Distributed Generation-Combined Heat and Power Impact Evaluation Report (2001–June 2011)

Final Report

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The New York State
Energy Research and Development Authority

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NOTICE

ABSTRACT

This report describes the impact evaluation of the direct incentive component of the Distributed Generation – Combined Heat and Power Program (DG-CHP or the Program). NYSERDA established the Program in 2001 to contribute to the growth of combined heat and power in New York through a multipronged approach, including direct customer incentives and market intervention to address systemic barriers. In the 10-year course of the Program, system installations with a combined capacity of 104 MW were incentivized at 89 sites. This Program is closed and no additional systems will be installed.

The Impact Evaluation Team assessed Program electric savings, natural gas usage at the site, and heat recovery leveraging data from multiple sources. The foundation of the evaluation was extensively available hourly metered data, providing direct measurement of gross savings. The net-to-gross factor was stipulated to be 0.90. The evaluated net annual Program savings are 469 GWh of electricity, -2,836 thousand MMBtu of natural gas (which indicates an overall increase in natural gas consumption at the site), and 71 MW of load system reduction during summer peak periods.

The Program has served a broad range of customers with diverse technologies as was intended. In addition, the Program instituted a near real-time Integrated Data Collection System (IDS), which collects robust hourly performance data from DG-CHP sites on an ongoing basis.

ACKNOWLEDGMENTS

This work plan was prepared by the Impact Evaluation Team led by ERS with Susan Haselhorst as the project manager. Stephan Barsun of Itron was the technical lead for the project. ERS conducted the on-site verification. The Impact Evaluation Team wishes to acknowledge the significant contribution of NYSERDA project manager Tracey A. DeSimone, the input of the NYSERDA impact staff, and also the valuable suggestions provided by Bill Saxonis of the DPS and its consultants, Ralph Prahl and Rick Ridge of TecMarket Works.

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SECTION 1: EXECUTIVE SUMMARY

This report describes the impact evaluation of the direct customer incentive component of the Distributed Generation-Combined Heat and Power Program (DG-CHP or, the Program) which accepted applications from 2001 through June 2011. NYSERDA established the Program in 2001 to contribute to the growth of combined heat and power (CHP) in New York through a multipronged approach, including direct customer incentives and market intervention to address systemic barriers. In the 10-year course of the Program, system installations with a combined capacity of 104 MW were incentivized at 89 sites. This Program is closed and no additional systems will be installed.

The primary objective of this impact evaluation was to determine the gross savings that resulted from the Program. Net savings were estimated using a stipulated net-to-gross ratio (NTGR) of 0.90. Table 1-1 summarizes the annual first-year savings for the Program.

Table 1-1. DG-CHP Program Impact Evaluation Results

	Reported Savings	Gross M&V Savings	Net Savings	Precision 90% CI
Number of sites	89	89	89	NA
Installed capacity MW	101	99	89	NA
Annual first-year energy savings (GWh)	611	521	469	5%
Annual first-year demand savings (MW)	105	79	71	21%
Annual first-year natural gas savings, (thousand MMBtu[1])	-4,204	-3,151	-2,836	5%

[1]Natural gas usage at the site is increased by the Program; it is computed as the difference between the natural gas displaced by the recovered thermal energy and natural gas consumption by the generator. .

The Program achieved a fuel conversion efficiency (FCE) of 61%. The Program successfully recruited a broad range of customers, from dairy farmers to Manhattan high-rise managers and sponsored diverse technologies. In addition, the Program instituted a near real-time Integrated Data Collection System (IDS), which collects robust hourly performance data from DG-CHP sites on an ongoing basis. This system is transparent, data-rich, and publicly available, providing valuable data for a variety of stakeholders.

1.1 APPROACH

This impact evaluation was designed to leverage data from multiple sources. The foundation of the evaluation, however, was extensive hourly metered data, a unique characteristic of DG-CHP systems where the electrical and thermal energy is typically metered with hourly resolution, providing direct measurement of gross savings. High-resolution metered data was available for about 89% of the installed capacity.

1.2 FINDINGS, CONCLUSIONS, AND RECOMMENDATIONS

Although this Program is closed, DG-CHP is an important component of the statewide energy portfolio and the lessons learned in the ten years operation of this program will apply to future programs and future administrators. The evaluators also note that the current NYSERDA programs (CHP Acceleration, CHP Performance) have incorporated lessons learned in proactive and creative ways. However, the responsibility for CHP may migrate to others parties, and there may be pressure to cut corners to meet goals. These recommendations are offered in that spirit.

1.2.1 Finding: Customers Have Difficulty with the Technology

About 25% of the sites responding to surveys (13 of the 50 sites surveyed) were at or near failure on average six years after installation. Shortened lives can be in a large part traced to ill-conceived and designed projects and in some cases, a focus on generation only. While this represents only 9% of the installed capacity and is a significantly better survival rate than that found in another large scale evaluation, [1] the collective difficulties signify opportunities for improvement.

The end user survey also revealed a high degree of smaller system start-up challenges and complaints about underperformance that evaluators later validated. Specifically, two-thirds of the respondents provided unsolicited comments about the difficulties of system start-up, one-third reported ongoing heat recovery underperformance, and one fifth reported electric generation underperformance.

Possibly because of the difficulty of the technology, about half of the participants surveyed and, surprisingly, about a quarter of the non-participants (those who installed systems in the 2011-2012 period, but did not receive a NYSERDA incentive) cited NYSERDA's endorsement of DG-CHP as influential in their decision to install systems. NYSERDA has a role as a trusted advisor.

[1] A DG-CHP evaluation in California found that after nine years, approximately 2/3 of the reciprocating engines in the Self Generation Incentive Program (SGIP) program were offline. Marin et al., Ten Years of California Distributed Combined Heat and Power – Living up to Expectations, ASME Power Conference, 2014

Recommendations

The following four recommendations, listed through the next three sections, result from these findings.

1. **As trusted advisors, NYSERDA (or future program sponsors) should define technical performance requirements and review applicant design plans to ensure applicant projects are designed to meet them**.

   Part of NYSERDA's role in animating the DG-CHP market is to reduce the time, complexity and expense of installing systems. However, this drive to expand the market must be balanced with NYSERDA's role as a trusted advisor (as reported by participants in surveys) and the real technical challenges DG-CHP presents. Systems that are not properly sized or do not have matching thermal loads risk low economic benefit to the customer, which could lead to increased emissions or abandonment of the system.

   The current NYSERDA programs require applicants to demonstrate viable load profiles and a design meeting FCE thresholds which will help ensure the economic viability of the projects.

2. **Adopt an interventionist posture to extend system live**s.

   As noted in the previous recommendations, the longevity of systems can be enhanced by first ensuring the systems are designed well. In addition, the IDS data provides the means to monitor individual system performance and remediate poor performance. Finally, because systems require ongoing service and substantial overhauls every three to five years, therefore maintenance contracts are a necessity.

   The current NYSERDA program design includes a five year maintenance contract and a post installation commissioning feature which will contribute to system longevity.

1.2.2 Finding: NYSERDA's IDS is a Valuable Resource

IDS is a repository of near real time (data is uploaded daily) site-specific CHP performance data. The data is available by the hour or in informative summary performance graphs. Metered data streams are largely populated and reliable.

3. **Continue to require and support IDS for performance monitoring, system optimization, and for impact evaluation**.

   NYSERDA's IDS system is a powerful tool for ensuring the long-term effectiveness of CHP. This resource serves multiple stakeholders, including planners, implementers, evaluators, and end-use customers. Both Massachusetts and California are implementing systems modeled after NYSERDA's IDS.

1.2.3 Finding: CHP Benefit is Diminished by Poor FCE

For the entire population of projects evaluated, the FCE was 61%, which is considered good. However, excluding the big turbines, projects averaged 49%–54% FCE (see Table 4-2).The evaluators identified underperformance of heat recovery as the primary reason for low FCE. Lower FCE may negatively impact customer economics and net emissions savings.

4. **Design and maintain CHP installations to high FCE standards to maximize customer benefit and emission reductions.**

   It is critical to educate customers on the importance of maximizing use of the thermal energy produced, which requires evaluating hourly thermal loads and temperatures. We recommend that NYSERDA increase emphasis on CHP system design and proposed operational profiles and to do so early in the application process when reviewers can pinpoint potential design flaws. The Program has the most leverage with a customer at the design and application stage, where the incentive is an inducement to design to the 60% FCE standard. Both current Programs require demonstration of thermal and electrical load profiles as a critical step in a design that will yield a high FCE, thus achieving a major step in this direction. The CHP Acceleration Program should monitor the FCE outcomes of the prescriptive path projects to ensure they yield the expected FCEs.

SECTION 2: INTRODUCTION

This section presents a program description, the evaluation goals, and a summary of previous evaluations.

2.1 PROGRAM DESCRIPTION

The goal of the DG-CHP Program was to contribute to the growth of combined heat and power (CHP) in New York beginning in 2001. The program provided funding for single-site and multi-site (fleet) demonstrations and sought to improve end users' and project developers' awareness and knowledge of CHP. The program also sought to address DG-related issues such as DG permitting, Standard Interconnection Requirements (SIR), utility standby service tariffs, technology risk, and renewable fuel options such as biomass and landfill gas, and the impact of fluctuating prices of natural gas. The Program was closed to further applications in June 2011, and the last incentivized system came online in 2013.

In general, projects funded by the DG-CHP program were selected based on their ability to demonstrate and evaluate opportunities for application of DG systems, or to demonstrate and validate advanced features (such as synchronous-parallel interconnection).

In addition, NYSERDA initiated and maintains the Integrated Data System (IDS)[2], a website for access to performance data from DG-CHP sites. IDS is a repository of hourly measurements of key energy streams from participating DG-CHP systems.

2.1.1 Summary of Program Reported Savings

The Program incentivized systems at 89 sites. The Program took the unusual step of revising the original tracking savings for DPS reporting. The original tracking savings reflected estimates of performance submitted by Program applicants. The revised tracking savings reflects Program Staff re-estimates of savings using average performance factors derived from IDS data. The revised reported savings were computed as the product of the site installed site peak demand reduction and an average capacity factors for electricity and an average thermal performance factor for the natural gas savings. Two of the large gas turbine sites were estimated using site-specific capacity and thermal factors. Table 2-1 presents the revised reported savings.

[2] http://chp.nyserda.ny.gov/home/index.cfm

Table 2-1. DG-CHP Revised Reported Savings for All Program Installations

Number of Projects	Installed Capacity (MW)	Gross Annual Electric Savings (GWh)	Gross Annual Natural Gas Savings (thousand MMBtu)
89	101	611	-4,204

In addition, the Program sponsored feasibility studies at 19 sites for which no savings were reported.

2.2 EVALUATION OBJECTIVES

The objectives of this impact evaluation included the following two tasks:

1. Estimate evaluated gross impacts for electricity and natural gas savings.
2. Conduct additional research regarding customer decision making.

The impacts for electricity and natural gas require an assessment of multiple energy streams, with the intermediary and the key reporting parameters identified in Table 2-2.

Table 2-2. DG-CHP Energy Stream Definitions

Energy Stream	Definition
Electric energy impacts – key reporting parameter	Annualized energy savings based on electric reductions (kWh) at the customer meter based on the first year of normal operation (generated electricity [or avoided electrical use] minus parasitic electric loads)
Electric demand impacts – key reporting parameter	Electrical demand at the customer meter consistent with the New York Technical Manual definitions.
Thermal energy recovery	Annualized thermal heat recovered from the production of electricity adjusted for the thermal production efficiency; based on the first year of normal operation.
Natural gas generator usage	Annualized natural gas consumption by the generator based on the first year of normal operation.
Natural gas impact – key reporting parameter	Avoided natural gas at the site (thermal energy recovery minus the natural gas usage of the generator). This is usually negative.

This report complies with the requirements listed in *New York Evaluation Plan Guidance for EEPS Program Administrators*[3], which was issued by the DPS and is intended to provide robust, timely, and transparent results. The impact methods are in line with the guidelines of the *National*

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3 http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/766a83dce56eca35852576da006d79a7/$FILE/NY_Eval_Guidance_Aug_2013.pdf

Action Plan for Energy Efficiency (NAPEE) Model Energy Efficiency Program Impact Evaluation Guide[4].

2.3 PREVIOUS EVALUATION RESULTS

The DG-CHP Program has undergone various assessments four times in the past, although these studies were not rigorous meter-based impact assessments. In addition to these four studies of the DG-CHP Program, eleven of the sites were evaluated as part of two other metering and verification (M&V) impact evaluations using metered interval data. The results for 10 of these sites were directly incorporated into this evaluation. The previous evaluation work is summarized in Appendix B.

