While the eligibility criteria are minimal, the Standard Offer contract provisions, by contrast, are more extensive (see Table 2-5). Project sponsors assume significant performance risks and are liable for penalties for non-delivery of energy savings by the agreed-upon installation date and under-performance (i.e., for not maintaining 80 percent of the forecast demand reductions expected to occur in the summer prime period). Given these transaction costs and performance risks, some large customers prefer to have ESCOs assume the responsibilities of project sponsor.

In addition to the $1/kW submitted with the project proposal, project sponsors must establish a liquidated damages fund (about $73/kW), which they lose if their projects fail to come on-line within three months of the commercial operation date. Project sponsors also must post security if they choose the levelized payment option and meet PSE&G's minimum insurance requirements. After commercial operation, project sponsors will incur penalties if they deliver less than 80% of the committed summer prime period kWhs.

In terms of program administration, PSE&G requires project sponsors to pay the utility $10/kW per year initially for administrative expenses. This amount is trued up to reflect the actual specific and general administrative costs incurred by each project sponsor over the contract term; thus it could, in actuality, be much higher or lower. PSE&G also has the option of conducting site visits and audits prior to and during implementation of the project,

10 Under the settlement agreement, 15 MW were pre-committed to ESCOs participating in the residential market under the electric Standard Offer, although only recently (April 1995) has an ESCO taken advantage of this option.

Table 2-5. Standard Offer Program Description

Program Goals	150 MW to be submitted by December 31, 1995
Administrative Budget	• $1,900,000 for PSE&G's advertising campaign • $300,000 for direct promotion of the Standard Offer Program and development of measurement & verification protocols
Eligibility Criteria	
Eligible Measures	Energy efficiency equipment (e.g., lighting, cooling, heating, etc.), including load shifting and fuel switching equipment; for new construction, measures that exceed prespecified standards
Location	In PSE&G's service territory and must receive (or will receive for new construction) retail electricity service from PSE&G
Demonstrated Life	At least 5 years
Cost-Effectiveness	Each project proposal, in total, must pass the Total Resource Cost test
Minimum Acceptable Proposal	• 100 kW of Summer Prime Period Average Demand Reduction (SPPADR) and 12,500 therms of Peak Period Therm Reduction for existing construction • 50 kW of SPPADR and 6,250 therms of Peak Period Therm Reduction for new construction
Contract Provisions	
Initial Security	$1/kW must be submitted with each project proposal
Contract Length	5-, 10-, and 15-year contracts
Contract Payments	Levelized and unlevelized payment (see Table 2-3)
Payment Tracking Account	If project sponsors receive levelized payments, they must secure the amount that they are paid above the amount they would have received had they chosen unlevelized payments
Replacement Capacity Costs	(0.80 - (SPP kWh Delivered/SPP kWh Committed)) x (SPP kWh Committed/ SPP Hours) x PJM Capacity Deficiency Rate (~ $73/kW)
Liquidated Damage Fund	One-half of the PJM Capacity Deficiency Rate per kW of SPPADR for each host facility at time of execution and the other half about 5 months prior to the in-service date
Liquidated Damages	PSE&G receives liquidated damages if project sponsor fails to achieve commercial operation within 3 months after the in-service date for a host facility; if project sponsor achieves commercial operation by the in-service date, the liquidated damages associated with the host facility are returned
Administrative Service Charge	$10/kW/year, trued up to actual administrative expenses incurred
Monitoring	PSE&G shall conduct a pre-implementation, implementation, and up to 15 post-implementation audits per facility, at the project sponsor's expense
Insurance	PSE&G specifies minimum insurance requirements (e.g., project sponsor shall maintain comprehensive personal injury and property damage insurance)
M&V Requirements	See Table 2-6

as well as up to 15 post-implementation audits at each facility. The costs of these audits and site inspections are also charged to the project sponsor.

2.4.4 Measurement & Verification Protocols

The program has as an explicit design objective that DSM resources should be as reliable as supply-side resources to the extent feasible. There are standardized verification protocols for monitoring various types of retrofit applications (see Table 2-6). For example, one protocol covers constant load, constant operating hours, non-weather sensitive end uses such as lighting system conversions and constant-load motors and typically involves continuous metering of hours of operation. The M&V protocol specifies that PSE&G and the project sponsor must agree on a savings verification agreements at an individual facility for certain measures with approved protocols and for new applications that don't have protocols (e.g., system and process improvements). These agreements must also be approved by the staffs of the BPU and Division of Ratepayer Advocates (i.e., the consumer advocate).[11] In Chapter 7, we review and critique PSE&G's M&V procedures and sampling plan in more detail.

2.5 Comparison of Standard Offer Concept to DSM Bidding and Customized Rebate Programs

Because the Standard Offer concept is a new way to deliver DSM resources, it is useful to compare it with alternative program designs that are often targeted at large C/I customers, such as customized rebate and DSM bidding programs (see Table 2-7). The Standard Offer concept combines elements of these two other approaches. In both customized rebate and Standard Offer programs, eligible customers participate on a "first come, first serve" basis, subject either to a program budget constraint or a limit on resource block size, based on standard contract terms and conditions. However, the agreement between a utility and customer is typically quite short (1-2 pages) in a customized rebate program with limited performance requirements compared to the Standard Offer. In a customized rebate program, customers typically propose one or more measures at their facility based on an audit.[12] The utility must approve the project and customers receive a one-time incentive payment (which is often capped at a percent of project costs or a ¢/kWh limit) upon verification of installation.

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11 PSE&G and the project sponsor have the option of presenting any proposed protocols that are not approved by BPU and Division of Ratepayer Advocates staff to the Commissioners for final resolution.

12 Customized rebate programs are designed to encourage customers to propose and install site-specific applications that are not easily covered by rebates for individual products.

Table 2-6. Summary of Standard Measurement and Verification Protocols for C/I Sector

	kW Baseline Connected Load	kW Post-Installation Connected Load	Hours of Operation or kWh
Commercial & Industrial			
Method 1:			
Measures Affecting Constant Load, Constant Operating Hours, Non-Weather Sensitive End Uses -- Lighting	Obtain from Luminare Wattage Tables	Obtain from Luminare Wattage Tables or from actual measured kW of installed luminaries	Meter run time after measure installation on all or sample of individual devices or control circuits • Energy savings shall be in proportion to light level reductions • 5% credit where lighting measures are installed in conditioned space
Measures Affecting Constant Load, Constant Operating Hours, Non-Weather Sensitive End Uses --Motors	For simple replacements, use either manufacturer's performance curve or nameplate efficiency coupled with derating table; or for system improvements, conduct recording wattmeter measurements	Measure load on each new motor or sample of motors continuously or over a representative time period	Meter run-hours or kWh on each individual motor or on a sample of motors
Method 2:			
Measures Affecting Operating Hours of Constant Load, Non-Weather Sensitive End Uses (e.g., Automatic Controls)	NO STANDARD PROTOCOL DEVELOPED		
Method 3:			
Measures Affecting Variable End Use Requirements (e.g., motors, VSDs, process improvements, HVAC affected by weather)	Conduct wattmeter measurements, measure system output over the same time, and develop load curves		1. Measure output and electrical input continuously and compute savings as difference between post-installation electrical input and electrical input predicted by pre-installation load curve 2. Establish post-installation load curve from measured results and use these two curves to determine savings
Method 4:			
Other Technology Specific Measurement Methodologies			
Method 4A: Thermal Storage	PROTOCOL DEVELOPED, BUT NO INSTALLED MEASURES		
Method 4B: Heat Recovery	NO STANDARD PROTOCOL DEVELOPED		
Method 4C: Energy Management System	NO STANDARD PROTOCOL DEVELOPED		

Figure 2-7. Comparison of "Typical" Programs

Feature	Customized Rebate	Standard Offer	DSM Bidding
Resource Need	Defined implicitly by program budget cap	Limit on resource block size	Resource block size range
Eligible Participants	Large customers	Large customers & third parties	Third parties & large customers
Program Selection Criteria	First-come, first-serve; some target marketing by utility field reps & vendors	"First-come, first-serve"	Utility selects winning bids, based on bid evaluation criteria; customers targeted by winning bidders
Financial Incentive	One-time, up-front rebate (paid after installation); often capped at % of project cost, or ¢/kWh, or payback criterion	Fixed payments over contract term (time-differentiated based on value of savings to utility)	Based on bidder's price
Terms & Conditions (Scope)	Standard (Limited)	Standard (Comprehensive)	Negotiated, based on sample contract (Comprehensive)
Performance Requirements	Maintain equipment to provide energy-related benefits for specified period (e.g., 5 years)	Sponsor must verify savings over contract term; penalties for non-performance	Bidder typically verifies savings; penalties for non-performance negotiated in contract
Performance Monitoring	Impact evaluation	Standardized protocol	Utility M&V guidelines; bidder M&V plan approved utility

The Standard Offer extends incentive payments over the economic lifetime of the measures with payments linked to verified savings. DSM bidding and Standard Offer programs are similar in that they have comparable performance requirements and contract terms and conditions. However, in DSM bidding, financial incentives are not pre-specified and the utility screens and selects third-party providers, who, in turn, target customers as they see fit within the assigned market segment.

For us, the major implications are as follows: (1) the utility has relatively more influence in determining preferred providers in DSM bidding compared to either the Standard Offer or customized rebate programs where customers have sole responsibility for judging the technical competence, experience, and track record of service providers; (2) both Standard Offer and DSM bidding programs effectively shift performance risk to DSM developers and away from ratepayers, but the cost premium can be significant compared to customized rebate programs (~1.0-2.5 ¢/kWh); (3) compared to DSM bidding, the Standard Offer concept is more attractive to many ESCOs and large customers because development risks are lower because potential bidders may not recover their initial up-front project development and marketing costs if their bid is not accepted by the utility; and (4) with comparable financial incentives, customized rebate programs are likely to achieve greater market penetration than the other two approaches although persistence of savings is more uncertain.

Program Impacts: Market Response

3.1 Overview

This chapter assesses market response to the Standard Offer program over the first 18 months of its field operation (June 1993 - December 1994). During this period, PSE&G approved projects representing about 40 MW of summer prime period average demand reduction (SPPADR)[13] of which 9 MW are operational, which is significantly less than the original program target of 150 MW of savings in two years. We report on activity levels of various market participants (e.g., PSCRC, other ESCOs, and customer sponsors), savings in various market sectors, and the distribution and types of measures installed. PSE&G's energy services subsidiary, PSCRC, has sponsored projects representing about 43 percent of the committed savings for the program. In a relatively short time (i.e., less than three years), PSCRC has become a significant player in the energy services market in PSE&G's service territory. Thus far, various lighting and fuel switching measures account for the bulk of savings from the program (66% and 17%, respectively). Furthermore, our review of the types of projects that have been approved as well as the work of others (Gordon et al. 1994) suggests that the Standard Offer program design works better in situations where customers are planning to replace equipment or considering discretionary retrofit and early replacement of functional equipment than in situations where equipment fails and decisions must be made quickly or on short notice.

Comparing the market response of the Standard Offer program with utility-sponsored studies of the economic potential for DSM, we found the market response to be less than 5 percent of the estimated economic potential in most target markets and end uses. Assuming the program design and incentive payments remain at current levels (which appears unlikely given PSE&G's forecast of lower avoided supply costs), the program could continue at its present pace for at least the next 4-5 years, primarily capturing lighting opportunities, although market penetration would have to increase in sectors that have typically been difficult to penetrate (e.g., large office buildings that are not owner-occupied). In Chapter 9, we suggest changes to the program's design that could enhance PSE&G's ability to achieve the original program goals (~75 MW/year) even under less favorable market conditions.

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13 Summer Prime Period Average Demand Reduction is defined as the total kWh saved during the summer prime period divided by the total number of hours (430) in the Summer Prime Period. The Summer Prime Period includes the weekday hours between 12 noon and 5 p.m. from June 1 to September 30, except holidays.

Table 3-1. Distribution of Projects by Sponsor Type

Sponsor Type	Number of Facilities	Committed Projects: Connected Load Savings (MW)	Committed Projects: SPPADR (MW)	Commercial Operation: SPPADR (MW)
ESCOs (excluding PSCRC) (14)	94	24.5	15.1	1.8
PSCRC	146	16.2	10.7	4.9
PSCRC -- Bright Investments	782	7.1	7.1	2.4
Customer Sponsors (19)	34	12.4	7.2	0.2
TOTAL	1,056	60.2	40.1	9.3

3.2 Market Response

Table 3-1 provides summary statistics on committed projects and projects in commercial operation that have been approved by PSE&G through December 31, 1994, including the number of facilities and the associated reductions in connected load and summer prime period demand. We have grouped projects by type of sponsor (ESCOs vs. customer sponsor) and show PSCRC's activities separately from other ESCOs. Committed projects include all projects submitted by sponsors to PSE&G, which are in various stages of development (i.e., pre-implementation, under construction, commercial operation). Projects that are in commercial operation represent a subset of committed projects that are providing delivered savings to the utility. Unless otherwise noted, summary statistics reflect SPPADR for committed projects.

Through December 1994, over 1,050 facilities have been involved in the program, representing about 60 MW of committed connected load savings. PSE&G has received commitments for about 40 MW of SPPADR, of which about 9 MW are on-line. The fact that only 9 MW are operational roughly eighteen months into the program is indicative of the long project development times compared to a typical utility rebate program. The market response is significantly less than the original program target of 150 MW of SPPADR in two years. However, the original program target was probably somewhat unrealistic, at least based on the experience of other utility programs that have required customers to sign long-term, performance-based contracts (e.g., DSM bidding programs). The market response to the Standard Offer compares favorably with most DSM bidding programs, assuming that almost all submitted projects proceed and become operational.[14] Direct comparisons of market response are difficult because, in bidding programs, the utility selects a limited number of ESCOs who then must meet individual contract demand reduction goals. In contrast, the number of potential competing firms is limited only by the market in the Standard Offer, while the quantity constraint is program-wide. However, from a customer's decision-making perspective, the performance risks associated with the proposed deals by ESCOs in DSM bidding and Standard Offer are comparable compared to the risks that customers typically assume in utility rebate programs.

Figure 3-1 provides additional detail on the status of submitted proposals. Of the project proposals submitted, PSE&G has conducted initial cost-effectiveness screening on, and sent project acceptance letters to about 38 MW of projects, while projects representing about 25 MW have received pre-implementation audits.

By almost any measure, PSCRC has played a significant role in the market. As a project sponsor, PSCRC accounts for about 43 percent of the SPPADR from committed projects, with almost 80 percent of the savings from projects that are in commercial operation. PSCRC has been active in both large and small C/I markets, where its Bright Investment program promotes lighting efficiency options to customers with projects that save less than 50 kW per facility. PSCRC has also provided construction and permanent financing to many of the other ESCOs and several customer sponsors. While it is not possible to give a precise answer, based on our interviews with ESCOs and customers, it appears that PSCRC may be providing some type of financing for 60 to 70 percent of the projects.

Table 3-2 summarizes information on average savings at individual facilities for ESCOs' host customers and customer sponsors. Summer prime period demand savings average about 9 kW among participants in the Bright Investment program sponsored by PSCRC. In the large C/I market, the average reduction per facility in SPPADR is about 50 percent higher for customer sponsors compared to host facilities that are using ESCOs (210 vs. 107 kW). This result is not surprising because projects sponsored by customers initially had to offer at least 200 kW in savings (but subsequently lowered to 100 kW) to meet the minimum threshold requirements, while ESCOs typically aggregate jobs at individual customer facilities to meet minimum project sponsorship size requirements. A few ESCOs have submitted projects that far exceed the minimum requirements, which explains why the standard deviation in average savings is twice as large as the mean value.

14 We believe that there is a high probability that almost all projects that have passed PSE&G's initial cost-effectiveness screening (about 38 MW) will be developed because of the significant time and up-front investment involved in proposal development and because of the contractual commitments between ESCOs and host customers.

Figure 3-1. Project Status

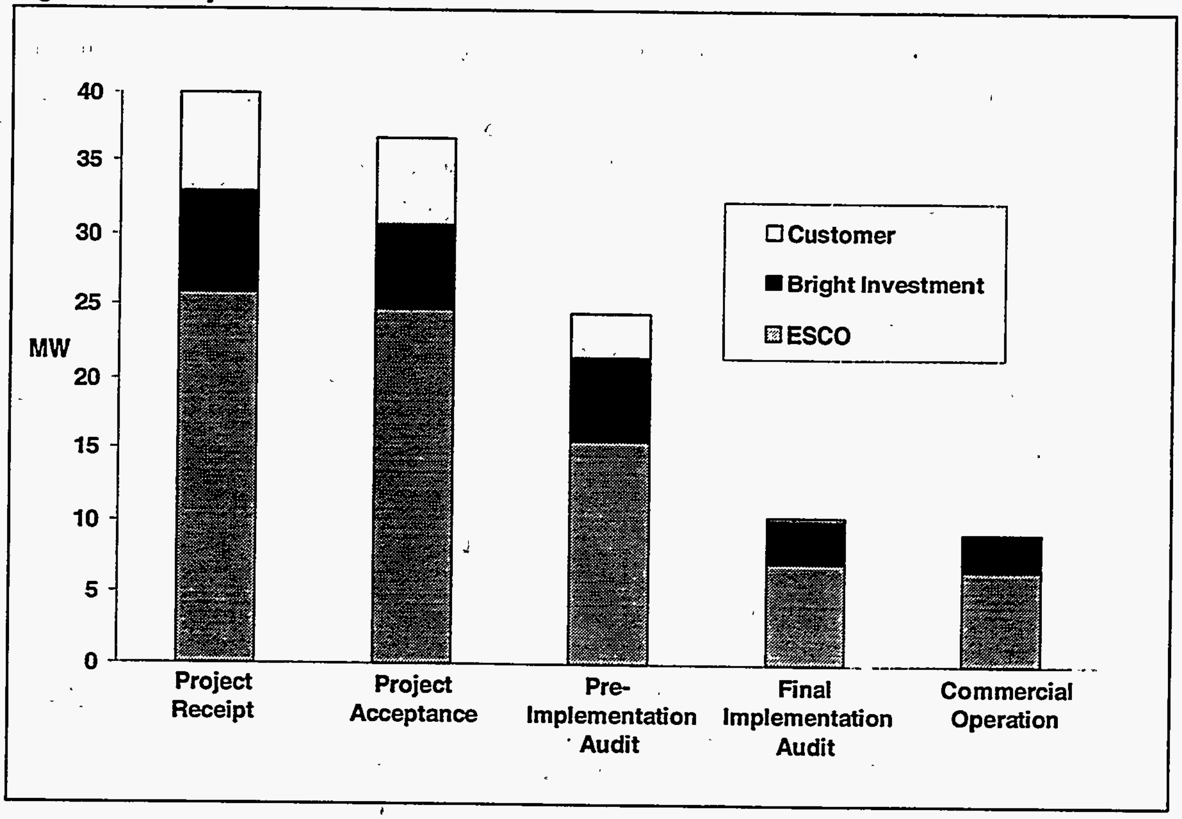


Table 3-2. Average Savings at Individual Facilities

Market Sector	No. of Facilities	Average Savings per Facility SPPADR ± Std. Dev. (kW)			Annual Electricity Savings (GWh)
ESCOs	240	107.4	±	251.6	619.7
Bright Investment	782	9.1	±	10.3	33.7
Customers	34	210.3	±	188.6	1,246.4
TOTAL	1,056				

3.2.1 Distribution of Savings by Sector

Theoretically, customers from all classes can participate in the Standard Offer Program, subject to meeting the minimum size requirements for project proposals of 100 kW and 50 kW of SPPADR for existing and new construction respectively.[15] As a practical matter, because of the threshold size requirements, residential and small C/I customers must participate through third party sponsors. Thus far, about 98 percent of the committed savings are retrofits of existing commercial/industrial facilities with about 2 percent of the activity in C/I new construction.

Projects have been submitted at 10 new facilities for less than 1 MW of SPPADR. These facilities, representing about 600,000 square feet of floor space, include several small industrial plants, an office building, a church, and a large hardware store. Thus far, project sponsors have installed only lighting measures in new construction. PSE&G staff claim that there has been little new construction occurring in the service territory but were unable to provide estimates of the amount of new floor space added in 1993 and 1994, so we were not able to estimate market penetration rates. By way of comparison, utilities considered to be national leaders in DSM (e.g., New England Electric System, Pacific Gas & Electric) report that annual market penetration for their new commercial/industrial construction programs ranges from about 25-35 percent of the new floor space under construction.

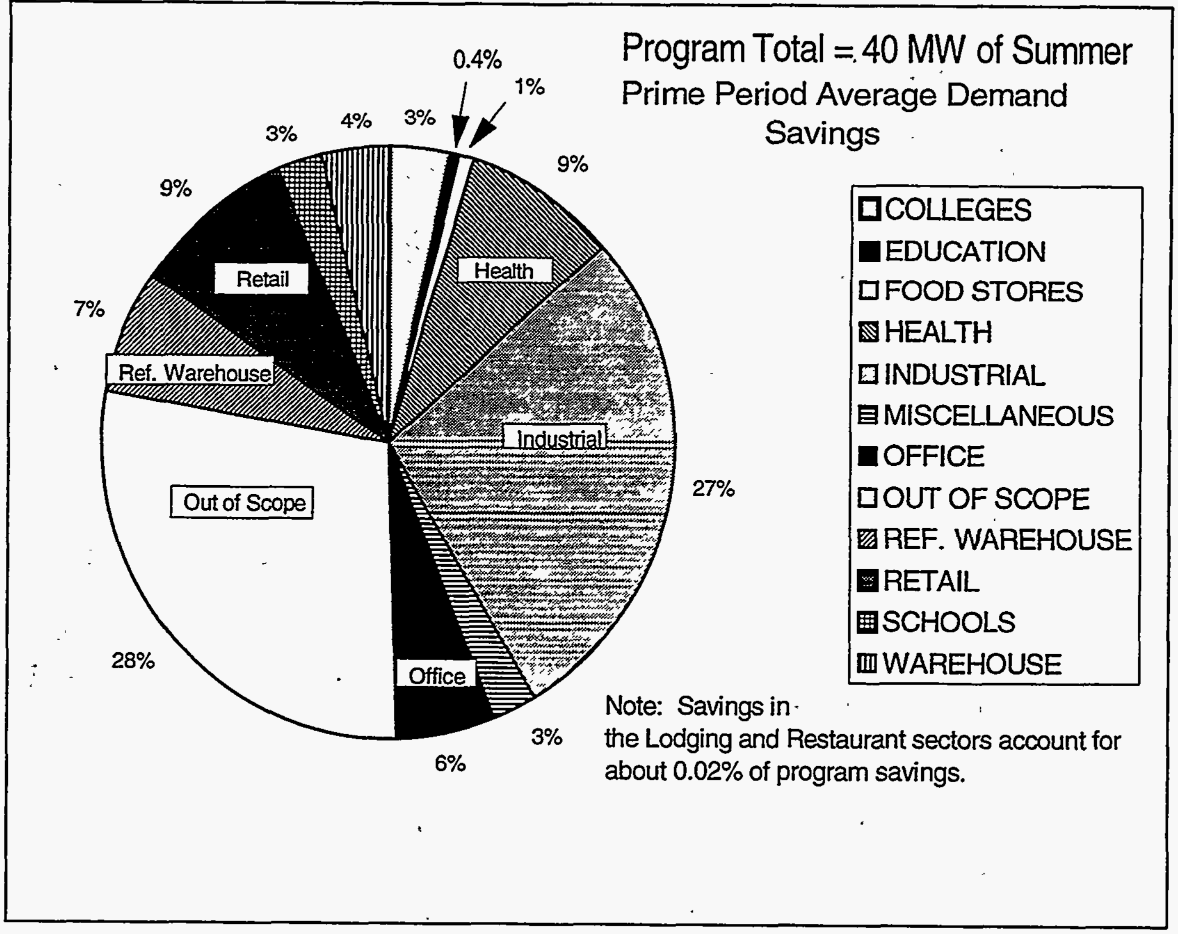
The lack of activity in the residential sector is not surprising given the transaction costs and risks involved for third parties and the existence of many PSE&G "core" programs that are targeted at this market.[16]

In Figure 3-2, we show SPPADR for projects in thirteen target market sectors. We mapped the SIC codes reported by each project sponsor into thirteen market segments based on building types used in a commercial/industrial forecasting model (COMMEND) developed

15 Sponsors can also submit proposals involving gas savings with the minimum size requirements of 12,500 and 6,250 therms of peak period therm reduction for existing and new construction respectively. However, no projects that involve gas savings have been submitted.

16 However, in April 1995, PSE&G approved its first contract under the Standard Offer for an ESCO targeting residential customers, although no savings have been delivered.

Figure 3-2. Savings by Target Market



by EPRI (1988).[17] The linkage between SIC codes and building types provides a rough first cut at segmenting the commercial market.[18]

By far, the largest categories are "out of scope" and "industrial" accounting for about 28 percent and 27 percent respectively of SPPADR. "Out of scope" is a catch-all category that includes SIC codes for which building types are not defined. These include research/testing labs, transportation, and trucking businesses, and sanitary facilities. "Industrial" includes

17 Building types are assigned to business locations on the basis of structural characteristics, end-use equipment, operating characteristics, and occupancy patterns.

18 SIC codes represent the line of business or type of good or service provided by a business or government entity and can be crudely linked to the building type/market segment concept. The limitations of linking and mapping SIC codes to building types are: (1) many building types may be used within a particular line of business (e.g., manufacturing firms that have production, office, and warehouse space), and (2) particular building types (e.g., offices) may be used by a wide variety of industries (EPRI 1988). EPRI recommends that actual site data on building type should be used over SIC codes whenever this information is available.

facilities of various types of manufacturing firms (e.g., plastics, chemicals, pharmaceutical companies, paper and allied products, textiles, and fabricated metals).

Roughly two-thirds of the savings for projects in these two sectors come from lighting measures, and one-third from other measures. For the non-lighting measures, we are fairly confident that, in most cases, industrial plants and facilities are being retrofitted because of the types of measures installed. However, for lighting measures, a facility-by-facility analysis would be required to determine whether retrofits are occurring in corporate headquarter offices or manufacturing plants, because SIC code information reported by project sponsors does not allow us to distinguish between headquarter offices and factories. Compared to the C/I DSM programs of many other utilities, the Standard Offer seems to have been relatively successful in getting industrial customers to participate. This is attributable in part to the demographic characteristics of PSE&G's service territory, which includes a sizeable industrial load (~25% of total sales). Industrial customers have also been heavily marketed by ESCOs, particularly with respect to lighting efficiency opportunities, and a number of large industrials have become project sponsors. Warehouses (including refrigerated warehouses), health care and retail facilities have each accounted for about 3-4 MW of savings (8-9% each). The market penetration in office buildings is quite low at 2.2 MW (6% of total program savings), but apparently reflects barriers associated with the Standard Offer design.[19]

Table 3-3 provides summary information on the size range for individual facilities in the large C/I and new construction markets as well as the Bright Investment program. The typical (i.e., median) facility size in the large C/I market is about 100,000 sq. ft., although the average is significantly higher (about 250,000 sq. ft.) because of a few very large sites with multiple

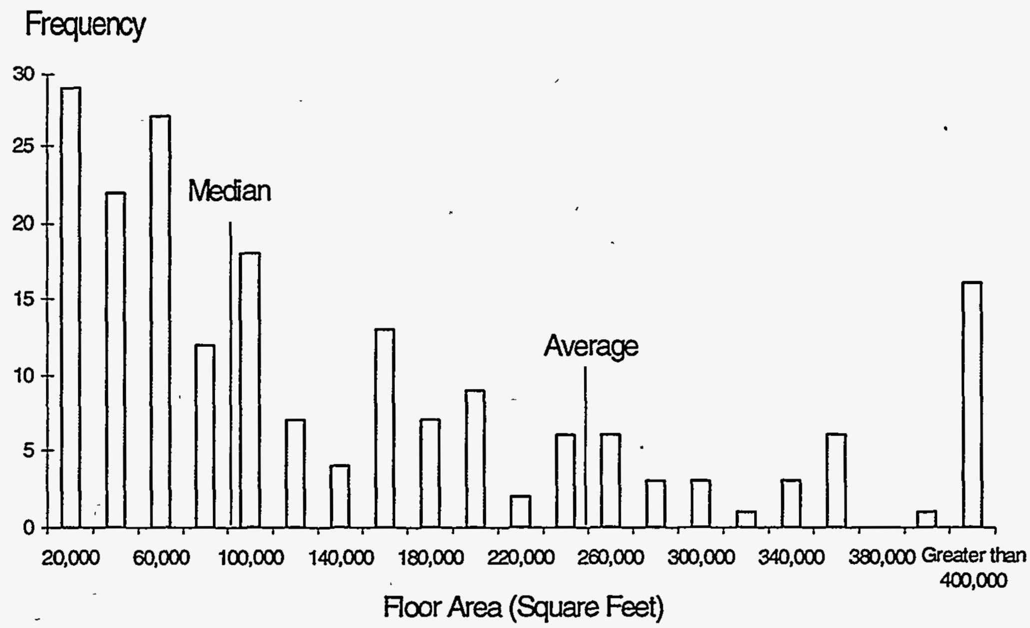
Table 3-3. Average Floor Area of Facilities in Various Market Sectors (Sq. Ft.)

Market Sector	Average	Median	Minimum	Maximum
Large C/I (195/264)†	246,164	96,700	1,400	19,000,000
Bright Investment (774/782)	18,606	5,800	400	820,000
New Construction (8/10)	73,108	60,203	50,000	114,195

† Numbers in parentheses refer to the number of facilities that reported floor area compared to the total number of facilities in market sector.

19 See Xenergy 1994. Owners of tenant-occupied buildings are wary of the long contract terms, which typically exceed tenant leases, and penalty provisions that may be invoked if existing tenants leave and savings do not persist.

Figure 3-3. Distribution in Floor Area for Large Commercial/Industrial Customers

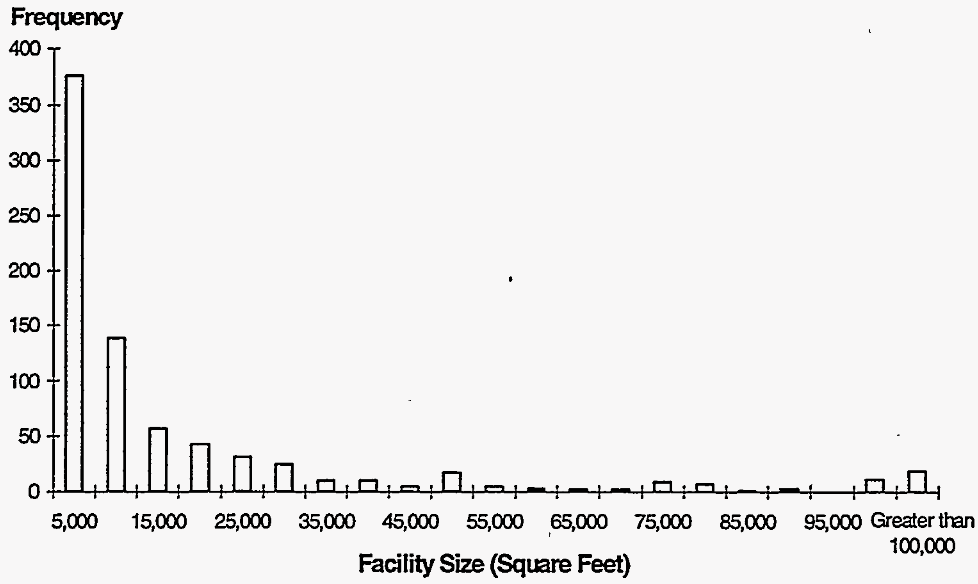


facilities. Figure 3-3 shows the distribution in floor area for the 195 facilities in the large C/I retrofit market that included this information; 15 facilities exceed 400,000 sq. ft.[20]

We were somewhat surprised to find about 25 relatively large facilities (i.e., >100,000 sq. ft.) that are participating in the Bright Investment program (see Figure 3-4). These include several elementary and high schools, a few warehouses, commercial office buildings, and various types of industrial manufacturing facilities (e.g. apparel, paper products, paint/glass). Recall that the M&V requirements are more lenient for facilities that save less than 50 kW because each facility in a project does not have to be monitored and that the Bright Investment program offers only lighting measures. Thus, we are concerned that the combined effects of the way in which the M&V requirements are specified and PSCRC's marketing strategy may inadvertently be encouraging partial retrofits. For example, assume that a customer owns a large facility that has cost-effective retrofit savings opportunities in several end uses which together with lighting exceed the 50 kW savings threshold. In the worst case,

20 It is important to note that the floor area reported for a particular facility is partly dependent on the way that the project sponsor develops and submits the project. For example, subject to meeting the threshold requirements on minimum savings, a large university may submit separate proposals for improvements in various buildings or it may bundle the entire package together.

Figure 3-4. Distribution in Floor Area for Bright Investment Customers



the customer chooses to participate in the Bright Investment program and receives only a lighting treatment, foregoing the other opportunities, either because they want to minimize their performance risks or are unaware of other options under the Standard Offer program. We discuss possible ways to revise program requirements to minimize these type of occurrences in Section 9.5.4.