[4] http://www.epa.gov/cleanenergy/documents/suca/evaluation_guide.pdf

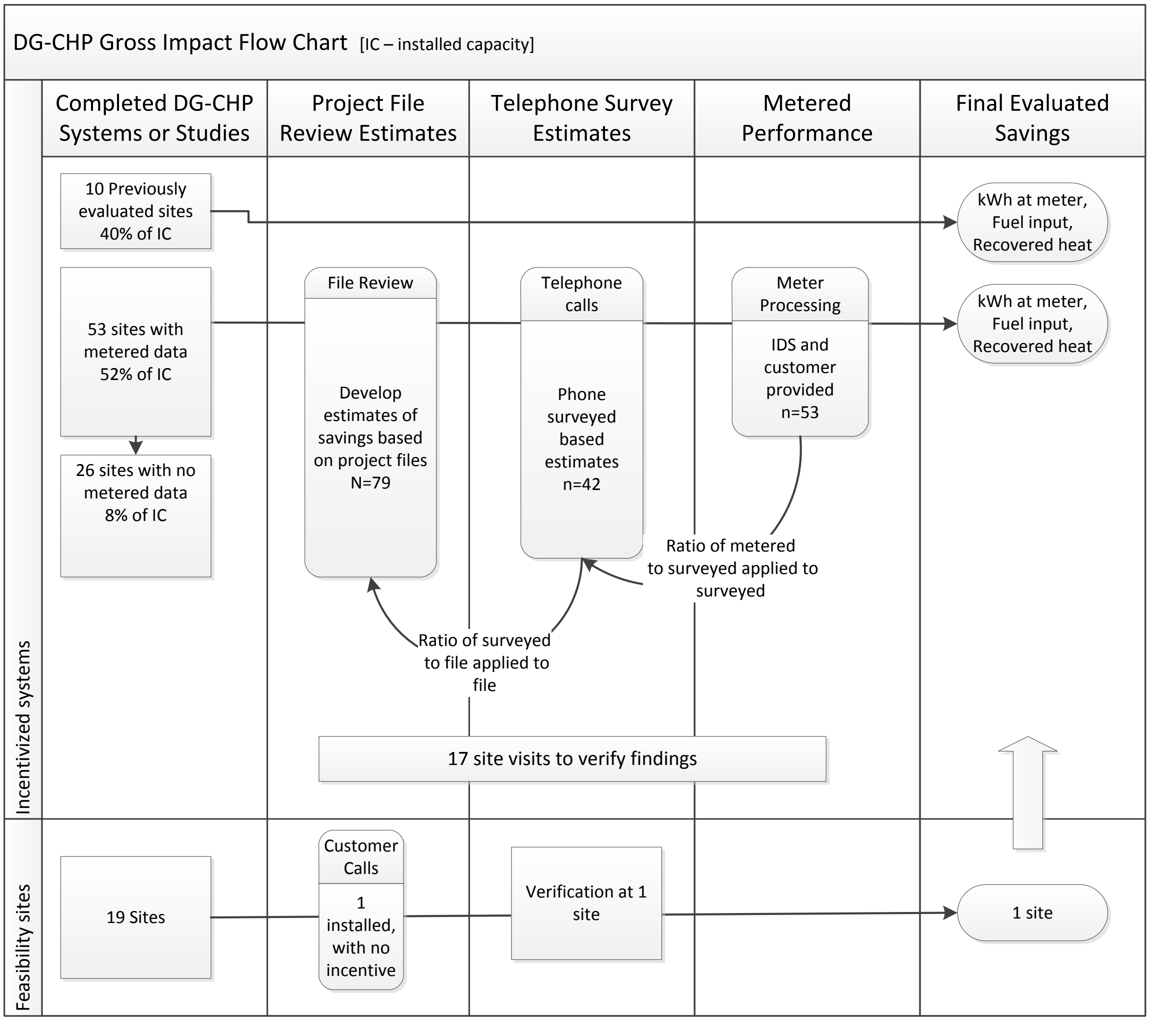
SECTION 3: METHODS

The scope of work consisted of two distinct activities. The first activity, which constituted the bulk of the work, was to determine the gross impacts of the Program. The second activity entailed telephone interviews of participants and nonparticipants to gain further insights into how decisions regarding CHP were made; this activity had no direct bearing on the impact results.

3.1 GROSS IMPACT EVALUATION METHODS

This impact evaluation was designed to leverage diverse and rich data from multiple sources, including project file estimates, telephone survey-reported operational characteristics, and site inspections. However, the foundation of the evaluation was the availability of extensive hourly metered data, a unique characteristic of DG-CHP systems where the electrical and thermal energy is typically metered with hourly resolution, providing direct measurement of gross savings. High-resolution metered data was available for about 92% of the installed capacity. Figure 3-1 illustrates the overall approach.

Figure 3-1. DG-CHP Impact Method Flow Chart



The Program population consisted of ten sites that had been previously evaluated and the current evaluation sub-population consisting of 53 sites with extensive metering captured by either the customer or NYSRDA as part of implementation and 26 sites that did not have metering available. The non-metered sites constituted 8% of the installed capacity.

For current sites, the research was designed to capture site information from three sources: a) review of project files, b) customer surveys, and c) metered data of generated electricity, recovered heat, and natural gas burned. The metered data savings was the evaluated savings for those sites with metered data. For the non-metered sites, a technology specific ratio adjustment was applied to the project file review estimate of savings. The ratio was the weighted sum of a single ratio (for sites without survey data) and double ratio (for sites with survey data).

An important step in the analysis was a thorough data review and cleaning of metered data to determine first year savings. First year savings was defined as either the first calendar year (58%

of installed capacity of sites with metered data), the first annum of metered data was available (34%), or based on the first annum of normal operation as defined by the customer or apparent in the data (8%). The data was combined into separate models of electrical savings, thermal recovery, and natural gas usage for each of five major technology groups. The electrical savings, thermal recovery, and natural gas usage results for each group were adjusted using ratio estimators, as noted above, and summed to determine program-level savings. Parasitic loads and the impact of absorption cooling were included in the model.

Metered data and project documentation was further verified through the telephone surveys, where customers confirmed the system configuration and operation as well as through seventeen on-sites, where equipment was inspected and verified.

Finally, recipients of feasibility studies that had not subsequently participated in a NYSERDA program were surveyed. It was determined that one of the recipients had installed a DG-CHP system and that the study had been influential in the decision to install a system. The verified savings from this site were added to the program gross savings.

The evaluated savings of the 10 sites that had been previously evaluated were used directly, after a review of the site reports and IDS data.

Since the Program is closed and some program participants enrolled over a decade ago, a traditional self-report net-to-gross analysis would not be useful or reliable. The DPS and NYSERDA agreed that net savings would be calculated as the product of the evaluated gross savings and a stipulated net-to-gross ratio (NTGR) of 0.9.

Final net savings was calculated as follows:

Evaluated net savings = (Previously evaluated savings + Current evaluated metered savings + Current evaluation ratio adjusted savings + Feasibility study savings) × Stipulated NTGR

The final program precision was calculated using ratio estimation statistics.

The methods employed are described in more detail in Appendix C.

3.2 DECISION-MAKING RESEARCH

In addition, participating and nonparticipating customers were surveyed to gather qualitative insights into the factors driving a decision to invest in DG-CHP.

The Impact Evaluation Team interviewed 27 participants who had knowledge of the decision to install a DG-CHP system. The interviews were designed to examine factors that prompted the decision to install DG-CHP. In addition to the participants, the Impact Evaluation Team was able to complete interviews with 13 nonparticipants. Nonparticipants were identified from a US Department of Energy-sponsored website that inventories DG-CHP sites throughout the country[5]. The interview guidelines are included in Appendix D.

The survey results were compiled and analyzed to identify themes across the interviews along with an attempt to discern differences between participants and nonparticipants.

[5] http://www.eea-inc.com/chpdata/

SECTION 4: RESULTS, CONCLUSIONS, AND RECOMMENDATIONS

The section presents the results and conclusions from the gross impact activities followed by the decision-making research. The section concludes with recommendations.

4.1 IMPACT RESULTS AND CONCLUSIONS

This section summarizes the results of the M&V activities.

4.1.1 Electric Generation Performance

The implied realization rate (RR) of the program, calculated as the evaluated savings divided by reported savings, is excellent at 85% for electrical energy savings. This rate was achieved in part because Program staff members took the initiative to re-estimate program-reported savings using factors developed from IDS. The RR using original applicant estimates of savings would be closer to 80% for the Program as a whole and 67% for all but the three largest projects. In many cases, the original estimates of electric production were overestimated and did not properly account for actual facility demand for electricity or equipment downtime.

Another useful indicator of DG-CHP electric savings performance is the capacity factor which is a measure of system utilization. It is calculated as the annual actual electric production divided by the maximum possible production and is useful for comparisons between systems or future estimates. Table 4-1 summarizes the performance by technology as observed in this evaluation. This table also illustrates the diversity of technologies sponsored by the Program.

Table 4-1. DG-CHP Technology Evaluated Capacity Factor Performance

	Number of Sites	Claimed Peak Reduction MW	Evaluated GWh	Evaluated Capacity Factor	Capacity[a] Factors Comparisons
Gas turbine	3	52.5	314	0.75	0.83
Reciprocating engine	51	40.3	132	0.38	0.20
Fuel cell	11	6.7	49	0.91	0.67
Micro-turbine	19	4.0	16	0.46	0.37
Back pressure turbine	3	0.6	7	0.50	N.D.
Organic rankine cycle	1	0.54	3	0.53	N.D.
Chilled water absorption	1	N/A	<0.5	N/A	N.D.
Total	89	105	521	N/A	

a) 2012 SGIP Impact Evaluation and Program Outlook, Prepared by Itron, Feb 2012

The capacity factors above are similar to capacity factors observed in other CHP program evaluations.

4.1.2 Heat Recovery and Fuel Conversion Efficiency Performance

The heat recovery component of the Program met Program expectations, resulting in an overall fuel conversion efficiency (FCE) of 61% (calculated using the higher heating value of natural gas, or HHV consistent with NYSERDA practice). In the best-run plants with high rates of heat recovery, the FCE can approach 80%. As another comparison point, the two current NYSERDA DG-CHP programs require design basis and/or achievement of an FCE of 60% or higher for a site to receive an incentive.

Table 4-2 shows the electrical, thermal, and fuel conversion efficiencies by type of system. These values are calculated using data from metered systems and they exclude any systems fueled by biogas. These values represent weighted averages by type of prime mover and size category. The break in size at 1.3 MW is for convenience to align with the current NYSERDA programs which specify a maximum installed capacity of 1.3 MW for participation in the CHP Acceleration Program. Larger systems can apply to the CHP Performance Program.

Table 4-2. DG-CHP Fuel Conversion Efficiencies by Type of System and Size

Type of Prime Mover	Number of Sites	Electrical Efficiency[a]	Thermal Efficiency[a]	Fuel Conversion Efficiency[a]
<1.3 MW	**63**	**28%**	**19%**	**47%**
Fuel cell	9	39%	7%	46%
Microturbine	17	23%	29%	52%
Reciprocating engine	37	27%	19%	46%
>1.3 MW	**11**	**29%**	**44%**	**72%**
Fuel cell	1	35%	17%	53%
Gas turbine	3	27%	48%	75%
Reciprocating engine	7	35%	19%	54%
Total	**74**	**28%**	**38%**	**66%**

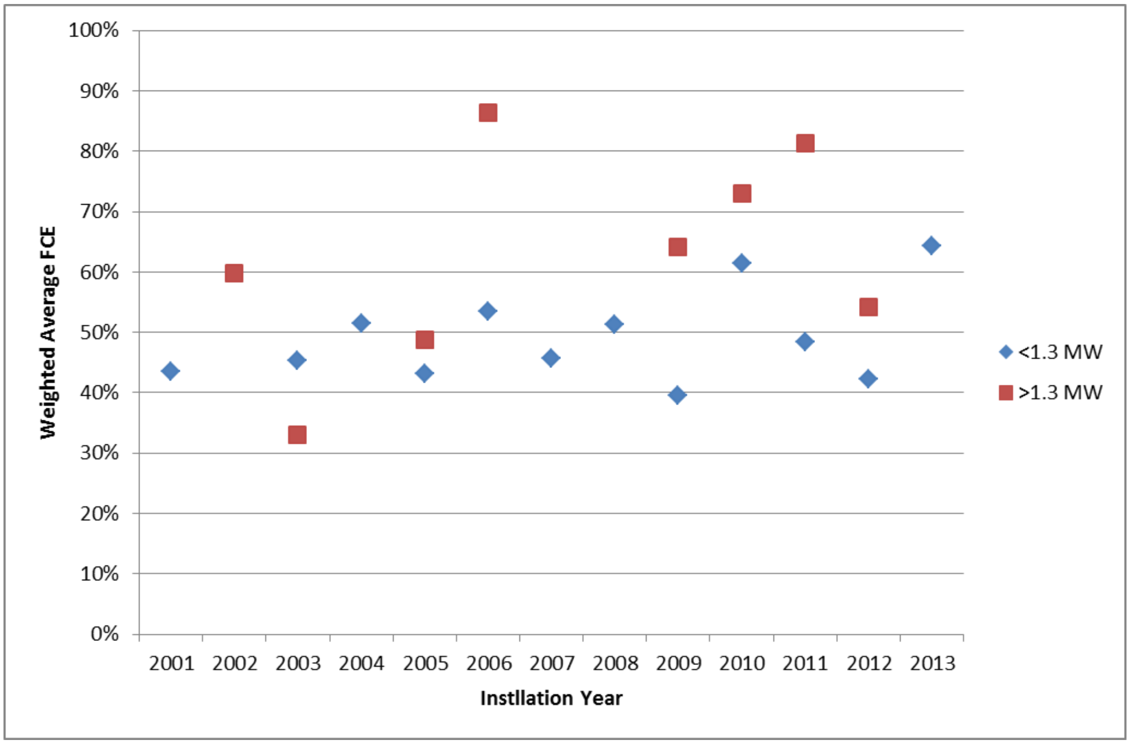
[a]Efficiencies were calculated using the higher heating value (HHV) of fuel, consistent with NYSERDA program practices.

While the Program met the 60% FCE efficiency threshold, it did so due to the high efficiency of three gas turbine sites accounting for half of the Program's installed capacity. None of the other technologies met the standard on average.

There is a weak trend towards improved FCE over time, as shown in .

Figure 4-1.

Figure 4-1. DGCHP FCE Trend



4.1.3 Feasibility Study Savings

Of the 19 Program-sponsored feasibility studies, one site confirmed that a system was installed, that it did not receive an incentive, and that the study had been essential to the decision to install. During an on-site verification, the engineer collected customer metered data which was used to estimate first year system savings of 1.4 GWH. The back pressure turbine system was installed at this site but did not require any additional gas usage; therefore, there is no natural gas impact.

Of the remaining sites, six had installed systems with incentives, three confirmed that no system had been installed, and eight did not respond. It is likely, although not certain, that all but one of the eight non-responders installed systems since only one of them is listed in the DOE sponsored inventory of DG-CHP sites.

4.1.4 Program Net Savings

Final gross and net savings using the stipulated net-to-gross ratio (NTGR) of 0.90 are presented Table 4-3.

Table 4-3. DG-CHP Program Impact Evaluation Results

	Reported Savings	Gross M&V Savings	Net Savings	Precision 90% CI
Number of sites	89	89	89	NA
Installed capacity MW	TBD	99	89	NA
Annual first-year energy savings (GWh)	611	521	469	5%
Annual first-year demand savings (MW)	105	79	71	21%
Annual first-year natural gas savings (thousand MMBtu[1]) at this site	-4,240	-3,151	-2,836	5%

[1] Natural gas usage is increased by the Program; it is computed as the difference between the natural gas displaced by the recovered thermal energy and natural gas consumption by the generator. .

4.1.5 Premature System Failures

Approximately 25% of sites surveyed (13 out of 50) had prematurely failed. (This figure excludes sites that were non-responsive to surveys even if a lack of IDS data might cause someone to presume that the system is not operational, since a unit may not have failed, but is simply not reporting data to IDS.). Premature failure includes sites that have been removed, are completely offline, were replaced, or are expected to be brought offline soon. These findings are summarized in Table 4-4.

Table 4-4. DG-CHP Summary of Operational Status of Surveyed Sites

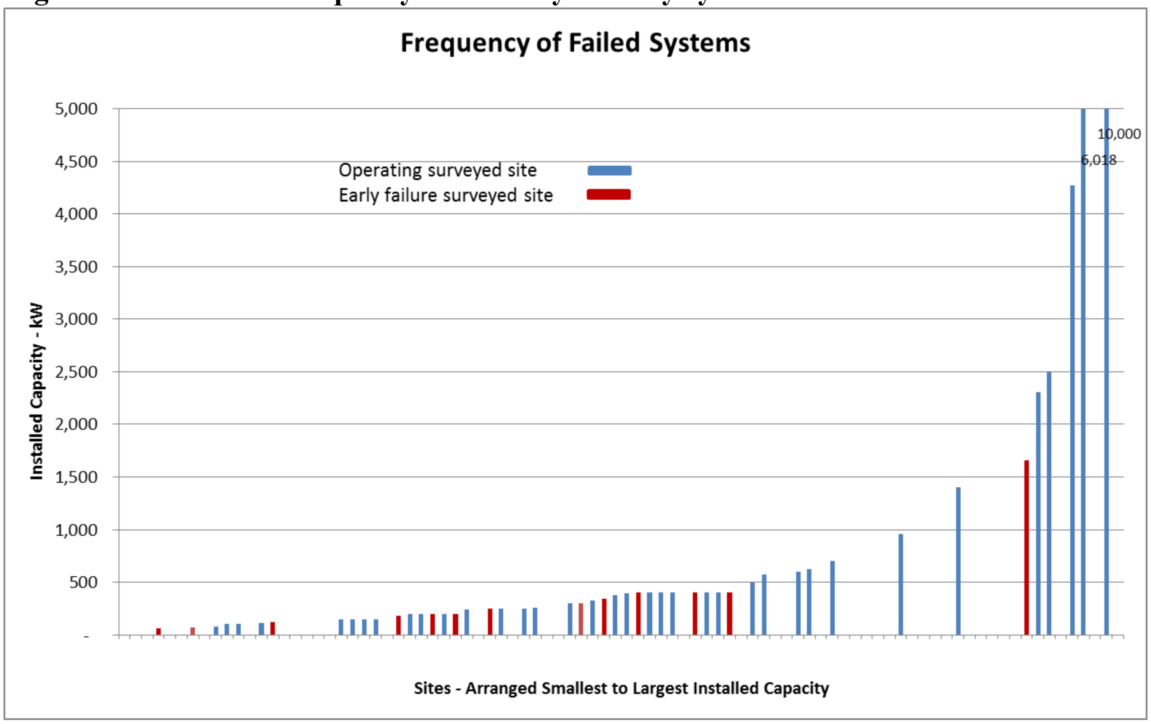
Current System Status	Number of Sites	Percentage of Sites	Percentage of Installed Capacity	Average Years to Fail
In service	37	74%	91%	NA
Replaced	4	8%	1%	5.3
Inoperative	2	4%	0%	6.0
Major repairs, not online	2	4%	2%	9.5
Will remove on failure[1]	2	4%	5%	8.5
Removed	3	6%	1%	4.3
Subtotal	**50**	**100%**	**100%**	

[1] Systems are still operational, but customer is expecting failure shortly and will not repair.

Underlying causes of early failure include oversizing, unresolved equipment flaws, and high cost of operation due to maintenance and fuel costs. Selection of systems to match the thermal load and more realistic performance assessments including maintenance costs may have led to better purchase decisions and outcomes. The NYSERDA failure experience is not unique; CHP system failures occurred in California's Self-Generated Incentive Program (SGIP), although the rate of failure is lower than California's, where two-thirds of the reciprocating engine DG-CHP systems were offline after nine years.

This high number of prematurely failed systems and a somewhat counterintuitive high percentage of the installed capacity still online indicate that smaller systems have a much higher rate of failure, while larger systems operate well. This effect can be seen in Figure 4-1, where all but one of the failed systems is less than 1 MW in size. The graph lists surveyed sites by size, with gaps indicating non-surveyed sites; color coding indicates online and failed systems.

Figure 4-2. DG-CHP Frequency of Failed Systems by System Size



Larger systems require large capital expenditures of tens of millions of dollars and are typically well engineered, financed, maintained, and operated. Smaller systems tend to be installed in locations that have fewer resources for overseeing their design, implementation, and operation. In 2008, the Program instituted a bonus for modular package units. All of the seven surveyed sites receiving the modular package were operating. However, due to the recent install dates (2010-2013), further monitoring is required to confirm that the modular package design reduces the incidence of early failure.

On a related note, in the surveys, customers often provided unsolicited descriptions of start-up problems. The number citing problems (60%) is particularly noteworthy because the survey did not include any questions about start-up problems. Table 4-5 summarizes respondent characterization of start-up problems.

Table 4-5. DG-CHP Customer Reported Frequency of Start-Up Problems

Startup Issues	Number of Sites	Percentage of Sites	Percentage of Installed Capacity in Survey
Major problems	18	36%	26%
Minor problems	12	24%	7%
None noted	20	30%	67%
Subtotal surveyed	50	100%	100%

4.2 DECISION-MAKING RESEARCH

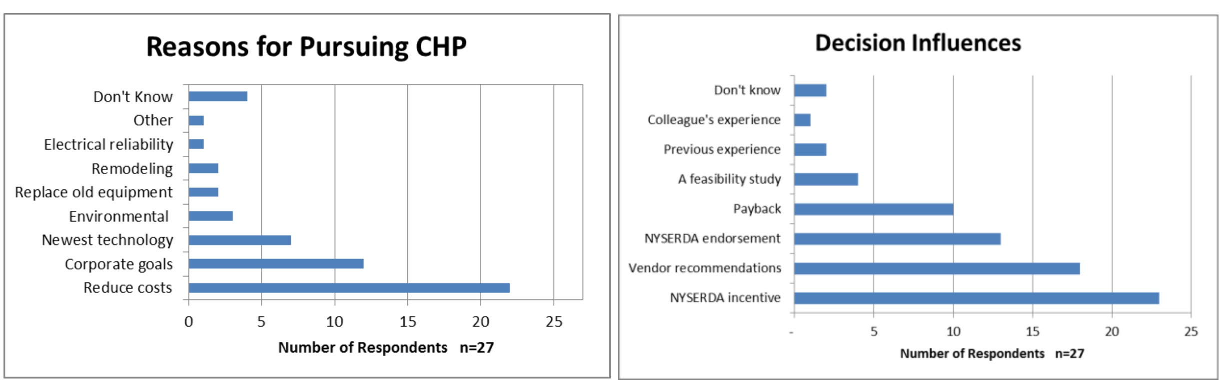
Both participants and nonparticipants were surveyed to gather insights into those factors that were the most influential in their decision to invest in CHP.

4.2.1 Participant Surveys

Decision-making surveys were completed with 27 individuals having knowledge of the original consideration and decision to install CHP.

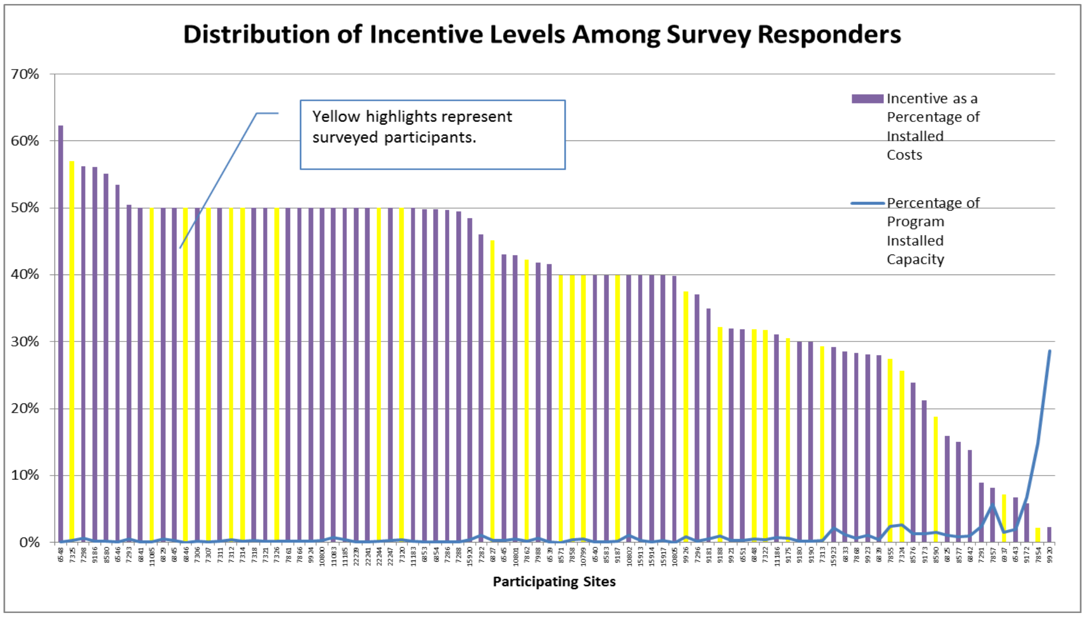
The pair of graphs in Figure 4-2 illustrates both the motivation for initially considering CHP and the factors that influenced the decision to install. In both graphs the financial influence is apparent. CHP was largely pursued as means to reduce operating costs and the NYSERDA monetary incentive helped make the project feasible. However, the actual decision to install was not strictly a financial decision; it also depended upon reassurance by other parties – vendors, NYSERDA, colleagues, or personal experience that the venture would work. While most participants when asked about NYSERDA's role would first mention the incentive, the NYSERDA backing was important to half of the responders.

Figure 4-3. DG-CHP Participant Survey Results



The role of the incentive, particularly for smaller customers, was critical. The average incentive received by the 81% of the sites that were less than 1.3 MW was equal to 41% of the reported installed cost, as illustrated in Figure 4-3. Generally, smaller systems tend to receive a higher incentive as a percentage of the installed cost. The distribution of survey respondents is noted as well and appears to be firly evenly distributed throughout the population.

Figure 4-4. DG-CHP Graph of Incentive as a Percentage of Installed Costs

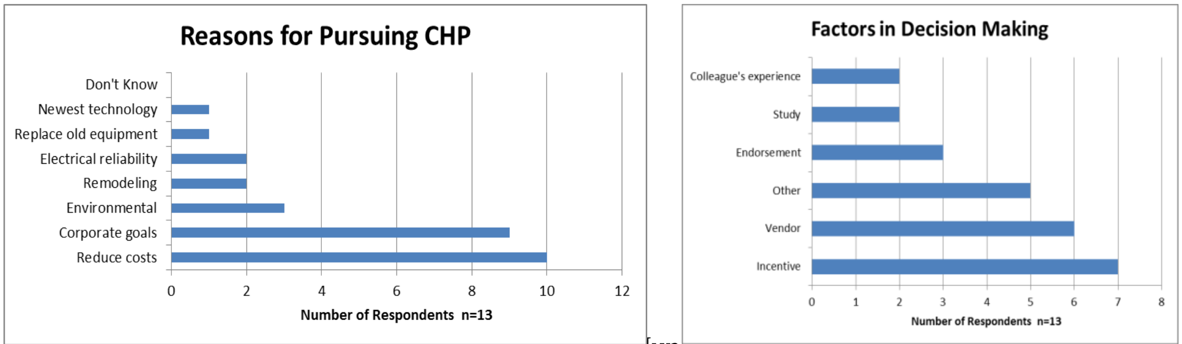


4.2.2 Nonparticipant Surveys

The nonparticipants were identified from the DOE-sponsored inventory of DG-CHP, which listed 45 CHP systems installed in New York in the 2010 – 2011 timeframe. Of the 45 sites, 19 had participated in a NYSERDA program and 10 could not be identified with the information provided in the inventory, leaving a sample frame of 16 sites. Surveys were completed with 13 of the 16 remaining sites.

Like the participants, the nonparticipants cited operating-cost reductions as the motivation for pursuing CHP. However, meeting corporate environmental goals was almost equally important, as shown in Figure 4-4. Interestingly, some of the nonparticipants cited incentives as important in their decision-making. Two of the responders had applied for a NYSERDA incentive, but one project ultimately did not qualify, and in the second case, NYSERDA had run out of money. Two sites were served by LIPA and were not eligible for the Program. Other responders identified tax breaks and specialized loans as incentives. NYSERDA's endorsement of CHP was cited by three respondents as a factor in the decision to install. This apparent spillover lends support to the decision for stipulating a higher NTGR.

Figure 4-5. DG-CHP Nonparticipant-Reported Survey Results



The DG-CHP program was closed to applications in June 2011, at which time new DG-CHP applicants were directed to the two current NYSERDA programs: The CHP Acceleration and CHP Performance programs. These current programs are substantially different from the evaluated DG-CHP program in both objectives and design. The current programs reflect lessons learned from the earlier DG-CHP program in creative ways. Nonetheless, DG-CHP is envisioned as an important component of the energy future and the lessons learned in the 10-year operation of this program warrants documenting for the record for use by NYSERDA or other future program administrators. These recommendations are offered to guide the future CHP program modifications.

1. **As trusted advisors, NYSERDA (or future program sponsors) should define technical performance requirements and ensure that applicant projects are designed to meet them**. Part of NYSERDA's role in animating the DG-CHP market is to lower the time, complexity, and expense of installing systems. However, this drive to expand the market must be balanced with NYSERDA's role as a trusted advisor (as noted in participant surveys) and the real technical challenges that DG-CHP presents. With DG-CHP, unlike most efficiency technologies, poor performance can translate to worse than no savings – that is, negative savings. As indicated in the participant surveys, start-up problems are frequent and early failure is common. DG-CHP systems require high rates of heat recovery for long-term economic operation and reductions in project-level emissions. Systems that are not properly sized or do not have matching thermal loads risk low economic benefit to the customer.

   The Impact Evaluation Team applauds the technical review program design of the two current NYSERDA programs:

   a. CHP Performance includes a robust technical review process. While it is extensive, the information should be available as part of the normal design process, which will minimize the burden.

b. CHP Acceleration offers an opt-in to a "prescriptive" path for select building types otherwise a "custom" path that requires profiles based on measurement.