3.3 Types of Measures Installed

Roughly 66 percent of the program savings come from lighting projects or about 26 MW (see Figure 3-5). Table 3-4 shows the distribution of lighting measures installed under the program, grouped into various categories: T-8 lamps with electronic ballasts (76%), conversion of inefficient fluorescent and mercury vapor lighting to metal halide or high pressure sodium lights (12%), T-12 lamps with electronic ballasts (7%), compact fluorescents (3%), high-efficiency exit signs (0.5%), and a few applications using incandescent lamps.

Electric-to-gas fuel substitution accounts for another 17 percent of the SPPADR. Virtually all of the fuel substitution measures involve conversions of space and water heating equipment (e.g., replacement of electric boilers with gas units), cooking equipment, or change-outs to

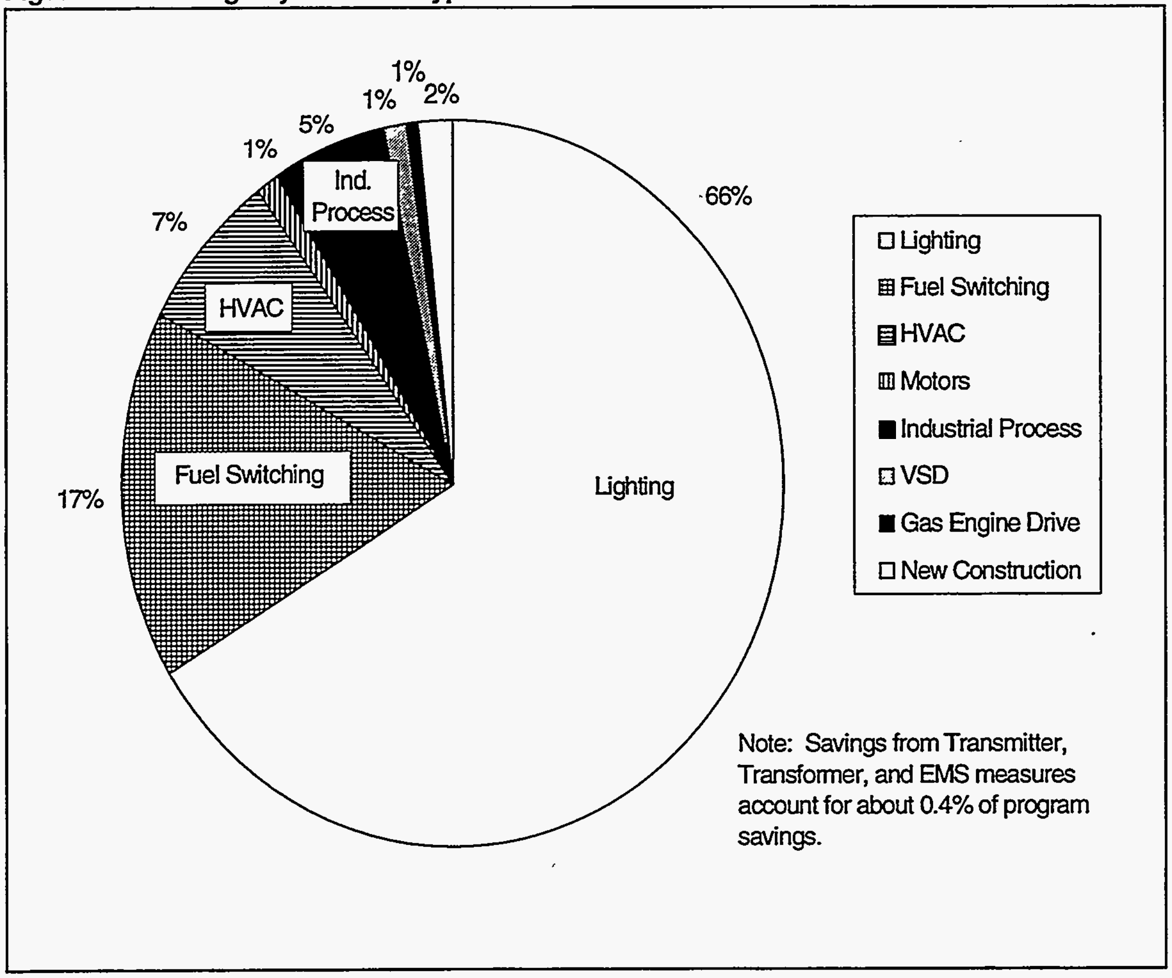
Table 3-4. Breakdown of Installed Lighting Measures

Category	SPPADR (MW)
T-8/Ballast	19.79
T-10/Ballast	0.07
T-12/Ballast	1.74
Compact Fluorescent	0.86
Halogen	0.13
High-Efficiency Exit Signs	0.12
Metal Halide	1.20
High Pressure Sodium	1.93
High Efficiency Incandescent	0.03
Quartz	0.02
TOTAL	25.77

industrial processes, rather than chiller conversions. HVAC measures account for about 7 percent of SPPADR. Applications include replacement of rooftop units, new chillers, and adding variable air volume (VAV) systems to ventilation equipment. Energy management control systems (EMCS) for HVAC applications were noticeably absent in the program. There are not yet approved M&V protocols for EMCS, primarily because of the complexity of measurement issues and the variability in savings in site specific applications. Various types of industrial process retrofits (5%) and motors and variable speed drive applications (1% each) account for the remaining measures. There appear to be significant opportunities for various applications of variable speed drives, some of which are starting to occur through the Standard Offer program. These include industrial process applications, HVAC fans, boiler draft fans and feedwater pumps, and municipal waste water pumping.

The Standard Offer program does not appear to have significantly affected the market share for high-efficiency motors in the PSE&G service territory. Thus far, high-efficiency motors account for only about 450 kW of SPPADR (~1% of total program savings). About 75 percent of the savings come from motors that exceed 100 HP. Table 3-5 shows the distribution of high-efficiency motors installed through the Standard Offer program by size range, the average efficiency of current and proposed motors for each size range, and the SPPADR for each size range. High-efficiency motor applications have occurred in several hospitals, refrigerated warehouses, and a plastics manufacturing facility. Various studies and

Figure 3-5. Savings by Measure Type



market research on motors conducted by utilities suggests that the majority of the potential savings from replacing motors are in relatively smaller units, less than 20 HP (Nadel et al. 1992; Fryer and Stone 1993; Nelson and Ternes 1993).[21]

One of the interesting findings thus far is that lighting measures account for about 75 percent of the savings from projects sponsored by ESCOs, while non-lighting measures represent 75 percent of the savings from projects sponsored by customers. Possible explanations for this phenomenon include the fact that: (1) a number of ESCOs focus only on measures for which there are approved M&V protocols; (2) customer sponsors may be more willing to invest the resources (both money and time) to get M&V protocols approved for site-specific process and equipment retrofits because they receive the entire Standard Offer payment; and (3) non-

21 The Fryer and Stone study was sponsored by three large New England utilities and covers the motor replacement market in Connecticut, Rhode Island, Massachusetts, and New Hampshire. They found that most distributor sales are for failed motors which are replaced with standard efficiency motors; thus changing distributor stocking practices was critical to making premium efficiency motors available in time-sensitive replacement situations.

Table 3-5. High Efficiency Motors Installed in Standard Offer Program (Through Dec. 1994)

Size Range	Number	Current Efficiency (Average)	Proposed Efficiency (Average)	Summer Prime Period Average Demand Reduction (kW)
0 - 1 HP	0	-	-	-
1.1 - 2 HP	3	0.83	0.87	0.12
2.1 - 5 HP	41	0.82	0.90	13.7
5.1 - 10 HP	26	0.85	0.93	25.4
10.1 - 25 HP	47	0.87	0.93	42.1
25.1 - 50 HP	12	0.89	0.94	67.9
50.1 - 100 HP	6	0.89	0.96	13.3
Greater than 100.1 HP	13	0.87	0.94	297.0
			TOTAL	459.5

lighting projects tend to take longer for ESCOs to develop because they are more complex (and thus the mix of savings for projects sponsored by ESCOs will change over time).

3.4 Concerns Regarding Potential "Lost Opportunities" and Partial Retrofit Treatments

The design of the Standard Offer program appears better suited to capturing certain types of efficiency opportunities than others because of several program features. Specifically, the size threshold, M&V requirements, and approval process for measures means that the Standard Offer is not designed to operate quickly or to acquire resources that often come in small packages (Gordon et al. 1994). Gordon et al. (1994) argue that those conservation opportunities where decisions must be made quickly, on short notice, and in very limited windows of opportunity create potential "lost opportunities" because at the time of failure or planned replacement, the societal cost of acquiring high-efficiency equipment is only the incremental cost of improved efficiency. If the one-time opportunity is missed, the societal cost of the energy efficiency improvement in a retrofit situation becomes the total cost of the new equipment less salvage value (if any), which often makes it uneconomic to pursue.

Potential "lost opportunities" may also be created if a program design encourages partial or selective treatments of facilities, which then make it impractical or uneconomic for providers of energy services to capture the remaining conservation options cost-effectively. Gordon et al. (1994) are particularly concerned about non-lighting measures (e.g., HVAC, shell or refrigeration) where the cost per kW saved is extremely variable among measures and between sites. In this situation, they believe that ESCOs are naturally driven to look for the least expensive savings and less complex projects (because of the performance risks associated with the M&V requirements). Gordon et al. (1994) acknowledge that, over time, some ESCOs will develop niche markets that focus on these more complex, sophisticated technologies. However, they believe that many other ESCOs will be discouraged from offering comprehensive services or targeting more complex HVAC, refrigeration, and shell measures because these services intrinsically have higher costs per kWh, which will put them at a competitive disadvantage to lighting service contractors.

Discussion and debate over this aspect of DSM program design -- whether or not a program encourages partial or selective treatments in facilities -- often has not been very productive (e.g., charges of "cream-skimming"). Conceptually, it is useful to distinguish between "width" and "depth." "Width" refers to the range and breadth of end uses addressed by ESCOs or customer sponsors in their installations (e.g., lighting, HVAC, motors). The extent to which savings occur across multiple end uses is one indicator of comprehensiveness in terms of "width." "Depth" refers to the comprehensiveness of measures installed for a particular end use at facilities and the associated savings. Without conducting detailed investigations of each site, percentage reductions in usage for a particular end use are a rough proxy that provides an indication of the "depth" of contractor installations.

Based on our experience, we treat and evaluate "width" and "depth" issues somewhat differently. We believe it is appropriate to make comparative assessments of the extent to which a utility program is capturing all cost-effective conservation opportunities within a particular end use (i.e., "depth") relative to the economic potential as well as the experience of other utilities. However, the value of quantitative comparisons among utility programs is more limited in assessing savings across multiple end uses in the C/I sector (i.e., "width"), primarily because of the large variations among utilities in the magnitude of the DSM economic and technical potential in non-lighting end uses and because of differences in customer decision-making patterns and preferences within and among particular market sectors. For this reason, we think that it is reasonable to assess whether a program provides customers with reasonable opportunities to pursue comprehensive retrofits across multiple end uses (e.g., number of ESCOs offering these services). Over the long run, it is also important to compare market response in particular end uses with the utility's estimates of economic potential.

We would offer the following comments based on our analysis of the program tracking database and interviews with ESCOs and customers:

3.4.1 Failed Equipment/Emergency Replacement Situations

We agree with Gordon et al. (1994) that the design of the Standard Offer program is unlikely to capture conservation opportunities that arise when equipment fails and must be replaced quickly (i.e., emergency replacement). Based on market research at other utilities in the northeast, this is often the case with motor replacements (Fryer and Stone 1993). Gordon et al. (1994) note that the existing vendor structure is the key to equipment availability and delivery in emergency replacement situations. Based on our review, the fuel substitution and few HVAC and motor measures that have been installed under the Standard Offer appear to be planned equipment replacements or major renovation/remodels with long-lead times. For us, the important issues are the relative magnitude of these type of conservation opportunities in New Jersey and the likely costs to the utility and society of acquiring them compared to the Standard Offer (see Chapter 9 for discussion and recommendations).

3.4.2 Comprehensives ("Depth")

There appears to be little evidence of selective and partial lighting treatments completed under the Standard Offer program, with the exception of lighting controls, which are not covered by the M&V protocols. For the program overall, sponsors expect to reduce prime period kW demand for lighting fixtures being replaced by about 50 percent. Based on their pre-implementation audits, utility program staff indicated that sponsors typically replace about 90-95 percent of the existing lights (Torres 1994). If correct, this means that lighting savings are about 45 percent of baseline lighting energy usage. This percentage reduction in lighting usage compares favorably to the reductions achieved by other utility DSM programs.

3.4.3 Comprehensiveness ("Width")

Based on our interviews with ESCOs, it appears that the program's stringent and time-consuming requirements for approval of M&V plans do contribute somewhat to the relatively low market penetration of HVAC equipment, refrigeration, motors, VSDs, and industrial process application retrofits in the program. For example, several ESCOs reported instances where they have installed high-efficiency motors outside of the program in facilities that were receiving lighting retrofits, because the savings benefits were small relative to measurement costs.

Several other ESCOs noted that they encourage customers to install all cost-effective measures in their facility. However, since HVAC equipment replacement and some fuel switching projects often fail to pass a TRC test, ESCOs are unable to offer them through the Standard Offer program. These measures would be attractive to customers, but are ineligible under the program.[22] This issue of projects failing the TRC test will become more prominent in the future because the utility's current projections of avoided costs are expected to be significantly lower than those used in the initial Standard Offer pilot.

The marketing strategies of some ESCOs as well as customer's decision-making processes and financial performance requirements also appear to limit comprehensive retrofits in certain market segments. A comprehensive package of measures involves a tougher and longer sell compared to a lighting project for many customers. Thus, several ESCOs claim that they are pursuing a staged approach, in which lighting projects will be followed by marketing of other applications such as VSDs, motors, and chillers. In part, this strategy is based on their assessment that they want to limit their up-front marketing and project development costs that must be recovered from projects that ultimately move forward, given the competition in the service area and the cost structure of their competitors. Based on previous experience, these ESCOs claim that 25-50 percent of the customers ultimately agree to additional efficiency improvements if they are satisfied with the ESCO's initial performance. A few ESCOs maintain that their marketing strategy targets customers that want to pursue more comprehensive or complex retrofits.

Thus far, for projects sponsored by ESCOs under the Standard Offer, lighting measures account for about 75 percent of the savings, with fuel switching measures representing the bulk of the remaining savings. By comparison, a recent DSM potential study sponsored by PSE&G (Xenergy 1994) estimated that lighting, HVAC, and process measures account for about 71, 21, and 8 percent respectively of the efficiency opportunities in the C/I sector (see Appendix J for a summary of that study). This suggests that HVAC measures have not been implemented aggressively under the program. The mix of measures in the Standard Offer is similar to that found in the C/I rebate programs of many utilities (excluding fuel switching). However, compared to the "best practice" among utilities that are acknowledged to be leaders in DSM, HVAC, refrigeration, and industrial process appear to be under represented in the Standard Offer. For example, Pacific Gas & Electric reported that about 58 percent of the savings from its 1992 commercial/industrial rebate program came from lighting measures, 28 percent from HVAC options, 7 percent from industrial process changes, 6 percent from refrigeration, and <1 percent from motor efficiency improvements (PG&E 1993).

The issue of partial treatment of facilities is of greater concern in the small C/I market because PSCRC's Bright Investment program markets lighting measures only and because there have been few other ESCOs actively targeting these customers. Although PSE&G offers a pilot small C/I program that offers rebates for certain non-lighting measures, that program has

[22] In some cases, ESCOs have installed and financed these measures at host customer facilities outside of the program.

apparently not established a strong market presence.[23] When asked why they chose the Bright Investment program rather than PSE&G's rebate program, most respondents indicated that they were unaware that the utility had a rebate program. We found that only one of the 25 Bright Investment customers interviewed was aware that the rebate program existed, because this customer had previously participated.

3.5 Market Response vs. Economic Potential

PSE&G recently sponsored a study which estimated the technical and economic potential for various energy efficiency, fuel switching, and load management options (e.g., load curtailment) in their service territory (Xenergy 1994). We focus only on the economic potential results for the C/I sector, given that the market response to the Standard Offer program has been exclusively among C/I customers; see Appendix J for a more detailed summary of the DSM potential study. Figure 3-6 shows the economic potential in various C/I market sectors by type of DSM measure; projections of 1994 summer peak and annual sales used in the study are also included for comparison. The industrial, office, education, and retail sectors provide the bulk of the savings opportunities in existing buildings.

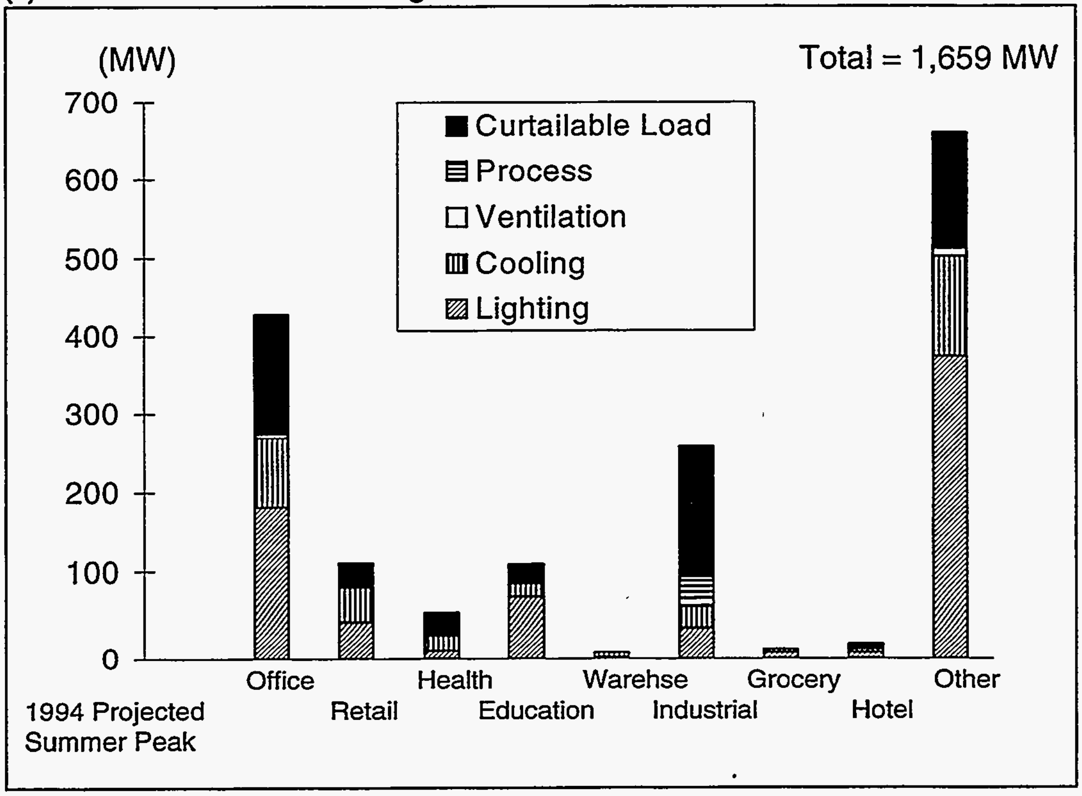
In the C/I new construction market, the economic potential for energy efficiency measures is estimated to be about 20 MW and 50 GWh. The Xenergy study assumed that summer coincident peak demand would increase by about 128 MW and electric sales would increase by about 477 GWh, so the savings potential represents about 16 percent of peak demand and 10 percent of sales growth.

We would offer several observations on the market response to the Standard Offer program vs. the economic potential for DSM in PSE&G's service territory. Our comments on this topic are primarily illustrative, given problems with the quality of data and methodological issues. For example, the DSM potential study did not analyze the impacts for a number of measures that have been implemented under the Standard Offer (e.g., several fuel switching and refrigeration measures). In addition, as noted in Section 3.2.1, the linkage between SIC codes and building types provides only a rough first cut at segmenting the commercial market.[24]

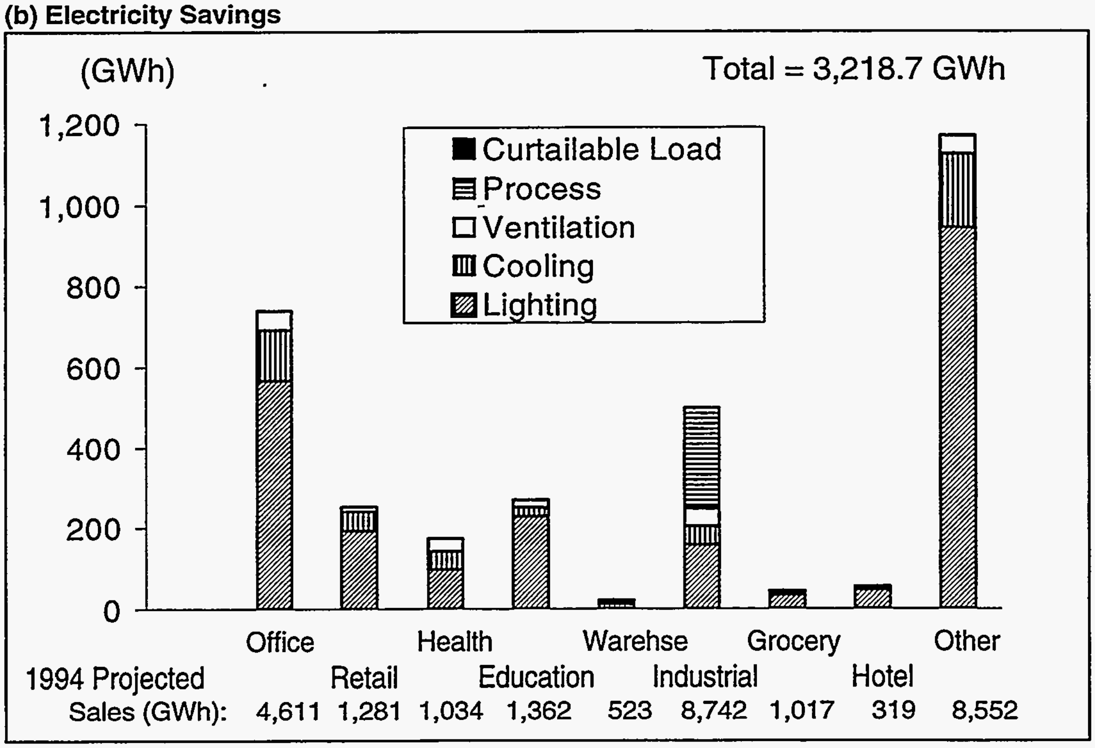
23 Since its inception in 1993, about 4 MW have been saved under the Small I/C pilot program through Dec. 1994.

24 The target market sectors used in PSE&G's DSM potential study do not appear to be completely consistent with the SIC code mapping process used in the COMMEND model. This illustrates some of the analytical issues that utilities must resolve so that information from program tracking databases can be fed back and linked with the utility's DSM planning/marketing models.

Figure 3-6. Estimates of Economic Potential in Commercial/Industrial Sector
(a) Summer Peak Demand Savings



(b) Electricity Savings



- Compared to the economic potential for DSM, the market response to the Standard Offer appears to be small in most C/I target markets and end uses (<5%), with a few notable exceptions.[25] For example, the program has made little impact in the large commercial office building sector (e.g., 2.2 vs. 270 MW). In contrast, market response appears to be over 35 percent of the DSM economic potential identified in warehouses (e.g., 3.8 vs. 9 MW).

- In C/I new construction, projects representing slightly less than one MW of SPPADR have been approved through the Standard Offer compared to the estimated economic potential of about 20 MW. However, savings in this sector are particularly sensitive to the level of new construction activity, and we have no information on how actual construction activity compares to forecasted levels assumed in the Xenergy study.

- Lighting projects account for about 25 MW of SPPADR in the Standard Offer compared to the economic potential of 740 MW for lighting measures. This indicates that the program could continue at its present pace for at least the next 4-5 years, primarily capturing lighting savings. However, even for lighting, the program would have to increase market penetration in sectors that have been difficult to penetrate, such as large office buildings where lighting measures account for 182 MW of potential savings.

- Finally, we believe it is important for PSE&G to assess actual program performance relative to achievable DSM potential in specific market sectors. This will allow the utility to identify future opportunities and possibly adapt and revise program offerings to target under-served, but potentially attractive market niches (see Chapter 9 for recommendations).

[25] The DSM bidding program has produced an additional 29 MW of savings, which should be considered when estimating DSM market penetration in the large C/I sector; lighting measures account for 80-90 percent of the total savings in the bidding program.

Program Costs and Cost-Effectiveness

4.1 Overview

This chapter examines the costs and cost-effectiveness of the Standard Offer program. We first describe the method and underlying assumptions used to calculate our three primary figures of merit: levelized Utility Costs, levelized Total Resource Costs (TRC), and the Benefit/Cost ratio (B/C) from a TRC perspective. We also compare the costs of the Standard Offer program with a sample of performance-based DSM programs (e.g., DSM bidding) conducted by other utilities to provide background on the ranges found in current practice.

For the program overall, the TRC levelized over the contract term for each facility (typically 10 years) average 6.8 ¢/kWh, which is about 74 percent of the utility's avoided supply costs (which includes an environmental externality adder). We found that the Standard Offer payments from PSE&G to ESCOs account for 91 percent of the total resource costs in ESCO-sponsored projects in the large C/I market, while cost contributions from host customers were less than 10 percent of total cost. Cost contributions from customers were greater in PSCRC's Bright Investment program which targeted smaller C/I customers (about 2.1 ¢/kWh), averaging about 26 percent of total project costs. Payments from PSE&G cover about 97 percent of the total resource costs of customer-sponsored projects. Total resource costs varied somewhat by types of measures installed: lighting-only projects averaged about 5.9 ¢/kWh, while the 27 projects that involved both fuel switching and other measures averaged about 7.3 ¢/kWh. Our analysis suggests that facility size and differences in hours of operation may explain some, but not all of the differences in levelized total resource costs among lighting-only projects. The average TRC for the Standard Offer program are somewhat lower than the DSM bids in PSE&G's 1989 all-source solicitation (6.8 vs. 7.1 ¢/kWh), while costs are in the mid- to high-range compared to nine other DSM bidding programs.

4.2 Approach

We obtained information from PSE&G's tracking database on program costs, annual energy savings, avoided supply benefits, and contract lifetimes in order to analyze the costs and cost-effectiveness of the Standard Offer program. PSE&G initially screens projects for cost-effectiveness based on documentation submitted by the sponsor on project costs and estimated energy savings. However, PSE&G payments depend upon delivered energy savings, by time period. Thus, if the distribution of actual savings by time period differs from the engineering estimate, our estimates of levelized program costs per kWh will change.

However, this should not affect the overall cost-effectiveness of the projects because PSE&G payments are always less than the avoided cost benefits.[26]

Project sponsors provide estimates of energy savings in each of PSE&G's seven time periods over the life of the contract. For lighting measures, a sponsor provides a list of current and proposed lamps and fixtures in a facility, with the kW demand taken from a Luminaire Wattage table developed by PSE&G. Energy savings depend upon the difference in kW demand and the hours of operation specified for each measure or group of measures installed, which are continuously monitored with a run-time meter over the contract term. The energy savings estimates for non-lighting measures are developed on an individual basis by the project sponsors. In both cases, PSE&G staff or contractors conduct pre- and post-implementation audits to verify baseline and post-retrofit connected loads.

At our request, PSE&G included avoided cost benefits in its tracking database. The benefits are provided for each host facility and each year of contracted energy savings. In the initial cost-effectiveness screening, the avoided cost benefits are based upon estimated energy savings. However, as noted earlier, changes in delivered energy savings over the contract term should not adversely affect the overall cost effectiveness of projects because PSE&G payments are based on delivered energy savings as well.

The tracking database also specifies the contract terms for each host facility project for each type of measure installed at each facility. We use the contract term as a conservative proxy for the economic lifetime of the measures in calculating levelized costs. Because PSE&G payments depend upon verified energy savings, we expect the measures' lives to extend at least through the contract term and possibly longer. Our estimates of levelized program costs would decrease if the energy savings were to extend beyond the contract term.[27]

The program cost categories included in PSE&G's tracking database are PSE&G payments, capital and installation costs, cost contributions from host facilities (for projects sponsored by ESCOs), operation and maintenance (O&M) savings, measurement and verification (M&V) costs, and incidental energy costs.

One difficulty in comparing costs across projects is that projects have different completion dates, payment structures, and contract terms. Specifically, project sponsors are scheduled to begin commercial operation between 1993 and 1996. They can choose levelized or unlevelized payment streams and 5-, 10-, or 15-year contract terms, although 93 percent of the contracts are for ten years. We present program costs in terms of nominal, levelized

26 However, if the other cost components are fixed (e.g., customer contributions), then energy savings shortfalls could adversely affect the cost-effectiveness of projects. PSE&G has addressed this concern by requiring Standard Offer staff to reevaluate the cost-effectiveness of each project proposal three months after commercial operation.

27 Levelized TRC would be about 15% lower if measures produced savings for an additional five years after a ten year contract term expired.

utility and TRC per kWh.[28] We make no adjustments for start-date because most of the projects will come on line in 1994 or 1995 and, for projects that are not yet on-line, the actual start date is not known.

We define levelized utility costs as follows:

$$\text{Levelized Utility Costs} = (PP) \times [(I(1+I)^n)/((1+I)^n - 1)]/ES$$

where:

PP	=	PSE&G Payments
I	=	Discount Rate, 11.2%
n	=	Contract Term
ES	=	Energy Savings (kWh)

Utility costs include only PSE&G payments because sponsors pay virtually all of the program's administrative costs.

For ESCO-sponsored projects, we defined levelized TRC as follows:

$$TRC = (PP+O\&M+HFP+IEC)x[(I(1+I)^n)/((1+I)^n - 1)]/ES$$

where:

PP	=	PSE&G Payments
O&M	=	Incremental O&M Savings (or additional costs)
HFP	=	Host Facility Payments
IEC	=	Incidental Energy Costs
I	=	Discount Rate, 11.2 %
n	=	Contract Term
ES	=	Energy Savings (kWh)

The O&M savings category includes the incremental savings (or costs) in operation and maintenance that result from the installation of new measures. PSE&G has developed typical values for various lamp/fixture/ballast combinations which are used to estimate incremental

28 We calculate levelized utility and TRC costs per kWh using a method proposed by Leung and Durning (1978), which divides levelized costs by levelized kWh saved. This method is equivalent to dividing the NPV of annual costs by the NPV of the annual kWh savings. We use this levelization technique primarily because projects often do not provide comparable savings in each year of the contract (i.e., ramp up over several year period). The Leung and Durning method allows us to reflect the timing and occurrence of payments and other costs and the corresponding energy savings (Goldman and Kito 1994, Appendix B).

O&M savings for lighting measures. The host facility payments include any payments from the host customer to the third-party sponsor (i.e., ESCO) and can include shared bill savings, contributions towards equipment purchases, etc. Incidental energy costs are included only for fuel-switching projects and capture incremental costs of the new fuel (e.g., gas).

For customer-sponsored projects, PSE&G conducts its cost-effectiveness screening using the total project costs (e.g., capital and installation costs, M&V costs, incremental O&M savings or costs) reported by the customer. PSE&G does not include the Standard Offer payment, which is regarded as a transfer payment. Thus, for these projects, we calculated the levelized TRC as follows:[29]

$$TRC = (CC+O\&M+M\&V+IEC) \times [(I(1+I)^n)/((1+I)^n - 1)] / ES$$

where:

CC	=	Capital Costs
M&V	=	Measurement and Verification Costs

Capital costs include the total capital cost of the energy saving measures that are being installed. The M&V costs represent the actual and estimated costs associated with monitoring and verifying the savings over the contract term in accordance with PSE&G's M&V requirements.

4.3 Results

In analyzing program costs and cost-effectiveness, it is important to recall the decision-making context of customers as well as the competitive market situation faced by ESCOs. In deciding among various sets of potentially applicable DSM measures, customer sponsors must decide whether they want a project's turnkey costs to be partially or totally offset by the Standard Offer incentive payment. If customer sponsors are willing to make a cost contribution, the program provides an implicit incentive to install all cost-effective measures in a facility, subject to passing the TRC test. In contrast, ESCOs must always factor in the

29 The California Public Utilities Commission (CPUC) decided that for customer-sponsored projects in bidding programs, utilities should consider the higher of the utility payments plus customer contributions or the cost to the customer of installing and maintaining the measure. We performed the levelized cost calculations using both methods (New Jersey and California) and found that the total resource costs were slightly higher using the CPUC method (7.4 vs. 6.6 ¢/kWh). This occurs because some customers are installing measures that they calculate will cost them less than the payment they receive from PSE&G. The relative merits of the CPUC or New Jersey approach hinges on whether one believes that the cost paid by PSE&G to the host customer over and above the measure cost are necessary to cover some hidden cost or barrier that prevents the customer from undertaking this project or whether it simply represents a transfer payment. This issue is not addressed in this study and, for simplicity, we use the New Jersey method throughout the report.

host customers' alternatives in preparing their technical and cost proposal. These alternatives include the customers' option of sponsoring the project themselves (if the project is of sufficient size) or working with competing ESCOs that possibly offer a different mix of measures, financing options, or terms and conditions in the Energy Service Agreement between ESCO and host customer. For a given set of measures, ESCOs will seek to minimize the cost contribution required from the host customer in order to be selected because payment levels from the utility are pre-specified.[30]

4.3.1 Costs Incurred by the Utility

Levelized utility costs average about 6.1 ¢/kWh for the program overall. Payments from the utility account for virtually all of these costs because most administrative costs incurred by the utility (e.g., program staff, costs of audits, general advertising) are charged to project sponsors. The Standard Offer contract specifies the types of administrative costs to be paid by project sponsors, and sponsors must internalize these costs in their estimates of total project costs.

4.3.2 Total Resource Costs: Program-Wide and by Market Sector and Sponsor Type

We calculate TRC for the program overall and various subcategories (e.g., market sector, type of measure) by weighting TRC costs by the lifetime kWh savings of each individual facility. We use this approach rather than a simple average of the TRC value for each facility in order to properly reflect the contribution that larger projects with longer contract lives have on overall program costs.

Table 4-1 shows the TRC for the program overall, by type of project sponsor (i.e., ESCOs vs. customer sponsors) and by market sector. We also show a more detailed breakdown of TRC costs for retrofit projects in the large commercial/industrial market, which groups facilities by various types of measures installed. The TRC, levelized over the contract term for each facility (typically 10 years), averages 6.8 ¢/kWh. Levelized costs range from about 6.6 ¢/kWh for large C/I projects sponsored by ESCOs to about 8 ¢/kWh for PSCRC's Bright Investment project, which is targeted at smaller C/I customers. Total resource costs average 6.6 ¢/kWh for customer-sponsored projects. Thus far, program costs vary somewhat by market sector (new vs. retrofit). Total resource costs are slightly lower among the 10 new construction facilities compared to retrofits at existing large commercial/industrial facilities

30 In addition to this simple case (i.e., customer wants proposal on specific set of measures), ESCOs will often offer different packages of measures (with differing customer cost contributions) as well as varying contract terms and conditions.

Table 4-1. Summary of Program Costs

	Number of Facilities	TRC (¢/kWh)	TRC as % of Avoided Costs
Overall Program	1,041	6.8	74%
Type of Project Sponsor			
ESCOs	239	6.6	74%
Bright Investment	768	8.0	85%
Customer Sponsors	34	6.6	71%
Market Sector			
New Construction	10	5.8	58%
Existing Large C/I[a]	263	6.6	73%
***Type of Measure** (Large C/I: Existing Buildings)*			
Lighting Projects	217	5.9	67%
Fuel Switching, plus other measures	27	7.3	81%
Lighting, plus other measures	7	7.8	89%
Other Measures (Non-Lighting)	12	6.9	73%

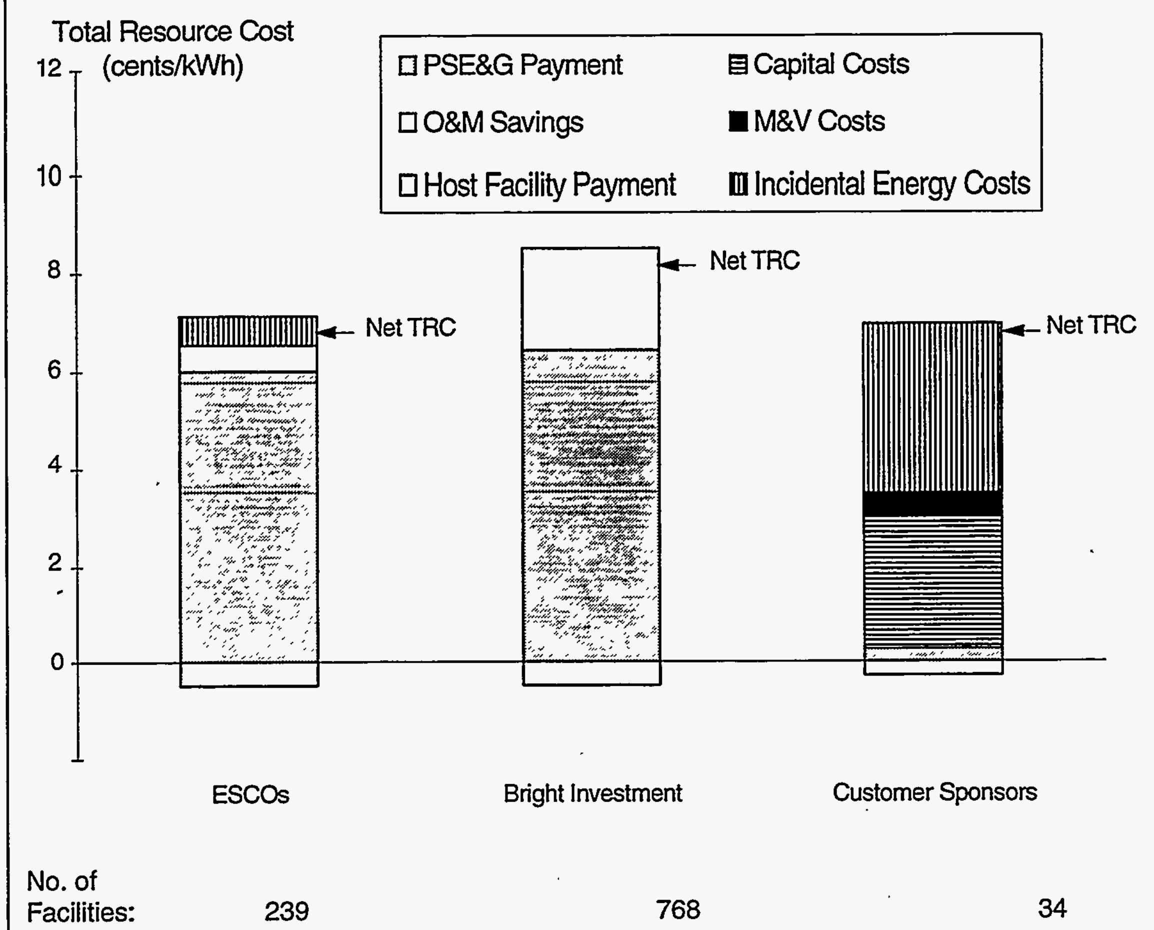
[a] Includes all measures for both customer sponsors & ESCOs.

(5.8 vs. 6.6 ¢/kWh). Lighting measures were the only measures proposed in projects that target new construction, which explains most of the cost differential.

Figure 4-1 provides a breakdown of the various cost components for each type of project sponsor. Incremental O&M costs are negative (e.g., high efficiency lighting retrofits are assumed to yield O&M savings) and thus serve to reduce total resource costs. Net total resource costs are shown by an arrow for each type of sponsor. Among projects sponsored by ESCOs in the large C/I market, the Standard Offer payment accounts for 91 percent of total resource costs. Host payments from customers and incidental energy costs (for fuel switching projects) average only about 0.52 and 0.57 ¢/kWh respectively, while estimated O&M savings average about -0.5 ¢/kWh. This means that, on average, large C/I customers are bearing about 9 percent of the total costs associated with these projects.[31] In the Bright

[31] In calculating the customer's share of total resource costs, we added the incidental energy costs in fuel switching projects (i.e., additional gas consumption) to the host facility payment and subtracted the O&M cost savings.

Figure 4-1. Total Resource Costs by Type of Project Sponsor



Investment program which is targeted at smaller C/I customers, the Standard Offer payment from PSE&G to PSCRC accounts for about 74 percent of the total resource cost. PSCRC requires a cost contribution from host customers, which is about 2.1 ¢/kWh on average. Thus, in these projects, customers are typically paying about 26 percent of the total resource cost.

For customer-sponsored projects, capital costs of the project account for about 42 percent of the total costs. Incidental energy costs are also a significant cost component in projects sponsored by customers (3.5 ¢/kWh), which reflects the prevalence of fuel switching projects.[32] PSE&G's payments to customer sponsors are estimated to be 6.4 ¢/kWh on

[32] The small PSE&G payment for customer-sponsored projects occurs because PSE&G's program tracking database includes utility payments for one customer-sponsored project. This gives an average for the entire group of 0.27 ¢/kWh. We questioned PSE&G staff about this anomaly but did not receive any clarifying information.

average, which means that these payments will cover about 97 percent of the total resource costs of these projects (i.e., capital costs, O&M costs, M&V costs, incidental energy costs).

4.3.3 Total Resource Costs for Types of Measures Installed in Large C/I Facilities

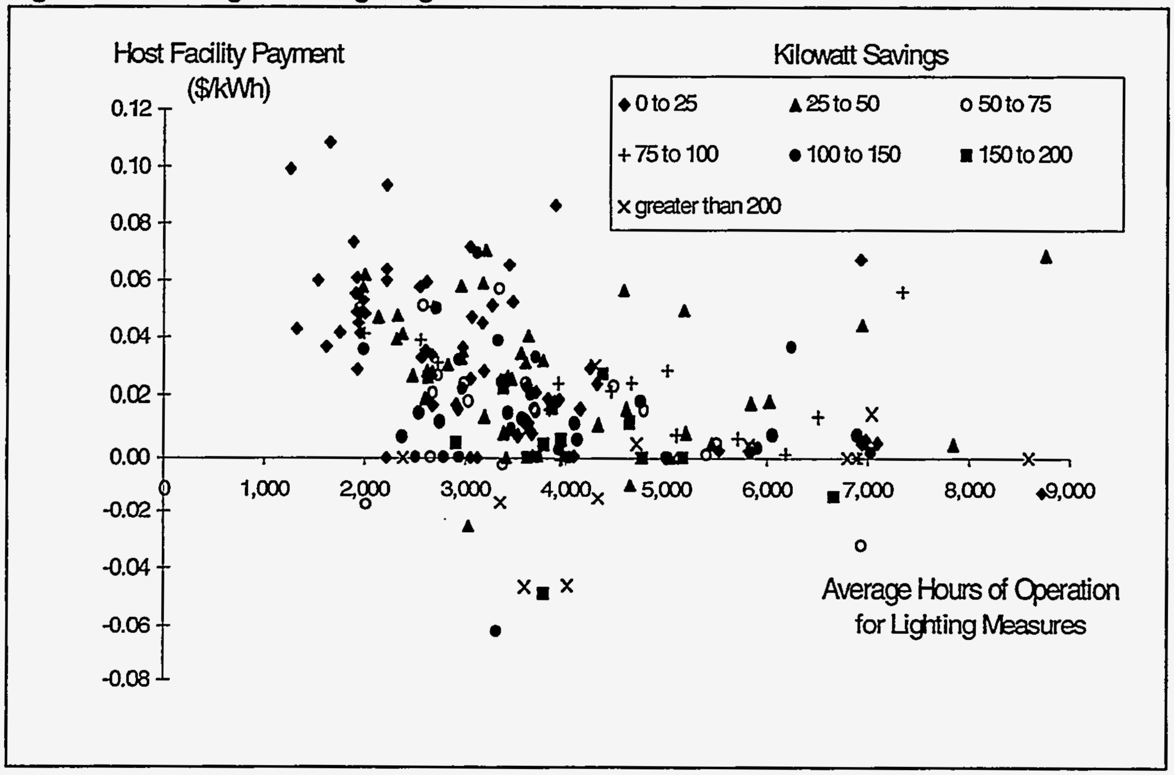
We disaggregated retrofit projects in large C/I facilities into four measure-related categories (number of facilities in parentheses): lighting-only projects (217), projects that involved fuel switching conversions from electric to gas equipment and which, in some instances, included other measures (27), projects that involved lighting plus non-lighting measures (7), and projects that involved various non-lighting measures such as HVAC, motors, variable-speed drives, and industrial process retrofits (12). For lighting-only projects, total resource costs average about 5.9 ¢/kWh (see Table 4-1). The Standard Offer payment from PSE&G accounts for over 90 percent of the total resource cost, which is more than most utilities are paying for lighting projects in the large C/I market (Eto et al. 1994). Levelized TRC are about 2 ¢/kWh higher for projects that involve both lighting and non-lighting measures (7.8 ¢/kWh). Levelized TRC average 7.3 ¢/kWh for the 27 facilities that are implementing fuel switching projects and 6.9 ¢/kWh for the 12 facilities that are installing various types of non-lighting measures.

4.3.4 Factors That May Explain Differences in Project Costs

We also analyzed cost trends in projects in order to obtain some preliminary insights on factors that might explain cost differences among projects as well as the extent of competition in the energy services market. We decided to focus on lighting-only projects in the large C/I market that were sponsored by ESCOs because the end use and types of measures installed were more homogenous than those in our other three measure groups. Based on our interviews, we examined the ESCO claim that hours of operation and a facility's size and savings potential (for which peak demand was a proxy) directly affect the costs and economics of lighting projects. For the same set of lighting measures and all else being equal, we would expect that project costs per unit of energy saved would be lower for facilities that have longer hours of operation and for facilities with greater savings potential. Given that the variation in Standard Offer payments per kWh saved among projects is very small, we focused on the amount of cost contribution that ESCOs obtained from host customers as the independent variable that could be affected by facility hours of operation and peak demand usage.

In Figure 4-2, we plot cost contribution from host customers vs. hours of operation for 202 facilities sponsored by ESCOs in the large C/I market (with host customer cost data). Host facility payments average about 0.5 ¢/kWh for all facilities, weighted by kWh savings, but there is tremendous variation in cost contributions paid by individual customers (e.g., -0.6 ¢/kWh to 10 ¢/kWh). Facilities where absolute demand reductions are larger (> than 150 kW) typically make very small cost contributions. By way of contrast, customer cost contributions exceed 5 ¢/kWh at 31 facilities (15% of all facilities). These facilities tend to have lower hours of operation and smaller absolute savings (< 25 kW). Total resource costs average 11.6 ¢/kWh for these facilities, which is quite high and surprising, given the choice of technologies (i.e., lighting). Possible explanations include: (1) inaccurate or inconsistent reporting of customer cost contribution by ESCOs, (2) high turnkey project costs to serve these smaller facilities (e.g., higher marketing costs per unit energy saved), (3) varying levels of sophistication among host customers in understanding the program design (e.g., that the ESCO is also receiving substantial financial incentives from PSE&G) and/or underlying lighting technology costs, or (4) limited competition in certain market niches which may allow ESCOs to obtain excess economic rent. Overall, the data show some correlation between customer cost contribution and hours of operation: lower cost contribution with higher hours of operation (correlation coefficient is -0.38).

Figure 4-2. Savings from Lighting Measures



We also observe that the Standard Offer payment covers the entire cost of the lighting project for about 19 percent of the facilities (i.e., no cost contribution from the host customer). In fact, ESCOs report that the cost contribution from host customers is negative in about 15 large facilities; savings from these 15 facilities represent about 15 percent of total savings from lighting projects sponsored by ESCOs. This may imply that in order to sell a project to certain large customers that are particularly desirable and to fend off potential competitors, ESCOs are willing to offer financial incentives (i.e., payments) to customers for the opportunity to "mine" the savings in their facility. Given the Standard Offer payment level, in these situations, the large customer with the desirable site often extracts price concessions from the ESCO for lighting-only projects.

We would make the following observations based on our limited investigation of the market for lighting energy services among PSE&G's larger C/I customers and the extent of competition. Fourteen ESCOs have submitted lighting-only projects, although PSCRC has a significant market share (e.g., PSCRC-sponsored projects account for about 53 percent of the total savings). The varying degrees of bargaining power and/or sophistication among customers is typified by the contrast between the 30 facilities where customer costs exceed 5 ¢/kWh (and TRC costs exceed 11 ¢/kWh) and those facilities where large customers incur zero or negative costs for their lighting projects. In many cases, the large C/I customer's decision to install high-efficiency lighting is discretionary (i.e., the existing lighting equipment is functional and a major renovation or remodeling of the facility is not being planned). In these situations, given the Standard Offer payment, a sophisticated C/I customer with a desirable site is in an excellent position to negotiate very favorable pricing terms for lighting-only projects.

4.3.5 Program Cost-Effectiveness

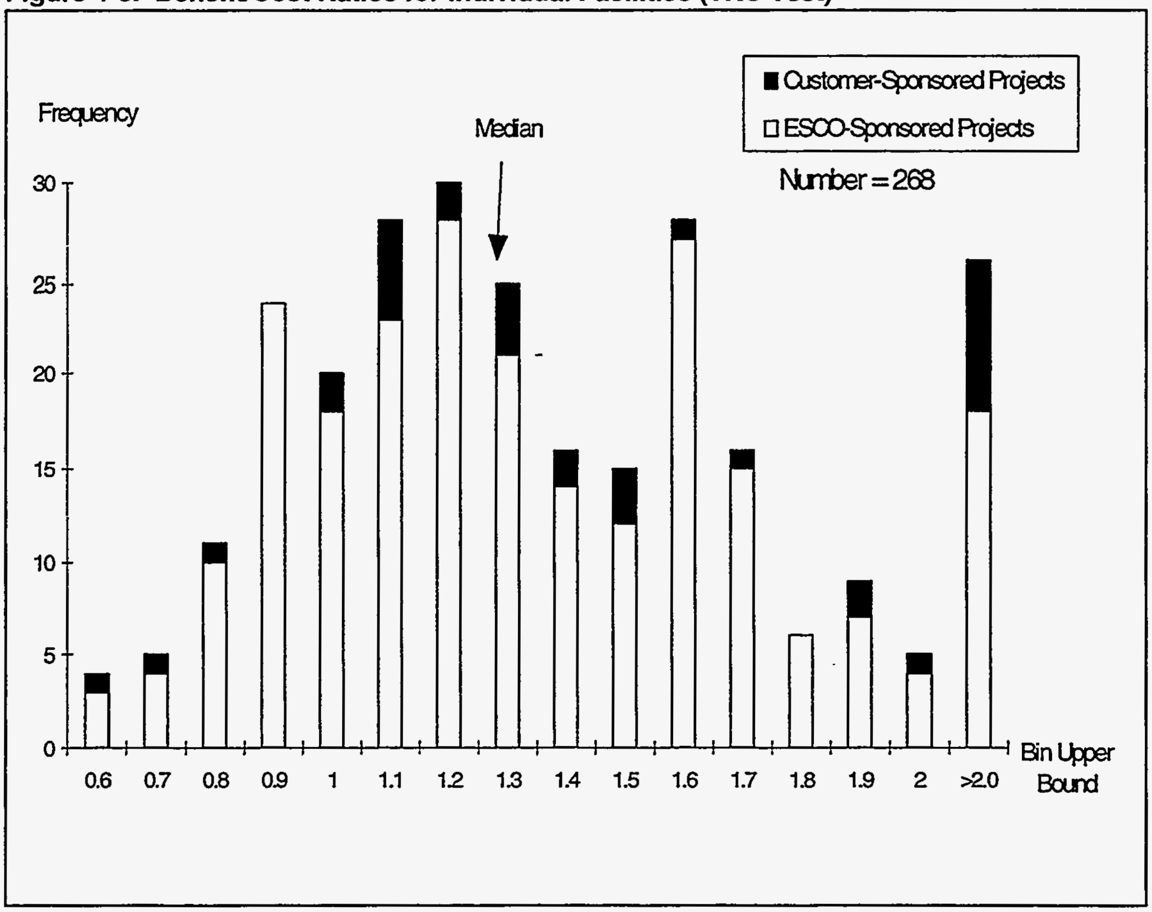
For the Standard Offer program overall, total resource costs (6.8 ¢/kWh) average about 74 percent of the utility's avoided supply costs (including an externality adder), weighted by lifetime savings (see Table 4-1). Total resource costs as a percent of avoided costs vary somewhat by type of measures, ranging from 67 percent of avoided costs for lighting projects to 89 percent for projects that include lighting and other measures. Time-differentiated energy savings (which affect PSE&G payments and avoided cost benefits) and hours of operation (which affect customer contributions) drive these results. Avoided supply costs average 9.1 ¢/kWh for the entire program and include an externality adder of about 2 ¢/kWh which was adopted by the New Jersey BPU in their DSM rules. Current forecasts of future avoided costs are expected to be significantly lower; we discuss the implications of lower avoided costs in Chapter 9.

At the individual facility level, we found significant variation in total resource costs and costs were quite high for some individual facilities. PSE&G requires that projects submitted by sponsors must pass the total resource cost test in aggregate. This means that project sponsors are allowed to bundle together jobs for individual customers that would fail the TRC test on a stand-alone basis, if the project proposal passes the TRC for the entire set of facilities. In the large C/I market, about 24 percent of the individual facilities (64 out of 268) have TRC B/C ratios less than one (see Figure 4-3). Of those that fail the TRC test, about twenty facilities have B/C ratios less than 0.8.

4.3.6 Comparison with Similar DSM Programs at Other Utilities

In this section, we make some preliminary comparisons of the costs of the Standard Offer program from a utility and societal perspective with DSM programs of other utilities that have offered a similar mix of measures to the same target markets. These type of "yardstick" comparisons are only suggestive given differences in eligibility requirements between programs, local labor market conditions, and variations in the characteristics of the C/I sector among utilities. However, these comparisons do provide policy makers with information on current practice and "best practice" benchmarks. They may also offer

Figure 4-3. Benefit/Cost Ratios for Individual Facilities (TRC Test)



insights on potential opportunities to lower the costs of acquiring certain types of DSM measures in various market sectors and estimates of the magnitude of the implicit "cost premium" for bearing transaction costs and performance risks.

Standard Offer vs. DSM Bidding Programs

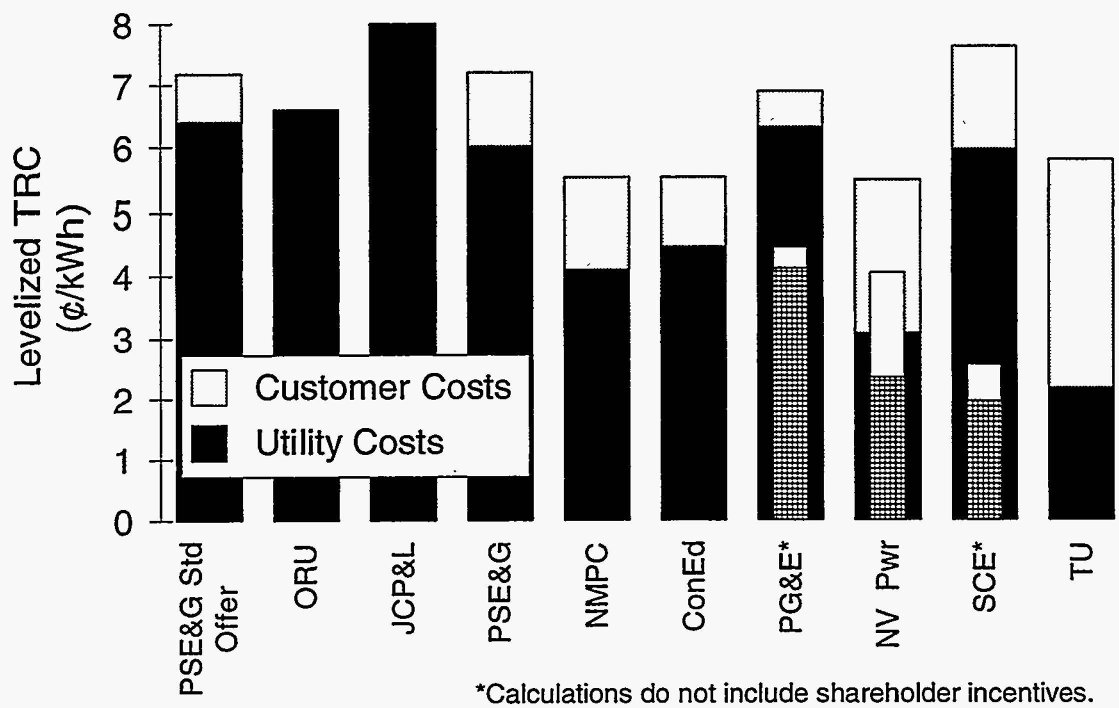
Initial results from the Standard Offer program can be compared with DSM bidding programs in which DSM developers/project sponsors bear most or all of the risks associated with project development and performance as opposed to utility ratepayers. Figure 4-4 shows the levelized TRC values for nine DSM bidding programs, which are ordered chronologically.[33] Almost all contracts in these programs targeted large C/I customers. The mix of measures varies among the programs, but lighting measures typically account for over 75 percent of the savings, except for the Standard Offer and Niagara Mohawk's program, and the Standard Offer allows fuel switching options (i.e., electric to gas). For three programs (PG&E, Nevada Power; and SCE), we show a range of levelized TRC values, which vary depending on the assumed economic lifetime of the measures (e.g., contract term or estimated measure life).[34] Assuming that committed projects develop, the Standard Offer is larger than most other bidding programs, with the exception of Texas Utilities. The total resource costs of PSE&G's Standard Offer program (6.8 ¢/kWh) are slightly lower than the average of PSE&G's 1989 DSM bids (7.1 ¢/kWh). Levelized total resource costs of the Standard Offer are in the mid-range compared to the other utilities that have implemented DSM bidding programs (5.2 - 8.1 ¢/kWh), using economic lifetimes based on contract term. However, utility costs (i.e., financial incentives and administrative costs) are higher in the Standard Offer (about 6 ¢/kWh) compared to recent DSM bidding programs (2.5 - 3 ¢/kWh).[35] In these other programs, ESCOs are taking the risk that they can develop projects that involve significant customer cost contributions.

33 Program cost data are taken from Goldman and Kito (1994) and LBNL's analysis of contracts signed in three recent bidding programs (Nevada Power, Southern California Edision, and Texas Utilities).

34 For these three programs, contract terms are shorter than the estimated measure lifetimes which the utility used in evaluating the cost-effectiveness of these DSM projects.

35 For SCE, we assume that the economic lifetime of projects will be closer to the engineering measure life rather than the much shorter contract terms, which average four years in this program.

Figure 4-4. Standard Offer vs. Other DSM Bidding Programs



	Std Offer	ORU	JCP&L	PSE&G	NMPC	ConEd	PG&E	NV Pwr	SCE	TU
Size (MW)	40	6	10	29	20	6	18	14	32	68
Contract Term	10	15	15	10	15	14	10	11	4	10
Measure Life	-	-	-	-	-	-	20	14	16	-

PSCRC's Bright Investment Projects vs. Small C/I Lighting Programs

We also compared PSCRC's Bright Investment projects with 1993 results for two other utility programs that explicitly targeted small C/I customers. Both utilities are located in the northeastern part of the U.S., have relatively high avoided supply costs, and have installed mostly lighting measures (i.e., they account for over 97 percent of the savings in both programs).

- Utility A - Customers with average monthly peak demand less than 150 kW are eligible for Utility A's program which has been marketed mostly through word-of-mouth with about 800 to 900 customers per year participating for the last four years.

The program is a direct install-type program with a pre-approved list of lighting measures that have been shown to be cost-effective based on typical operating hours and conditions. Recently, participants have been asked to pay a portion of the cost of the measures, which is equal to the projected energy savings in the first year.

- Utility B - Utility B's program is also a direct install program of lighting and non-lighting measures but no customer contribution is required. About 2500 customers participated in 1993; eligibility size requirements are more stringent than Utility A or Bright Investment program (i.e., average monthly peak demand less than 50 kW or annual usage less than 150,000 kWh). The program is delivered through several contractors that bid competitively to provide services within a geographic area.

Table 4-2 summarizes information on market response, program-level and individual facility savings, and levelized total resource costs. We attempted to use similar assumptions in calculating levelized program cost for all three programs.[36] Utility A and B reported both engineering estimates and net savings impacts for their programs, which we use in calculating a range of levelized TRC costs. For Utility B, net savings reflect the results of a billing analysis of large samples of participants and a comparison group. For Utility A, we report a gross realization rate, which includes savings by participants based on a pre- and post-retrofit billing analysis. We offer the following observations:

- Over the last several years, many utilities have experimented with innovative program designs that deliver DSM measures to small C/I customers in a cost-effective manner. The combination of smaller savings potential at each facility plus high transaction and marketing costs associated with convincing significant numbers of smaller customers to undertake investments in energy efficiency has proven to be challenging.

- Levelized TRC for the Bright Investment program are about 8 ¢/kWh. These costs are midway between the range of levelized costs for Utility A and B's programs, which are around 5.9 to 6.2 ¢/kWh on the low end and 8.7 to 10.5 ¢/kWh on the high end. In comparing costs among these programs, the principal uncertainty is the likelihood that the savings obtained by Utility A and B will persist over the 10-year time horizon.

- We note that there appears to be some significant variations in customer characteristics among the three programs. Thus far, PSCRC's Bright Investment programs appears to be targeting customers with higher hours of operation compared

36 We assumed an economic lifetime of ten years and a discount rate of 11.2%. In their evaluations, Utility A and B estimate that measure lifetimes are somewhat longer (14-15 years), which lowers program cost on a per kWh basis.

Table 4-2. Bright Investment Program Compared to Other Small C/I Programs

	Number of Partici-pants	Hours of Opera-tion	Eligibility Require-ment	Estimated Savings Summer Peak (MW)	Estimated Savings (GWh)	Savings per Participant Summer Peak (kW)	Savings per Participant (GWh)	Levelized TRC[a] (¢/kWh)
Bright Investment	≈780	≈3,700	Summer prime period savings < 50 kW					
Committed				7.1	26.3	9.1	34	8.0
On-line				2.4				
Utility A	≈900	≈2,900	Average monthly peak demand < 150 kW					
Engineering Estimate				5.5	14.3	6.1	17	6.2
Gross Realization Rate				3.3	8.7	3.7	10	10.3
Utility B	≈2,500	≈3,100	Average monthly demand < 50 kW					
Engineering Estimate				7.7	23.1	3.1	9	5.9
Net Realization Rate[b]				5.6	15.5	2.3	6	8.7

a In the TRC calculation for Utility A and B, LBNL used similar assumptions as for PSE&G (i.e., 10-year measure life and 11.2% discount rate). We also assumed O&M savings for Utility A and B were 50% of the value used by PSE&G.

b Ideally we would use the gross realization rate, but we were unable to add back in savings from free riders for this program, so we use the net figure for illustrative purposes only.

to 1993 participants in Utility A and B's programs. In addition, because the Standard Offer defines eligibility in terms of maximum savings rather than usage level, it is reasonable to assume that facilities of customers that participate in PSCRC's Bright Investment program are definitely larger on average than participants in Utility A's program and may be larger than participants in Utility B's program.

Overall, program costs for Utility B compare favorably with the costs of Utility A's program and the Bright Investment projects, based on a qualitative consideration of the effects of hours of operation and facility size. Assessing market response is more problematic among the three programs for several reasons. Program budget constraints effectively limit the annual market penetration of Utility A and B's program, while this is not a major consideration for the Bright Investment program. However, the Bright Investment program has been offered for far less time than Utility A and B's programs, and may still be in the ramp-up stage. About 2.5 MW of summer peak demand savings are operational in the Bright

Investments program in about eight months (the program started in May 1994), while Utility B achieved 5 to 7 MW of summer peak demand savings in 1993. Finally, we have no information on the total size of the target market for each utility.

ESCO and Customer Reactions to the Standard Offer Program

5.1 Overview

This chapter discusses reactions to the Standard Offer program based on interviews with the following groups of customers and ESCOs:

- Project sponsors - 12 of the 16 ESCOs and 11 of the 19 customer sponsors that signed Standard Offer contracts with PSE&G through December 31, 1994.

- Customers that used ESCOs as project sponsors (i.e., host customers) - interviews with respondents representing 48 of the 240 customer facilities and 37 of the 782 customer facilities that have agreed to participate in PSCRC's Bright Investment program.

- Thirteen ESCOs that are not active in the program.

In terms of chapter organization, we first discuss responses from project sponsors and host customers involved in the large C/I market. Next, we present responses from host customers that are participating in PSCRC's Bright Investment program which is targeted at smaller C/I customers. We then discuss reactions from a sample of ESCOs that are not active in the program. Finally, we report ESCO and customer responses on their overall satisfaction with the program.

Topics that are discussed include respondent's experience with other utility DSM programs, their views on the utility's administration and delivery of the program, their marketing strategies and assessment of the market's reaction to the program, views on the role of PSCRC, customer satisfaction with the program and their energy service provider, and overall assessment and suggestions for improvement. For each topic, we include statements that reflect the range of views on each issue among the various groups of respondents.

5.2 Approach

As part of our process evaluation, we conducted telephone interviews with project sponsors, host customers that used ESCOs as project sponsors, and ESCOs that are not active in the program. Given the time and budget constraints of the project, we developed the following sampling approach.

We attempted to interview all project sponsors, both ESCOs and customers, that had submitted proposals under the Standard Offer program as of December 1994 (see Table 5-1). Project sponsors include firms that develop full-service turnkey projects including financing, firms that primarily provide services, and firms that offer project financing. During the course of our interviews, we discovered that other types of energy service firms had also participated in various aspects of the program: engineering firms and consultants that advised customers, contractors that provided lighting design and installation or measurement and verification services, etc. Our sampling approach for these firms was ad hoc, primarily because PSE&G does not track their involvement in a systematic fashion.[37] We interviewed several of these companies based on information which indicated that they were particularly active in the program.