Both programs appear to have a serious commitment to an appropriately designed system, an approach that should be vigorously maintained, although there may be increasing pressure to ease reviews. The prescriptive path offers an innovative way to speed installations in the historically successful applications (like right-sized multifamily systems), but it warrants monitoring of the results and adjustments to sizing parameters as indicated by examination of installed system performance.

2. **Adopt an interventionist posture to extend system live**s. As noted in the previous recommendation, a significant portion of systems were brought offline early. This finding is consistent with the California DG-CHP evaluation cited earlier where two-thirds of the reciprocating generators were offline after nine years. These shortened lives in both programs can be in a large part traced to ill-conceived and poorly designed projects, and particularly in California from a focus on electrical generation without regards to heat recovery. Enforcing technical design requirements can partially mitigate these problems.

   In addition, customers may need assistance in the startup and early operation of systems. Of the participants responding to the surveys, more than half provided unsolicited comments about the difficulties of system startup, where some of these start-up issues were never resolved and led to system removal. The CHP Acceleration Program provides a no-cost site review 12 to 24 months after system commissioning. This is not only innovative, but it could be the missing link in fulfilling the promise of CHP.

   Finally, ongoing and expensive maintenance is a necessity. The CHP Acceleration program requires a five-year maintenance contract, which should cover the first major overhaul.

3. **Continue to require and support IDS for performance monitoring, system optimization, and impact evaluation**. NYSERDA's IDS system is a powerful tool for ensuring the long-term effectiveness of CHP. IDS is a repository of near real-time (data is uploaded daily) site-specific CHP performance data. Site-specific CHP performance data (hour electrical generation, heat recovery, and natural gas consumption) is available by hour or summarized in informative performance graphs. Each site is also characterized by a narrative containing a description and details of system installation. Meter data streams are largely populated and reliable. Both Massachusetts and California are implementing systems modeled after NYSERDA's IDS.

IDS serves these purposes:

a. Calculate performance payments and to confirm that systems meet the minimum FCE requirements.

b. Monitor overall program performance (as it was used in the revision of reported savings)

c. Improve individual site CHP performance through post-installation re-commissioning using the IDS data to diagnosis weaknesses and confirm improvements.

d. Provide a foundation of an impact evaluation, which lowers the overall cost of an evaluation by half or more and improves the quality of the results.

4. **Design and maintain CHP installations to high FCE standards to maximize customer benefit and emissions reductions.** The FCE reflects the combined efficiency of both the electrical and thermal recovery of a system. CHP electrical generation alone is typically in the 25%–30% efficiency range. At that efficiency level, each MWh will require about $90 of natural gas[6] and will produce about 1,300 lbs of CO_2. The economic benefits and emissions reduction power of CHP requires significant heat recovery offsetting a fossil fueled boiler (typically). However, with aggressive heat recovery, the combined emissions of all the energy will drop by almost half and the economic benefit to the customer will increase by about a third.

   Systems designed only for electric reliability, primarily for electric load production or operated in an electrical load-following manner, run the risk of poor FCE performance and disappointing emissions reductions. Without the economic benefit of heat recovery, the financial performance of CHP is marginal and is more sensitive to changes in natural gas prices.

   A FCE of 60% is an aggressive but achievable best practices standard for CHP combined electrical and thermal efficiency, maximizing energy production, customer savings, and emissions reductions. The Program has the most leverage with a customer and the design team at the design and application stage, where the incentive is an inducement to design to the 60% FCE standard and where an application review can pinpoint potential design flaws.

[6] http://www.nyserda.ny.gov/Energy-Data-and-Prices-Planning-and-Policy/Energy-Prices-Data-and-Reports/Energy-Prices/Natural-Gas/Monthly-Average-Price-of-Natural-Gas-Industrial.aspx

Both current Programs target a minimum FCE of 60% and both require demonstration of thermal and electrical load profiles as a critical step in a design that will yield a high FCE. The CHP Acceleration Program prescriptive path is an innovative approach to ensuring high FCE performance and rapid turnaround of projects. The Program should monitor the outcome of these projects to ensure they are meeting the FCE target and adjust the criteria if they are not.

APPENDIX A: GLOSSARY OF TERMS[7]

capacity factor – A measure of the utilization of installed electrical production calculated as the annual actual electric production divided by the maximum possible production.

census – All individuals in a group. In evaluations of energy efficiency programs census typically refers to all projects in a stratum of program projects.

Combined Heat and Power (CHP) – CHP refers to distributed generation that has additional equipment and design features to extract waste heat from electrical production to be used for other purposes like space heating.

Distributed Generation – Combined Heat and Power (DG-CHP) – DG refers to electrical generation located on customer premises and not owned by the utility. CHP refers to distributed generation that has additional equipment and design features to extract waste heat from electrical production to be used for other purposes like space heating.

error ratio – In energy efficiency evaluation, the error ratio is a measure of the degree of variance between the reported savings estimates and the evaluated estimates. For a sample, the error ratio is:

$$er = \frac{\sqrt{\sum_{i=1}^{n} w_i \frac{e_i^2}{x_i^\gamma} \sum_{i=1}^{n} w_i x_i^\gamma}}{\sum_{i=1}^{n} w_i y_i}$$

where,

n is the sample size

w_i is the population expansion weight associated with each sample point i

x_i is the program-reported savings for each sample point i

y_i is the evaluated gross savings for each sample point i, the constant gamma, $\gamma = 0.8$ (typically), and the error for each sample point $e_i = y_i - bx_i$, where b is the program realization rate

evaluated gross savings – The change in energy consumption and/or demand that results directly from program-related actions taken by participants in an efficiency program, regardless of why they participated, as calculated by program evaluators.

evaluated net savings – The total change in load that is attributable to an energy efficiency program, as calculated by the program evaluators. This change in load may include, implicitly or explicitly, the effects of free drivers, free riders, energy efficiency standards, changes in the level of energy service, and other causes of changes in energy consumption or demand.

free rider, free ridership (FR) – A free rider is a program participant who would have implemented the program measure or practice in the absence of the program. Free ridership refers to the percentage of savings attributed to customers who participate in an energy

[7] NYSERDA generally follows and uses the terms as defined in the "Northeast Energy Efficiency Partnerships Glossary of Terms", found at http://www.neep.org/emv-forum-glossary-terms-and-acronyms This glossary defines those terms absent from the NEEP report or provides more-specific definitions to generalized NEEP terms.

efficiency program but would have, at least to some degree, installed the same measure(s) on their own if the program had not been available.

heat recovery – The thermal energy captured from electrical generation typically using water jackets around the generator or an air to water heat exchangers in the exhaust gas stream. Typically, it refers to the energy used for other purposes, such as space heating.

Installed capacity – The size of the electrical generator(s) installed at a location measured in kW.

Integrated Data System (IDS) – This refers to the NYSERDA sponsored system that collects DG and CHP hourly meter data from individual DG-CHP sites served by NYSERDA. The system is hosted on a website (http://chp.nyserda.ny.gov/home/index.cfm) that is available to the community.

IPMVP Option A – This M&V option involves the partial measurement of isolated equipment affected by the evaluated measure. Relevant equipment variables are spot-measured when possible or stipulated when necessary.

IPMVP Option B – This M&V option involves full measurement of the isolated equipment affected by the evaluated measure. No stipulations are allowed. Both short-term and continuous data monitoring are included under Option B.

IPMVP Option C – This M&V option involves the use of utility meters to assess the performance of a total building. Option C addresses measure impacts in aggregate, not individually, if the affected equipment is connected to the same meter.

IPMVP Option D – This M&V option involves the use of computer modeling to determine facility or equipment energy use. Option D requires calibration with actual utility consumption data for either the pre-project or post-project period.

net savings – The total change in load that is attributable to an energy efficiency program. This change in load may include, implicitly or explicitly, the effects of spillover, free riders, energy efficiency standards, changes in the level of energy service, and other causes of changes in energy consumption or demand.

net to gross, net-to-gross ratio (NTG, NTGR) – The relationship between net energy and/or demand savings – where net is measured as what would have occurred without the program, what would have occurred naturally – and gross savings (often evaluated savings). The NTGR is a factor represented as the ratio of net savings actually attributable to the program divided by program gross savings. For NYSERDA programs the NTGR is defined as 1 minus free ridership plus spillover.

nonparticipants/nonparticipating – Any customer or contractor who was eligible but did not participate in the program under consideration. Nonparticipating contractors can include contractors that have never participated in the program and contractors that formerly participated, prior to the year(s) being evaluated, but have not participated since then.

population expansion weight – The total number of units in a population divided by the number of units in the sample.

realization rate (RR) – The ratio of the evaluated gross savings to the Program's reported savings. The RR represents the percentage of program-estimated savings that the evaluator estimates as being actually achieved based on the results of the evaluation M&V analysis. The RR calculation for electric energy for a sampled project is shown below:

$$RR = \frac{kWh_{evaluation}}{kWh_{program}}$$

where,

RR is the realization rate

$kWh_{evaluation}$ is the evaluation M&V kWh savings (by evaluation M&V contractor)

$kWh_{program}$ is the kWh savings claimed by program

relative precision – Relative precision reflects the variation due to sampling as compared to the magnitude of the mean of the variable being estimated. It is a normalized expression of a sample's standard deviation from its mean. It represents only sampling precision, which is one of the contributors to reliability and rigor, and should be used solely in the context of sampling precision when discussing evaluation results.

Relative precision is calculated as shown below. It must be expressed for a specified confidence level. The relative precision (*rp*) of an estimate at 90% confidence is given below:

$$rp = 1.645 \frac{sd(\mu)}{\mu}$$

where,

μ is the mean of the variable of interest

sd(μ) is the standard deviation of μ

1.645 is the *z* critical value for the 90% confidence interval

For the 90% confidence interval, the error bound is set at 1.645 standard deviations from the mean. The magnitude of the *z* critical value varies depending on the level of confidence required.

spillover (SO) – Refers to the energy savings associated with energy efficient equipment installed by consumers who were influenced by an energy efficiency program, but without direct financial or technical assistance from the program. SO includes additional actions taken by a program participant as well as actions undertaken by nonparticipants who have been influenced by the program. Sometimes SO is referred to as "market effects." Market effects are program-induced impacts or program-induced changes in the market. Market effects include impacts over time. These market effects may be current or may occur after a program ends. When market effects occur after a program ends, they are referred to as "momentum" effects or as "post-program market effects." SO is often a narrower definition because it does not include impacts that accrue due to program-induced market structure change and seldom looks for effects that occur well after program intervention or after a program ends. This evaluation addresses participant inside spillover, participant outside spillover, and nonparticipant spillover, but not the broader definition of program effects within market effects.

inside spillover (ISO) – Occurs when, due to the project, additional actions are taken to reduce energy use at the same site, but these actions are not included as program savings, such as when, due to the program, participants add efficiency measures to the same building where program measures were installed but did not participate in the program for these measures.

outside spillover (OSO) – Occurs when an actor participating in the program initiates additional actions that reduce energy use at other sites that are not participating in the program. This can occur when a firm installs energy efficiency measures they learned about through the program at another of their sites without having that other site participate in a NYSERDA program. OSO is also generated when participating vendors install or sell energy efficiency to nonparticipating sites because of their experience with the program.[8]

nonparticipant spillover (**NPSO)** – The reduction in energy consumption and/or demand from measures installed and actions taken at nonparticipating sites due to the program but not participating in the program and not induced by program participants – either building owners/managers or Program Performance Partners. These actions could be program-induced decision-making of nonparticipating building owners or encouraged by nonparticipating vendors or contractors because of the influence of the program.

stratified ratio estimator (SRE) – An efficient sampling design combining stratified sample design with a ratio estimator. It's most advantageous when the population has a large coefficient of variation, which occurs, for example, when a substantial portion of the projects have small savings, and a small number of projects have very large savings. The ratio estimator uses supporting information for each unit of the population when this information is highly correlated with the desired estimate to be derived from the evaluation, such as the tracking savings and the evaluated savings.

summer coincident peak demand period – For this evaluation NYSERDA defined the summer coincident peak demand period as the energy reduction during the hottest non-holiday summer (June through August) weekday during the hour ending at 5 p.m.

trade allies – Businesses that play a role in the development and/or implementation of program-qualifying energy efficiency projects. These are either developed through the program or outside of the program on the customer's own initiative. These trade allies include energy auditing firms (including the program's Performance Partner participants), and architect/engineering firms, contractors, and equipment vendors.

[8] This definition is one that NYSERDA has used throughout its history with energy efficiency programs. There may be other states where the latter circumstance of participating vendors influencing nonparticipating sites is defined as a type of nonparticipant spillover.

APPENDIX B: SUMMARY OF PREVIOUS EVALUATIONS

Table B-1 notes the primary author, the particular results relevant to this Program impact evaluation, and how the study findings were utilized in the planning or the results of this impact evaluation presented in their order of importance. Two prior evaluations were conducted in 2010 and 2012.