Most customers partner with an ESCO to participate in the Standard Offer program. Thus, in order to assess customer satisfaction with the program as well as with individual ESCOs, we stratified the sample to include host customers that had worked with each ESCO. We tried to ensure that our sample of host customers included participants in various stages of the program (e.g., pre- and post-implementation).[38] The following sampling scheme was used: we selected all customers for those ESCOs that had served less than five facilities, every third customer for those ESCOs that have served between five and fifteen facilities, and every fifth customer for those ESCOs that have served more than 15 facilities. We also selected about 10% of the customers that had participated in PSCRC's Bright Investment program, which is targeted at smaller facilities (i.e., projects that save less than 50 kW).

We also interviewed ESCOs that were potential participants in the program. We contacted members of the National Association of Energy Service Companies (NAESCO) as well as ESCOs that have participated in DSM bidding programs of other utilities. We asked these companies if they were aware of the program, whether they had considered participating, why they chose not to participate, and what changes, if any, the utility could make that would facilitate their participation.

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37 Appendix A lists the utility staff and ESCOs that we contacted for this report.

38 For each ESCO, we selected customers for our sample based on their proposal number. PSE&G assigns proposal numbers on a chronological basis, thus our sample of customers for each ESCO includes both initial and recent participants.

Table 5-1. Survey Response
(a) Project Sponsors and ESCOs Not Active in Program

Project Sponsor or ESCO	Number	Survey Participants
Project Sponsor		
- ESCOs	16	12
- Customers	19	11
ESCOs Not Active in Program	23	13

(b) Host Customers

	Program Participants		Sample		Respondents	
Host Customers of:	Number of Facilities	MWs	Number of Facilities	MWs	Number of Facilities	MWs
- PSCRC	146	16.2	50	4.6	13	1.6
- PSCRC-Bright Investment	782	7.1	65	0.8	37	0.5
- Other ESCOs*	94	24.5	45	5.4	35	3.7

*Includes: Vision Impact Corp., E-Finity Corp., EUA Cogenex Corp., Energy Options, Sycom, Energy Capital & Services II, L.P., Enersave Inc., PERCO, Central Hudson Enterprises Corp., PP Electrical Reduction Corp., Starlite Contractors Corp., McBride Energy Services LLC, Power System Solutions, and CES/Way.

All potential respondents were sent letters from PSE&G and LBNL describing the evaluation study, soliciting their cooperation, and assuring confidentiality of responses. LBNL then followed up with a telephone interview survey. Each respondent was contacted several times with varying degrees of success. As Table 5-1 shows, response rates were highest for ESCOs active in the program (75%), followed by customer sponsors and ESCOs not active in the program (55-60%), and then host customers (25-77%).[39]

We asked all respondents a mix of open-ended and close-ended questions (which are included as Appendices B-F).[40] Interviews were conducted between September 1994 and

39 In some cases, respondents for host customers represented more than one facility (e.g., an energy manager at a large university that submitted 15 different projects). Response rates for host customers are grouped according to the host utility affiliation of the ESCO (i.e., PSCRC vs. other ESCOs), in part to protect the confidentiality of responses from host customers of small ESCOs.

40 Appendices G and H contain the survey protocols for utility and regulatory staff.

March 1995. Respondent's position within the firm varied somewhat among ESCOs and customers (see Table 5-2). Among the ESCOs, respondents were generally either corporate officers (e.g., president) or project/sales managers in regional offices. Among customers, few were corporate officers, most were either plant/facility managers, chief or staff engineers, or facility energy managers. In discussing our findings, it is important to note that the response rates are based on the number of respondents expressing a particular viewpoint in comparison to the number of firms that responded to a specific question, which is typically less than the total number of firms interviewed.

5.3 Experience with Other DSM Programs

"Compared to DSM bidding, the Standard Offer is very favorable because there aren't the same types of transaction costs that are associated with bidding (e.g., pre-marketing). In the Standard Offer program, there is certainty of bid award and all the contracting is done; in bidding programs, contract negotiations could take up to 12 months. While the cost of entry is low [in the Standard Offer], more can enter, meaning more competition and more people in the territory." — Active ESCO

"DSM bidding has been an infuriating process at some utilities. At the same time, the Standard Offer is much more competitive." — Active ESCO

"Compared to other performance contracting programs that our firm has worked in, the Standard Offer is much more stringent in every way, particularly the M&V requirements." — Active ESCO

Table 5-2. Position of Respondents within Firm

	Project Sponsors			
	ESCO	Customer Sponsors	Host Customers	ESCOs That Are Not Active
Corporate Officer (Pres., V.P.)	5	1	3	5
Regional Sales/Project Manager	5			7
Plant/Facility Manager		2	7	
Engineer	1	6	4	
Energy Manager		1	3	
Consultant		1		

We collected information on respondent's experience with other utility DSM programs in order to better understand the context for evaluating their experiences with the Standard Offer program. ESCOs were asked how their experiences in other DSM bidding or performance contracting programs compared to the Standard Offer; while customers were asked if they had participated in other utility DSM programs and, if so, how these programs compared to the Standard Offer.

Seven of the 10 ESCOs that responded have participated in DSM bidding or performance contracting programs at other utilities. Among that group, five of seven preferred the Standard Offer approach. Three of 11 customer sponsors and four of 17 host customers had previous experience with utility DSM programs. The three customer sponsors with previous experience indicated that "the Standard Offer program was much more difficult to get approval for and to receive rebates." One host customer indicated that the Standard Offer was easier because the ESCO was handling the paperwork, but that view was the exception even among host customers.

5.4 Program Marketing, Delivery, and Administration

"If a utility is going to get in the game, they should use PSE&G's program as a model; you can't beat it, it is state-of-the-art."— Active ESCO

"I have the highest respect for the DSM program people, but the reps have been pitching PSCRC." — Active ESCO

"I've had to contact PSE&G continuously and they are sometimes helpful. They are overworked and understaffed. They can't make decisions on M&V protocols; they have to go to the Board and Rate Council so often that they are not helpful." — Active ESCO

"PSE&G has too many departments and they all pass the buck. It's very difficult to get a straight answer. There are a lot of grey areas and they tell you to read the book or read the contract, but it's 1,700 pages long." — Customer Sponsor

Respondents provided some important feedback on PSE&G's marketing, delivery and implementation of the program:

- About two-thirds of the ESCOs and customer sponsors indicated that PSE&G program managers were very responsive and helpful (see Table 5-3). Virtually all customer sponsors indicated that either they or their consultant had to contact PSE&G staff for assistance on the program, typically involving clarifications on contract provisions or M&V protocols. Roughly one-third of the project sponsors were somewhat more critical (i.e., somewhat helpful and not helpful). Typical complaints among this group were difficulty in gaining access to program staff or obtaining answers to questions. Five project sponsors indicated that the program was understaffed and needed more personnel. Several ESCOs commented that the utility's internal re-organization in December 1994 had been unsettling because the new staff were not as knowledgeable about the program's requirements and original intent, which according to them was a problem given the complexity of the program.

Table 5-3. Quality of Assistance Provided by Utility Program Staff

	ESCOs	Customer Sponsors
Very Helpful/Responsive	5	3
Helpful/Responsive	1	2
Somewhat Helpful	1	3
Not Helpful	2	0
Other (e.g., contractor did paperwork)	0	1
No Response	3	2

- Several ESCOs commented that the utility could do a better job of marketing the program if customer service representatives were trained to aggressively and effectively promote the program. For example, one ESCO stated that PSE&G should take a more proactive role in "controlling customer perceptions of the standard offer program" in terms of the overall concept. Specifically, they recommended that the company should place additional emphasis on simple, easy-to-read program descriptions and marketing materials that clearly articulate the trade-off between the financial incentives offered for verified savings and the risks borne by project sponsors. They thought this type of marketing material from the utility was necessary because many customers are confused by proposals received from ESCOs and the utility is likely to have more credibility with customers in explaining the program's main features.

- In most cases, customer sponsors and ESCOs thought that PSE&G had reviewed and approved their proposals in a timely fashion. Seven of nine customer sponsors that responded indicated that their proposals had been approved within three to four weeks, while two indicated that it took about two months. Among ESCOs that responded, four of six indicated that proposals were approved in two to four weeks, while two stated that it took between one and two months.

- Almost all customer sponsors and most ESCOs believe that PSE&G program staff have implemented the program fairly. However, about half of the ESCOs made a sharp distinction between program staff (who they regarded as generally fair) and PSE&G field representatives, who they felt have steered customers towards PSCRC.

- Project sponsors, both ESCOs and customers, gave very mixed reviews to PSE&G's program materials and the software that had to be used in preparing project proposals (i.e., Automated Entry/Standard Offer Program). ESCOs that had participated in the 1989 bidding program or were active in the collaborative that designed the program gave generally high ratings to the written program materials (average of 4 out of 5). However, ESCOs that did not have prior experience in the 1989 bid program and many customer sponsors were quite critical of the program materials and the project proposal software. For example, on a scale of 1 to 5 (1=poor and 5=excellent), five ESCOs rated the clarity and usefulness of the written material at a 1 to 2 (see Table 5-4). Only 10 percent of the customer sponsors said that the instructions for preparing project proposals on the required software were "very clear," while 50 percent said they were either "not at all clear," or "not too clear" (see Table 5-4). Some customer sponsors were so frustrated with the project proposal process that they hired an M&V contractor to fill out the forms. Several project sponsors commented that the instructions were clear for lighting measures but were not clear for other measures and required modification.

Table 5-4. Assessment of Program Materials and AESOP Software

Ranking	ESCOs	Customer Sponsors
Q: Clarity of Written Materials		
5 (Excellent)	1	NA
4 (Very Good)	5	NA
3 (Good)		NA
2 (Fair)	4	NA
1 (Poor)	1	NA
Q: Clarity of Instructions for Preparing Project Proposals (i.e., AESOP)		
Very Clear	2	1
Somewhat Clear	3	4
Not Too Clear	3	2
Not at All Clear	2	3

NA = Not Asked

5.5 Marketing the Standard Offer

Based on our interviews, we would characterize the market environment as follows:

- Overall, many ESCOs stress that the program has been a "harder sell" than anticipated and they report low proposal to closing ratios.[41] Four of ten firms responding estimated that their proposal to closing ratios were between 8 and 15 percent. A few firms that target their marketing efforts very selectively report higher values (e.g., 40-70% of customers that are pre-qualified by the ESCO). Almost all large customers have been contacted by more than one ESCO and it appears that there has been intense competition among firms for projects involving these large customers. For example, the number of proposals received ranged from one to 12 among the seventeen host customers interviewed, with a median of four proposals per large customer. However, among the 25 respondents that were small C/I customers, we found that it was not uncommon for customers to have been approached by only one firm.

- Based on responses from ESCOs on their target markets, it appears that several firms are currently active in most market sectors (see Table 5-5). Some ESCOs are focusing on niche markets (e.g., small colleges, government post offices) while other firms target any large C/I customer.[42] Four to six firms appear to be actively marketing large public and institutional (e.g., schools, hospitals) customers. This table provides additional evidence on the degree of competition in the large C/I market and also suggests that few of the ESCOs that we interviewed are focusing on small C/I customers.

- ESCOs report that the sales cycle is typically quite long for the Standard Offer, often taking nine to 18 months to complete a retrofit project for a large customer. It is not uncommon for transactions to take even longer for public and institutional customers (18-30 months).[43]

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41 Proposal to closing ratio refers to the number of proposals made to customers compared to number of accepted proposals that produce a project.

42 Some ESCOs that gave very general responses (e.g., large C/I) might have had strategic reasons for not wanting to reveal the focus of their marketing efforts in more specific detail.

43 The long sales cycle is common for performance contracting type DSM programs, although the M&V protocol requirements for non-lighting measures appear to create some additional delays in the Standard Offer.

Table 5-5. Target Markets Identified by ESCOs

Sector	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Large C/I		X		X	X								X	
Large Industrial						X				X		X		
Medium Industrial							X	X						X
Small C/I					X									
Large Comm. Offices (privately-owned)			X					X						
Public				X					X		X			X
Institutional (Schools, Hospitals)				X			X		X		X		X	X
Retail					X		X							X
Colleges (small)		X												
Government (Post Offices)	X													
Large Pharmaceutical		X												
Hotel/Motel						X								

- We also asked ESCOs if they could draw any generalizations regarding the types of customers that have chosen not to participate in the program. Four ESCOs mentioned that it is extremely difficult to get multi-tenant facilities (or the rental real estate market) to participate because owners typically have 3-4 year leases and do not want to commit to the ten year contract. This situation appears to have adversely affected market penetration in non-owner-occupied commercial office buildings. Another ESCO cited the reluctance of "smaller customers insecure about their economic well-being over 10 years" to participate in the program.

- ESCOs listed several factors that adversely affected participation. When the program first began, there was substantial confusion in the marketplace because some ESCOs were marketing both the 1989 bid program and the Standard Offer to customers. Moreover, ESCOs stated that many utility field staff in regional offices had difficulty initially explaining the Standard Offer to customers. Other factors that were mentioned include: (1) the general uncertainty in the economy which makes many companies hesitant to sign long-term contracts, particularly for facilities located in "high cost" states such as New Jersey, (2) customer perception that the program is too complex and risky, (3) unacceptable contract provisions, particularly the lengthy contract terms, penalties for non-performance, and termination values included in many ESCO's Energy Service Agreements with customers, and (4) the time, uncertainty, and cost involved in getting M&V protocols approved for non-lighting measures.

- In terms of customer perception, we found that many customers do not distinguish between PSE&G and its affiliate, PSCRC, and many view them as one entity. Some ESCOs also complain that PSCRC has not done enough to dissuade customers of that notion, which gives PSCRC a distinct marketing advantage.

5.6 Role of PSCRC

In this section, we explore the role of PSCRC in the Standard Offer based on the views offered by various types of energy service firms (e.g., ESCOs, engineering services firms, lighting services contractors) that are actively working in the program as well as interviews with a sample of customers that are participating in PSCRC's Bright Investment program, which is targeted at smaller C/I customers.

5.6.1 ESCO Views

"A lot of firms would like to be working with PSCRC."— Active ESCO

"PSCRC is an 800-pound gorilla in the marketplace."— Active ESCO

During the course of our interviews, ESCOs presented their views on PSCRC's role in the program, often in the context of answering questions on their overall assessment of the program, suggestions for improvement, or on whether PSE&G had implemented the program fairly. To provide a context for this discussion, recall that PSCRC anticipated that it would provide capital investment services for projects developed, constructed, and managed by ESCOs and customers and offer project facilitation services to the DSM industry and customers (see Section 2.3). PSCRC formed the Energy Services Network (ESN), which included various types of providers (engineering/construction/procurement firms, energy service companies, lighting service contractors), as the primary vehicle to implement this latter objective.

ESCOs stated that PSCRC had played a positive role in stimulating the energy services infrastructure in New Jersey by providing capital investment services to other ESCOs and customers. However, ESCOs expressed sharply divergent views regarding PSCRC's role as a project facilitator, as indicated by the comments in the beginning of this section. Several companies that were still actively working with PSCRC maintained that it has played a positive role. Other respondents were quite critical of PSCRC's initial efforts to facilitate projects through the ESN and noted that many of the original ESCO members had dropped out after disagreements with PSCRC. These ESCOs were disgruntled with the ESN for several reasons.[44] First, some ESCOs expected PSCRC to provide them with customer marketing leads, while PSCRC maintains that they never intended to provide other ESCOs with free marketing services. Second, some ESCOs that were members of the ESN initially wanted customer leads and/or proposals that they brought to PSCRC for financing treated as proprietary and confidential. These ESCOs claim that PSCRC talked to customers about their proposals and that there were instances in which PSCRC gave referrals to "favored" vendors. PSCRC responds that the ESN was a decent idea, but that PSCRC tried to deal with too many players, which contributed to the perception that they were playing games and favorites. PSCRC claims that the ESN did not work that effectively primarily because of the level of competition in the marketplace.

Apart from their assessment of the way in which PSCRC implemented its mission, a number of ESCOs offered their overall views on DSM financial incentives and opportunities that should be available to utility shareholders. Several ESCOs stated that, as a matter of public policy, for-profit utility subsidiaries should not be allowed to provide energy services in their own service territory because "it was an invitation to problems." Another ESCO argued that the utility-affiliated ESCO should be limited to that of investor with no active marketing presence because of the ability to control and dominate the market. We discuss various policy options in more detail in Chapter 9.

5.6.2 Customer Reactions to Bright Investment Program

In May 1994, PSCRC began offering lighting efficiency improvements to smaller C/I customers under the terms and conditions of the Standard Offer, which it marketed as its "Bright Investment" program. PSCRC markets the program through lighting contractors and service vendors who are paid on a flat rate per kW for completed jobs. These lighting/contractor vendors work in designated regions that are assigned by PSCRC. PSCRC requires that its Bright Investment contractors improve lighting levels in their installations to 116% of existing levels.[45] In contrast to the large C/I market where there is no competing utility program, PSE&G also has a pilot program that offers pre-specified rebates for high efficiency lighting, HVAC, and motor measures to small I/C customers. In accordance with the Standard Offer, PSCRC is required to conduct M&V at a sample of the Bright Investment facilities. The energy service agreement between PSCRC and participating customers is quite different than contracts typically offered in the large C/I market with respect to allocation of risks. PSCRC's energy service agreement is quite short (i.e., about two pages). Customers must maintain the lighting equipment over the contract

44 Given the complexity of the business arrangements, we acknowledge the possibility that the reasons offered by ESCOs (on a confidential basis) do not fully encompass the conflicts between members of the ESN and PSCRC.

45 This requirement effectively limits PSCRC's risks related to persistence of savings over the contract term because PSE&G reduces energy payments to PSCRC for all facilities in the project if lighting levels fall below pre-existing levels in the sample of buildings.

term, but are not subject to any financial penalties if hours of operation or their use of the facility changes over the contract term. Thus, PSCRC does not pass these risks back to the host customers in this program. PSCRC offers to pay about 50% of the cost of the measures and customers are offered several payment and financing options to cover the remaining costs.

In the remainder of this section, we discuss the survey responses of a sample of Bright Investment customers. Among the 25 respondents, 16 were business owners or corporate executives, while nine were either plant, office, or facility managers. Only one customer, who operated a chain of retail stores, had previously participated in the utility's rebate program. When asked why they chose Bright Investments rather than PSE&G's small I/C rebate program, very few customers were even aware that the utility had a rebate program.

Implementation: Initial Marketing

When asked how they first learned about the Bright Investment program, 17 of 25 respondents indicated that they were contacted by PSCRC or Bright Investment representatives. Two customers each indicated that they were contacted by Bright Investment contractors and PSE&G representatives, while four others first learned about the PSCRC program by other means (mailings, fliers, advertisements, etc.). Overall, these customers were extremely pleased with the information that was provided about the program (e.g., 52% were "very satisfied" and 48% were "satisfied").

Implementation: Utility Contact and Administration

Customers were asked whether they contacted PSE&G staff for assistance with the program and whether they found utility staff to be helpful and responsive. About one-third of the sample said that they had no contact with PSE&G, while the remainder indicated that they had some contact with PSE&G. However, among this latter group, about 60% said that the utility replaced ballasts and installed or checked monitoring and metering equipment, which suggests that customers were referring to PSCRC, and not PSE&G. For example, one customer said that he was unsure whether it was PSCRC or PSE&G who had called 3-4 times and had come to check the monitors. Thus, it appears that a sizeable number of our sample of Bright Investment customers had some difficultly distinguishing between PSE&G and PSCRC.

Factors Influencing Selection Among ESCOs and Decision to Participate

We asked the 25 customers whether they were also contacted by other energy service companies and the primary factors that led them to choose PSCRC's Bright Investment program. Eighteen customers (72%) had only been contacted by PSCRC, while seven customers (28%) had been contacted by other firms. Among this latter group, two customers reported one contact, three customers had 2-3 contacts, one customer had four, and another had six. Explaining the reason they chose PSCRC, two indicated that PSCRC gave them the best deal, two indicated that PSCRC had good references, one cited PSCRC's presentation, and the last thought that PSCRC's affiliation with PSE&G would ensure better coordination. Most customers expect to be contributing some payment to PSCRC for the project. Roughly half of the respondents indicated that they paid up-front, while the other half stated that they would be paying over time.

Many customers gave more than one reason for proceeding with the program. Nineteen mentioned that the main reason was to reduce operating costs, save money, or lower electricity bills, while six mentioned energy savings and conservation. Five customers indicated that the new measures would increase lighting levels and for some would result in a better display of their merchandise. Two customers mentioned the availability of financing, and one said that it was backed by PSE&G.

Overall Assessment of Bright Investments Program

Overall, nearly all customers in our sample had positive comments on the Bright Investment program, however four customers were dissatisfied with the performance of the installation contractors. One customer said that PSCRC did a great job, but that the installation contractors "dropped the ball;" another company echoed this sentiment and said that he had hired security during the installation. A third respondent wished that he could have chosen among 2-3 installation contractors, while a fourth said that they did not like the initial installation contractor and had to have another contractor come in and finish the job. In terms of suggested improvements, one respondent would have liked a similar program for high efficiency motors and another indicated that savings should be measured more carefully and efficiently.

5.7 Views of ESCOs That Are Not Active in Program

We also conducted telephone interviews with 13 ESCOs (from an original sample of 23) who could have participated in the Standard Offer program in principle but are not currently project sponsors. This group of 23 ESCOs were either members of NAESCO or had participated in DSM bidding programs of other utilities. The survey focused on several areas: (1) familiarity with and impressions of the program, (2) reasons for not participating,

(3) overall assessment of the Standard Offer program concept, and (4) suggested program modifications that would encourage them to participate.

Table 5-6. Reasons Given by ESCOs for Not Participating as Project Sponsor

Reason	Frequency of Response
Targeted market too difficult to penetrate	2
Too difficult to compete because program design (i.e., fixed payment) would encourage cream-skimming	1
Too difficult to compete with so many ESCOs	2
Payment terms (cents/kWh) doesn't favor load management	1
No local presence in New Jersey	3
Didn't want to expand too fast or in this region	3
Other priorities (e.g., busy with bids for other utilities)	1

12 of the 13 ESCOs were familiar with the Standard Offer program to varying degrees. Five of the thirteen were quite knowledgeable because they were either involved in PSE&G's 1989 DSM bidding program or had some involvement with PSCRC's Energy Services Network. Three of the 13 firms claimed to be actively marketing PSE&G customers, although two of these firms had consciously decided not to be project sponsors in the Standard Offer program. In terms of first impressions, several respondents commented that the program was "unnecessarily complex" and "loaded for bear with bureaucratic red tape."

For those ESCOs not participating in the program, the perceived level of competition among energy service firms and difficulties in penetrating the target market appear to be important factors (see Table 5-6). For about one-third of the respondents, the primary reasons given for not participating were related to the firms' internal priorities and business strategy rather than the features of the PSE&G Standard Offer program (e.g., didn't want to expand too fast or in this region, other priorities).

Six firms were quite enthusiastic about the Standard Offer program concept (i.e., offering fixed prices for savings that were verified over the entire contract term), although several of these firms were critical of the PSE&G program and/or the role of PSCRC. Two firms were critical of the basic program concept. Three of the 13 firms indicated that they might consider participating in the future, particularly if PSE&G provided more direct marketing assistance and the program requirements were streamlined.

5.8 Overall Assessment of Program

We asked customers to indicate their general level of satisfaction with the program and the ESCO they selected (for host customers). We also requested that ESCOs and customers comment on their overall assessment of the program, identifying strengths as well as aspects of the program that have been least successful, including suggestions to improve the program.

5.8.1 Customer Satisfaction

- We found that the group of 11 customer sponsors had very strong reactions to the program, with seven respondents (64%) giving a top rating (very satisfied) while two other respondents were dissatisfied (see Table 5-7). Both dissatisfied customers complained about the programs's complexity and one observed that it involves "kindergarten engineering, but PhD paperwork."

- Among the 17 host customers surveyed, overall customer satisfaction appears to be quite high (35% indicating that they were very satisfied) with only one dissatisfied customer. About 50% indicated that they were "very satisfied" with the performance of the ESCOs that they chose.

- Among participants in PSCRC's Bright Investment program, we found that 16 of 25 customers were "very satisfied." The one customer who indicated that he was "very dissatisfied," complained that he is "not saving money" as promised. Customers offered nearly identical responses when asked about their satisfaction with their energy service provider (PSCRC).

5.8.2 Overall Assessment

Table 5-7. Overall Satisfaction With the Program

	Customer Sponsors	Host Customers
Very Satisfied	7	6
Satisfied	0	4
Somewhat Satisfied	1	6
Neither Satisfied/Dissatisfied	1	0
Somewhat Dissatisfied	1	1
Very Dissatisfied	1	0

Energy Service Companies

> *"If a utility is going to get in the game, they should use PSE&G's program as a model because you can't beat it."* — Active ESCO

> *"The program is starting to achieve its objectives, but it has been a hard sell. The program's strengths are the endorsement by the utility and the financial incentives to sponsors.*

The least successful aspect is the complexity of the program (audits, M&V, performance obligations)." — Active ESCO

"The program has been fair to middling; it could have been more successful but PSE&G was under prepared, specifically with regard to the M&V protocols." — Active ESCO

These comments illustrate the diversity of responses among the 11 ESCOs on their overall assessment of the program. Their comments fall roughly into three equal-sized groups: those that thought the program was great, those that thought the program was starting to achieve its potential but offered various suggestions, and those that were fairly critical of the program and wanted to see major changes.

Customer Sponsors

"Program is good but requires a lot of detailed paperwork and metering and this probably turns a lot of the small customers off."

"The program in theory sounds good but if I had known how difficult it would be, I would have said 'the hell with it' right away."

It is important to recall that many customer sponsors installed predominantly non-lighting measures. These projects tended to be more complex technically and the M&V plans were often costly and time consuming to develop, which explains the frustration expressed by several customer sponsors.

Host Customers

"Don't see how you can beat it. We will be getting 100% of our lighting replaced, are seeing monthly benefits in terms of bill savings, daily benefits in terms of lighting quality, and will see O&M benefits."

"I like the idea of being paid for energy savings, but the paperwork is too damn complicated."

"They could organize seminars and show people how to do it. With the percentage taken by the ESCOs, the paperwork and the monitoring, it was almost not worth it."

These comments encompass the range of reactions given by host customers in their overall assessment of the program. Eleven of the 16 respondents were in this first group who indicated that the program was "excellent" or "great." Among this group, several customers offered enhancements: additional publicity for the program, inclusion of additional measures to be covered by the M&V protocol (e.g., lighting controls). The three host customers in the second group (i.e., like program financial incentives but transaction costs too high) generally wanted to see the program revised so that it would be easier for a company to do on their own without ESCOs. The two customers in the third group were relatively dissatisfied and cited problems with the project proposal software (i.e., AESOP), time delays in receiving payments from the utility, and the necessity to simplify the pre- and post-implementation audit process in order to lower transaction costs.

5.8.3 Problem Areas and Suggestions for Improvement

In Table 5-8, we have grouped problems identified by project sponsors (ESCOs and customers) into six major areas and then listed their recommended suggestions (and frequency in parentheses). The six areas are: (1) complexity and high transaction costs of program, (2) influencing market perceptions and minimizing customer confusion, (3) issues associated with M&V protocols, (4) factors contributing to high turnkey costs for projects, (5) partial retrofit treatments because of cost-effectiveness limits, and (6) role of ESCO affiliated with host utility. We discuss our views on the relative merits of these suggestions in Chapter 9.

Customer sponsors were particularly frustrated with the program's complexity and high transaction costs. To better meet their needs, they suggested that PSE&G consider streamlining the Standard Offer material (including the contract), reduce the paperwork involved in getting project proposals submitted and approved, and work more directly with customers who want to sponsor projects on their own. Many ESCOs also attributed their low proposal to closing ratios in part to the complexity of the program, the customers' limited knowledge of the program or confusion when confronted with multiple proposals, concerns over certain contract provisions, and the degree of competition among ESCOs. They thought the situation could be improved if PSE&G focused their efforts on "conditioning the market" by marketing and providing information to customers on the specifics of the Standard Offer program rather than general advertising on energy efficiency and by providing additional training of PSE&G field representatives. One customer sponsor thought that utility certification of engineers and consultants to assist customers in various aspects of the program would be useful.

Concerns regarding the M&V protocols were mentioned quite frequently by both ESCOs and customer sponsors (see Table 5-8). Suggestions include having PSE&G develop additional M&V protocols for measures not covered and streamlining the process for approval of M&V plans for non-lighting measures.

Table 5-8. Program Limitations and Suggestions for Improvement

Problem Area	Suggestion	Frequency
Program Is Too Complex With High Transaction Costs	• Reduce paperwork	3
	• Streamline Standard Offer package	1
	• Work more closely with companies that want to do on own	1
Confusion in Market and Among Customers	• Utility field reps should market program aggressively (rather than general advertising)	2
	• Certify engineers/consultants to assist customers in various aspects of program	1
	• Pre-qualify ESCOs to work in areas of expertise	2
	• Improve training of PSE&G staff (and consultants	1
Measurement & Verification (Time, uncertainty, and expense in gaining approval)	• Anticipate areas where protocols necessary and develop	4
	• Streamline review/approval process	6
High Turnkey Costs for Projects	• Revise allocation of performance risks	3
	• Reduce administrative cost uncertainties	2
	• Allow initial payments based on estimated savings with "true -up" based on verified savings	1
Partial Retrofit Treatments Because of Cost-Effectiveness Limits	• Eliminate TRC because unnecessary in competitive market	2
Role of Utility Affiliate	• Limit utility-affiliated ESCO role to that of investor	1
	• Prohibit participation by host utility ESCO (but probably too late in NJ)	4

A number of ESCOs acknowledged that the turnkey costs are high for projects under this program, which inadvertently limits the number of measures that can be installed cost-effectively. ESCOs cited various contributing factors, some of which are related to the program's design while others are related to the business environment in New Jersey. These include: (1) high up-front marketing costs because of intense competition among energy service providers, (2) stringent and time-consuming M&V requirements, (3) project dollars that must be set aside to cover potential utility administrative costs, (4) project dollars that must be paid for liquidated damages, and (5) prevailing wage requirements in certain sectors. One ESCO estimated that marketing and project development costs (expressed in terms of $/kW) were almost two times as high in this program compared to other utility programs.

To improve this situation, several ESCOs suggested that PSE&G reduce the uncertainties associated with future administrative costs, change the program's design to allow for initial payments based on estimated savings with year-end "true-ups" based on verified savings, and consider shifting some performance risks that project sponsors had little or no control over to other entities (e.g., ratepayers).

Several project sponsors also felt that the program requirement that projects pass the TRC test contributed to partial retrofit treatments at some facilities. They cited examples of HVAC equipment replacement and fuel substitution measures that were attractive to customers but failed to pass the TRC test. One customer sponsor thought that the BPU shouldn't be concerned about how much a company is spending on energy efficiency improvements over and above the utility's incentive, while several ESCOs felt that the requirement that projects pass a TRC test should be eliminated given the degree of competition among energy service providers.

Finally, several ESCOs thought that PSCRC has had a negative effect on the development of a robust, competitive energy services market in the PSE&G service territory. While these ESCOs were critical of the initial decision to allow an ESCO affiliated with the host utility to participate, they thought it was probably too late for drastic changes to the rules for the PSE&G program.

Analysis of Free Rider and Spillover Effects

6.1 Overview

In Chapter 3, we reported the gross savings from the Standard Offer program, which were used in our calculations of the levelized total resource costs of the program in Chapter 4. The gross savings from a program can be defined as the reduction in energy consumption and/or demand due to all the measures that were implemented by participants under the program. In this chapter, we discuss issues related to determining net savings for the Standard Offer program. Net load impacts or savings from a program can be defined as the savings that are attributable to a utility program. This change in load should include, implicitly or explicitly, the effects of free riders, free drivers, changes in the level of energy service, and state or federal energy efficiency standards (CPUC 1993). Conceptually, net savings of a utility DSM program equals gross savings minus the naturally occurring savings (i.e., "free riders") plus the spillover effects (Train 1994).

The chapter organization and main themes are as follows. We first review the pertinent DSM regulations in New Jersey and suggest that a broader framework is appropriate for determining net savings from programs (i.e., include program spillover and free driver effects). We then describe the assumptions currently used by PSE&G in the Standard Offer program regarding "free rider" effects. Next, we present the results of our interviews with customers and ESCOs that participated in the Standard Offer program on issues related to free rider and program spillover effects. Estimates of free-rider effects are about 30% for customer sponsors, 9% for host customers participating in PSCRC's Bright Investment program, and 43% for host customers of ESCOs in the large C/I market. About 25-30% of large C/I customers in our sample that are installing high-efficiency lighting measures indicated that there was a high probability that they would install these measures at some time in the future prior to the end of their contract, and thus appear to be "deferred free riders." We also discuss policy and program design implications of our findings.

6.2 New Jersey's DSM Guidelines on "Free Rider" Effects

In the DSM incentive regulations adopted by the New Jersey BPU, utilities are required to file a measurement plan for each "performance-based" program (see Section 2.2). The measurement plan must include energy and capacity savings estimates for each program, which "shall expressly reflect deductions for any free rider effects. Free rider effects shall be determined prior to program implementation and subsequent changes will apply only to prospective installations." Free rider effects are defined to mean energy and capacity savings resulting from measures which would have been implemented even in the absence of the utility program. The BPU acknowledged that free rider effects are difficult to quantify "but believes it is important to adjust for this effect where it is known to exist and can be quantified, rather than to ignore the effects of free riders" (NJAC 1991).