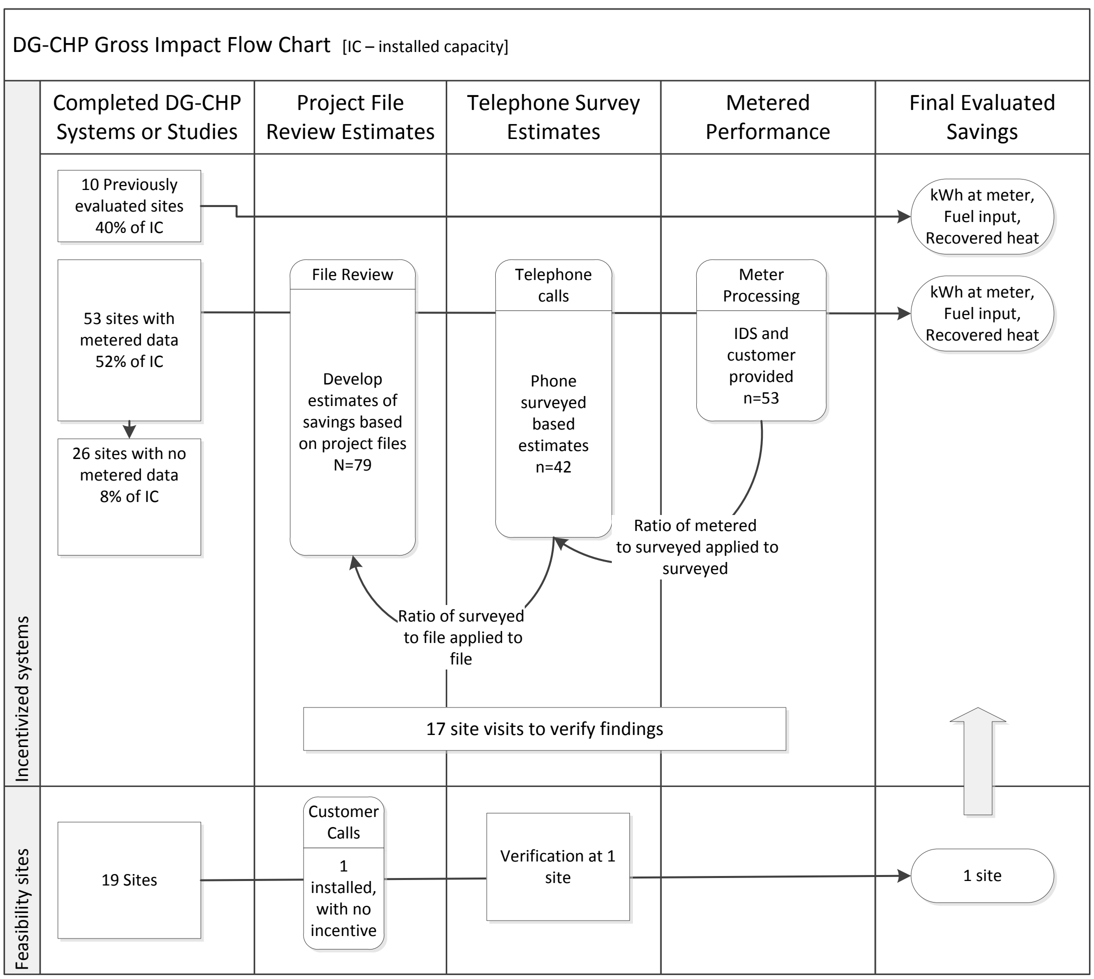
Table B-1. Previous R&D DG-CHP Evaluation and Assessment Studies

Report Title	Summary of Relevant Results	Use of Study
Impact Evaluation NYSERDA 2007 – 2009 FlexTech Program, prepared by Megdal & Associates (with ERS), March 2012.	Evaluated the gross and net impact of the 47 sites selected from a sample of FlexTech participants that installed recommended measures. This study included two DG-CHP projects. Gross savings were developed using on-site M&V.	The final evaluated savings of one of the DG-CHP sites was directly incorporated into the gross impact savings.
Impact Evaluation Largest Energy-Saving Projects, prepared by Megdal & Associates (with ERS), October 2010	Evaluated the gross and net impact of the 25 sites with the largest savings across all programs. This study included nine DG-CHP projects. Gross savings were developed using on-site M&V. Final evaluated gross savings of 42,913 MWh; -415,419 MMBtu annual energy savings and 8.4 MW in demand. Attribution for the same projects was 28% free-ridership and 7% market effects.	The final evaluated savings of nine DG-CHP sites was directly incorporated into the gross impact savings. The attribution results were referenced in the development of stipulated savings.
DG/CHP Data System Website Study, Exergy Partners Corporation, 2012	Twenty site reports for twenty DG-CHP sites with detailed findings regarding system operation and interval data validity.	Source of meter validation information.
Process Evaluation: DG/CHP Program Market Characterization, Market Assessment and Causality Evaluation, Skumatz Economic Research Associates, January 2005	Among other findings, the study estimated free ridership at 15% and total spillover at 25% indicating a net-to-gross ratio of 1.07 (ranging from 0.88 to 1.26). Results are based on surveys conducted with developers, system owners, and program staff.	The attribution results were referenced in the development of stipulated savings.
DG/CHP Demonstration Program, Research Into Action, December 2011	Process assessment found program (2005–2011) generally working well.	General background information
Distributed Generation – Combined Heat and Power Demonstration Program Market Characterization and Assessment Report, Navigant, August 2011.	Assessment for the 2006–2011 period based on in-depth interviews.	General background information
M&V Evaluation DG-CHP Demonstration Program, Nexant, June 2006 and March 2004	Engineering desk review and on-site verification of a sample of sites. No metering was deployed, nor was IDS interval data available.	General background information

APPENDIX C: METHODS AND INTERMEDIATE FINDINGS

This impact evaluation was designed to leverage diverse and rich data from multiple sources, including project file estimates, telephone survey-reported operational characteristics, and site inspections. However, the foundation of the evaluation was the availability of extensive hourly metered data, a unique characteristic of DG-CHP systems where the electrical and thermal energy is typically metered with hourly resolution, providing direct measurement of gross savings. High-resolution hourly metered data was available for about 73% of the installed capacity, while monthly metered data was available for an additional 19% of the installed capacity. Figure C-1 illustrates the overall evaluation approach with explanations following.

Figure C-1. Flow Chart of Impact Evaluation Approach



Starting with the left side of the diagram, the Program population consisted of ten sites that had been previously evaluated and the current evaluation sub-population consisting of 53 sites with extensive metering captured by either the customer or NYSRDA as part of implementation and 26 sites that did not have metering available. The non-metered sites constituted 8% of the installed capacity.

For current sites, the research was designed to capture site information from three sources: a) review of project files, b) customer surveys, and c) metered data of generated electricity, recovered heat, and natural gas burned. The evaluation estimated program savings using validated metered data with ratio applied to the non-metered sites. or in some cases, a double ratio applying metered data first to the surveyed sites, and then to the program savings estimates.

In addition to providing basic site information, the telephone interviews and on-site activities validated the IDS metering energy streams and operational characteristics of non-IDS sites. The evaluated savings of the 10 sites that had been previously evaluated were used directly, after a review. The savings estimated for a site that did not receive a NYSERDA incentive but was influenced by a Program-sponsored feasibility study was added to the gross savings program total The stipulated net-to-gross (NTG) ratio was applied to the sum of the components for net savings..

Equation 1: Program Evaluated Net Savings

Evaluated net savings = (Previously evaluated savings + Current evaluated metered gross savings + Current evaluation ratio adjusted gross savings+ Feasibility study savings) × Stipulated NTGR

The final program precision was calculated using ratio estimation statistics.

This appendix is organized into the following sections:

- Gross Impact Data Collection Activities
- Energy and Statistical Models
- Other Research

DATA COLLECTION ACTIVITIES

This impact evaluation was designed to leverage diverse and rich data from multiple sources. Figure C-2 summarizes the sources of the data used in the impact evaluation.

Figure C-2. DG-CHP Evaluation Data Sources

Valid Metered Data

- IDS source, 38 sites
- Customer provided, 15 sites
- Typically hourly performance for one year or more of at least one energy stream
- Vetted by impact evaluation team
- Available for about 92% of the installed capacity

Customer Surveys

- Census attempt of sites 79 sites, excluding previously evaluated sites
- 54 participants responded, 42 surveys were completed
- Confirmed installation and operation of first year

Project File Review

- Best estimate of savings at time of installation for all sites, except those previously evaluated
- Not always in agreement with tracking data
- Often required assumptions

Previously Evaluated

- Eleven sites previously evaluated
- Due diligence review of prior evaluations
- One site required natural gas consumption adjusted
- Ten sites previously evaluated accepted as is

Surveys could not be completed or were not sufficiently responsive for 22 of the sites with metered data and metered data was not available for 11 of the sites with completed surveys. Overall, though, only 8% of the installed capacity did not have some metered data to accurately quantify electrical impacts. Table C-1 shows the distribution of data sources by number of sites and the installed capacity.

Table C-1. DG-CHP Data Sources Available as a Percentage of Installed Capacity

Evaluation	Number of Projects	Percent of Installed Capacity	Project File Estimates Available	Survey Data Estimates Available	Metered Data Available	Number of Site Visits
Previously evaluated	10	40%	NA	NA	Yes	10
Current evaluation	31	30%	Yes	Yes	Yes	16
	11	4%	Yes	Yes	No	1
	22	22%	Yes	No	Yes	0
	15	4%	Yes	No	No	0
% of installed capacity	89	100%	63% Exclude Previous	39%	92%	58%

The high percentage of installed capacity with metered data minimizes the potential for bias in population results. Additionally, the sample was stratified by prime mover type, so the high capacity factors associated with large natural gas turbines did not directly impact the evaluated results for smaller engines that might tend to be operated in a more load-following manner. The use of surveys was also intended to compensate for potential differences between metered and unmetered sites. That said, there is a potential that the 4% of the population with no surveys or metered data may have performed somewhat differently than the metered sample, but given that this is a very small fraction of the population, the impacts on overall results of any bias would be minimal.

The methods employed accounted for parasitic loads (such as fans and pumps incorporated into the CHP equipment) and more significantly, the impact of displaced electrical cooling.

The next section discusses the assumptions that were used in the estimates and also the protocol for using data where sources may have provided conflicting data. The remainder of the section discusses each of the data collection activities.

ASSUMPTIONS AND DATA PROTOCOLS

There were often cases where assumptions were required to complete an estimate. In some cases, project files were missing estimates of natural gas consumption. Customer survey savings often required estimation of efficiency or other values. Metered savings calculations also required some estimation and engineering algorithms to quantify savings of the natural gas consumption of a boiler offset by heat recovery or of parasitic loads. Metered data explicitly included the impacts of parasitic loads per CDH standards and metering plans. Evaluated savings for surveys implicitly included internal parasitic electric loads inasmuch as reported average capacity factors or generating power levels were assumed net of internal parasitic types. We further assumed that file review is gross based and excludes parasitic loads. The impact of parasitic loads is minimal however; approximately 3 percent of generation, so assumptions about parasitic loads likely have less impact on results than sampling error.

Table C-2 shows the key assumptions used in developing the file review and surveys estimates and in evaluating savings from metered data. These assumptions largely impact natural gas savings/consumption since electrical generation is usually stated or measured directly.

Table C-2. DG-CHP Project File Review Assumptions

Assumption	Value	Source
Coefficient of performance (COP) for absorption chillers	0.7 for single effect (default) 1.1 for double effect	ASHRAE Standard 90.1-2010 Minimum full-load efficiency requirements
Electric chiller efficiency	0.68 kW/ton	
Lower heating value of natural gas	932 Btu/scf	National Energy Technology Lab (NETL) Specification for Selected Feedstock January 2012, DOE/NETL-341/011812
Higher heating value of natural gas	1,032 Btu/scf	
Boiler efficiency	0.8	Rough approximation based on minimum efficiencies specified in ASHRAE Standard 90.1-2010 Table 6.8.1F

Assumption	Value	Source
Electrical conversion efficiency	Varies by project and technology	Project file review, prime mover specification sheet, or average prime mover type efficiencies drawn from industry literature

At times, conflicting values were provided from different data sources, for example the projected generator efficiency might conflict with the observed on-site efficiency. The order of choice of sources for resolving conflicts is shown in Table C-3.

Table C-3. DG-CHP Estimated Values and Sources for Calculated Savings

Used for	Estimation Area	First Choice	Second Choice	Third Choice
Customer survey savings	Nominal electrical conversion efficiency	Project documents	Interval Contractor (CDH) Database	Default values compiled from industry literature
	Maximum heat recovery rate			
Both metered data and customer survey savings	Seasonal split of recovered heat use when used for both heating and cooling	Project documents	Customer survey	Default (50/50 split)
	Absorption chiller COP	Project documents	Customer survey	Default (single effect, 0.7)
	Boiler efficiency	Project documents	Default (0.8)	
	Electric chiller efficiency	Project documents	Default (0.68 kWh/ton)	

Explicit calculation of energy streams was required for the survey estimates of savings, and at times for project file and metered estimates of savings. The calculation methods follow.

The electrical generation estimate was the product of the project capacity, hour length of the time period, and the average capacity factor for the time period as reported in the survey or as provided in the documents (Equation 2).

Equation 2: Electrical Generation Calculation

$$Electrical\ generation = Capacity \times Capacity\ factor \times Hours\ in\ time\ period$$

The corresponding fuel consumption estimate was the electric generation estimate divided by the nominal electrical conversion efficiency (in higher heating value HHV). The electrical efficiency was assumed to be constant for a project, ignoring the actual variability with loading and ambient temperature. The calculation of the fuel consumption is shown in Equation 3.

Equation 3: Fuel Consumption Calculation

$$Fuel\ consumption = \frac{Calculated\ electrical\ generation}{Nominal\ electrical\ conversion\ efficiency}$$

A useful heat recovery estimate began with the product of the seasonal sum of electric generation estimates and a heat recovery rate. The product then was multiplied by the average percentage of available heat recovered for the season as reported in the project files or in the survey (Equation 4).

Equation 4: Heat Recovery Calculation

$$Heat\ recovery = Calculated\ electrical\ generation \times Maximum\ heat\ recovery\ rate \times Heat\ recovery\ fraction$$

In developing the survey heat recovery estimate, the question of percentage of available heat recovered in a season brought responses with the most admissions of uncertainty. When all heat was reported as recovered the surveyor asked which of several project characteristics lent themselves to such success. This second step was intended to both confirm the response and prompt reconsideration, since full heat recovery can be challenging with CHP.

Avoided fuel consumption and electricity estimates generally were based on the useful heat recovery estimate and types of existing systems supplanted by heat recovery. For heating and cooling, the avoided consumption estimate began with the product of the useful heat recovery for the season and the end-use percentage contribution. Avoided fuel consumption then was the quotient of that product divided by an assumed boiler efficiency (Equation 5). The avoided electricity value was that product multiplied by the product of an absorption chiller coefficient of performance and an assumed electric chiller coefficient of performance (COP, Equation 6).

Equation 5: Avoided Fuel Consumption Calculation

$$Avoided\ fuel\ consumption = \frac{Calcuated\ Heat\ Recovery}{Boiler\ Efficiency} \times Fraction\ of\ heat\ used\ for\ heating$$

Equation 6: Avoided Electricity Calculation

$$Avoided\ electricity = Calculated\ heat\ recovery \times Fraction\ of\ heat\ used\ for\ cooling \times COP \times Chillerefficiency$$

PREVIOUSLY EVALUATED SITES

Eleven of the installed sites were evaluated in 2009–2010 as part of either the Largest Energy-Saving or the FlexTech evaluation (see summaries and references in Appendix B). Both of these studies used a rigorous M&V approach typically based on hourly interval data from IDS or from the customer. Rather than re-evaluate these sites, it was decided to include the evaluated gross impact results directly into the current program savings as a census stratum after a due diligence review of the previous evaluation site report. The rigor of the due diligence varied in accordance with the expected impact of the site. For the two large sites (30,000 kW and 7,500 kW), due diligence included analysis of metered data to ensure that previously evaluated savings matched savings in this evaluation.   For the nine Large Saver sites, with a cumulative capacity totaling 10,070 kW, due diligence was focused on the reasonableness of evaluated savings and that resulting capacity factors and efficiencies were within expected ranges[1].