At the time these regulations were adopted (1991), typical industry practice assumed that net savings attributable to a utility's program could be determined by accounting for "free rider" effects. Since then, DSM planners, evaluation experts, and a number of regulatory commissions have recognized that, in determining net savings from a utility DSM program, the effects of free drivers and program spillover effects must also be included.[46] Free drivers refer to non-participants who adopted a particular DSM measure as a result of a utility program. Spillover effects are defined as "reductions in energy consumption and/or demand in a utility's service area caused by presence of the DSM program, beyond program-related gross savings of participants. These effects could result from: (1) additional energy efficiency actions that program participants take outside the program as a result of having participated; (2) changes in the array of energy-using equipment that manufacturers, dealers, and contractors offer all customers as a result of program availability; and (3) changes in the energy use of non-participants as a result of utility programs, whether direct (e.g., utility program advertising) or indirect." (CPUC 1993) This interest in estimating program spillover effects is based in part on evidence that some utility DSM programs have helped to transform energy service markets; thus, the societal benefits of these programs can extend beyond savings of direct participants.

In the Standard Offer pilot program, the parties agreed that for the purposes of cost-effectiveness evaluation, they would assume that there were no free riders. However, the New Jersey BPU required that PSE&G evaluate the issue of free-riders based on the experience gained in the pilot. The statewide M&V protocols do not address the issue of free riders directly, but recognize that energy and capacity savings measured under the protocol may be modified as appropriate to account for free rider effects.

6.3 Effect of Free Riders on Total Resource and Utility Costs

The presence of free riders means that a utility is paying for investments that some of the program participants would have made on their own. In essence, free riders take program dollars from utility ratepayers and provide no net savings to the utility (Eto et al. 1994). The incentive payment from the utility represents a transfer from ratepayers to participants and does not typically affect the total resource cost. However, the utility's costs to administer and operate the program per unit of energy saved increase because participants would have adopted measures in the absence of the program. The impact of free riders on total resource costs depends on the magnitude of utility administrative costs and the number of free riders.

46 Estimating spillover and free driver effects typically requires extensive surveys of all customers that focus on program awareness and customer decision-making processes (Sonnenblick and Eto 1995).

Because administrative costs are typically 10-20% of the total program cost, the net societal impact of free riders typically adds less than 5% to the total resource cost of a program, but can significantly increase the costs to the utility per unit of saved energy (EPRI 1991).

6.4 Approach

DSM program evaluators typically attempt to estimate free rider effects either through billing analysis of changes in energy consumption with an appropriate comparison group or surveys of participants.[47] Because of the difficulty in defining a comparison group in a program like the Standard Offer, we chose to survey customers and ESCOs that had participated in the program.[48]

We asked customer sponsors and host customers a series of questions designed to provide some initial insights on issues related to free rider and program spillover effects (see Chapter 5 for a discussion of sampling). In analyzing free rider effects, Saxonis (1991) delineates free-riders into the following three categories:

- Pure free-rider: Would have taken the identical action without the program;
- Incremental free-rider: Influenced by the program to take action but would have adopted some other actions anyway; and
- Deferred free-rider: Takes the action promoted by the program sooner than originally planned.

Customers were first asked whether they had considered installing the energy efficient equipment prior to the Standard Offer program and why they chose not to install the equipment. Respondents were then asked to assess the likelihood (i.e., low, medium, high) that they would have installed these measures at some future time (i.e., now, within the next 1-3 years, 4-5 years, and 6-10 years) in the absence of the program. For the latter questions, we drew upon a typology developed by Peters (1994) to identify and classify pure and deferred free-riders in a utility bidding program. Customer sponsors (but not host

47 Train (1994) offers an excellent critique of methods that are often used to estimate net savings using randomly selected comparison groups of non-participants. He points out that these methods fail to account for the fact that participation in DSM programs is voluntary, that participants may have a predisposition to implement energy efficiency measures, and that, even without the program, customers that participate in a DSM program are likely to have a different implementation rate than customers who choose not to participate.

48 The ideal comparison group would include customers who were not offered the program but are otherwise identical to program participants. In the Standard Offer, all customers are eligible either directly or indirectly (through a third party energy service provider) and almost all large C/I customers have been marketed.

customers) were asked whether the program had affected their choice of equipment efficiency level to determine whether they might be incremental free-riders.

We classified respondents as "pure" free riders if they indicated that there was a high probability that they would have installed the measures at the same time in the absence of the Standard Offer program. We classified respondents as "deferred" free-riders if they indicated that there was a high probability that they would have installed the measures at some specified time in the future. For deferred free-riders, we then credited the customer with energy savings for the years prior to the time when they indicated that there was a high probability that they would have installed the measures. We then calculated a net-to-gross savings ratio representing the credited savings compared to the project's lifetime savings over the term of the contract. For example, if customers indicated that there was a high probability that they would have installed the measures within one to three years and had signed a 10-year contract, we credited the customers with two years of savings and assigned a 20% net-to-gross savings ratio.

To estimate a net-to-gross savings ratio for each group of customers (i.e., customer sponsors and host customers in the large C/I market and those that participated in PSCRC's Bright Investment project), we calculated the total net energy savings over the program's lifetime for all individual customers and divided it by total gross energy savings for each customer. These net-to-gross savings ratios provide us with an initial estimate of free rider effects for customer sponsors and our sample of host customers. If we ignore program spillover effects, then one minus the net-to-gross savings ratio is sometimes called the rate of free ridership. For example, a net-to-gross ratio of 0.80 implies that free rider effects are about 20%.

We also explored potential program spillover effects in our interviews with customer sponsors and host customers. Specifically, we asked customers if they had installed additional measures that were not included in the Standard Offer program and if, as a result of installing these energy-efficient measures through the program, they would install similar measures on their own in the future.

6.5 Estimation of "Free Rider" Effects from Customer and ESCO Surveys

In this section, we present results of our interviews with customer sponsors and host customers on questions related to free rider effects.

6.5.1 Customer Sponsors

The project would have been "below the company hurdle rate without [the Standard Offer program]"

The Standard Offer program "pushed us over the company guidelines for investments."

The "sneaky thing is" that we probably would have installed the measures anyway and possibly sooner.

Seven of 11 customer sponsors indicated that they had considered installing the measures prior to the Standard Offer program. Among this group, four customers indicated that the measures were not installed previously because of economic considerations (e.g., they were either too expensive, not economic, below the company hurdle rate, or there were other projects with shorter payback periods). Four customers indicated that they had not previously considered installing these measures. One respondent said that he was not looking at fuel switching projects until he heard about the Standard Offer program and another indicated that their company's project was designed around the Standard Offer program and would not have been justifiable without financial incentives from the utility.

We categorized two customer sponsors as pure free-riders because they indicated that they would have installed identical measures at the same time. Another customer sponsor stated that his company would have installed new measures at the same time, but the equipment might not have been as efficient; this customer was classified as an incremental free-rider (see Table 6-1). One customer sponsor indicated that the retrofit would have been on the list of things to do to reduce operating costs and probably would have been installed within 1-3 years and was classified as a deferred free rider. Weighting the responses of customer sponsors by their energy savings, we calculated a net-to-gross ratio of 0.70, which includes both pure and deferred free-riders.

6.5.2 Host Customers (Large C/I Market)

"We were looking at lighting, but it would have taken longer" without the Standard Offer program.

"Weren't aware of the savings."

"Wasn't cost-effective to do it all without the program."

Ten of the 17 host customer respondents indicated that they had not considered installing new energy efficient equipment prior to the Standard Offer. One customer described his philosophy as, "if it's not broke, don't fix it," and others said that they weren't aware of

Table 6-1. Estimating Free Rider Effects for Customer Sponsors

Project Number	Measures	Customer Response: Would have done at same time?	Would have done in 1 - 3 years?	Would have done in 4 - 5 years?	Would have done in 6 - 10 years?	LBNL Classification: Incremental Free Rider?	Deferred Free Rider?	Pure Free Rider?	Net-to-Gross Savings Ratio
1	HVAC VSDs	High	High	High	High			✔	0%
2	Lighting Motors	Medium	High	High	High		✔		40%
3	Lighting	Low	High	High	High		✔		40%
4	Lighting	Low	Low	Medium	High	✔	✔		80%
5	HVAC Fuel Switching Lighting	Low	Low	Low	Low				100%
6	Fuel Switching Lighting	Low	Low	Low	Low				100%
7	HVAC Gas Eng. Driv.	High	High	High	High	✔			*100%
8	Fuel Switching Indus. Process	Low	Low	Low	Low				100%
9	Fuel Switching	Low	Low	Low	Low				100%
10	VSD HVAC Fuel Switching Lighting	High	High	High	High			✔	0%
11	HVAC Motors Lighting	Low	Medium	Medium	High	✔	✔		53%
Total: 4,829 kW Reduction								Weighted Average:	70%

* This customer indicated that there was a high probability that he would have installed new equipment, but that he would not have installed the more efficient gas equipment. We assume that this customer is not a free rider because it is unclear how efficient the new installation would have been had he done it on his own.

the measures, didn't know the savings potential, or they needed the permission of landlords. Among the seven customers that had considered installing these measures, reasons given for not going ahead previously were cost and trouble getting an installation contractor.

We classified one customer as a pure free-rider and six customers as deferred free-riders based upon their responses (see Table 6-2). For example, one host customer stated that without the rebate it probably would have just taken his organization longer to install the more efficient measures, while another indicated that the program probably affected the timing of the installation because they have a fixed budget and could not have afforded a complete change out. Weighting the responses by their energy savings, we estimate a net-to-gross ratio of 0.57 for our sample of host customers.

6.5.3 Bright Investment Customers

About 75% of our sample of 25 Bright Investment customers indicated that they had not considered this project prior to the Standard Offer program. Among the group that had considered their project before the program, about half said that they had not installed the measures because they were cost prohibitive. We classified only one Bright Investment customer as a pure free-rider. Six other customers indicated that there was a high probability that they would install the measures at some point in the future, which suggests that they might be viewed as deferred free-riders. We estimate a net-to-gross ratio of 0.91 for our sample of Bright Investment customers (see Table 6-3).

6.5.4 Energy Service Companies

We also asked ESCOs to assess the probability (high, medium, or low) that their host customers would have installed these measures at some time in the future without the program. Typically, ESCOs offered their responses in terms of the percentage of customers that would have installed the measures on their own or at some time in the future in the absence of the program. Thus, their answers are not directly comparable with the method we used to calculate net-to-gross savings ratios for customer sponsors and host customers.

Most ESCOs believe that free riders are not a large phenomenon. For example, six ESCOs indicated that they thought that the probability was low that any customers would have installed these measures on their own. One ESCO explained that customers generally install VSDs for comfort, purchase the cheapest mechanical rooftop units, and probably would not get around to installing energy efficient lighting measures. Another ESCO based his assessment on the fact that very few of the jobs in New Jersey have paybacks of less than one year.

Table 6-2. Estimating Free Rider Effects for Host Customers

		Customer Response				LBNL Classification		
Project Number	Measures	Would have done at same time?	Would have done in 1 - 3 years?	Would have done in 4 - 5 years?	Would have done in 6 - 10 years?	Deferred Free Rider?	Pure Free Rider?	Net-to-Gross Savings Ratio
1	Lighting	Low	High	High	High	✔		20%
2	Lighting	Low	Low	Low	Low			100%
3	Lighting	Low	Low	Low	Low			100%
4	Lighting	Low	Low	Low	Low			100%
5	Lighting	Medium	Medium	High	High	✔		45%
6	Lighting	Low	Medium	Medium	Medium			100%
7	Lighting	Low	Low	Medium	High	✔		80%
8	Lighting	Low	Low	Medium	High	✔		80%
9	Lighting	Low	Low	Medium	Medium			100%
10	Lighting	--	60%	70%	70%	✔		46.5%
11	Lighting	High	High	High	High		✔	0%
12	Lighting	Low	Low	Low	Low			100%
13	Fuel Switching	Low	Low	Low	Low			100%
14	Lighting	High	High	High	High		✔	100%*
15	Lighting	Low	Low	Low	Low			100%
16	Lighting	Low	Medium	High	High	✔		45%
17	Lighting	Medium	Medium	Low	Low			100%
Total: 4,917 kW Reduction								Weighted Average: 57%

* This customer indicated that there was a high probability that he would have installed the measures at the same time, but also indicated that he had not considered installing these measures prior to the Standard Offer and that the rebate helped him to convince his landlord to allow the installation. We classified this customer as a non-free rider because of the contradictory nature of his response.

Table 6-3. Estimating Free Rider Effects for Bright Investment Customers

	Customer Response				LBNL Classification		
Project Number	Would have done at same time?	Would have done in 1 - 3 years?	Would have done in 4 - 5 years?	Would have done in 6 - 10 years?	Deferred Free Rider?	Pure Free Rider?	Net-to-Gross Savings Ratio
1	Low	Medium	--	--			100%
2	Low	Low	Medium	Medium			100%
3	High	High	High	High		✔	0%
4	Low	Low	Low	Low			100%
5	Low	Low	Low	Low			100%*
6	Low	Medium	High	High	✔		45%
7	Low	Medium	Medium	Medium			100%
8	Low	Low	Low	Low			100%
9	Low	Medium	Medium	Medium			100%
10	Low	Low	High	High	✔		45%
11	Low	Medium	High	High	✔		45%
12	Low	Medium	Medium	Medium			100%
13	Low	Medium	Medium	High	✔		80%
14	Low	Medium	Medium	High	✔		80%
15	Low	Low	Low	Low			100%
16	Low	Low	Low	Low			100%
17	Low	Low	Low	Low			100%
18	Low	Low	Low	Low			100%
19	Low	Low	Low	Low			100%
20	Low	Low	Low	Low			100%
21	Low	Low	Low	Low			100%
22	Medium	High	High	High	✔		20%†
23	Low	Low	Low	Low			100%
24	Low	Low	Low	Low			100%
25	Low	Medium	Medium	Medium			100%¥
Total:	455.61 Gross kW Reductions/Term				Weighted Average:		91%

* This customer indicated that there was a high probability that he would have installed measures at some point in the future, but he also indicated that he would not have replaced with more efficient equipment, so we did not count him as a free rider.

† This customer indicated that there was a high probability that he would have installed the measures at the same time, but he also indicated that he had not considered installing these measures prior to the Standard Offer, so we did not count him as a pure free rider, only as a partial free rider.

¥ This customer indicated that there was a high probability that he would have installed more efficient measures within 1 - 3 years, but he also indicated that this installation will take place at the new facility where they will be moving in two years, so we did not count him as a free rider.

Three ESCOs implied that some customers might be deferred free-riders, but certainly no more than 10-20%. For example, one ESCO stated that there was a low probability that customers would have installed heat recovery and fuel substitution measures within five years because "customers just keep running their old equipment, as long as it's working." Another ESCO indicated that up to 10% might have undertaken the installations within 3 years, between 10-15% might have done it within 5 years, and 15-20% might have done it within 10 years (at least for HVAC applications which were driven by new regulations pertaining to CFCs). One ESCO estimated that "for 80-90% of the customers, the Standard Offer was the critical catalyst and that 10-20% might have done it" without the program.

6.6 Spillover and Free Driver Effects

In this section, we discuss results of our interviews with customer sponsors and host customers on questions related to program spillover and free driver effects.

6.6.1 Customer Sponsors

Two of 10 customer sponsors indicated that they will be installing additional measures that are not covered by the M&V protocols (e.g., controls). Customer sponsors were divided on whether they would choose to install these measures on their own now that they had some experience. Three respondents said that they would not install the measures. One customer explained that it's a matter of price and they probably would still use the less efficient equipment because of the lower up-front costs and shorter payback periods. Three others indicated that they would install the identical measures, although two indicated that they would have done so without the program. Three said that they haven't yet had enough experience with the measures.

6.6.2 Host Customers (Large C/I Market)

Eight of 17 host customers indicated that they will be installing a variety of measures outside of the Standard Offer program (e.g., air conditioning system, motors, VSDs). Among this group of eight host customers, five stated that they were planning to install these measures before they learned about the Standard Offer program. For example, one host customer indicated that his company has a 10% energy reduction goal by 1996, which is the driving force behind the installation of these other measures (e.g., VSDs, chiller optimization, EMS). Of the other three, one indicated that the program had encouraged them to think about ways to become more efficient, the second believed that this was a good time to install more insulation and storm windows, and the third was installing motors and other equipment on their own because the ESCO did not return and it was not clear that these measures would be covered under the program.

Eight of 17 host customers indicated that they would install the more efficient equipment now that they have had some experience with the measures and three others indicated that they would probably do so as well. One customer indicated that they have "included some of this stuff in our design standards" for new buildings.

6.6.3 Bright Investment Customers

Interestingly, 13 of the 25 Bright Investments customers in our sample indicated that they would install the lighting equipment on their own without a utility-sponsored program, now that they have had some experience with the measures. For example, one customer reported that they now ask the landlord to consider installing energy efficient lighting when they open a new store. Five customers indicated that they would not install these measures on their own, primarily because they were too expensive, while five other customers were unsure because they didn't have sufficient experience yet with the measures.

6.7 Discussion

As noted earlier, if program spillover effects are ignored, then free rider effects are simply the inverse of the net-to-gross savings ratio. Table 6-4 summarizes results of our interviews with customers and ESCOs and presents estimated free rider effects (including only pure free riders as well as the combined effect of pure, incremental and deferred free riders). Estimates of free rider effects are about 30% for customer sponsors based on our interviews. For ESCO-sponsored projects, our analysis of the sample of host customers yielded

Table 6-4. Summary of Free Rider Estimates

Group	Pure Free Riders	Pure & Deferred Free Riders
Customer Sponsors	16%	30%
Host Customers (Large C/I)	4%	43%
Host Customers (Bright Investment)	2%	9%
ESCOs*	0%	0-20%*
Type of Measure		
Lighting only	3%	33%
Projects with Non-Lighting Measures	18%	27%

* ESCOs responses given in terms of percentage of host customers that would have installed measures on their own at some time in the future.

estimates of 9% for Bright Investment participants and 43% in the large C/I market. For projects that ESCOs have sponsored in the Standard Offer, they generally believe that free rider effects are not a large phenomenon among large C/I customers (0-20% range).

We also calculated free rider effects by type of measures installed based on responses of customer sponsors and host customers. For lighting only projects in our sample, few customers were pure free riders (3%), although a number of customers indicated that they probably would have considered installing lighting efficiency improvements at some point in the future (net-to-gross savings ratio of 0.67, which implies 33% free ridership). For project involving non-lighting measures, we calculated a net-to-gross savings ratio of 0.73 (or 27% free ridership rate), including both pure and deferred free riders.

It is important to note the following caveats in interpreting these initial estimates of free riders. First, while we attempted to interview all customer sponsors (11 of 19 responded), we interviewed only a limited number of host customers and, thus, our sample may not be representative of the population of host customers. Second, developing estimates of free riders based solely on customer self-reported responses to survey questions necessarily involves some degree of judgment by the analyst in interpreting a customer's complex decision-making process. Third, the circumstances in New Jersey create a situation in which it is quite difficult to separate the underlying natural adoption rate for energy-efficient technologies from the effects of previous utility DSM programs on customer decision-making processes. ESCOs active in PSE&G's 1989 bid program have targeted and extensively marketed many large C/I customers. As a result, some large customers that appear to be free-riders in the Standard Offer program may have been influenced by the earlier bidding program. For example, when customers indicate that they considered this project prior to the Standard Offer or would have installed the measures at some point in the future, this might be the result of contact with ESCOs that were marketing another utility DSM program, rather than solely through their own internal project evaluation process.

As noted earlier, estimates of net savings for a utility DSM program should include free rider as well as spillover and free driver effects. Our interviews with customers suggests that the design of the Standard Offer creates some inadvertent spillover effects. In particular, some customers have installed additional measures that are not included in the program, primarily because of the M&V requirements. There is also some evidence for spillover effects that are more typically associated with a successful utility program. Specifically, a number of customers indicated that their future investment practices may change as a result of experience gained through the program with high-efficiency lighting and equipment. In our study, we made no attempt to develop quantitative estimates of program spillover and free driver effects. We have no doubt that some customers, after receiving preliminary audit and proposal from ESCOs that are marketing the Standard Offer, decide to install high-efficiency measures on their own. The low proposal closing ratios reported by ESCOs and customer perception of the risks involved in participating in the Standard Offer leads us to conclude that the Standard Offer program creates some free driver effects.

6.8 Summary

We would summarize our findings as follows:

- Based on our interviews with project sponsors and host customers and our subsequent analysis, it appears that the current planning assumption of 0% free riders is probably not appropriate.
- We have somewhat more confidence in the free rider estimates of 9% derived from our interviews with Bright Investment customers than those reported for host customers and customer sponsors in the large C/I market because the effects of previous large-scale utility DSM programs are less of a factor.
- A sizeable number of large C/I customers in our sample that are installing high-efficiency lighting measures may be "deferred" free-riders.
- We found evidence to suggest that the Standard Offer program creates some program spillover effects and potential free drivers, which, though unquantified, will tend to partially offset free rider effects.

6.8.1 Recommendations

- If PSE&G and other interested parties in New Jersey believe that developing improved estimates of net program savings are a high priority, then we would recommend that PSE&G devote additional resources to quantifying program spillover and free driver effects and refining estimates of free rider effects through various statistical and survey methods.
- Our preferred approach would be to minimize potential free rider effects through program design changes, but the Standard Offer concept is not particularly amenable to this approach.[49] One of the byproducts of offering a pre-specified payment for savings that are available to all customers is that some customers may be considering these actions on their own. In the future, PSE&G could adjust future Standard Offer payment levels to account for free rider effects as one option to address the equity

[49] For example, in a utility customized rebate program, the utility may exclude certain measures with short economic payback times or not provide an incentive for certain measures that customers are adopting at a rapid pace on their own.

issue between ratepayers and project sponsors/customers (e.g., ratepayers providing financial incentives to customer sponsors or ESCOs whose host customers would have undertaken these actions on their own). However, this approach will not reduce the number of free riders and, if pursued, any adjustment to payment levels should also reflect the countervailing effects of program spillover and free drivers.

- Because free riders reduce estimates of savings directly attributable to the utility, free rider effects should also be considered in the context of utility efforts to recover "lost revenues."

Review of PSE&G Measurement & Verification Procedures

7.1 Overview

The statewide measurement and verification (M&V) protocols, supplemented by the M&V procedures and sampling plan(s) developed by PSE&G, are a defining and distinctive feature of the Standard Offer program.[50] The New Jersey BPU's DSM regulations require that measurement techniques used to verify savings in "performance-based" programs, such as the Standard Offer, be periodically reviewed (every two years) in order to reflect implementation experience as well as advances in measurement techniques. In this chapter, we review selected portions of PSE&G's M&V procedures and Sampling Plan as outlined in the Standard Offer RFP.[51]

First, we discuss the baseline assumptions used by PSE&G to establish energy savings. Defining the baseline is critical to determining the net savings attributable to a utility DSM program: distinguishing the naturally occurring changes in the efficiency of the equipment and building stock from the impact of the utility's program (see Chapter 6). We have some concerns that PSE&G's approach may overstate program savings. Second, we examine one of the M&V protocols in some detail (i.e., Method 1, which covers most lighting measures), because about 65% of the program's estimated savings derive from lighting measures. Based on our review of this protocol and the sampling plan required by PSE&G, we see no direct evidence to suggest that savings measured under this protocol meet the stated objective of the statewide M&V protocol (i.e., 90% confidence that savings equal or exceed the value measured). We discuss limitations in the current Sampling Plan and suggest alternatives that may provide better accuracy for an equivalent or reduced cost. Third, we provide an overall assessment of the New Jersey M&V protocols compared to "typical" practice at many utilities at the time they were adopted. We conclude that the incremental benefits or value of the M&V protocols, specifically improved accuracy and reduced bias of savings estimates, appear to be cost-effective compared to the costs. However, we also urge parties in New Jersey to reassess the adequacy of the M&V protocols taking into account the confidence level standard that is appropriate for verifying DSM savings,

50 The M&V protocols were developed as part of the collaborative process involving utilities, regulatory staff at the New Jersey BPU and Division of Ratepayer Advocates, ESCOs, and contractors. Each utility was also required to develop a measurement plan for specific DSM programs that would include both Sampling Plans and verification procedures.

51 Our review draws upon recent work by LBNL on DSM program evaluation (Sonnenblick and Eto 1995), M&V procedures used by Pacific Gas & Electric in their performance-based DSM programs (Schiller 1995), and the work of other analysts that have looked at PSE&G's M&V procedures (Gordon et al. 1994; Halpern 1995).

improved impact evaluation techniques, and ways to make use of existing data that has been collected in the program (e.g., hours of operation in different types of facilities).

7.2 Establishing Appropriate Baseline Conditions to Estimate Savings

The Standard Offer RFP indicates that "any energy savings measure that is required by law, is required by building or other codes, or in the opinion of PSE&G, which represents standard industry practice, is not eligible." The approach used by PSE&G to establish appropriate baseline conditions varies by sector.

7.2.1 New Construction

In new construction, PSE&G uses the State energy building code as the "baseline" against which energy-efficiency improvements are compared. Conceptually, savings should be determined relative to "typical construction practice" which may exceed or lag current building codes depending on building type, end use, and code enforcement. If current practice exceeds the State energy code, then savings attributable to the program may be overstated because developers are being paid to install equipment which is typical of current construction. We agree with Gordon et al. (1994) that PSE&G should conduct a detailed study of current practices in order to establish the appropriate baseline in new construction.

The M&V protocols are particularly problematic in new construction. For example, in lighting retrofits, the developer/sponsor must measure hours of operation. For buildings constructed on speculation or build-to-rent, the developer is not the occupant and usually does not even know the ultimate tenants, yet project economics are based on hours of operation. In these situations, hours of operation almost become a random and uncontrolled factor for the developer. It would be simpler and no less risky (for the developer) to be paid incentives for lighting efficiency in new construction based on typical operating hours for each particular building type. In new construction, it is more realistic to conduct program-wide evaluations to assess overall savings, assure contractor performance through visual inspection, equipment testing, and spot metering, and verify typical savings of individual equipment through laboratory and field testing (Gordon et al. 1994).

7.2.2 Existing Buildings

For existing buildings, PSE&G typically uses the connected load of existing equipment to establish baseline conditions. This method is reasonable for early replacement (i.e., retrofit) situations, but not for situations where the customer was already planning to replace the equipment. In these latter cases, savings should be determined by comparing the estimated usage of the conventional equipment that the customer would have purchased with the high-efficiency equipment proposed by the sponsor.[52] Using existing equipment to establish the baseline is likely to overstate savings because conventional equipment that the customer plans to install would be more efficient than existing equipment. For fuel switching projects that we reviewed, it appears that appropriate baseline conditions are being established.

However, for some lighting projects, we are concerned that baseline conditions are not appropriately established. For example, if an existing building is undergoing a major renovation or remodel and has standard magnetic ballasts (which were commonly used in the 1970s and 1980s), the appropriate baseline should be energy-efficient magnetic ballasts (which are required by the federal standards). These ballasts have higher minimum efficiencies than the standard magnetic ballasts. However, in reviewing the program tracking database, we found that prior to retrofit, project sponsors claim that about 85% of the ballasts were standard efficiency magnetic ballasts, while only 15% of the ballasts were energy-efficiency magnetic ballasts.[53] Thus, for lighting, it appears that PSE&G assumes that all lighting system changes involve discretionary retrofits rather than remodel or major renovation situations. At a minimum, we recommend that PSE&G examine the incidence of major remodeling/renovation in commercial buildings to ensure that savings are not being overestimated in these situations.

7.3 Description of M&V Protocol for Lighting Measures

In this section, we examine the M&V protocol and PSE&G's Sampling Plan for lighting measures that do not modify hours of lighting operation. For these types of measures, savings are estimated in accordance with the statewide protocol (Method 1) and additional M&V procedures and sampling plan specified by PSE&G. The stated objective of the statewide M&V protocols are to provide "90% confidence that savings equal or exceed the

52 As noted previously, the RFP gives PSE&G the option of excluding measures that are standard industry practice. The language is ambiguous in some situations, for example where the customer is planning to replace their HVAC equipment, proposes a high-efficiency product, and wants to take credit for the difference between that product and their existing equipment. Based on current industry practices, the customer would choose a similar product with somewhat lower efficiency (but still more efficient than the existing equipment). In this situation, it is not a question of excluding the measure, but rather establishing the appropriate baseline.

53 We used information in the program tracking database on pre-retrofit condition to calculate existing lighting equipment.

value measured." The basic procedure used to verify the savings of measures that are included by the Method I protocol is as follows:

(1) Establish baseline connected load

Project sponsors provide a complete inventory of current fixtures in a facility that are to be modified or replaced, with the kW demand taken from a Luminaire Wattage Table developed by PSE&G.[54] The sum of connected loads is determined based on these tabulated values. PSE&G verifies this information during a pre-implementation audit which includes the number and type of fixtures, type and number of ballasts, type and number of lamps, and foot-candle (fc) readings of representative areas of the facility.

(2) Establish post-installation connected load

For each luminaire proposed for installation, the sum of connected loads is determined based on either values as determined by the Luminaire Wattage table or actual metering of the installed luminaires. PSE&G conducts a post-implementation audit during which it verifies installation of new equipment, and takes fc readings to determine light level reductions.

(3) Determine hours of lighting operation

Hours of lighting operation are estimated by installing permanent metering on control circuits or individual devices, or a sample of control circuits or devices in accordance with PSE&G's sampling plan (PSE&G 1993).[55] PSE&G's sampling plan provides that a selected number of control circuits be metered within each facility based on groupings in pre-specified hours of operation bins. PSE&G's stratification scheme classifies control circuits according to combinations of estimated weekly on-peak and off-peak hours of operation. Weekly on-peak hours of operation are grouped into three strata: 0 to 30 hours per week, 31 to 50 hours per week, and 51 to 70 hours per week. Weekly off-peak hours of operation are grouped into five strata: 0 to 5 hours per week, 6 to 20 hours per week, 21 to 50 hours per week, 51 to 75 hours per week, and 76 to 98 hours per week. Thus, there are fifteen (3 x 5) groups defined by the sampling scheme and each affected control circuit in a facility is assigned to one of these 15 groups.

The number of control circuits metered in a group depends on the total number of control circuits assigned to that group, using the following guideline (see Table 7-1).

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54 Available lighting equipment was grouped by lamp, ballast, and fixture type based on information provided by manufacturers. Wattage values were selected within each group to include most fixtures with a 5% deviation from the selected value and were then assigned to all fixtures within a class.

55 PSE&G's Sampling Plan for Control Circuits is in the Standard Offer RFP, Appendix A (Exhibit 5).

Table 7-1. PSE&G Sampling Requirements for Control Circuits

Number of Control Circuits in Group	Number of Control Circuits in Group to be Metered
1-3	All
4-10	3+20% of total circuits
11-30	5+10%% of total circuits
31-50	8+8% of total circuits
51-100	10+5% of total circuits
>100	15

Source: PSE&G Standard Offer RFP, Appendix A, Exhibit 5

Run hour meters must be installed on a permanent basis and hours of operation are metered for the term of the contract. In determining the average hours of operation for a particular group, a control circuit whose actual metered hours of operation vary by more than 10 percent from the bounds of its originally assigned bin will be removed and not included in determining the actual hours of operation for that group. The "outlier" control circuit will then be reassigned to another bin on the basis of the observed data. Reapportionment will be made monthly barring extenuating circumstances. Within an assigned group, the selection of control circuits to be metered is not necessarily random: control circuits with large connected loads are in general to be selected for metering to represent the group.

The data from each group are combined using simple or load-weighted averaging to derive a single estimate of run hours for that group, differentiated by Utility Time Period.

(4) Determine energy savings as the product of run hours and the difference between pre-installation and post-installation connected loads

For each group, the difference between the pre-connected load (Step 1 above) and post-connected load (Step 2) over all affected equipment is determined. The product of this difference and the estimated run hours for the group (Step 3) during each time period established by the utility yields the estimate of energy savings for that time period.

(5) Adjustments to lighting energy savings payments: lighting quality and lighting - HVAC interactive effects

In order to receive full payment for delivered energy savings, light levels after installation must meet or exceed pre-implementation lighting levels. Payments will be reduced proportionately (by the ratio of footcandle readings) in situations where post-implementation lighting levels are below pre-implementation levels. Over the contract term, the project sponsor must maintain lighting levels at 90% of base minimum lighting levels. Payments are reduced in proportion to the footcandle reductions (above the 10% deadband) and thus the standard encourages equivalent lumens in building spaces before and after retrofit.

The Statewide protocol also specifies that lighting measures installed in conditioned space be credited with a 5% interactive factor to reflect HVAC savings that are assumed to occur as a result of decreased indoor lighting wattages. PSE&G increases payments by 5% in all time periods to account for these interactive effects.

7.4 Critique of PSE&G's Sampling Plan

In this section, we critique several aspects of PSE&G's sampling plan for control circuits. Without knowing PSE&G's underlying rationale for the stratification scheme used in the Utility's Sampling Plan, the motivation for some aspects of the scheme remain unclear.[56] We raise the following issues:

- The articulation of the *required statistical level* of the estimate "90 percent confidence that the true value equals or exceeds the estimated value" seems incomplete in that there is no requirements for the statistical power of the test or precision of the estimate.

- It may be difficult to appropriately *allocate* control circuits to hours of operation groups, given that the bins seem fairly narrow relative to the probable accuracy of a priori estimates of hours of operation.

- There is no requirement that control circuits within a group be *randomly selected* for metering; instead sample selection within a bin appears to be based on a combination of convenience and of connected load.

- The monthly *reallocation* of mis-binned control circuits violates the statistical basis of stratified sampling.

- We see no explicit acknowledgment of the connection between the specifications of the *number of control circuits to be metered within a group* and the expected contribution of the estimates made for the group to the accuracy of the overall estimate of hours of operation, energy savings, or monetary savings.

- The strata definition and therefore the resulting *groups* do not seem completely coherent in terms of payment and other dimensions.

In the next sections, we address each of these issues in more detail and then propose an alternative to PSE&G's sampling plan scheme.

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56 We requested that PSE&G provide any relevant background studies or workpapers on their Sampling Plan; utility staff informed us that the relevant information was included in the Standard Offer RFP.

7.4.1 Required Statistical Level

PSE&G's Sampling Plan is based on hours of operation, and thus target levels of precision and accuracy would be for *hours of operation*. However, we believe that the true target of the sampling should be energy savings and/or the concomitant value of energy savings (i.e., lifecycle net benefits), rather than hours of operation. While hours of operation constitutes an absolute measurement, savings constitutes a relative one. The stated design objective for utility sampling plans as given in the Statewide M&V Protocol is "90 percent confidence that savings equal or exceed the value measured."[57] This means that the hypothesis that the true mean is less than the estimated mean will be rejected at level 0.10 (the p-value must be less than or equal to 0.10). This articulation seems insufficient, because it fails to specify the required power of the test. That is, if one sampled very few circuits, confidence intervals would be very broad and therefore probably cover the "true" mean, but fail to give sufficiently precise information. Statistical power or an equivalent threshold, such as 10 percent precision as commonly articulated in the so-called "90/10" standards, should be specified for the stipulation to be meaningful. The question remains whether this standard articulation of "10% precision" is appropriate in this context; we address this issue in more detail in Section 7.6.2. In any case, we can not adduce any direct connection between the sample sizes specified in PSE&G's current sampling plan and the efficient achievement of 90 percent confidence, even for implied target levels of precision.

7.4.2 Allocation

It may be difficult to assign control circuits to groups on the basis of weekly hours of operation because hours of operation is not a readily observable characteristic. While the appropriateness of the group assignment made for any particular metered circuit may be judged after some data are collected, the accuracy of the assignment of other control circuits relative to their true group membership will remain unknown. While the PSE&G plan provides for the reassignment of *metered* control circuits to new groups if they appear not to fall in the group to which they are originally designed, the majority of control circuits are not metered and therefore their group assignment remains in question. The reassignment of metered control circuits to new groups based on observed data raises additional statistical issues, which are discussed in Section 7.4.4.

57 "That is, if the sampling operation were repeated many times, and for each time a 90 percent confidence interval was computed, then in about 90 percent of these many trials, the bounds about the estimated value would equal or exceed the true value." There are other possible interpretations of confidence intervals (for example, a Bayesian interpretation), but the one described above is a "traditional" (frequentist) interpretation.

7.4.3 Non-Random Selection within Strata

The statistical validity of estimates derived from any sampling scheme depends on appropriate definitions of populations and/or subpopulations, and on random sampling within such groups. However, in practice, truly random selection of subjects in any sampling scheme is difficult to achieve. We are concerned that PSE&G's current sampling plan does not appear to have provisions for encouraging random sampling, leaving the door open for samples of convenience. This increases the potential for sample bias and reduces the accuracy of estimates derived from such a scheme. Moreover, the plan calls for preferential sampling of circuits with high connected loads within any sampling group. While it is true that circuits with high connected loads have potentially higher impact on energy savings, it is methodologically preferable to have such considerations explicitly introduced into the sampling scheme (e.g. stratifying control circuits on the basis of connected load), rather than PSE&G's suggested procedure, which appears somewhat ad hoc.

7.4.4 Reallocation

PSE&G's sampling plan calls for reallocation of points for which observed data does not fall within 10 percent of the bounds for the bin to which it is currently assigned. While this seems intuitively reasonable, such reassignment complicates, and perhaps invalidates, the statistical interpretation of estimates (Halpern 1995). The statistical model presumes that each control circuit falls into one of the assigned bins. However, stochastic variation of the measurement of hours of operation for a control circuit in any given month may render the control circuit officially outside of its predetermined, and perhaps (in the long run) proper, bin.[58] The bin reassignment of a control circuit has a dual impact: (1) the hours accorded to the monitored point are reassigned to a new group, impacting the mean hours of operation determined for both the old and the new group; and (2) the connected load associated with that control circuit also switches from one bin to another.

This reallocation raises several issues: (1) reassignment *may* lead to bias in estimates of actual hours of operation for various groups, and (2) the subpopulation formerly represented by a now reassigned control circuit - and perhaps, therefore, any metered control circuit - is less well defined. The importance of the first issue remains unclear.[59] The second issue, however, may be quite important, as shown by this hypothetical example:

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58 By reassigning control circuits in such a manner, each group may tend toward its *defined* center.

59 Biases may cancel out when bins are combined, and the interaction of the difference between pre-installation and post-installation connected loads and hours of operation (and shifts made by reallocation) complicate the interpretation.

> Suppose 115 control circuits are assigned to Group O. Corresponding to the sampling plan, 15 of these control circuits are selected for metering. Say eight - just over half - of these are found to be misassigned, according to observed data, and are thus reassigned to Group J. This reclassification may lead one to question whether the assignment of all of the remaining nonmetered control circuits assigned to Group O was appropriate, and thus the weight of each group in terms of number of control circuits represented.

Some groups may then be under-represented, or even unrepresented, and others over-represented by the sample. Nonmetered circuits may be misallocated. To summarize, we are concerned that under the current sampling scheme, the subpopulation being represented by any metered circuit is unclear, particularly with reassignment.

7.4.5 Group Definitions

The bin groups specified by PSE&G show substantial overlap in terms of the total hours of operation and the potential value of the energy savings within each bin. Table 7-2 shows the 15 hours of operation groups specified in PSE&G sampling plan (Groups A through O). We then calculate the potential range in energy use for a fixed change in wattage for each group as well as the potential range in the value of payments per kW of energy savings (using the unlevelized payment schedule for projects that begin commercial operation in 1993).[60]

Based on this example, we conclude that the strata described by PSE&G do not seem to define appropriately homogenous bins. Interestingly, PSE&G combines the summer prime and summer peak periods into the on-peak category, although the value of energy saved to the utility is significantly different during each of these periods. Moreover, the strata for hours of operation during the utility's off-peak periods are more finely disaggregated than the strata for hours of operation that include on-peak periods (i.e., 5 vs. 3 categories).

7.4.6 Number of Circuits Metered Within a Group

Stratified sampling can increase the precision of population estimates over that achieved by simple random sampling if a heterogeneous population is appropriately divided into relatively homogeneous subpopulations. For example, sampling points may be allocated to provide different levels of precision for different strata in order to achieve higher levels of

60 For ease of presentation, we assume, in this example, that a facility has constant lighting wattage in each hours of operation bin, although the distribution of wattages are likely to be unequal across bins in an actual facility.

Table 7-2. Potential Energy Use and Energy Value Ranges Corresponding to the Sampling Group Definitions Given in PSE&G's Sampling Plan for Control Circuits

Group	Potential Energy Use (Range of Weekly Hours of Operation)	Potential Energy Value (Range of Weekly Payment per kW)
A	0 - 35	$0 - 3.27
B	6 - 50	$0.10 - 3.51
C	21 - 80	$0.34 - 4.00
D	31 - 105	$0.83 - 4.41
E	76 - 128	$1.25 - 4.79
F	31 - 55	$3.22 - 3.90
G	37 - 70	$3.32 - 4.14
H	52 - 100	$3.56 - 4.64
I	82 - 12	$4.05 - 5.05
J	107 - 148	$4.46 - 5.42
K	51 - 75	$3.86 - 4.55
L	57 - 90	$3.96 - 4.79
M	72 - 120	$4.20 - 5.39
N	102 - 145	$4.69 - 5.70
O	127 - 168	$5.10 - 6.07

precision in "more important" groups (e.g., those with high connected loads and/or high levels of coincident operating hours).[61]

However, the stratification offered in PSE&G's sampling plan does not appear to take advantages of these properties. The strata described by PSE&G do not seem to define appropriately homogenous bins, nor does the sample size for each group appear proportional to the potential importance of the bin. For an illustration of how this seems suboptimal under certain conditions, consider the following extreme example:

Facility X has 903 control circuits: three classified as Group A, and 900 classified as Group O. According to the sampling plan, 18 control circuits should be metered: all three of the

61 "The theory of stratified sampling deals with the properties of the estimates from a stratified sample and with the best choice of the sample sizes n_h to obtain maximum precision" (Cochran 1977:90).

Group A control circuits, and 15 of the Group O circuits. Thus, 100 percent of the circuits estimated to have at most 30 on-peak and 5 off-peak hours - but perhaps as few as zero on-peak hours would be metered, but only 1.7 percent of those which are estimated to have a minimum of 51 on-peak hours. It is true that within a bin, the incremental value of sampling gradually decreases (yielding smaller and smaller potential increases in precision). Still, given a fixed number of control circuits to be metered, intuition suggests that the best value in terms of precision and accuracy could be achieved by concentrating on the circuits which have relatively high potential influence on savings (like those in Group O), rather than those that have minimal influence on savings (like those in Group A).

7.5 Suggestions on PSE&G's M&V Lighting Protocol and Sampling Plan

In this section, we discuss our recommendations on PSE&G's M&V protocol and sampling plan. These include changing the experimental design of the Sampling Plan from stratification on the basis of hours of operation to usage areas, with simple random sampling within each of these usage area strata. Our less preferred option is to modify the current definitions used to establish hour of operation bins and the allocation of samples within each group. We also discuss methods to develop more accurate estimates of HVAC-lighting interactive effects and the use of audit acceptance techniques to verify certain input parameters in the M&V protocol (e.g., existing connected load).

7.5.1 Revise Sampling Plan for Control Circuits

We recommend that PSE&G modify its Sampling Plan so that control circuits are stratified based on usage areas rather than hours of operation (Schiller 1995). One major problem with the current sampling approach is that we could not adduce any direct connection between the sample sizes specified and the New Jersey M&V protocol's design target for sampling plans, even if precision levels were fixed (i.e. achieve a 90% confidence that savings equal or exceed the value measured). This alternative approach is used by PG&E in its DSM bidding program and project sponsors bear the responsibility for defining appropriate usage areas (e.g., hallway, building entrance, and offices) rather than making a priori estimates of weekly hours of operation (PG&E 1995, Appendix K). One key feature of this alternate approach is that once appropriate usage areas have been defined, simple random samples can be taken from each usage area.[62] The size of such samples may depend on the anticipated impact of the usage area on estimated total savings, which in turn depends on number of fixtures, the change in connected load relative to pre-installation

[62] In contrast, the PSE&G plan does not use simple random sampling within sampling strata, which we and other regard as a significant shortcoming (Halpern 1995).

levels, and the hours of operation.[63] An important advantage of such a scheme over one based only on hours of operation strata is that, although the definition of usage areas is somewhat subjective, once such areas are defined, the assignment of control circuits to groups is relatively simple and straightforward, with low potential for error.

Another potential, but less preferable, alternative is to retain PSE&G's current sampling plan (i.e., stratification based on hours of operation) but to institute changes in order to address several concerns that were discussed. For example, precision may be improved by concentrating monitoring on control circuits likely to have the most impact on the estimated energy savings, random sampling could be required within any strata, and migration of control circuits could be disallowed between groups.

7.5.2 Explore Using Audit Acceptance Testing Methods to Verify Connected Load

We recommend that PSE&G explore using audit acceptance testing methods to verify existing connected loads. Currently, PSE&G determines the existing kW by an audit which includes the type and number of fixtures, the type and number of ballasts and lamps within each fixture type (based upon sampling), and footcandle (fc) readings of representative areas of the facility. Recently, several other utilities (PG&E, SCE) have adopted audit acceptance testing methods in their DSM bidding programs which they have found can reduce the time necessary for the utility to perform its pre-implementation audit with the same degree of accuracy (Halpern 1995; Schiller 1995). The procedure involves first determining how many pieces of information need to be tested in a group, selecting individual entries on a random basis, and testing until the audit is completed or more than a maximum number of allowed errors are found. If the auditor finds an allowable number of errors, the sponsor receives full credit for the proposed kW baseline (or kW reduction, if post-implementation audit). If the audit fails, the project sponsor resubmits the package and the utility re-samples and re-audits the facility (the cost of which is charged to the sponsor).

7.5.3 Estimating Effects of Lighting-HVAC Interactions on Lighting Energy Savings

The Statewide M&V protocol specifies that lighting measures installed in conditioned space be credited with a 5% interactive factor to reflect HVAC savings that are assumed to occur as a result of decreased indoor lighting wattages. All parties recognized that this approach was a first approximation. However, we believe that the 5% credit, which is applied to lighting energy savings during all time periods, overstates savings in the heating periods and may understate savings in the cooling periods. In updating and revising the M&V

63 Sample allocation can also depend on expected variability of run hours within a usage area, since variability affects estimate precision.

procedures, we encourage PSE&G to examine several recent research studies that used sophisticated simulation models (e.g., DOE-2) in some cases to investigate lighting-HVAC interactive effects (Crossman 1995; Rundquist et al. 1993; Sezgen and Huang 1994; Sonnenblick and Eto 1995). These studies found that the magnitude of this effect depends on building characteristics, weather, and heating and cooling equipment. Thus, Sezgen and Huang (1994) examined the magnitude of these interactive effects among various building types and climate zones. Sonnenblick and Eto (1995) made parametric runs of the DOE-2 building simulation model to examine the magnitude of the HVAC-lighting interactive effects for different types of HVAC system in large and small office buildings. These results suggest that sophisticated building simulation models could be used to improve the accuracy of estimates of lighting-HVAC interactive effects compared to the current assumption. For example, a simulation modeling study could take explicit account of building and HVAC type using New Jersey weather data and produce revised assumptions regarding lighting-HVAC interactive effects based on a set of DOE-2 runs.

7.6 Overall Assessment of the New Jersey M&V Protocols

Thus far, our discussion of the M&V protocols and PSE&G's sampling plan has focused primarily on technical issues. In this section, we examine the merits of the M&V protocols as implemented by PSE&G in the Standard Offer program in a broader policy context. Our discussion emphasizes two themes: (1) the ultimate standard for assessing the adequacy of DSM savings estimates should be the ability to make good business decisions in a utility resource planning context, bearing in mind that the uncertainties associated with both supply-side and DSM options (Hanser and Violette 1992; Raab and Violette 1994), and (2) the incremental costs of verifying DSM savings should be weighed against the incremental benefits or value of such efforts, specifically accuracy (bias) and improved precision of savings estimates.[64]

7.6.1 Accuracy of Savings Estimates in M&V Protocol Compared to "Typical" Utility Practice

One way to assess the merits of the New Jersey M&V protocols is to assess the improved accuracy in savings estimates compared to other DSM evaluation approaches vs. the incremental costs of obtaining that information. Ideally, we would examine evaluation results obtained by other utilities in DSM programs that targeted similar customer classes and measures. A recent study by Sonnenblick and Eto (1995) analyzed the accuracy and

64 Bias refers to the accuracy of an estimate. A biased estimate of savings systematically deviates from the true value, either over- or under-estimating savings. Precision attempts to reflect the relative uncertainty in a savings estimate; a 90/10 criterion means ±10% relative precision at a 90% confidence interval. An unbiased but imprecise estimate can still be useful because, on average, it provides the correct value. Biased overestimates of savings are a concern because they may cause utilities to continue programs that are no longer cost-effective (Sonnenblick and Eto 1995).

precision of evaluation methods used by 20 utilities in their commercial lighting rebate programs, which we draw upon. For several of these studies, the utilities used various techniques to determine key inputs to energy savings (e.g., characterization of the baseline equipment efficiency, estimated hours of operation, persistence of savings over time).[65]

Table 7-3 summarizes the findings for each input variable and the implication and potential effect on estimated annual savings. One way to interpret these results is that they represent a "worst case" scenario of the potential biases in estimating energy savings that could occur in a prototypical lighting rebate program in which customers report their facilities' hours of use on a rebate application or audit form and the utility does not conduct or require a site- inspection prior to installation. In compiling results of various evaluations, Sonnenblick and Eto (1995) found that the baseline equipment characteristics and efficiency were often inaccurately characterized in program tracking system estimates. Site inspections (i.e., pre-implementation audits) improved the accuracy of the savings estimate, which was typically overstated by 15-20% because the equipment being replaced was often more efficient than originally thought. Customer self-reports of lighting hours of use were also typically overestimated by 15-25% for most programs (with one or two exceptions), which would result in an overestimate of annual savings by a comparable amount. Imprecision in estimating hours of operation also had the largest effect on the uncertainty of the resulting annual savings estimate (i.e., relative precision). Sonnenblick and Eto also explored issues that arise when end-use metering is used in samples of customer sites and installed measures. Based on an analysis of a small sample of new commercial buildings, they found that there were unexplained variations in hours of use over long time periods (e.g., new occupants, commissioning). Overall they found that long-term metering improved the precision in the estimate of hours operation by about 10%. We regard this value as an upper bound estimate because unexplained variations are likely to be less of a factor in existing buildings.

- If we assume, for the moment, that the findings from the Sonnenblick and Eto study are representative of typical utility DSM evaluation practice, then we could infer the following. In the worst case, annual savings estimates for a lighting rebate program based on customer self-reports of hours of operation and baseline equipment efficiency could be biased upwards by 30-40%. The M&V protocols adopted in New Jersey would prevent this type of situation from occurring (because of the pre- and post-implementation audit requirements and metering of hours of operation).

65 The techniques used to check and improve customer self-reports on hours of operation and baseline equipment efficiency included site visits by utility auditors, data loggers to record hours of operation, and end-use metering of lighting circuits in a sample of the buildings. On-site inspections were used to verify that high-efficiency lighting equipment was still in use and had not been removed for various reasons (e.g., dissatisfaction, theft).

Table 7-3. Review of Accuracy and Precision of Lighting Savings Estimates

Input Feature	Finding	Effect on Annual Savings Estimate
Customer Reports of Hours of Operation	Hours of use typically overestimated by 15-25% from customer self-reports, with 1-2 exceptions	Potential bias of 15-25% (overestimate of savings)
Characterizing Baseline and Efficient Equipment Wattages	Site Inspections (e.g., pre- and post-implementation audits) improved accuracy, spot watt metering improved even further	Potential bias of 15-20% bias (overestimate of savings)
Short- vs. Long-Term Metering	Metering of hours of operation for limited time periods vs. annual (in new construction)	Improve precision of hours of operation estimate by≈10%
Persistence of Savings (Equipment Removal)	Site visits by several utilities uncovered removal rates of 10-15% for a few lighting measures	Small reduction in lifetime energy savings

Source: Adapted from Sonnenblick and Eto (1995).

- The potential biases in energy savings that are reported by Sonnenblick and Eto probably were representative of "typical practice" four to five years ago. However, we believe that the situation has improved markedly since then because many utilities have devoted significant resources to impact evaluations (and because of information transfer that has occurred even among less advanced utilities). At least for C/I lighting, leading utilities can and have improved both the accuracy and precision of annual energy savings estimates using information gained from impact evaluations. These utilities tend to use simpler verification procedures (e.g., site visits to determine baseline condition and proper equipment installation, short-term metering and end-use monitoring on samples of buildings) supplemented by process and impact evaluations. Impact evaluations often include test and comparison groups, so that changes in baseline consumption among all customers can be estimated.[66] Thus, we recommend that PSE&G compare the long-term costs and value (i.e., accuracy and precision of savings estimates) of approaches that combine simpler verification procedures with impact evaluation with the M&V strategy in New Jersey which relies on extensive site verification procedures to estimate gross savings.

- Turning to M&V procedures for specific measures, there probably were diminishing returns associated with continuous metering of hours of operation for lighting retrofits at every large facility in the program. That is, the incremental cost of

66 This provides the utility with a proxy to separate out the effects of the program intervention from other economic drivers (e.g., the economy, electricity prices).

evaluation may outweigh the value of improved evaluation results. Over time, as the sample of buildings in the Standard Offer program increases, PSE&G could use information on hours of use to assess the mean and variance in specific building types and usage areas. This type of data could be used to improve the efficiency of the sampling scheme and may mean that continuous long-term metering at every site would not be required, so that M&V costs for various lighting measures could be further reduced.[67]

- Because of the more limited experience measuring and verifying savings from more complex HVAC measures and industrial process retrofits and the variance in savings due to site-specific applications, the current M&V protocols and the site M&V plans appear to be well-conceptualized technically. We would suggest that acceptable M&V protocols can and should be developed for various types of HVAC and lighting controls applications. Other utilities (e.g., PG&E) have adopted M&V protocols for these type of measures in their bidding program which appear to reasonably balance the savings potential (and associated uncertainties) of these applications with the cost of verifying the savings (Schiller 1995).

- Overall, compared to "typical" practice among utilities at the time they were adopted, we conclude that the M&V protocols represent an important step forward in improving the credibility of DSM as a reliable resource. Has the improved accuracy in savings estimates been worth the additional cost spent on M&V in New Jersey? A definitive answer to that question is beyond the scope of this study, but we provide an initial, first-cut assessment. Based on interviews with regulatory staff in 12 states, Raab and Violette (1994) estimate that utilities in those states spent an average of 6% of their DSM budgets on evaluation, with a range of 3-10%.[68] In the Standard Offer program, the 19 customer sponsors reported that, on average, M&V costs accounted for about 7% of total utility costs.[69] ESCOs were not required to estimate M&V costs in their proposals, although, in our interviews, we asked ESCOs to estimate the percentage of total project costs that were spent on M&V and other reporting requirements.[70] M&V costs reported by five ESCOs for

67 This approach might be most feasible in applications involving owners of chain stores or similar buildings.

68 The 12 states were Arizona, California, Connecticut, Florida, Iowa, Massachusetts, Michigan, Nevada, New York, Vermont, Washington, and Wisconsin.

69 We would expect M&V costs to represent a smaller fraction of total project costs for customer sponsors compared to ESCOs because most customer-sponsored projects were in larger facilities and included non-lighting measures (e.g., fuel switching, HVAC). In large non-lighting jobs, M&V costs typically represent a smaller percentage of project costs.

70 Because customer contributions only represent about 10% of total project costs, we chose to ignore the fact that total project costs are not directly comparable with utility DSM program budgets, which we assume includes utility administrative costs and rebates (but not customer cost contribution).

lighting projects ranged from 6-20% of total project costs with an average of 10-12%. Several ESCOs also indicated that M&V costs for non-lighting measures represent a much smaller share of total project costs.

To summarize, this first-cut analysis suggests that M&V costs in the Standard Offer represent a higher share of total utility (or project) costs compared to evaluation budgets for utility DSM programs. We are also convinced that the additional costs spent on M&V by project sponsors in the Standard Offer program have significantly improved the accuracy of savings estimates, although we have not been provided with any direct evidence that the sampling plan ensures that savings estimates meet a 90% confidence level.

7.6.2 Re-Assess Guidelines for Accuracy of DSM Savings

At the time that the statewide M&V protocols were developed, there appears to have been a broad consensus among the parties in New Jersey that DSM impacts should be measured with the same standard of accuracy as the output from supply-side resources to the extent feasible. This would ensure that savings from energy efficiency investments would provide a firm, reliable resource to utilities. Since that time, a number of studies have examined the issue of target confidence intervals and relative precision levels for DSM savings estimates and PUCs in several other states (e.g., Massachusetts, New York, Wisconsin, California) have either adopted or revised their policies in this area (Raab and Violette 1994; Hanser and Violette 1992). In New Jersey, the Statewide M&V protocol states that Sampling Plans should be designed to provide a "90% confidence that savings equal or exceed the value measured." This objective can be interpreted as the magnitude of impacts that a utility resource planner can reasonably assume will be achieved, or exceeded, by a DSM program and may be viewed as similar to a "minimum dependable capacity rating" (Hanser and Violette 1992).[71] We have also been told that target precision levels are 10%, although the Protocol does not explicitly indicate the desired precision.[72]

Raab and Violette (1994) offer the following insights on policy and technical issues regarding the use of target confidence and precision levels: (1) in setting the target, PUCs should consider the intended application(s) for DSM savings estimates; some applications may justify more stringent targets than others (e.g., recovery of net "lost revenues" vs. cost-

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71 This wording implies that a one-tailed confidence interval should be used, the lower bound indicates the minimum achieved savings for a given confidence level. All else being equal, estimated savings with similar t-values will have greater relative precision in percentage terms with a one-tailed vs. two-tailed confidence interval (Hanser and Violette 1992).

72 In our discussions with parties in New Jersey, they referred to a 90/10 standard, which we assume was the implicit understanding among the parties. Precision attempts to capture and reflect the uncertainty in any estimate of energy savings (e.g., we are more confident that the actual savings from a program that saves 2,000 MWh ± 150 MWh is closer to the mean estimate compared to a program that saves 2,000 MWh ± 1,200 MWh)..

effectiveness evaluation), (2) precision levels should be viewed only as design targets because unexpected outcomes in field studies may affect relative precision (e.g., actual savings lower than initial estimate of savings used to determine sample size), and (3) it is easier to attain higher precision levels for programs with large percentage savings.

If we assume that the primary application for DSM savings estimates in the Standard Offer program is resource planning decisions, then the underlying question for New Jersey utilities and regulators is the level of accuracy necessary for making good decisions about appropriate investments in DSM programs. In this context, the acceptable level of uncertainty in DSM saving impact estimates should be compared to uncertainties associated with supply-side resources (e.g., future fuel prices, changing environmental regulations); uncertainties associated with various supply-side and DSM resource options affect the investment risk of that resource. Sonnenblick and Eto (1995) argue that this notion of "good" business decisions regarding DSM investments can be interpreted as determining the likelihood that DSM programs are cost-effective from a societal perspective (i.e., TRC greater than one). They show that for programs with TRC values much greater than one, relative precision levels can be on the order of 50%. In Massachusetts, the Department of Public Utilities decided not to specify target precision levels and directed utilities to "seek the best precision it can expect to attain with a 90% statistical confidence, subject to the constraint that the marginal value of the precision attained should not exceed the marginal cost of attaining it" (Massachusetts DPU 1992). In its conservation verification protocols, the U.S. Environmental Protection Agency (1993) decided that a 75% confidence level that the actual savings were equal to or greater than estimated savings was appropriate for rewarding emission allowances for conservation investments with reasonable certainty. Hanser and Violette (1992) also suggest that a 75% confidence level may be a reasonable hurdle.

We think the accuracy level required by EPA (i.e., 75% confidence level) strikes a reasonable balance considering such factors as the uncertainties in supply-side and DSM resources (from a resource planning perspective), the inherent uncertainties in measuring DSM savings, and the fact that not all resource options considered by a utility necessarily need to meet the same level of accuracy, or certainty, in determining their ultimate value to a utility (Hanser and Violette 1992). Obviously, the issue of appropriate target guideline for measuring is a judgment call for policy makers in New Jersey and we urge PSE&G and interested parties in New Jersey to revisit this issue.

Role of PSCRC

8.1 Overview

In this chapter, we examine the role of PSE&G's energy services subsidiary (PSCRC) in the Standard Offer program and the effect of its involvement on the development of the energy services industry in New Jersey. We first discuss the extent to which PSCRC's actions have been consistent with the DSM incentive regulation policies adopted by the New Jersey BPU and the Stipulation of Settlement agreement which established entry conditions and set limits on the scope of their activities. As part of our evaluation, we also introduce concepts and analytic tools that are traditionally used in anti-trust analysis: estimates of PSCRC's market share in an appropriately-defined product market and market concentration ratios. These tools help address the competition policy issues raised by the role of PSCRC. We also summarize recent work by several economists and legal scholars who provide guidelines which can be used to judge the potential benefits of direct utility participation in emerging technology and services markets and to balance any such benefits against anticompetitive effects.

8.2 PSCRC's Performance vs. Regulatory Intent and Guidelines

The New Jersey BPU's DSM incentive rules provide utilities with the opportunity to profit from investments in energy efficiency, using the utility's unique position to expand the market for energy efficiency products and services (EEPS). These policies are justified on the grounds that various market failures have resulted in significant under-investing in energy efficiency technologies and services. In approving the formation of PSCRC and allowing it to operate in PSE&G's service territory, the New Jersey BPU was well aware of possible conflicts of interest and potential for abuses, which it sought to limit through various policies and regulatory oversight (e.g., requiring PSCRC to rely on third parties to directly install and maintain high-efficiency products and limiting PSE&G's marketing activities). However, from the outset, the BPU implicitly endorsed PSE&G's efforts to use its brand-name credibility to create a "market pull" for EEPS as exemplified by PSE&G choice of the name for its ESCO - Public Service Conservation Resources Corporation - which suggests a clear association with the utility.

8.2.1 Stipulation of Settlement Agreement: PSCRC's Mission and Objectives

In the Stipulation of Settlement agreement (NJBPU 1992), PSCRC stated its general mission (*emphasis added in italics):*

> 'of facilitating a viable and enduring performance-based DSM marketplace' through '*close alliances with members of the DSM industry which will develop, construct and maintain investment-grade energy conservation projects on behalf of host customers and PSCRC*. PSCRC believes that there are sufficient, qualified third-parties available to provide the service required by PSCRC to meet its DSM objectives. Therefore, it is PSCRC's present intention to develop a corporate structure that *relies on third-parties to directly implement the installation and service requirements* of the end-use equipment to be installed under PSE&G's standard offer. PSCRC will select third-parties solely on the basis of valid business reasons, including, but not limited to relevant price and performance factors' (NJBRC 1992).

PSCRC anticipated providing capital investment services for projects developed, constructed, and managed by DSM industry members and for projects developed by customers and offering customer and DSM industry project facilitation services. PSCRC formed an Energy Service Network (ESN) as the primary vehicle to implement this latter objective, which included various types of providers (e.g., energy service companies, engineering/construction/ procurement firms, lighting service contractors).

8.2.2 PSCRC's Track Record

Based on our interviews, PSCRC appears to have been successful in its role of providing capital investment services (see Section 5.6.1). A number of ESCOs acknowledge that PSCRC's financial support and backing has provided an important stimulus to the energy services infrastructure in New Jersey. However, ESCOs expressed sharply divergent views regarding PSCRC's role as a project facilitator. The majority of respondents were critical of PSCRC's initial efforts to facilitate projects through the ESN and many of the original ESCO members have dropped out after disagreements with PSCRC (see Section 5.6.1 for summary of disagreements along with PSCRC's views). Some ESCOs believe that PSCRC's actions did not fully live up to the intent of the Stipulation and that, over time, PSCRC has become a direct competitor.

It is unfortunate that PSCRC could not resolve differences with many of the original ESCO members of the ESN. Although PSCRC's implementation of the ESN could certainly have been improved, the fact that major problems arose was not too surprising given the ambiguities in the Settlement of Stipulation language and the inherent difficulties in organizing energy service providers. For example, the first sentence of the Stipulation implies that other entities (i.e., full-service ESCOs) will develop, construct, and maintain projects on behalf of host customers and PSCRC, while the second to last sentence implies that "the close alliances" will primarily be with those energy service firms that install and service projects (i.e., only the construction and maintenance function). More fundamentally, the overlap in services offered to customers by various providers makes it difficult to establish "boundaries" between and among types of service providers.[73]

With the benefit of hindsight, it might have been preferable if the settlement agreement had spelled out PSCRC's DSM objectives more explicitly. For example, this might have taken the form of some percentage cap on the number of projects that PSCRC could directly sponsor (e.g., 25-30% of total program savings). A limit on PSCRC's market share would have provided an implicit incentive for PSCRC to continue pursuing an aggressive project facilitation role in support of other ESCOs. On the downside, limiting PSCRC's market share could have had the effect of unduly limiting PSE&G from achieving its MW goals for the Standard Offer. At a minimum, these type of discussions would have forced parties to grapple with very different expectations about how the market would evolve prior to program implementation. However, given the ambiguities in the settlement agreement language, there is no basis to conclude that PSCRC has violated the agreement.

8.2.3 Impacts on the Local Energy Services Market

We also offer several observations on the evolution of the energy services market in PSE&G's service territory since the inception of the Standard Offer:

- Overall, there has been a significant shake-out in the local energy services market during the last two to three years. A number of ESCOs that had either been active in the 1989 DSM bid or recruited by PSCRC left the Energy Service Network. A few of these ESCOs appear to have significantly downsized their marketing efforts in PSE&G's service territory and, in some cases, have moved to other areas of the U.S. where opportunities are perceived to be greater and they don't face a well-capitalized, utility-affiliated ESCO.