The previously evaluated results from 10 sites were accepted as is and incorporated into the current savings estimates. However, the previously evaluated results were not accepted for one site where it appeared that the total natural gas usage input to the plant did not include the duct burner, so this site was reevaluated.

Table C-4 summarizes the savings from 10 ten previously evaluated sites that were incorporated into the current impact evaluation.

Table C-4. DG-CHP Summary of Savings from Sites Previously Evaluated

Evaluation	Installed Capacity kW	Previously Evaluated Impacts		
		Electricity Savings (MWh)	Peak kW Reduction	Gas Savings (MMBtu)
FlexTech site (1 site)	30,000	164,508	15,355	(664,711)
Large Saver total (9 sites)	10,070	42,913	8,444	(415,419)

PROJECT FILE REVIEW ESTIMATES OF SAVINGS

The purpose of this activity was to use the project file information to produce a best estimate of expected first-year savings for each project at the time the actual equipment was installed (also known as an *ex ante* estimate).

The current tracking estimates are essentially deemed savings values calculated as the product of a deemed capacity factor and the estimated peak demand reduction of the site. Two of the large natural gas-driven turbine sites were assigned unique capacity and net natural gas usage factors while all other sites employ the same deemed values for capacity and net natural gas usage.

However, each of the current 79 sites has site-specific project files which usually document estimates of expected electrical production, natural gas consumption, and heat recovery. These files were examined to determine the best estimate of the customer's expectation for these energy streams at the time of installation. These estimates were systematically extracted from the project file documents and entered into a spreadsheet template (one per site). The spreadsheet documented the energy streams, identified data sources, and included a narrative description of the site and the energy estimates. An Excel macro pulled relevant data from each site spreadsheet into a single program data set for further analysis.

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[1] One large saver had zero previously evaluated savings, resulting in more scrutiny. Further investigation revealed that the CHP system at this site never operated.

The majority of sites had either detailed monthly estimates of performance or an annual electrical generation and overall efficiency. In some cases, engineering algorithms were used to estimate some values, such as fuel consumption based on nominal system efficiencies and electrical generation using the protocols established in earlier in this section.

CUSTOMER SURVEY ESTIMATES OF SAVINGS

The purpose of this activity was to systematically confirm the installed system features and to collect the customer's characterization of the system's operation in its first normal year of operation. A census of the 79 current evaluation sites was attempted. Fifty-four customers were reached and completed at least a portion of the survey. Forty-two surveys were complete enough to be used in the gross savings analysis.

These estimates were based strictly on a customer's firsthand knowledge of actual project operations using a consistent method across projects. These estimates did not reference metered performance data that might exist. Engineering algorithms were developed to estimate savings from detailed knowledge of project performance and engineering assumptions about project efficiencies including existing systems that heat recovery would supplant.

Survey Objectives

Customer surveys aimed to verify and, where necessary, to adjust values from program records of:

- Equipment installed
- Nominal generating capacities
- Prime mover technologies
- Fuels consumed
- End uses served by heat recovery
- Energy avoided by heat recovery

Surveys also gathered customer's characterizations of the first 12 months of normal (post-commissioning) operations related to:

- Start date of normal operations
- Electric generation and heat recovery performance metrics
- Types and periods of various load following patterns
- Seasonal, weekday/weekend, daytime/nighttime electric performance variations

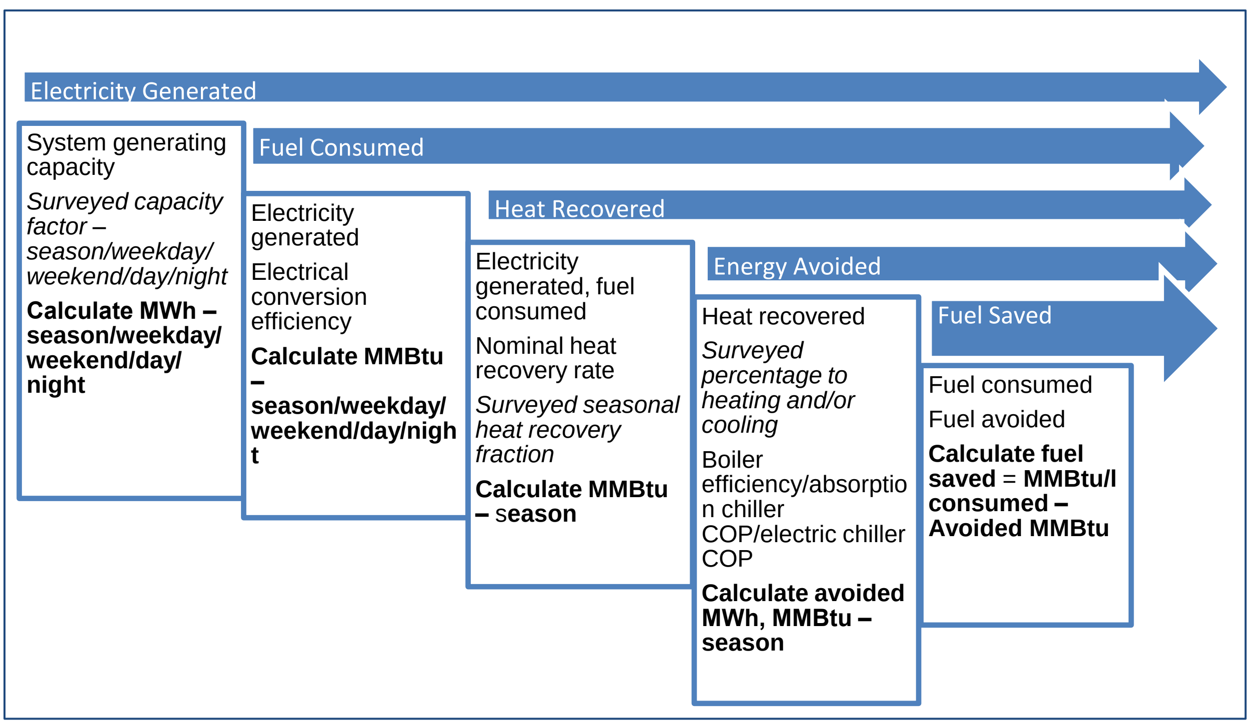
- Seasonal heat recovery performance variations
- Heat recovery proportions where both boiler and chillers supplanted
- Absorption chiller efficiencies

Customer Surveys Estimates of Savings

Savings estimates were developed for electricity and natural gas consumption adjusted for any heat recovery. Estimates for electricity included electricity generated as well as electricity consumption avoided by either absorption chillers served by heat recovery or compression chillers driven directly by the prime mover. Estimates for natural gas included consumption by the generator as well as fuel consumption avoided where heat recovery displaced the boilers' thermal loads.

Figure C-3 summarizes the sequence and inputs to the estimation methodology. The starting point is an estimate of the electrical generation using the customer-reported generator operating profile in an engineering algorithm. The electrical generation is the basis of the estimate of natural gas consumed and heat recovered using nominal efficiencies and heat rates. The heat recovery estimate is also dependent upon the customer-reported heat recovery profile.

Figure C-3. DG-CHP Customer Survey Savings Estimation Methodology



METERED ESTIMATES OF SAVINGS

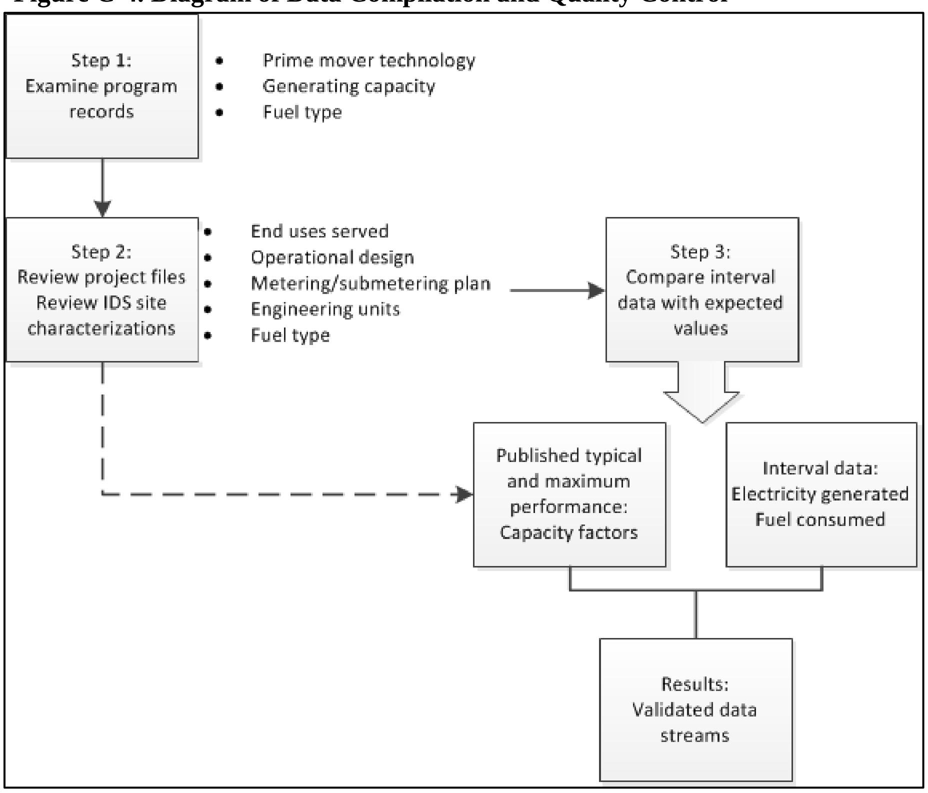
Metered data provided the final and most accurate estimate of savings. The use of this data began with the compilation of metered data streams acquired from IDS or provided by individual customers. IDS data streams were at hourly intervals while most customer data streams were at monthly or annual intervals. A quality control review of these compiled data streams follows. Only data passing the quality control review was used to representative first-year savings estimates.

Metered Data Quality Control

The metered data was examined and checked for quality and reasonableness. Individual observations with values above published maximum performance levels did not pass the quality control review and were excluded from the analysis. In the cases where many observations in a data stream did not pass quality control, the whole data stream was removed from the data stream. Data that passed quality control was used as validated data for the analysis.

Figure C-4 summarizes the data compilation and quality control process.

Figure C-4. Diagram of Data Compilation and Quality Control



As a first step, Program records were used to identify the prime mover technology, electrical generating capacity, and fuel. Detailed review of the project profiles, IDS database notes, and M&V plans determined the end uses served, which interval data streams and engineering units to expect, and which estimates to develop for each project[2]. Quality control consisted of validating data stream values relative to published typical and maximum performance capabilities by technology and generating capacity. Observations deemed suspect were flagged for further review and excluded from the analysis if the values were outside of a range of expected performance.

The original IDS data included quality control flags supplied by the IDS administrator on each observation in each data stream. The evaluators' quality control of IDS data began with these flags and excluded all observations not meeting the best quality of "Data Passes Relational Checks." A summary review of the first 24 months of IDS data for 45 projects found the heat recovery data stream most likely to have observations not meeting best quality standards.[3] Table C-5 summarizes the mean percentages of observations with the best quality flag over first 24 months of metered IDS data. While 90.7% of the electric data was of the highest quality, only 63.4% of the hours had all three energy streams that were of the highest quality.

Table C-5. DG-CHP Mean Percentages of Observations with Best Quality Flag in First 24 Months of Data

<table>
<tr><th>Data Stream</th><th>Individually</th><th>Electricity & Fuel</th><th>Electricity, Fuel, & Recovered Heat</th></tr>
<tr><td>Electric generation</td><td>90.7%</td><td rowspan="2">81.7%</td><td rowspan="3">63.4%</td></tr>
<tr><td>Fuel consumption</td><td>89.9%</td></tr>
<tr><td>Heat recovery</td><td>86.8%</td><td></td></tr>
</table>

This quality control process examined electricity generation relative to capacity as well as several rates derived from the data streams. Observations with unreasonably high electrical conversion efficiency or heat recovery rate for the technology, or with unreasonably high overall efficiency, were flagged for examination. Instances in hourly interval data of prolonged lack of generation or lack of heat recovery during generation also were flagged for examination. Instances in hourly interval data of prolonged high or zero rates were deemed invalid and excluded from the analysis. The on-site team also investigated any identified anomalies as part of the on-site review protocol.

The same quality control review applied to IDS data was applied to data received from customers. All customer data passed the quality control review and were included in the analysis. Table C-6 lists initial and excluded counts of projects and data streams ultimately included in the analysis.

[2] For example, a system fueled entirely by biogas would not have a natural gas consumption estimate.

[3] This is expected, given that heat meters tend to be the most prone to errors. This is especially true of heat meters that have a mechanical flow meter (usually a turbine) in the fluid stream. These turbines can easily become fouled and read lower than actual flow.

Table C-6. Counts of Projects with Metered Data by Source, Interval Length, and Data Streams Validated

Source & Interval	Project Counts			Final Project Counts with Validated Data Streams		
	Initial	Excluded	Final	Electricity, Fuel, & Heat	Electricity & Fuel	Electricity Only
IDS hourly interval	49	11	38	27	9	2
Customer hourly interval	1	0	1	1		
Customer monthly interval	9	0	9	9		
Customer annual interval	5	0	5	5		
Total	64	11	53	42	9	2

The final metered data set used in the evaluation includes 38 sites with IDS data and 15 with customer data. The first 24 months of data provided sufficient numbers of validated observations to represent all four seasons for most projects.

Metered Estimates of Savings

First program year[4] energy savings were estimated from validated metered data. This section discusses the development of first-year energy savings estimates from metered data.

First program year savings for a project could not be determined by simple summation of metered observations from its first 365 days' of metered data. Validated metered data seldom began the date the first program year started. Quality control of metered data also excluded some observations and whole data streams from the 365 days following the start of the first program year. The start date of the first program year also was often subject to question.