- As a practical matter, PSCRC has de-emphasized the Energy Service Network concept somewhat. However, PSCRC has formed effective alliances with several lighting service contractors and engineering/construction firms who bring jobs to PSCRC that it sponsors. Moreover, a number of new ESCOs and other types of energy service providers have entered the market, often with PSCRC's financial support.

[73] For example, lighting service contractors design and directly install lighting measures whereas ESCOs design, manage the installation, and finance those measures.

- Other "full-service" ESCOs have adapted to PSCRC's presence in the market by consciously focusing on market segments and niches where PSCRC and its trade allies are less active.

8.3 The Market for Energy Efficient Products and Services in PSE&G's Service Territory

In this section, we attempt to define the market for energy efficiency products and services more precisely in order to begin exploring such questions as the extent to which the market has expanded because of utility DSM programs (which was a key objective of New Jersey's regulators), the market share of the utility's energy services subsidiary (i.e., PSCRC), and evidence of the potential for market power. We rely mainly upon concepts and techniques drawn from anti-trust law and analysis, where such issues are traditionally examined. We view our use of these concepts and indicators as illustrative and exploratory because of the number of factors typically considered in anti-trust cases (which go well beyond the scope of this study), the limitations of market concentration indices, and the practical difficulties in defining energy efficiency product and services markets.

8.3.1 Defining the Market

In assessing market structure, one must first define the market, which involves developing appropriate product and geographic definitions. We use PSE&G's service territory to establish the geographic boundary for the local energy services market. Product definition for energy-efficient products and services (EEPS) is more complex.[74] Figure 8-1 provides a conceptual illustration of the market for EEPS among commercial/industrial customers prior to and after DSM interventions by a utility. We have grouped the types of products offered to customers in the EEPS market into two broad categories: a performance contracting/financing product (which we refer to as Product A) and a services/"cash" product (which we refer to as Product B).[75]

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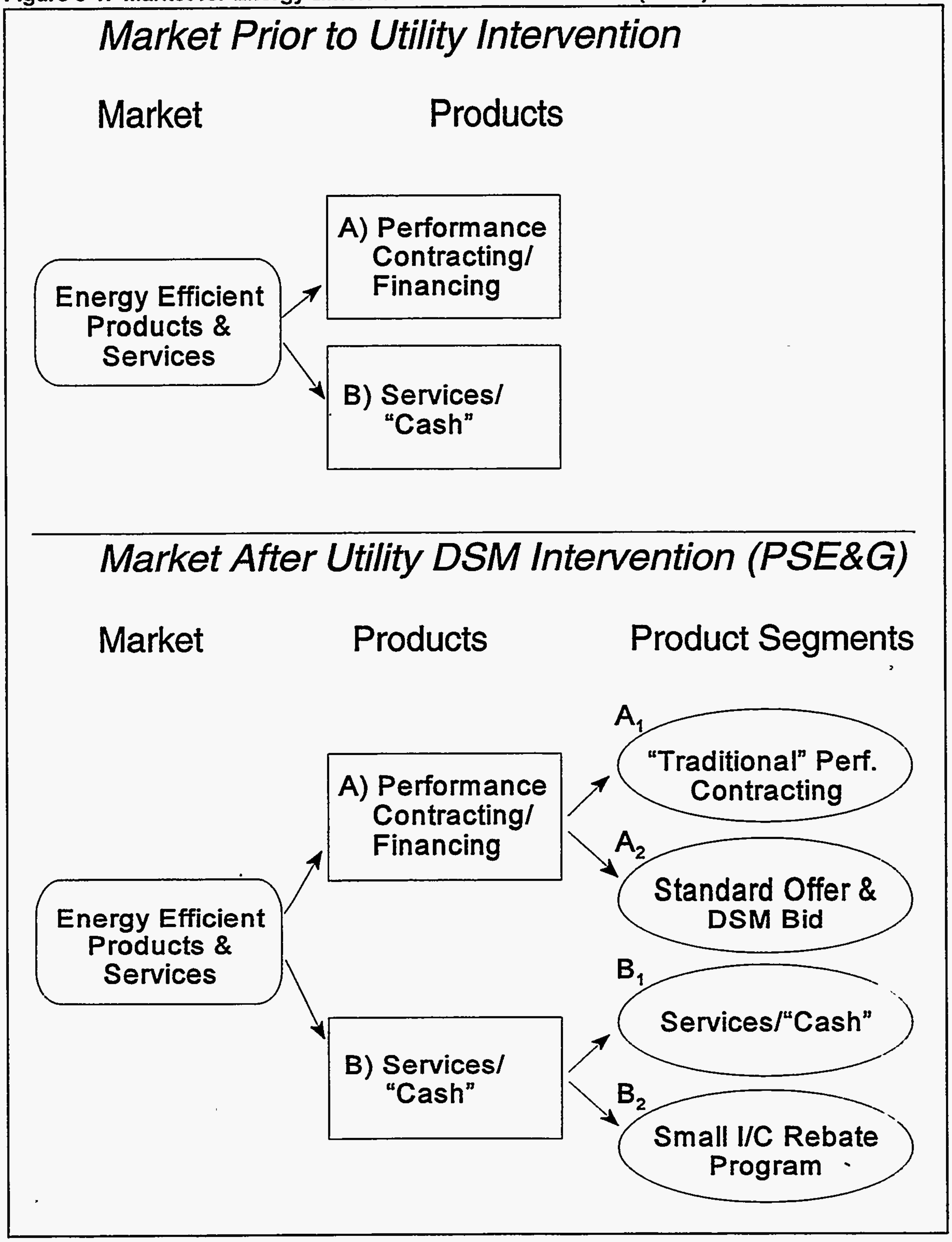
74 For purposes of this discussion, high-efficiency products can be defined as products purchased by the customer with efficiency levels that exceed applicable building and equipment standards and codes or "typical" industry practices.

75 Performance contracting is a generic concept which includes a number of performance risk/financial product options between ESCOs and customers: shared savings contracts, pay from savings, and guaranteed savings. There are also a number of other financing approaches that are often used by public sector customers, such as operating leases, municipal leases, and general obligation or revenue bonds, which are essentially debt products. Bullock (1994) argues that the host customer ultimately assumes the performance risk in many of these latter approaches because payments are required, "hell or high water."

Figure 8-1. Market for Energy Efficient Products and Services (EEPS)



In Product A, customers receive packaged services (e.g., design, installation, construction management, monitoring, and, in some cases, preventative maintenance services) from an ESCO. The customer obtains energy-related improvements without a large up-front investment because the ESCO (or a financial institution) provides the capital for the project. Moreover, the ESCO is at risk for project performance as the ESCO's compensation is in some way tied to the energy cost reductions achieved by the project. This feature reduces the customer's information concerns and financial risk should the project not perform as anticipated (NYSERDA 1986). This type of product also addresses the capital constraints and/or high investment hurdle rates of many C/I customers In Product B, customers use more "conventional" methods to procure energy-related capital and operating improvements. Customers purchase high-efficiency products without some type of savings performance guarantee.[76] In contrast to Product A, we assume that access to third-party capital on attractive terms and conditions is not a key driver or limiting factor in these customers' decision to purchase a high-efficiency product. Thus, we characterize these customers as willing to pay the up-front costs of energy-efficient products and services with "cash." One way to think about our market and product definitions is by analogy to new automobiles. In that case, we can define a market for new automobiles; product options available to customers include paying cash or various types of financing.[77]

Figure 8-1 also illustrates how various types of demand-side management interventions by a utility (e.g., PSE&G) affect the EEPS market. We group PSE&G's DSM programs targeted at C/I customers into two categories: performance contracting/financing, which includes the DSM bidders from PSE&G's 1989 Solicitation and the Standard Offer program, and rebates, which includes the Small I/C rebate program. After the utility's intervention (i.e., since 1991), Product A now includes two segments: the traditional performance contracting activities of those ESCOs active in the local service territory (A_1) as well as PSE&G two DSM programs (A_2). Historically, prior to utility DSM programs, performance contracting has achieved some success in certain C/I market segments - the so-called MUSH markets: municipalities, universities, schools, and hospitals. Unfortunately, quantitative information is not reported or readily available on the size of A_1 in New Jersey, either prior to the program or currently. However, based on qualitative anecdotal evidence, we are fairly certain that the size of A_1 is significantly smaller than A_2.

Product B also includes two segments: services/"cash" activities that are not included under a DSM rebate program (B_1) and PSE&G's Small I/C rebate program (B_2). We treat utility DSM rebates as a segment of Product B, primarily because most customers will simply use the rebate to offset some fraction of the up-front cost of energy-efficient products and will

76 In this situation, customers assume performance risk, which they manage by relying on the manufacturers' equipment guarantees for that product.

77 Our car market analogy is not directly comparable because customers receive similar performance guarantees irrespective of their payment method.

not receive performance savings guarantees from vendors that use the utility DSM program to promote their products.[78] Unlike many other utilities, PSE&G's rebate programs play a relatively minor role in their DSM activities targeted at the C/I market (~4 MW of savings through 1994), and we assume that the program has not had much impact on the larger EEPS market.

Table 8-1 shows the bundling of the various elements of Product A into an integrated package which includes design, engineering, construction and construction management, performance monitoring, and financing as well as the types of entities and firms that are involved in each element. The relationships among firms and between firms and host customers for Product A varies somewhat between utility DSM and non-utility segments. For example, in the utility DSM segment, PSE&G has defined additional project performance requirements that are associated with the delivery of verified savings and which are reflected in the Standard Offer contract between the utility and a "project sponsor." In traditional performance contracting activities, the ESCO typically assumes the obligations and risks that are defined by the "project sponsor" designation in the Standard Offer. There are few barriers to entry in the utility DSM segment, as both ESCOs and large customers can become project sponsors in the Standard Offer.[79] In terms of the types of entities that are involved, contractors and vendors typically perform design and construction

Table 8-1. Performance Contracting/Financing: Service Elements and Firms

Service Elements	PSE&G DSM Programs: 1989 DSM Bid	PSE&G DSM Programs: Standard Offer Program	Performance Contracting Activities (Non-Utility)
Design, Engineering & Construction Services		Contractors Vendors Engineering/ Construction Firms	
"Project Sponsor" - project perform-ance risk	ESCOs	PSCRC Other ESCOs Customers	ESCOs
Capital Investment Services	PSCRC Other ESCOs Financial Institutions		Financial Institutions ESCOs

78 Utility DSM rebates are also used by ESCOs in their marketing of Product A; ESCOs will offer to finance the remaining capital costs of an energy-efficiency project which is not covered by the utility's DSM as part of a performance contracting arrangement with the customer.

79 The minimum bid size in PSE&G's 1989 RFP was higher than the Standard Offer (i.e., 400 kW vs. 200 kW of SPPADR), which had the effect of severely limiting customer bids.

services for ESCOs in both utility DSM and non-utility segments of Product A. As noted previously, one of the limits placed on PSCRC's involvement in the Standard Offer was that it had to agree to use third parties to directly install and maintain high-efficiency products.

8.3.2 Effect of PSE&G's DSM Programs on the Local Energy Efficiency Services Market

To what extent have PSE&G's DSM programs expanded the local EEPS market in the C/I sector? Conceptually, to answer this question, we would compare the size of the EEPS market before PSE&G's DSM programs (Products A and B) to the size of the current EEPS market (e.g., Products A and B, each having a utility and non-utility segment). We also have to address issues related to the substitutability of related products across and within segments. For example, in the absence of the Standard Offer program and its incentives, some customers might install high-efficiency products under a traditional performance contracting arrangement with an ESCO. Another possibility is that some customers would have chosen a high-efficiency product using a Product B arrangement now or at some time in the future in the absence of the Standard Offer (see Chapter 6 for discussion of "free riders"). However, the combination of the Standard Offer payment and the ESCO's performance guarantees (as a project sponsor) is sufficiently attractive so that they choose Product A rather than Product B.

Our ability to draw conclusions regarding the effects of PSE&G's DSM programs on the larger EEPS market is hampered by very limited information on the segments of the market outside of utility DSM programs. However, we assume that the market for Product B has not been stimulated or affected much by PSE&G's small I/C rebate program, given its relatively small size. If we also assume that there is limited substitution between Products A and B, then much of the growth in Product A is attributable to PSE&G's two DSM programs (i.e., the Standard Offer and the DSM bid winners). With that assumption, it is reasonable to conclude that since 1992, some fraction of the ~65-70 MW of SPPADR from committed projects in the Standard Offer and the winning DSM bidders has contributed to an expanded EEPS market.

8.3.3 PSCRC's Market Share

What is PSCRC's market share for Product A (i.e., performance contracting/financing) and what evidence is there regarding market concentration? We define market share as the percentage of the total product market provided by an individual firm, as indicated by savings in connected kW load.[80] However, because we lack information on firms that are active in traditional performance contracting outside of utility DSM programs, our initial market share calculations are based only on Product Segment A_2 (i.e., the Standard Offer and DSM results from the 1989 RFP). Through December 1994, PSCRC's market share as a project sponsor is about 25% in Product Segment A_2, which we regard as an upper bound for Product A. If we focus solely on the provision of capital investment services ,which is a key element of this product, then PSCRC's market share is probably between 50-60% of the utility DSM segment because PSCRC has provided financing for a significant number of the projects sponsored by other ESCOs and customers in both the Standard Offer and 1989 DSM bid programs.[81]

8.3.4 Market Concentration Indices

Economic theory suggests that the vigor of competition is related positively both to the number and relative size of firms in a relevant industry, assuming other factors, such as entry barriers, are comparable (Scherer and Ross 1990). The Herfindahl-Hirschman Index (HHI) is the most popular measure used in examining potential market power of firms in particular products or industries, and is given by the formula:

$$HHI = \sum_{i=1}^{N} S_i^2$$

where S_i is the market share of the i^{th} firm and N is the number of firms.[82] In its guidelines regarding mergers, the Department of Justice (DOJ) indicates that for markets with HHI values above 1,800 (corresponding roughly to a situation with six equal-sized sellers), it is likely to challenge mergers that increase the HHI by 100 percentage points or more. For markets with HHI values below 1,000, a merger challenge is unlikely, while merger challenges are more likely than not for markets with HHI values between 1,000 and 1,800 if mergers have a large structural impact. An HHI index is not a perfect indicator of market power, it has been criticized for its underlying premises regarding the nature of competition (e.g., static vs. dynamic competition) as well as technical issues in application (e.g., proper

80 Market share calculations are typically done in terms of annual revenues. However, in utility merger analysis, products are often described in physical terms. Reductions in connected kW load proposed by project sponsors is a reasonable way to measure relative levels of activity among firms, given problems in obtaining accurate information on annual revenues.

81 Data on the market share of capital investment services are not publicly available (in contrast to project sponsorship); our information is based on interviews with PSCRC and other ESCOs.

82 The HHI index weights the values of large firms relatively more than for small firms because market share is squared; this means that the market shares of the largest sellers must be measured accurately.

Table 8-2. Market Concentration: HHI Index

ESCO/Customers	Connected Load Reduction (MW)	% Total	HHI Index
ESCO #1	3.89	4.24	18
#2	0.23	0.25	0
#3	0.19	0.21	0
#4	1.16	1.27	2
#5	1.55	1.69	3
#6	1.58	1.73	3
#7	13.89	15.13	229
#8	0.34	0.37	0
#9	12.96	14.12	199
#10	0.19	0.21	0
#11	0.27	0.30	0
#12	23.31	25.40	645
#13	0.33	0.36	0
#14	9.55	10.40	108
#15	2.56	2.79	8
#16	2.02	2.20	5
#17	1.26	1.37	2
#18	4.12	4.49	20
Customers (19)	12.37	13.48	24
Total	91.76	100.00	1,266

market definition, substitutability of products) (Jorde and Teece 1991). Scherer and Ross (1990) note that "at best, concentration indices are a rough, one-dimensional indicator of market power, and their use must be tempered with common sense."

With this in mind, HHI indices provide some prima facie evidence on market competitiveness and structure. We calculated an HHI index for Product A_2 (see Table 8-2). We estimated market shares for individual firms and customers that are project sponsors based on their combined connected kW load reductions for the two programs (Standard Offer and 1989 RFP) and calculated an HHI index value of ~1,270. We also conducted a sensitivity analyses for Product A, assuming that A_1 was 25% of the size of A_2 and that from 2-4 other ESCOs were active in that market, which gave HHI values in the 910-1,010 range. Using the DOJ merger guidelines, there is prima facie evidence for some, but not overwhelming, concern over the potential for market power.

8.3.5 Effects of Ease of Entry on Market Competitiveness

The DOJ merger guidelines also include other factors that should be considered in analyzing market competitiveness and structure, of which ease of entry is particularly important. If new entry by firms is particularly easy, then the DOJ might not challenge mergers even if the HHI index values were higher than the guideline thresholds. Ease of entry relates to the economist's notion of "contestable" markets. For customers of a certain minimum size (200 kW savings), one could argue that there are no formal entry barriers to becoming a "project sponsor" in the Standard Offer program and assuming the associated performance risks and financial obligations. Moreover, the program design of the Standard Offer places few eligibility restrictions on ESCOs becoming "project sponsors." Thus, overall, we would argue that ease of entry acts to further mitigate concerns regarding market power in this product market.

8.3.6 Criteria for Assessing Direct Utility Participation in Local Energy Service Markets

Economists and legal scholars that are active in the area of anti-trust policies have proposed guidelines for evaluating situations in which firms with potential market power want to pursue activities in a certain product market. These criteria may also have some applicability to decisions that state regulators confront regarding appropriate utility roles in emerging energy services markets (Starrs 1995). In particular, Brodley (1987) has developed several criteria which we think can be applied by regulators to judge the potential benefits of direct utility participation in energy services markets and to balance any such benefits against anticompetitive effects.

Brodley argues that the basic goals of anti-trust policy are to increase aggregate social wealth (economic efficiency) subject to the constraint that consumers shall receive an appropriate share of the social wealth created by such efficiency gains (i.e., consumer welfare or surplus).[83] Among the three basic components of economic efficiency (production efficiency, innovation efficiency, and allocative efficiency), Brodley argues that the promotion of innovation and production efficiencies should be the primary goal of anti-trust economic policies, rather than promoting allocative efficiency.[84] Thus, he argues that, in some cases, anti-trust policies should subordinate the immediate interests of consumers (e.g., lower prices) to the longer-run interest in maximizing social wealth (economic efficiency). In situations in which firms have potential market power or markets are excessively concentrated or imperfectly functioning, Brodley suggests that anti-trust law permit activities that increase social wealth by these firms at the expense of short-term consumer interest only when the action meets three requirements:

(1) the proposed activity must increase total social wealth by realizing *significant* production or innovation efficiencies,

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83 Economic efficiency refers to actions or events that increase the total value of all economically measurable assets in the society. Brodley defines appropriate share as that which would be provided by a competitive market.

84 "Production efficiency is achieved when goods are produced using the most cost-effective combination of productive resources available under current technology. Innovation efficiency is achieved by the invention, development, and diffusion of new products and production processes that increase social wealth (which is particularly important because technological progress is the most important factor in growth of real output). Allocative efficiency is achieved when existing stock of goods and output are allocated through the price system to those buyers who value them most, in terms of willingness to pay." Anti-trust enforcement is directed mainly at cartels and collusion with the aim of forcing prices closer to marginal cost; based on the premise that marginal cost pricing will increase allocative efficiency by increasing output. (Brodley 1987)

(2) the activity must be necessary to achieve such efficiencies, and must be the least harmful in its effects on consumers among reasonably available alternatives, and

(3) the activity must not permanently suppress interfirm rivalry, but must allow for the eventual reestablishment of competition.

In terms of process, Brodley recommends that a two-stage procedure be used to evaluate these three requirements: (1) in the first stage (ex ante), firms with potential market power would have to argue that the productive and innovative efficiencies created by their participation are plausible and that their participation provides the least restrictive means to overcome existing market failures, and (2) in the second stage, courts or agencies would examine the firm's efficiency claims based on actual experience (i.e., an ex poste audit).

Applicability to Situation in New Jersey

We now discuss the potential relevance of these competition policy guidelines to the specific situation in New Jersey -- PSE&G's proposal that its ESCO subsidiary be allowed to directly participate in the energy services market in its own service territory. Brodley's first requirement provides a standard against which to judge proposed policies - that they must increase economic efficiency by realizing significant production or innovation efficiencies. For example, one reason given by PSE&G to justify PSCRC's participation in the local energy services market and its special position (by virtue of its association with PSE&G) was that PSCRC would be able to achieve innovations and streamline the delivery of energy efficiency services. Using Brodley's approach, this type of claim would probably be sufficient ex ante to justify the participation by an energy services subsidiary of the host utility. However, after a sufficient period of time, PSCRC would have the burden for demonstrating that significant efficiency benefits attributable to their participation had actually occurred.

Brodley also gives several examples of policies that are consistent with his third requirement, which is no permanent suppression of competition. Specifically, he cites examples of a consent decree for a joint venture of two large car manufacturers with market power (GM and Toyota) that was limited both in time (e.g., number of years) and scope (size of market). Turning to our situation, many parties perceived that an ESCO subsidiary affiliated with the host utility may have potential market power. Therefore, one option would be to establish explicit limits on the market share of that ESCO. Another option would be to set a time limit which would either trigger a review of PSCRC's role and effects on the energy services market.

Brodley's second requirement - necessary and least restrictive means - implies that PSE&G has some obligation to show that direct involvement by PSCRC in the energy services market is necessary to overcome market failures and has the least harmful potential effects on consumers. For example, it can be argued that, in offering project sponsorship services, PSCRC provided additional opportunities for many host customers to participate, who otherwise would have been quite reticent, given their lack of previous experience with other ESCOs.

8.4 Summary

In order to assess PSCRC's role in the Standard Offer program, we must first establish the appropriate policy context: (1) the BPU's overall policy objective of expanding the EEPS market for all firms by incenting utilities and (2) the development of "competition" policies for energy services markets -- guidelines and criteria that can be used to weigh the potential benefits of direct utility participation against anticompetitive effects.

Based on available information, it appears that PSE&G's DSM programs, and particularly the Standard Offer, have expanded the local EEPS market during the last several years. PSCRC has also assumed a major position in the local performance contracting/financing product market. In our opinion, PSCRC's provision of construction and project financing to other ESCOs and customers along with innovative design and successful marketing of its Bright Investment program which targets smaller C/I customers represent its most important contributions to the BPU's first policy goal. PSCRC's efforts to facilitate projects sponsored by other ESCOs in the large C/I market have been less successful, as evidenced by the disappointing experiences of many ESCOs that participated in PSCRC's Energy Services Network.

In terms of the second objective, the New Jersey BPU attempted to mitigate potential anticompetitive effects and market power by limiting the scope of PSCRC's activities (e.g., requiring that third party firms install and service end-use efficiency products) and PSE&G's marketing efforts. As a project sponsor, we estimate that PSCRC has a market share of about 25% in the performance contracting/financing product market (based on committed projects). We also estimated an HHI index values in the range of 1000-1270 among firms that are active in PSE&G's performance-based DSM programs that target C/I customers. Both of these values represent an upper bound because quantitative information on the size and market shares of firms participating in "traditional" performance contracting activities outside of utility DSM programs is not readily available. The Department of Justice guidelines on mergers imply that HHI values between 1000-1800 are in a "grey area" with respect to triggering challenges based on market power concerns, although ease of entry for firms (and customers) in this product market tends to mitigate some of our long-run concerns regarding PSCRC's potential market power.

Looking to the future, given PSCRC's major role (and financial stake) in the Standard Offer program, we would argue that PSE&G has some continuing responsibility to ensure the development of a healthy, competitive energy services industry in New Jersey. On balance and in light of the low barriers to entry in the Standard Offer, we believe that the existence of PSCRC has done more to increase the viability of a local energy services industry that promotes performance contracting/financing services rather than impede it. In our interviews with PSE&G senior management, we found a high degree of enthusiasm and commitment to DSM, the Standard Offer and, not surprisingly, PSCRC. In our experience, this type of commitment to DSM is becoming more rare among utility executives in the current business environment.

However, at least in the PSE&G service territory, PSCRC is not just another ESCO and should not be treated as such by the regulators. Thus, we also believe that a significant regulatory oversight and monitoring role will be required both to ensure the development of a robust and competitive energy services market and to ensure that ratepayer investments in DSM continue to be prudently managed by PSE&G. We believe that this is one of the costs that regulators and utilities must bear if they decide that public policy is best served by allowing a utility buyer to purchase from a seller affiliated with the host utility in their own service territory.

One goal of our analysis has been to suggest criteria that can be used by state regulators to judge the potential benefits of direct participation by ESCOs affiliated with the host utility in local energy services markets vs. potential anticompetitive effects. We discuss policy options that can potentially limit market power and/or mitigate conflicts of interest that arise from having the utility on both sides of the transaction (i.e., a buyer and seller) in more detail in Section 9.7.

Discussion and Recommendations

9.1 Overview

In this chapter, we summarize our findings in terms of the four other major objectives of the evaluation of PSE&G's Standard Offer program: (1) to analyze program costs and cost-effectiveness, (2) to assess market response, (3) to review and evaluate the utility's administration and implementation of the program, and (4) to discuss the transferability of the Standard Offer concept to other utilities (see Chapter 8 for a discussion of the fifth objective: the role of PSCRC and its effect on the energy services market). We also suggest a number of changes to the program's design and administration based on experience gained during the pilot and in light of the current conditions facing the utility.[85]

Our proposed changes to the program's design are guided by three overall goals and themes:

- The Standard Offer should be performance-based, but the program should better accommodate the distinctive characteristics of DSM resources (rather than attempt to make DSM look like supply-side resources). This means that project sponsors should be paid for verified savings over the contract term but that appropriate guidelines for the accuracy of DSM savings estimates should be reassessed (see Chapter 7) and that some contract terms and conditions may need to be revised by either utilities or ESCOs (see Chapter 5).

- It is essential to reduce the turnkey costs of projects substantially, given the likelihood that PSE&G's forecast of future avoided costs will be much lower than those currently used for cost-effectiveness screening. We identify opportunities for PSE&G to reduce M&V and administrative costs. To be successful in the future, project sponsors will also have to innovate and find additional ways to reduce up-front marketing costs, lower the cost of financing, and creatively manage project risks.

- Program design changes should position DSM and the energy services industry to function more effectively in an increasingly competitive electricity industry. This means that participating customers should bear an increasing share of total project costs.

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85 Our suggestions are drawn from our analysis of interviews with project sponsors and host customers (Chapter 5), information from the program tracking database, other studies provided by PSE&G, and our experiences with "performance-based" DSM programs at other utilities (Chapters 3 and 4).

We also recommend that PSE&G consider narrowing the program's current scope and target market and developing alternative program designs to supplement the Standard Offer, which can more effectively target certain markets (e.g., new construction) and types of opportunities (e.g., emergency replacement of failed equipment).

9.2 Program Costs and Cost-Effectiveness

- Total resource costs (which include costs to the utility and customers), levelized over the contract term of each facility, average 6.8 ¢/kWh overall for the program, which is about 74% of the utility's avoided supply costs. Total resource costs vary somewhat by market segment, averaging 6.6 ¢/kWh for ESCO- and customer-sponsored projects in the large C/I market and about 8 ¢/kWh for PSCRC's Bright Investment projects, which are targeted at smaller C/I customers (see Chapter 4).

- Total resource costs average about 5.9 ¢/kWh for 217 facilities in the large C/I market that installed only lighting measures, 7.3 ¢/kWh for the 27 facilities that are implementing fuel switching projects, and 6.9 ¢/kWh for the 12 facilities that are installing various types of non-lighting measures (see Table 4-1).

- The Standard Offer program has a benefit/cost ratio of about 1.6 from a societal cost perspective.[86] About 25% of the individual facilities (59 out of 234) in the large C/I market have TRC B/C ratios less than one, with twenty facilities having B/C ratios less than 0.8. This result is possible because project sponsors are allowed to bundle together facilities for individual customers that would fail the TRC test on a stand-alone basis if the project proposal passes the TRC for the entire set of facilities.

We recommend that the program's requirements be tightened and that PSE&G require that TRC test results for individual facilities be greater than a pre-specified value (e.g., 0.9). This would limit situations in which ratepayers support the installation of sets of measures that are not cost-effective from a societal perspective.

86 In New Jersey, the BPU requires that utilities include environmental externality costs of about 2 ¢/kWh in the total resource cost test calculation.

9.3 Market Response

- Through December 1994, PSE&G received commitments from 35 project sponsors (16 ESCOs and 19 customer sponsors) for a total of about 40 MW of SPPADR in over 1,050 facilities. About 9 MW are operational (see Chapter 3). The market response is significantly less than the original program target of 150 MW in two years, but compares favorably with most DSM bidding programs, assuming that almost all committed projects come on-line.

- Various types of lighting measures (66%) and electric-to-gas conversions of space and water heating equipment and industrial processes (17%) are the most popular measures in terms of SPPADR. Most fuel-switching projects appear to be driven by the attractive economics from the customer's perspective given differences in electricity and gas prices, and relative efficiencies of some gas and electric equipment and industrial processes, which are further enhanced by the attractive Standard Offer payments.[87]

- Non-lighting measures represent 75% of the savings from customer-sponsored projects, while lighting measures represent 75% of the savings from projects sponsored by ESCOs and contractors.

- The Standard Offer program has succeeded in creating a high level of interest and support among various types of energy service providers (e.g., ESCOs, lighting service contractors, energy engineering firms and consultants, and firms that specialize in measurement and verification of savings). The program has also been relatively successful in reaching industrial customers; some industrials have chosen to be customer sponsors and they have also been heavily marketed by ESCOs.

- However, many ESCOs note that the program has been a "harder sell" than anticipated to customers and stress the intense competition among firms for projects involving large C/I customers. Program design features that were cited most often by ESCOs and customers which adversely affect participation include: (1) the program's overall complexity and contract performance requirements which make it difficult even for large customers to sponsor their own projects, (2) stringent measurement and verification protocols which are time-consuming and costly to develop for non-lighting measures, and (3) relatively long contract terms and

87 As a combined utility, PSE&G has supported fuel switching if the economics are attractive to the customer. In most DSM bidding and performance contracting programs sponsored by electric-only utilities, the utility excludes fuel substitution measures as a threshold requirement

unacceptable contract provisions (e.g., penalties for non-performance).[88] Thus, despite providing commercial/industrial customers with financial incentives for DSM that are currently among the most attractive offered by any U.S. utility, ESCOs have found it difficult to get certain types of customers to participate (e.g., non-owner occupied commercial office buildings).

9.4 Program Design and Scope

In these next two sections, we discuss possible changes to the program design and scope in light of experiences gained during the last several years implementing the current program and likely future market conditions (i.e., lower avoided supply costs). We recommend that PSE&G consider major changes that involve modifications to the program's requirements, a narrowing of the Standard Offer program scope and target market, and development of alternative program designs that can more effectively target certain markets (e.g., new construction) and types of opportunities (e.g., failed equipment/emergency replacement). We believe that the success of the program over the next three to five years depends on the ability of PSE&G (and ESCOs) to adapt and modify the Standard Offer so that market penetration can be increased in market sectors that have significant cost-effective opportunities but are apparently reluctant to participate (e.g., large office buildings), and among smaller customers, and by targeting additional high-efficiency opportunities in other end uses besides lighting.[89]

9.4.1 Potential Impacts of Changing Market Conditions (Lower Avoided Supply Costs)

Comparing the market response to the Standard Offer (~40 MW) vs. estimated economic potential in the C/I sector (~1000 MW), we conclude that the program could continue to acquire a significant block of savings (30-60 MW/year) for the next three to four years, primarily from the most attractive end uses (e.g., lighting), assuming comparable financial incentives and no other changes. However, we are less sanguine about the future, when we factor in some of the more troublesome aspects of current experience in conjunction with

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88 These include contract provisions that are required by ESCOs of their host customers. Termination value provisions were cited frequently which require the host customer to pay the ESCO the unrecovered cost of the project if the customer chooses to terminate the contract prior to the end of the term.

89 We implicitly assume that any decision on industry structure and the utility's obligation to serve includes a transition period (e.g., 3-5 years). For purposes of this discussion, we also define long-run success as the ability of PSE&G to achieve the original program goals (~75 MW/year) in the most cost-effective manner. We recognize that lower avoided supply costs typically imply that the utility has a reduced need for additional resources in the future, which might affect the size of a future Standard Offer resource block.

the likelihood of less attractive market conditions (i.e., lower avoided supply costs and resulting lower payment levels, assuming the current formula is retained).[90]

To illustrate the potential impacts of lower avoided supply costs on market response, we have developed a stylized example in Figure 9-1 which shows the current economics for a prototypical lighting-only project and a project that involves installation of both lighting and other non-lighting measures (e.g., various HVAC, motor, and refrigeration measures). For this discussion, we will refer to a project that includes lighting plus other measures as a "comprehensive retrofit."[91] For illustrative purposes only, we also disaggregate total costs into two broad categories: direct measure costs (e.g., installation and capital cost of equipment, O&M) and all other costs (e.g., marketing, administration, M&V, profit, reserves to deal with contingencies and potential adverse outcomes). Looking to the future, based on recent trends (e.g., lower forecasts of future gas prices, technological improvements in gas-fired generating technologies) and experiences at other U.S. utilities, we expect that PSE&G's forecast of future avoided costs will be significantly lower (~30%) than the avoided costs used in cost-effectiveness screening of DSM projects in the current pilot program.

In a "business-as-usual" situation (i.e., avoided costs decline by about 30% with no other changes in the program's method for setting the Standard Offer payment), many lighting projects would just pass the TRC test, while lighting projects in facilities with low hours of operation or those that targeted small C/I customers are more likely to be marginally uneconomic.[92] Some project sponsors would likely respond by installing fewer and/or lower cost measures rather than pursuing more comprehensive lighting retrofits. Almost all "comprehensive" projects would fail the TRC test, and thus, for the program overall, lighting measures would account for almost all of the program's savings.

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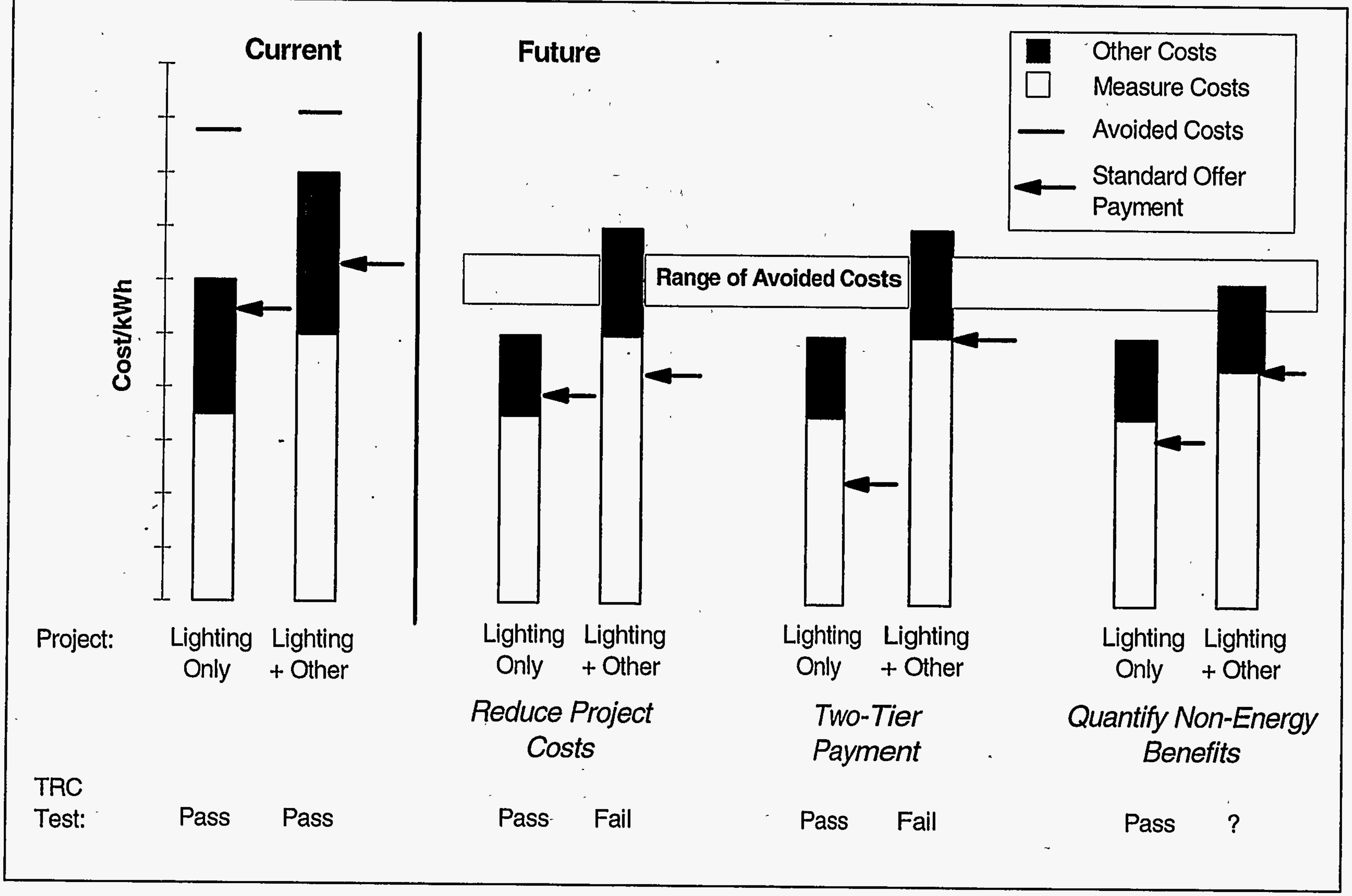
90 In the current program, project development times have been lengthy (i.e., the huge gap between operational and committed projects), most large customers have already received multiple proposals from ESCOs, and fuel switching options have been quite popular among customers, but their role in any future program hinges, to some extent, on the continuation of current regulatory policies.

91 This stylized example ignores the range of installed costs.

92 The implications of the "business as usual" scenario can be seen by comparing current project costs with the range of future avoided supply costs.

Figure 9-1. Implications of Lower Avoided Costs and Possible Design Changes



9.4.2 Design and Policy Options

Reduce Turnkey Costs of Projects

We believe that there are significant opportunities to reduce the turnkey costs of projects through a combination of changes to the program's design and administration as well as opportunities for ESCOs to improve operating efficiencies and reduce costs. In Section 9.4.3, we discuss opportunities to reduce M&V and administrative costs because that is the DSM in which participating customers bear an increasing share of direct program costs. Second, a two-tiered payment scheme will make more customers financially indifferent to lighting-only vs. comprehensive retrofits and would allow "full-service" ESCOs that offer comprehensive packages of measures to compete more effectively against competitors that promote lighting-only projects. Even if a two-tiered payment scheme is adopted, if avoided costs drop significantly, the program's requirement that projects pass a TRC test acts as a binding constraint and means that fewer "comprehensive" projects will be cost-effective using this perspective.

Two-Tiered Payment Scheme

As avoided costs drop, the market niche for those ESCOs that offer comprehensive services or develop more complex projects gets significantly smaller in the utility's program (and possibly disappears). These ESCOs incur higher up-front marketing and project development costs (e.g., longer sales cycle, higher costs for project design, and development of M&V protocols), which they may not be able to recover if the potential market for these services is limited. From the customer's perspective, the deals offered for lighting projects will look even more attractive than comprehensive projects. For this and other reasons, we recommend that PSE&G consider a two-tiered Standard Offer payment.[93] Projects that install only lighting measures would receive lower payments, while projects that involve significant savings from other end uses (e.g., HVAC, refrigeration, industrial process) would receive payment at the higher price. For example, one option could be to offer higher payments to projects that achieve about 25-30% of their savings from non-lighting measures. Several utilities have signed contracts in their DSM bidding programs with tiered payment systems (e.g., Pacific Gas & Electric) or included requirements that projects achieve a certain percentage of total savings from non-lighting measures (e.g., Long Island Lighting Company, Sacramento Municipal Utility District).

93 The two-tiered approach would involve some modification to the current formula used for setting the maximum Standard Offer payment. The current formula is: (Avoided Energy + Avoided Capacity Costs + Environmental Externalities Costs) - (Fixed Cost Revenue Erosion*0.5). It is possible to adjust the fixed cost revenue erosion factor to achieve other policy objectives.

Depending on the method used to set payment levels, a two-tiered payment scheme could achieve several objectives. First, it would lower the cost to ratepayers of acquiring savings from lighting-only projects, while the customer's cost contribution would increase. This approach is consistent with trends at other utilities and an overall strategic direction for DSM in which participating customers bear an increasing share of direct program costs. Second, a two-tiered payment scheme will make more customers financially indifferent to lighting-only vs. comprehensive retrofits and would allow "full-service" ESCOs that offer comprehensive packages of measures to compete more effectively against competitors that promote lighting-only projects. Even if a two-tiered payment scheme is adopted, if avoided costs drop significantly, the program's requirement that projects pass a TRC test acts as a binding constraint and means that fewer "comprehensive" projects will be cost-effective using this perspective.

Relax TRC Cost-Effectiveness Threshold Requirements?

Given this situation, several ESCOs have suggested either relaxing or eliminating the requirement that all projects pass the TRC test (see Section 5.8). The first option allows ESCOs to include jobs at individual facilities that customers desire (but which don't pass a TRC test) as long as their entire portfolio of projects has a TRC B/C ratio that exceeds one. The underlying rationale is that they are building a "DSM power plant," and that the bundling of facilities in 100-200 kW savings increments is part of the construction process.[94] The second option (i.e., elimination of the requirement that projects pass a TRC test) would mean that individual customers (or ESCOs working with them) could proceed with "comprehensive" projects if they so choose. This argument is based on the notion that the TRC test initially served two functions: (1) from a societal perspective, it protects ratepayers from paying too much for DSM resources compared to supply-side alternatives, and (2) it protects customers from being taken advantage of and "overpaying" for DSM. Given the degree of competition among energy service providers, these ESCOs argue that the second function of the TRC requirement is unnecessary.

We believe that suggestions to eliminate the TRC requirement should only be considered as part of a broader discussion of the primary objectives of the Standard Offer program and the future role(s) for ratepayer-funded DSM programs. For example, the underlying rationale for the Standard Offer program remains the net resource benefits that are being provided to ratepayers compared to the utility's supply-side alternatives. If the program is not being pursued primarily for its resource benefits, then the "performance-based" aspect should be reassessed as well. M&V standards that are sufficient to satisfy customers' performance requirements might be quite different than M&V standards which provide the

94 This approach would tend to favor ESCOs that have been more active in the current program (e.g., submitted several 200 kW blocks of projects).

basis for the utility to include DSM savings as a firm, reliable resource in its Integrated Resource Plan.

Some DSM programs may produce benefits beyond those that are measured by the direct savings impacts of program participants - the possibility that the program has market effects and may help transform markets. However, quantifying program spillover effects, such as encouraging introduction and acceptance of new technology or lowering prices of high-efficiency products sold in a region because of increased volume, is quite difficult. Other DSM programs, which may have resource value to ratepayers, also help utilities achieve customer service objectives in an industry facing increasing competitive pressures (e.g., customer retention and increased customer satisfaction). If utilities offer DSM programs solely for customer service purposes, program designs would typically not involve direct financial incentives to participants and passing the TRC test would not be the primary criterion used to judge the value of the program.

With respect to modifying the requirements for the next Standard Offer, broadening the TRC threshold requirement to include the entire portfolio of projects submitted by a project sponsor has some merit, when combined with a minimum TRC B/C ratio for individual facilities (e.g., 0.9). Another possible alternative involves a more limited approach in which project sponsors have the option of quantifying any non-energy benefits of "comprehensive" projects that are valued by customers, but still retaining the TRC test as a threshold requirement. In Figure 9-1, we show a stylized example of a comprehensive retrofit project that provides significant non-energy benefits to the customer, which makes the project marginally economic (which are included as cost reductions in the cost-benefit analysis, similar to incremental O&M savings).[95]

9.4.3 Potential Opportunities to Reduce M&V and Administrative/Transaction Costs

Given the high likelihood that PSE&G's estimates of future avoided costs will be significantly lower than those currently adopted, it is imperative, in our opinion, that PSE&G and project sponsors find innovative ways to reduce the turnkey cost of projects.

M&V Costs

Several of our recommended changes to PSE&G's M&V and sampling procedures may potentially reduce M&V costs (see Section 7.5). These include: (1) modifying the Sampling Plan to stratify and sample hours of operation for lighting control circuits based on usage areas, (2) exploring the use of audit acceptance techniques to verify certain key inputs during pre- and post-implementation audits (e.g., connected load, number and type of

95 In this example, non-energy benefits, which are valued by the customer, are shown as reductions in other costs.

fixtures), (3) re-assessing target confidence and precision levels for accuracy of DSM savings, and (4) revising M&V protocols for smaller C/I customers (because incremental costs of M&V may exceed value of benefits to utility, particularly given lower avoided costs).

Program Administration and Transaction Costs

We also suggest several ways in which administrative or transaction costs or cost uncertainties for project sponsors can be reduced. Many of these involve minor changes but cumulatively they may be significant.

Reduce maximum number of post-implementation audits

The Standard Offer contract specifies that PSE&G can perform 15 post-implementation audits at the project sponsor's expense. Currently, in estimating turnkey costs for projects, an ESCO would typically set aside some amount to cover this possibility. At a minimum, the maximum number of post-implementation audits should be linked to contract term directly (e.g., maximum of 10 audits for 10 year contract).

Allow initial payments based on estimated savings with "true-up" based on verified savings

Many other utility DSM bidding programs allow project sponsors to bill the utility and receive the first-years payments based on pre-specified estimates of energy savings once the project has come on-line and been approved for commercial operation by the utility. Estimated savings are then trued-up after the first year based on verified savings. This approach helps project cash flows with minimal risk to ratepayers.

Move toward less frequent billing and payment

PSE&G currently requires sponsors to submit monthly billing statements. Less frequent billing and payment intervals (e.g., quarterly or semi-annual) has the potential for reducing administrative costs incurred by both the utility and project sponsors. These time intervals still allow the utility to identify anomalies and project sponsors to correct problems that may arise at specific sites.

9.5 Program Scope and Target Market

Based on the experience during the pilot phase, the Standard Offer approach is not particularly well-suited for all market sectors and types of opportunities. In this section, we offer recommendations on the scope of the Standard Offer program and recommend changes for various target markets.

9.5.1 Residential Markets

We recommend that PSE&G evaluate the performance of the one ESCO-sponsored project that is targeting residential customers and assess the likelihood that ESCOs will target this market in the future if Standard Offer payments are significantly lower. PSE&G should also develop additional "performance-based" program designs which are targeted at specific efficiency opportunities in the residential market (e.g., appliance efficiency programs), if this can be done cost-effectively.

Through December 1994, PSE&G had not approved any projects in the residential sector. However, in April 1995, the company signed its first contract with an ESCO that targets residential customers, although no savings have yet been delivered. Based on experience in DSM bidding programs, the total resource costs of performance-based programs targeting residential customers tend to be higher than those targeting large C/I customers (Goldman and Kito 1994). Moreover, the Standard Offer design is not well-suited for certain types of DSM programs targeted at residential customers (e.g., high-efficiency appliance replacement equipment that rely on equipment dealers as point of contact, "Golden Carrot"-type programs).

9.5.2 Commercial New Construction/Major Remodel Market

We recommend that PSE&G consider alternative program designs in commercial new construction and remodeling markets that have proven effective at other utilities in addressing "lost opportunities."

The current program design does not appear particularly well-suited for capturing the potential savings in many types of commercial new construction markets (see Section 7.2). Thus far, it is difficult to make a definitive judgment on the performance of the Standard Offer program in the commercial new construction market because of depressed market conditions and the utility's limited information on construction activity (and thus market penetration) and baseline practices. Although the DSM savings potential does not appear large at PSE&G, some attention is warranted in the commercial new construction market for at least three reasons: (1) concern regarding creation of "lost opportunities," (2) opportunities to promote innovation in energy efficient design, technologies and operational practices, and (3) other utilities have developed cost-effective programs, even after accounting for difficulties and uncertainties in measuring savings in new construction. From a societal perspective, given the long lifetimes of new buildings, it is typically far more cost-effective to design and build energy-efficient buildings at the time of construction rather than to retrofit those buildings later.

Based on our review, we concur with the observations made by Gordon et al. (1994) in their recent study that looked at PSE&G's programs in relationship to "lost opportunities." They conclude that:

- The characteristics of developers influence receptiveness to energy efficiency and must be accounted for in the design of commercial new construction programs. Projects in the new construction market can be categorized as either speculative, build-to-rent, or owner-occupied development. The Standard Offer will be a very hard sell to speculative developers and may have limited appeal for build-to-rent or owner-occupied developers. Even among this latter group, there is a concern that the M&V requirements will potentially eliminate many cost-effective measures in new construction (e.g., daylighting, EMCS, controls).

- Most ESCOs have a very limited track record with new buildings and marketing in new construction often involves a different set of contacts and sales approaches than the retrofit market. For those ESCOs that pursue new construction or the major remodel market, the Standard Offer may be potentially appealing to government or non-profit institutions because they have a longer-term perspective, are generally capital-constrained, and often build or improve on a relatively slow schedule.

9.5.3 Other Potential Lost Opportunities: Failed Equipment/Emergency Replacement Situations

We recommend that PSE&G supplement the Standard Offer approach with other pilot programs that can target potential lost opportunities, based on an assessment of the relative magnitude and cost-effectiveness to the utility and society of acquiring these lost opportunities (compared to other program alternatives).

We and others (Gordon et al. 1994) have noted that the program is unlikely to capture conservation opportunities that arise when equipment fails and must be replaced quickly (see Section 3.4.1). Those conservation opportunities where decisions must be made quickly, on short notice, and in very limited windows of opportunity create potential "lost opportunities" because at the time of failure or planned replacement, the societal cost of acquiring high-efficiency equipment is only the incremental cost of improved efficiency. Based on market research at other utilities in the Northeast, these situations often arise with motor replacements. For emergency replacement situations, the existing vendor structure is key to equipment availability and delivery. Another example is replacement/conversion of centrifugal chillers which use CFC as a refrigerant where combined analysis of chillers, auxiliaries, and thermal loads such as lighting can lead to integrated treatments which significantly increase savings and lower energy and capital costs because of equipment downsizing (Gordon 1994b).

9.5.4 Small Commercial/Industrial Sector

We offer several suggestions for program design changes in the small commercial/industrial sector.

We recommend that PSE&G consider alternative program designs (e.g., a direct install program or small I/C rebate program) for very small C/I customers (<50 kW monthly peak demand) as well as possible changes to the M&V and sampling procedures.

Currently, small C/I customers can participate in either PSE&G's I&C Pilot Rebate Program or through an ESCO in the Standard Offer (e.g., PSCRC's Bright Investment program). It is unclear if many smaller C/I customers would be able to participate cost-effectively under the Standard Offer program, if avoided costs decrease significantly. Thus, we would not rely solely on the Standard Offer program design among the smallest customers in the C/I market (<50 kW monthly peak demand) without a more in-depth analysis of other alternatives (e.g., the small I/C rebate program, program designs that have been successful at other utilities). Another option for PSE&G to consider involves re-evaluating its lighting M&V and sampling procedures to determine if they are appropriate (and cost-effective relative to the value of the information) for this group of customers.

We recommend adding a maximum usage limit to the M&V requirement (e.g., 100-150 kW monthly peak electric demand) for facilities with less than 50 kW of summer peak demand reduction.

The program M&V requirements for facilities with less than 50 kW of summer peak demand reduction need to be modified to ensure that customers in large facilities are not encouraged to undertake partial treatments (see Section 3.2). An additional eligibility requirement which is based on the facility's maximum annual usage or peak demand requirement would greatly improve the situation. Based on the experience of other utilities in small C/I markets, a maximum usage requirement in the range of 100-150 kW would be reasonable.

9.6 Program Delivery and Administration

- About two-thirds of the project sponsors indicated that PSE&G program managers were very responsive and helpful. In most cases, customer sponsors and ESCOs thought that PSE&G had reviewed and approved their proposals in a timely fashion (2-4 weeks) and were technically competent and knowledgeable in negotiating appropriate M&V plans for specific projects. However, a number of project sponsors were more critical and complained about difficulties in gaining access to program staff and obtaining answers to questions.[96] There is a fairly widespread sentiment among project sponsors that the program is understaffed (see Section 5.4).

- Almost all customer sponsors and most ESCOs believe that PSE&G program staff have implemented the program fairly. However, about half of the ESCOs made a sharp distinction between program staff (who they regarded as generally fair) and PSE&G field representatives, who they felt steered customers towards PSCRC.

- Project sponsors gave very mixed reviews of PSE&G's program materials and the Automated Entry/Standard Offer Program (AESOP) software used to prepare project proposals. Many customer sponsors and those ESCOs with less experience in the program were quite critical of the program materials and project proposal software, particularly the instructions for non-lighting measures. In contrast, ESCOs that had more experience with the Standard Offer or had worked previously in the 1989 bid gave higher ratings to the program materials and were more understanding of PSE&G's original rationale for requiring all project proposals to be submitted using the utility's standard software.

9.6.1 Program Staffing and Management

PSE&G senior management needs to recognize the long-term staffing commitments required to successfully manage the implementation of the Standard Offer.

The Standard Offer promises ratepayers that long-term payments are being made for delivery of "performance-based DSM." For DSM departments of virtually all utilities, this type of commitment is unprecedented. It requires committed, knowledgeable, and experienced program managers, technical expertise in developing and reviewing M&V protocols and plans submitted by sponsors, and sophisticated program information management capabilities. Moreover, because PSE&G's energy services affiliate is

96 When probed further, it became clear that customer sponsors were often frustrated by the M&V development and approval process, specifically developing plans that were acceptable to the utility and the fact that utility staff could not approve new M&V protocols on their own but had to gain approval from the BPU and Division of Ratepayer Advocate staff.

participating actively in the program, the utility must maintain a particularly high standard of performance to avoid even the appearance of impropriety or favoritism.

PSE&G has added program staff slowly as the pilot program has ramped up over the last 18 months. As of January 1995, the program had four to five full-time staff as well as an independent contractor who handles most of the site audits. We concur with the widespread sentiment expressed in interviews with project sponsors that the program workload, given current staffing levels, requirements and procedures, appears to be quite heavy. At first glance, the program volume appears to be significantly higher than most DSM bidding programs (170 projects and 1,050 facilities) and it is not uncommon for these type of programs to have three to five full-time equivalents (FTE) in program staffing. This suggests that either PSE&G's procedures used to administer the Standard Offer need to be "re-engineered" and streamlined and/or additional personnel (utility or contractors) need to be committed to managing and overseeing the program. We do believe that some savings in staff time could be achieved through improved administrative procedures, which might allow program staff to focus on other tasks that have more long-run strategic importance (e.g., additional M&V protocols, customer focus groups, new marketing strategies and materials).

During the last six months, PSE&G has also gone through a major reorganization and several key program staff left the utility. Staffing changes are inevitable in large utilities, particularly during a period when the industry is facing major restructuring and may be "downsizing." However, the disruptive effects caused by such changes should be minimized. At a minimum, PSE&G needs to improve its documentation of internal and external program administrative procedures (see suggestions in Section 9.6.2). This would allow new personnel to get up to speed quickly and would mean that the "institutional memory" of the program would not reside solely with several key individuals.

9.6.2 Program Delivery

PSE&G should consider streamlining the Standard Offer program material (including the contract) and develop ways to work more closely with those customers that want to be project sponsors.

The current Standard Offer program material is sufficiently complex and imposing that relatively few customers choose to become project sponsors and those that do typically rely on consultants to prepare many aspects of the proposal. If, and we emphasize if, the program wants to make a concerted effort to target customer sponsors, there is a continuum of activities that PSE&G could undertake to make the Standard Offer program more "user-friendly" to customers.[97] These involve providing varying levels of marketing and technical support. At the low end, PSE&G could revise and streamline the RFP package to make it more understandable and acceptable to the customer sponsor. This process would be essential if the minimum size requirements for project sponsors were reduced further. At the high end, PSE&G field marketing representatives could offer various types of assistance to customers in preparing their proposal. This would certainly curtail some opportunities for ESCOs to sponsor projects and for consultants that currently provide these services for a fee. Another option is for PSE&G to certify engineers and consultants to assist customers in various aspects of the program. Ultimately, these type of customer marketing and technical support services should be addressed and resolved as part of broader discussions regarding future program concept and scope.

Internal Administrative Procedures

The program tracking database should be fully documented, including some explanation of various individual databases, specific data fields, and algorithms used to calculate savings, cost-effectiveness, and payments.

PSE&G has developed an AESOP user's manual for potential project sponsors, but to our knowledge has not produced an internal manual or report that fully documents its program tracking database (AESOP), primarily because it is still under development. In our view, the algorithms used to calculate savings, cost-effectiveness and payments should be well-documented, including how specific data fields are used in these calculations.[98]

Backup documentation on individual projects should be improved and standardized, particularly information on project costs.

After project sponsors submit their proposal (using the AESOP software), PSE&G also creates a documentation file for each project sponsor which includes the original hardcopy proposal, correspondence between the utility and sponsor, and any additional documentation requested (e.g., project cost proposal, savings and cost of baseline equipment, M&V plan). Based on our review of these files, we have several concerns. For ESCO-sponsored projects, we recommend that the Energy Service Agreement between the host customer and ESCO be included as part of the documentation or that a representative of the host customer be required to sign a statement which specifies their financial

97 At a minimum the Standard Offer program material could be better organized. Suggestions include a table of contents for the entire document (not just the standard pricing offer), moving most asked questions and answers to the front, and moving the M&V protocols and examples to the back as technical appendices.

98 Ultimately, we were able to replicate the most important economic calculations, but it involved numerous conversations with PSE&G program managers because there was insufficient documentation of the program tracking database.

arrangement with the ESCO. For customer-sponsored projects, the utility should develop an internal form that clearly shows the various cost components and the customer's documentation (e.g., capital cost of the project, additional M&V costs) and indicates the utility's review process for reasonableness. These procedures will help ensure that customer cost contributions and project costs are accurately reported by project sponsors.

PSE&G should consider preparing a manual for project sponsors (with periodic updates) that describes payment procedures and their linkage to measurement and verification protocols.

As projects have come on-line, several issues have arisen with respect to calculation of payments for verified savings that are not fully explained in the Standard Offer RFP. For example, there are a number of possible methods that can be used to calculate monthly kWh and bill savings based on aggregating the sample of lighting circuits. Several utilities (e.g., Pacific Gas & Electric and Southern California Edison) have prepared manuals that document billing and payment adjustment procedures for their DSM bidding program; these manuals also include guidelines on M&V procedures. We suggest that PSE&G consider a similar approach as one way of improving its internal administrative procedures and reducing the potential for conflicts with project sponsors.

9.6.3 Development and Approval of Measurement & Verification Protocols/Plans

We recommend that PSE&G take a more proactive role in improving existing M&V procedures and sampling plans, develop additional M&V protocols for measures not covered, and provide additional examples of acceptable site-specific plans.

We support setting aside the necessary program administration funds to develop M&V protocols for measures that are currently not covered by existing protocols (e.g., HVAC and lighting controls), to improve the accuracy of existing protocols (e.g., the effect of lighting measures in reducing HVAC loads), and to improve sampling techniques (see Chapter 7). The Standard Offer RFP includes the Statewide M&V Protocols as well as PSE&G's additional M&V procedures and Sampling Plan (see Section 2.3). Since the program's inception, PSE&G and project sponsors have negotiated a number of M&V plans, which have been approved for certain types of retrofit applications (e.g., variable-speed drives). These plans should be included in the next RFP and made available to prospective project sponsors.[99]

We recommend that the BPU and Division of Ratepayer Advocates staff retain a consultant(s) with technical expertise on measurement and verification to provide an

[99] In many cases, it should be possible to provide examples with specific details altered so that proprietary concerns of individual customers are addressed.

independent review of M&V plans negotiated by PSE&G and project sponsors. This approach could also help streamline the process for approving M&V plans.

M&V of DSM savings is a rapidly evolving science and few regulatory commissions or consumer advocates have the resources, time, or technical expertise to be directly involved in critiquing and reviewing proposed M&V plans.[100] Several PUCs that have been quite active in DSM (e.g., California, New York, Michigan, Massachusetts, Rhode Island) have pursued an alternative strategy in which the PUC or consumer advocate staff issues an RFP and hires a team of independent consultants that are experts in various aspects of M&V to either review utility DSM plans, develop evaluation protocols for various types of DSM programs, or review utility DSM evaluation studies (often in proceedings where financial incentives for utility shareholders are to be determined).[101] The independent consultant(s) reviews M&V plans negotiated by the utility, works with utility staff (or the utility's consultants) with expertise on M&V to resolve technical issues in a timely fashion, and periodically reports to the PUC staff. Based on interviews with project sponsors and our knowledge of approaches that work well in other states, it appears that the present system in New Jersey is too cumbersome and unwieldy. As the program moves forward, we recommend a different approach to ensure that ratepayer interests are protected.

9.6.4 Program Implementation and Market Planning

PSE&G program staff should collect actual site information on building type and strategic market segment at the time of pre-implementation audits and devote sufficient analytic resources to ensure that this information can be used effectively by the utility's forecasting, marketing, and DSM planning departments. Information on market penetration will help PSE&G and third party providers to target future DSM efforts towards under served markets more effectively (see Section 3.5).

100 The Stipulation of Settlement required that the BPU and Division of Ratepayer Advocates staff approve new M&V protocols as well as M&V plans for certain measures at individual facilities. This requirement was included, in part, because work on the M&V protocols was not completed, and more fundamentally, some parties thought this type of check was needed to protect ratepayer interests.

101 Typical practice in these states is to set aside a small portion of the utility's DSM budget (e.g., 1-2%) for these activities that are under the management of PUC staff.

9.7 Transferability of the Standard Offer Concept to Other Utilities

In discussing the transferability of the Standard Offer to other utilities, we believe that it is important to distinguish between the underlying concept and the PSE&G program because the Standard Offer pilot has been shaped to a great extent by the policy and design choices made by PSE&G, New Jersey's regulators and interested parties. For example, the policy decision to allow the utility's subsidiary to participate actively in the program, the design philosophy of "making DSM look like supply," and eligibility requirements were particularly significant. Thus, in transferring the Standard Offer program concept to other utilities, we offer the following suggestions :

- The design goal of "performance-based" DSM (e.g., payments for energy savings linked to long-term performance) is laudable, but can best be achieved by recognizing the distinctive characteristics of DSM resources. Despite the fact that PSE&G is offering very attractive financial incentives to project sponsors for verified savings (about 5.5-6.0 ¢/kWh), certain program design features appear to create significant obstacles to participation in various market segments. Thus, we would place additional emphasis on developing contracts whose length and scope is more suitable for customers and whose terms and conditions are specifically tailored to managing the uncertainties associated with DSM resources. This could potentially reduce transaction and marketing costs and ultimately lead to a more efficient allocation of performance and development risks among ratepayers, utility shareholders, participating customers, and project sponsors (e.g., ESCOs).

- The initial results in New Jersey suggest that the "one size fits all" approach implied by the Standard Offer is not appropriate for all customer classes or market segments. The Standard Offer concept appears to work best in commercial/industrial markets in either retrofit or planned retrofit situations. At PSE&G, there has been a limited response in C/I new construction and residential markets. We and others (Gordon et al. 1994) would argue that the program design is not particularly amenable to capturing many of the technical opportunities in commercial new construction or in situations where there are limited windows of opportunity to influence investment decisions.

- Incentive mechanisms will also affect the utility's role and interest in a Standard Offer type program. The combination of cost recovery through expensing, the opportunity to recover net lost revenues and profit through PSCRC's activities has provided strong motivation for PSE&G to pursue DSM resources. PSCRC's presence has facilitated the development of the energy services industry in New Jersey in the short-term, particularly through PSCRC's willingness to provide various types of financing to small, relatively new firms and customers (see Chapter 8). However, direct participation by an ESCO that was affiliated with the host utility also created additional program implementation and monitoring challenges for the utility and regulator. Over the long term, incentive mechanisms that place the utility on both sides of the transaction (i.e., buyer and seller) necessitate additional regulatory scrutiny to minimize problems that inevitably arise from perceived or actual conflicts of interest. If other states adopt the Standard Offer concept, regulators should seriously consider alternative approaches that offer opportunities for financial incentives to utility shareholders (e.g., sharing of net resource benefits produced by program) or institutional arrangements and requirements that minimize potential conflicts of interest. These include the option of having an independent agency administer the program if the host utility's energy services affiliate participates directly, or establishing additional conditions that limit market power (e.g., initially limiting the potential market share of the utility's energy services subsidiary).

- Other jurisdictions and utilities need not necessarily adopt the formula used in New Jersey to establish the Standard Offer price. Payments could be set low initially to maximize contributions from participants and ratcheted up over time if necessary. Some experimentation will be required to develop realistic assessment of the price-quantity relationship in various market sectors. Experience at PSE&G also suggests that other elements of program design (e.g., contract term and conditions, measures without acceptable M&V protocols) create their own barriers that discourage participation.

- Many analysts have argued that the reality (or even the threat) of electric utility industry restructuring presents a fundamental challenge to the continuation of large-scale, ratepayer-funded utility DSM programs. Assuming there is a suitable funding mechanism (e.g., non-bypassable distribution surcharge), one attractive aspect of the Standard Offer concept is that it could be managed by a statewide agency or consortium empowered to acquire various types of DSM resources in pursuit of societal objectives. For example, a statewide consortium could define standard terms and conditions for all entities that wish to provide verified energy savings (California Working Group Report 1995). The Standard Offer concept is also compatible with notions of "customer choice" because it maximizes customer's choice of service providers and theoretically places fewer constraints on their choice of acceptable end use efficient technologies. The Standard Offer concept certainly merits consideration by those state PUCs and utilities looking to preserve and/or stimulate the energy efficiency services industry during a period of electricity industry restructuring and regulatory reform.

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