The program included no formal commissioning incentive or process by which to consistently identify the date of completion of system commissioning that signals the start of the first program year. Program and CDH project data track several dates assumed to indicate completion of commissioning. But these dates frequently differed by months or contrasted with expected post-commissioning performance observed in metered data. The dates also sometimes differed from survey responses to questioning about start date of 'normal operations.' As a result, first program year start dates first were taken from among tracked project dates but in many instances were pushed forward where metered data suggested or survey responses

[4] First program year consists of 365 days starting from Program record's date of project operational start.

indicated later start dates. Table C-7 provides descriptions relative to program tracked start dates of the metered data periods used in estimates and associated project counts and capacity sum.

Table C-7. DG-CHP Counts of Projects by Period of Metered Data

Description	Project Count	Capacity (MW)
Validated meter data from first calendar year of operation	2235	30.6
Metered data not available for 1st program year	11	17.8
Commissioning/troubleshooting apparent in data from 1st program year	74	3.2
Survey found 1st normal operational year later than 1st program year	311	1.2
Total	53	52.8

Savings estimates for 35 out of 53 metered projects, or 58 percent of metered capacity were based on metered data from the first calendar year of operation defined by tracked start dates. Savings estimates developed for the remaining metered projects used periods later than the first calendar year as defined by tracked start dates. For many of the non-first year projects (11, representing 34 percent of metered capacity), metered data were only available after the end of the first year as defined by tracked start dates. For the remaining 7 projects (8 percent of capacity), commissioning was either evident in the data or the survey responses defined a different period other than that the first year defined by tracked start dates. Selecting data from a later period may introduce some bias. However, an informal review of these sites over multiple subsequent years indicated little change. Any bias would have minimal impact on total program savings since these projects represent less than 10% of the metered capacity.

Seasonal performance of CHP can vary dramatically and it is important to have representative data from at least three seasons (winter, summer, swing). For many projects, a full complement of 8760 hours of data was not available due to invalid data, potentially poorly representing a particular season. To maintain validated observations as source of estimates, observations were selected by season beginning at the start of normal operations until each season had a full complement of hours. This led to use of observations from periods later than the first 12 months, and for a small number of projects with many invalidated observations, from later than the first 24 months. Projects with a small number of missing hours were expanded to full seasonal complements by multiplying seasonal sums by the ratio of seasonal to metered hours. In rare cases whole season substitutions were used.

With four seasons defined, seasonal savings estimates were computed as the sum of the data stream within each season. Seasonal savings estimates of avoided consumption of electricity and fuel were then performed using these metered data streams. For savings calculations, boiler efficiencies, chiller efficiencies, and absorption coefficients of performance were drawn from the same sources in the same order as for the customer surveys that were shown in Section 1.2.

ON-SITE VERIFICATION

The purpose of the site visits was twofold:

1. Acquire meter data for data streams missing in IDS for large sites that would substantially impact on the results.
2. Independently validate the project file review, telephone surveys, and metered data.

During the work plan phase, analysis of the IDS data indicated that the evaluation results would likely meet the 90/10 sample precision target with the data in-hand; however, there were gaps. Specific sites were targeted for additional data acquisition either through direct on-sites with evaluator metering or if available, from customer-installed metering.

Regarding the second purpose, neither the DG-CHP program nor IDS had ever been rigorously and independently evaluated previously. An on-site audit of all the data collected for the site provided the final validation of the information collected by the program, by IDS, and by the evaluators through the project site reviews and telephone surveys. If differences were observed, the results were intended to be used to adjust individual site observations, and if they were pervasive, to develop another layer of ratio estimator adjustments. However, no significant differences were found between the on-site observations and other data collection findings.

In retrospect, one of the important purposes of the on-site data activity was to provide the back story and details of the problems and successes of the installations.

Sampling and Sample Disposition

The analysis conducted to produce the work plan showed that with the metered data on hand, the evaluation results would likely meet the 90/10 sampling precision. The intention of the site visits was to audit the data collection process to make sure the site reviews, telephone surveys, and metered data did not introduce any field-observable bias.

The original sample design targeted a selection of sites as follows:

- Six sites with large installed capacities and missing one or more of the key energy streams. If necessary, install evaluator metering.
- Fifteen additional sites without IDS meter data, to audit other data collection and to collect customer metered data if available. In particular, site N which constituted 7% of the installed capacity, was targeted for on-site to acquire metered data.

Sites were recruited for on-sites as part of the telephone survey process. The final selection of sites was partly driven by customer willingness to host a site visit. In addition, many sites that were not reporting to IDS did have in-house metered data, blurring the line between IDS and non-IDS sites. The sites with IDS were slightly oversampled, while the non-IDS sites were under sampled. However, more importantly, metered data was acquired for 8 non-IDS sites, including all data streams for Site N, which accounts for about 7% of the Program's installed capacity.

The final sample disposition is summarized in Table C-8.

Table C-8. DG-CHP On-Site and Meter Data Acquisition Disposition

	Sample Quota	On-Site Activity	Meter Data Acquisition
Sites with IDS (N=53)	6	9 on-sites	9 with IDS
Sites without IDS (N=26)	15	8 on-sites	8 customer provided
Targeted large sites	*5*	*2 on-sites*	*5 customer provided*
Site N	*1*	*no on-site*	*1 customer provided*
No customer meter data	*9*	*6 on-sites*	*2 customer provided*

On-Site Methodology

Customers were recruited for on-site visits during the telephone survey. Those who indicated a willingness to host a site visit were later scheduled by the site engineer. In preparation for the site visit, the engineer gathered the results from the project file review and the telephone survey and any IDS data to provide a compendium of findings for verification on-site.

During the site visit, the on-site engineer typically met with the person responsible for the overall operation of the system, conducted an interview, and then walked the site. During the walk-through, the engineer verified equipment nameplate data, took pictures, and checked on the location of metering equipment. Site observations and findings were documented in a site report.

CALCULATION OF PROGRAM SAVINGS AND UNCERTAINTY

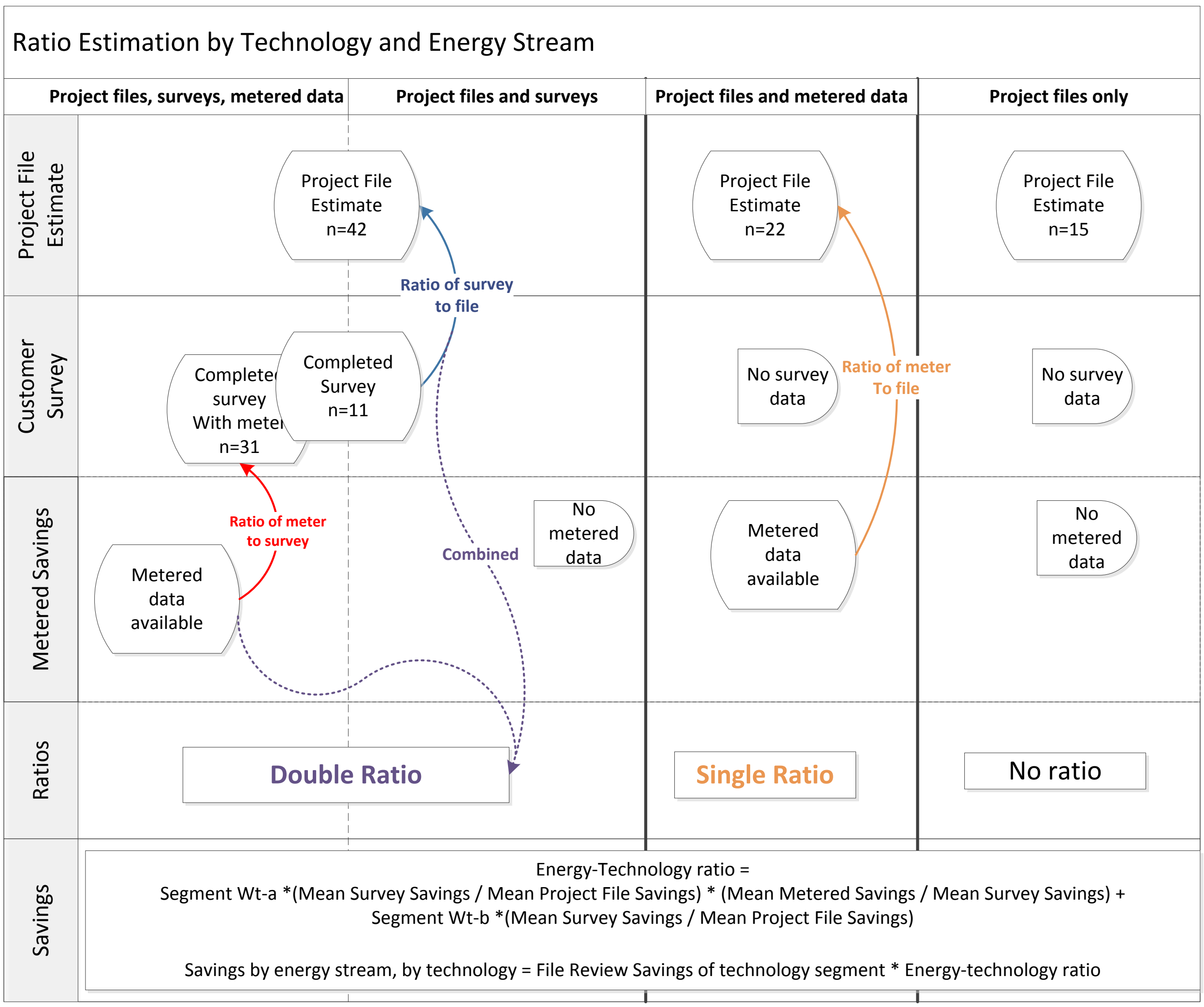
For the evaluated projects, this study applied an approach called ratio estimation to evaluate the total program gross savings. The objective of ratio estimation is to compare estimates of savings (electrical energy, electrical demand, natural gas consumption, and natural gas offset) from a sample to the expected population values to determine a ratio of realized savings. This ratio – or realization rate – is then applied to the total population expected savings to fill in savings for projects without directly evaluated savings. For example, if the data collected for a sample of projects shows that electricity savings were 80% of the expected value, this ratio can be applied back to the full population. While the calculation and application of the ratio is relatively straightforward, an advantage to the approach is that it allows for the estimation of relative precision, which shows the accuracy of the estimated population savings.

As noted in the introduction, this study relied on three sources for evaluated savings: project file data, customer survey data, and metered data. To get the most value from this data, the analysis applied two different types of ratio estimation to estimate total population savings. The first type of ratio estimation is called double sample ratio estimation. Double sample ratio estimation is commonly used when there are two different samples with different estimates of savings. Generally, the first sample is based on a source of data that is less accurate but available for a larger number of projects, and the second is more accurate but not available for as many projects. In this study the first sample is the projects with survey data and the second is the projects with metered data. The first sample allows for a broader estimation of the ratio using the survey data and the second sample provides an adjustment based on the more accurate metered data.

One requirement of double ratio estimation, however, is that the metered data projects must be nested within those projects with survey-based estimates. That is, a project with metered data but no accompanying survey cannot be used in the analysis. Because there were many projects that met this condition, the study also used a single ratio estimation approach for those projects with metered data but no survey information. If there were metered data for all of the projects with a completed survey, the analysis could rely exclusively on single ratio estimation, but this combined approach maximizes the use of the collected data.

To further explain how the availability of survey and metered data determined which ratio estimation approach was applied (double or single), Figure C-4 shows how the projects were separated into the two types of analysis groups. In the leftmost two columns, the projects that have both a project file review estimate and a completed customer survey are there along with the nested subset that has metered data and is subjected to the double ratio estimation approach. The projects with metered data but no completed survey in the third column are used in single ratio estimation. Finally, the fourth and final column represents those projects with only a project file estimate. These projects are not included in the development of ratio estimators. Instead, their expected savings are adjusted with ratio estimators to calculate the total evaluated savings for a given energy stream (Electrical Energy Savings, Electrical Demand Savings, Natural Gas Consumption, and Avoided Natural Gas).

Figure C-4. Assignment of Projects to Double and Single Ratio Estimation



After separating the projects into separate sets for double and single ratio estimation, the ratios of expected to observed/evaluated savings and corresponding estimates of precision were calculated by technology type. The calculations for the two types of ratios are shown at the bottom of **Figure 2-1**.

The formulas for ratios for double and single ratio estimation are presented below in **Equation 1** and **Equation 2**, respectively.

Equation 7: Double Ratio Estimation Formula

$$Double\ ratio = \frac{\bar{X}_s}{\bar{Z}_s} \times \frac{\bar{Y}_m}{\bar{X}_m}$$

where,

$\bar{X}_s = Mean\ survey\ value$

$\bar{Z}_s = Mean\ project\ file\ value\ for\ projects\ with\ survey$

$\bar{X}_m = Mean\ survey\ data\ value\ for\ projects\ with\ metered\ data$

$\bar{Y}_m = Mean\ metered\ data\ value$

Equation 8: Single Ratio Estimation Formula

$$Single\ ratio = \frac{\bar{Y}_m}{\bar{Z}_m}$$

where,

$\bar{Y}_m = mean\ metered\ data\ value$

$\bar{Z}_m = mean\ project\ file\ value\ for\ projects\ with\ metered\ data$

In the calculation of the ratios using both approaches, the variability in the inputs allows for the calculation of a standard error, which can be used to estimate the relative precision of the ratio. The standard errors are used to calculate the relative precision as presented in in Equation 3 for the 90% confidence level.

Equation 9: Relative Precision

$$rp = \frac{1.645 \times SE\_ratio}{Ratio}$$

The standard errors for the double and single ratio estimation are presented below in Equation 10 and Equation 11, respectively. More detailed documentation on these standard errors can be found in the footnoted references[5], both of which include discussions of bias that are associated with each method.

Equation 10: Standard Error Estimation for Double Ratio Estimation

[5] For single ratio estimation, the standard errors are defined in Cochran, W. (1977) Sampling Techniques, Wiley and Sons. For double ratio estimation, the standard errors is define in equation 6 of "Yadav, A. (2003) A Chain Ratio Exponential Type Estimator in Two Phase Sampling Using Auxiliary Information, Statistica, anno LXXIII, n. 2, 2013.

$$MSE(\bar{y}_{rd}^{(C)} = \bar{Y}^2 \left[\left(\frac{1-f}{n} \right) C_y^2 + \left(\frac{1-f'}{n'} \right) C_z^2 (1 - 2K_{02}) + \left(\frac{1-f''}{n} \right) C_x^2 (1 - 2K_{01}) \right]$$

Where

$f = \left(\frac{n}{N} \right), \quad f' = \left(\frac{n'}{N} \right), \quad f'' = \left(\frac{n}{n'} \right)$

$C_y = (S_y/\bar{Y}), \quad C_x = (S_x/\bar{X}), \quad C_z = (S_z/\bar{Z}),$

$K_{01} = \rho_{yx} \left(\frac{C_y}{C_x} \right), \quad K_{02} = \rho_{yz} \left(\frac{C_y}{C_z} \right)$

ρ_{yx} *and* ρ_{yz} *are the correlation coefficients between* y *and* x *and* y *and* z*, respectively*

Equation 11: Standard Error Estimation for Single Ratio Estimation

$$\sqrt{\left(SSE/\left(n(n-1)\right)\right)} \times n/\sum_{i=1}^{N} x_i \times \sqrt{1-n/N}$$

$$SSE = \sum_{i=1}^{n} (y_i - bx_i)^2$$

Where y_i = the metered savings for project i, x_i = the project file savings for project I, and b = the overall ratio of the mean of y to the mean of x for a given strata, n = the number of projects in the sample for a strata, and N = the number of projects in the population..

The single and double ratio estimation routines were stratified by type or prime mover, meaning each type of prime mover was treated individually. This was necessary to prevent the variability associated with different types of prime movers from distorting the overall accuracy of the evaluated savings. For example, if microturbines tend to have a much lower ratio of metered to expected savings than, say, fuel cells, then including them in the same analysis would produce an exaggerated and misleading estimate of savings.

Stratifying by type of prime mover and using two versions of ratio estimation maximized the use of available data. However, use of the two methods across different strata required that the results and precision needed to be combined to achieve program-level results. First, the results from single and double ratio estimation were combined at the strata level by weighting each method by the expected savings. For example, consider a hypothetical case when the total population expected savings for a type of prime mover was 100 MWh. If the samples used for single and double ratio estimation totaled 20 and 30 MWh, respectively, then population weights would be 40 (20/50×100) for single and 60 (30/50×100) for double.   These ratios are shown in C-9.

Table C-9. DG-CHP Electric Generation Precision by Prime Mover Type

Prime Mover	Population Total Savings	Population Weight for Prime Mover	Ratio Type	Sample Savings	Weight for Ratio Type
Back Pressure Turbine	10,742	2.7%	Double	2,840	32.5%
			Single	5,901	67.5%
Chilled Water Absorption	424	0.1%	Single	424	100.0%
Fuel Cell	36,356	9.3%	Double	16,831	69.9%
			Single	7,249	30.1%
Gas Turbine	151,437	38.7%	Double	85,248	61.7%
			Single	52,941	38.3%
Microturbine	25,324	6.5%	Double	9,527	40.5%
			Single	13,981	59.5%
Reciprocating Engine	167,168	42.7%	Double	89,142	60.1%
			Single	59,190	39.9%

The prime mover specific-ratios were used when possible to calculate the total estimated savings. In some cases, such as double ratio for back pressure turbines, where all sites within particular strata and ratio method were metered, the relative precision is zero.

Table C-109. DG-CHP Electric Generation Precision by Prime Mover Type [6]

Evaluation	Prime Mover Type	# of Sites	Ratio	Sample Size	Segment Ratio	Relative Precision	Std Error
Current	Back pressure turbine	3	Double	2	29%	0%	0%
			Single	1	89%	0%	0%
	Chilled water absorption	1	Single	1	66%	0%	0%
	Fuel cell	10	Double	7	96%	29%	18%
			Single	2	102%	11%	7%
	Natural gas turbine	2	Double	1	100%	0%	0%
			Single	1	96%	0%	0%
	Microturbine	18	Double	7	77%	42%	26%
			Single	5	53%	31%	19%
	Reciprocating engine	44	Double	25	59%	44%	27%
			Single	11	64%	37%	22%
Previous	Fuel cell	1	NA	1	NA	0%	0%
	Natural gas turbine	1		1		0%	0%
	Microturbine	1		1		0%	0%
	Reciprocating engine	7		7		0%	0%

The estimates of precision were aggregated in a similar fashion – first by prime mover type, then overall – but rather than weighting by population savings, a pooled savings approach was applied where the estimates of precision were first converted to estimates of variance, then combined, and then translated back into estimates of precision. The details of this approach are presented in The 2004 California Evaluation Framework. The formula for the pooled relative precision presented in Equation 12 .[7].

Equation 12: Formula for Pooled Relative Precision

$$RP_{Pooled} = \frac{\sqrt{\sum_{i=1}^{i}(RP_i \times ES_i)^2}}{\sum_{i=1}^{i} ES_i}$$

Where RPi = Relative Precision for Strata I, ESi = Total Estimated Savings for Strata i

This evaluation also incorporated savings from ten previously evaluated projects**.** These 10 projects were treated as a separate population with no associated variance or uncertainty. When combined with the evaluated population, the relative precision of the total estimated savings improved.

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[6] Only 78 sites show in the current field for this table since one site had no electrical impacts, only natural gas impacts.

[7] The California Evaluation Framework, Project Number: K2033910, Prepared for the California Public Utilities Commission and the Project Advisory Group, June 2004, TecMarket Works and the project Team Members.

The program realization rate is the sum of site evaluated savings for each site adjusted for the stipulated NTG factor and the sum or the feasibility study site savings adjusted for program influence divided by the sum of the program tracking savings.

OTHER RESEARCH METHODS AND INTERMEDIATE FINDINGS

Other research described in this section includes the non-impact results of the customer telephone surveys and the feasibility study research.

SURVEY AND SITE FINDINGS

As part of the surveys and onsite data collection, information was gathered concerning the current disposition of the sites. Customers also offered their assessment of the start-up process, although this was not a formal part of the survey. Responses are summarized in Table C-11. The key to the table is as follows:

Start-up Problems: MJ-Major, MN-Minor, N-None

Current Status: RP-original system was replaced, RM- system was removed, InOP-system is inoperative although in place, OP-original system is in operation, P-original system will be removed on failure (pending), FIX-system is offline due to major unresolved repair issues.

Performance: These two columns report the customer's perception of whether the system is under performing or meeting expectations of performance.

Problems and issues are highlighted in red, although minor start-up issues were not so noted.

Table C-11. DGCHP Summary of Customer Reported System Performance and Status

Site #	Start-up problems	Current Status	Performance Expectations		Year installed	Notes
			Elec	HR		
6846	MJ	RP	Meets	Meets	2001	Thermal following load runs absorber for injection machine cooling. Replacing 8 of 25 orginal MTs. Happy with system.
6551	N	InOP	Meets	Meets	2002	Initial system worked well, however, subsequent additions to the building, obviated the need for the absorber which began to experience maintenance problems
6848	N	OP	Meets	Meets	2002	
6839	N	OP	Under	Under	2003	A modest portion of available heat is used for DHW only. Changes in the facility made the recovery impractical for other uses. In addition, there is no call for space heating when the unit is online.
6841	MN	RP	Meets	Meets	2003	Units needed replacement after nine years; customer was pleased with the old and new systems.
7307	N	OP	Meets	Meets	2003	Customer happy. Load following and slightly undersized.

7321	N	OP	Meets	Meets	2003	
7325	MN	FIX	Meets	Meets	2003	Both installed units are down and no money for repairs. Was working well, although dumping in summer.
6842	MJ	P	Under	Under	2004	While originally enthusiastic about self-gen, O&M is high and will return to grid. The absorber is no longer operational and only about 20% of the intended is recovered.
7291	N	OP	Meets	Under	2004	Self-gen sites that has worked well on generation, but only one of four units has operational heat recovery. Ran out of landfill supplemental gas about two years ago.
7306	MJ	InOP	Under	Under	2004	The generator unit never operated properly. The absorber never operated properly. Generators were likely insufficiently cooled causing high temp cut-out.
7312	MJ	FIX	Under	Meets	2004	Out on repairs since Nov-2013. Waste steam runs a generator without any heat recovery.
7314	N	OP	Meets	Meets	2004	Electric load following, base load, although large amoun of heat recovery.
7318	N	OP	Meets	Meets	2004	
7320	N	OP	Meets	Under	2004	Generally happy with system which provides 60% of electric load but would like more heat recovery.
7311	MJ	RM	Under	Under	2005	Very unhappy with performance and refused to keep system on site.
7326	N	OP	Meets	Meets	2005	Electric load following, dumping about a third of the heat.
7858	MJ	RM	Under	Under	2005	Direct drive of a grinding process that never worked properly.
7862	N	OP	Meets	Meets	2005	Customer happy. Recover heat used for digester. Second unit installed a few years later.
8571	MN	OP	Meets	Meets	2005	Burns landfill gas and works well. Dumps heat in the summertime.
7313	MN	OP	Meets	Meets	2006	Happy customer.
6548	MJ	RP	Under	Under	2007	Shutdown due to ongoing recuperator maintenance issues. Replaced under a subsequent maintence contract.
6741	MJ	RP	Under	Under	2007	Initial methane recovery and generator system installed in 2002 did not work. Replaced in 2007. Replaced MT with recips, but still not enough heat recovery.
	MJ	RM	Under	Under	2007	Intended to run 24/7 but system kept failing. Repairs were expensive so system was abandoned.
9186	MN	P	Meets	Meets	2007	Change in ownership. New owner will remove system upon failure which is expected imminently. System operated well, but only installed DHW heat recovery.

7855	N	OP	Meets	Under	2008	This is a refrigerated warehouse. Heat recovery is used for space heating but the refrigeration system, although installed, never worked.
9181	MJ	OP	Meets	Meets	2008	
7857	N	OP	Meets	Meets	2009	Self-gen site serves campus. Works well with system FCE of 51%.
9187	MN	OP	Meets	Under	2009	DHW was smaller than expected so less heat recovery than expected.
9190	MJ	OP	Meets	Meets	2009	
9926	MN	OP	Meets	Meets	2009	Operates well.
10799	N	OP	Meets	Meets	2009	Works great.
10800	MN	OP	Meets	Meets	2009	
7854	N	OP	Meets	Meets	2010	Electric load following.
7866	MJ	OP	Meets	Under	2010	Significant downtime. No heat recovery installed.
7988	MJ	OP	Meets	Meets	2010	Fuel cell is performing well although the recip unit is not.
9173	MJ	OP	Under	Under	2010	One of two generators has failed. Heat recovery doesn't work because exchangers are 'hopelessly plugged'. Many start-up and operational problems. Not happy with the generator manufacturer.
9188	MJ	OP	Meets	Meets	2010	Electric load following with some use of recovered heat.
11183	MN	OP	Meets	Meets	2010	
11085	MJ	OP	Meets	Meets	2011	
11185	N	OP	Meets	Meets	2011	
15913	N	OP	Meets	Meets	2011	
15920	MN	OP	Meets	Meets	2011	
15923	MJ	OP	Meets	Under	2011	Problems with absorption chiller. Can’t recover enough heat; thinks it’s a design flaw.
9175	MJ	OP	Under	Under	2012	Equipment is still not operating properly. No heat recovery because no provisions to supply campus as was intended.
10801	N	OP	Meets	Meets	2012	Works well thermal following.
15917	MN	OP	Meets	Meets	2012	
22239	N	OP	Meets	Meets	2012	
22241	N	OP	Meets	Meets	2012	
22244	MN	OP	Meets	Meets	2013	

This table illustrates the following points. First, the reasons for system failures, underperformance, and start-up difficulties are varied and demonstrate the potential for technical difficulties. Second, although there are fewer identified issues in more recent installations, it is not known whether this is due to better system implementation or because the newer systems are not old enough to experience problems that begin to appear typically at about the five years point.

FEASIBILITY STUDY SITES

During the defined evaluation period, approximately 19 projects received feasibility studies. The purpose of this task was to identify any sites that had installed a system, had not received a NYSERDA incentive, and had been influenced by the Program through the study. The savings achieved by sites meeting these criteria would be credited to the Program.

The evaluators estimated savings in a two-step process. First, an attempt was made to determine whether a DG-CHP system had been installed at each site and if so, whether the study had been influential. Secondly, an on-site was conducted to confirm the installation and estimate the savings for sites that passed the telephone survey screen.

Prior to calling participants, other NYSERDA program tracking data was cross-checked for DG-CHP installation under another program. These sites were dropped from further considerations, because the saving is already counted by the incentivizing program. However, during the telephone survey, additional sites were determined to have participated as well. As another check, the participant sites were cross checked with the DOE sponsored inventory of installed DG-CHP systems to indicate a likelihood of an installation to have occurred.

In the final step, on-site verification was conducted at the one site that met the criteria above: it did not receive an incentive from another program and was influenced by the feasibility study. The on-site contact provided metered data for production of the estimate of savings. The results were documented in a site report.

Disposition of the Feasibility Sites

Table C-10 summarizes the disposition of the telephone survey. Not all of the telephone surveys were successfully recruited. While seven of the sites could not be reached by telephone, six of the sites were not listed in the DOE inventory of DG sites.

Table C-11. DG-CHP Feasibility Study Site Disposition

Category	Confirmed Installation
Installed a system and tracked by NYSERDA program	5
Call complete, site reported participation in NYSERDA program	1
Call complete, no system installed	5
Call complete, system installed, study was influential	1 site; site visit completed
Could not reach customer, site not listed in DOE inventory	6
Could not reach customer, site apparently listed in DOE inventory	1
Total	19

DECISION RESEARCH

The Impact Evaluation Team called all 79 of the current sites with a goal of completing 20 short interviews with key decision-makers who were integrally involved in the decision-making process for installing a DG system. Twenty-seven surveys were completed. The interview guidelines can be found in Appendix D.

The interview was designed to gather information on the following topics:

- Identification of factors that prompted the participant decision to install a DG-CHP facility
- The decision makers' relative ranking of the importance of these program and non-program factors in making the final decision
- Identification of any program influences or design features that are likely to increase the installation of DG-CHP systems in New York for past participants or for the market as a whole.

Both program and non-program influences on DG decision-making were explored: cash rebates, technical assistance, regulatory assistance in gaining permits, usefulness of case studies, economic conditions, and perceived future energy prices.

In addition, the Impact Team attempted to contact non-participant decision makers at the 13 DOE inventory of DG-CHP sites installed in 2010–2011 that do not have a match in the R&D Program and provide sufficient customer identification for this attempt to be made. The interviews focused on the decision-makers' awareness of the NYSERDA program at the time of the decision, any influence it may have had on decision-making, and the factors driving the decision to install the system.