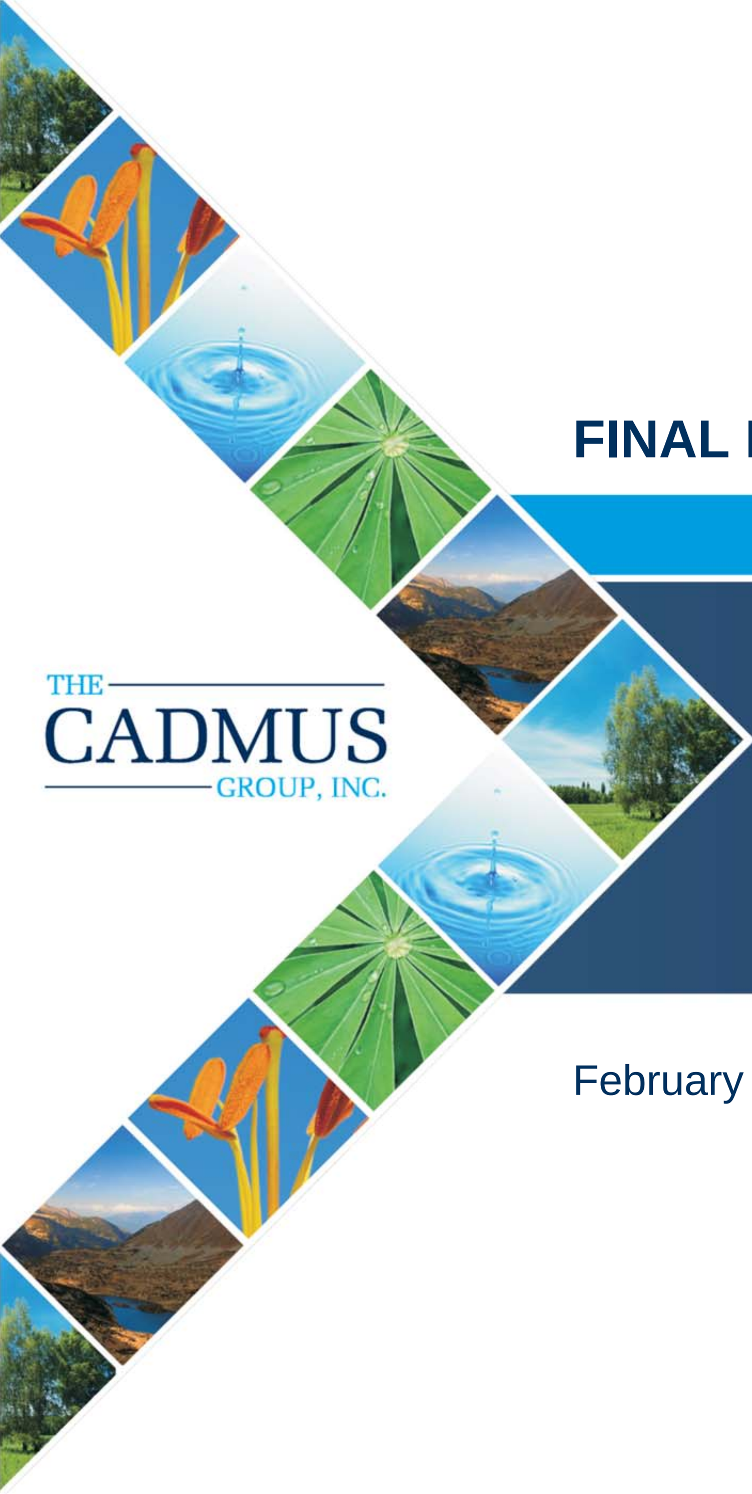

FINAL REPORT

Assessment of Energy and Capacity Savings Potential in Iowa

February 28, 2012

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EXECUTIVE SUMMARY

Chapter 35 of the 1999 Iowa Administrative Code (199 IAC 35) sets forth the Iowa Utility Board (IUB) rules to implement legislation enacted in 1990 and modified in 1996, requiring Iowa's investor-owned utilities to "file with the Board an assessment of the potential for energy and capacity savings from actual and projected customer usage by applying commercially available technology and improved operating practices to energy-using equipment and buildings."

In compliance with this requirement, the Iowa Utility Association selected, through a competitive bidding process, The Cadmus Group, Inc., (Cadmus) and its sub-contractors Nexant, Inc. (Nexant), and First Tracks Consulting (First Tracks), to assess the remaining potential for energy and capacity savings within the service territories of Iowa's three largest investor-owned utilities. Referred to collectively as "the Utilities," Alliant Energy Corporation (Alliant, electricity and natural gas), Black Hills Energy (Black Hills, natural gas only), and MidAmerican Energy Company (MidAmerican, electricity and natural gas) serve approximately 72% of Iowa's electric customers and 85% of the state's natural gas customers.

Study Scope

This study builds upon five previous assessments of potential in Iowa, conducted since 1989, particularly the most recent (2008) study, led by Cadmus (formerly, Quantec, LLC).[1] The assessment builds upon the substantial primary data collection activities from the 2008 study, updating the data based on recent studies commissioned by the Utilities, DSM achievements of the Utilities in the intervening years, and current customer and load forecasts. This information was supplemented with data from several secondary data sources. The compiled data provided a complete characterization of both the current state of energy consumption in the Utilities' service area and the landscape forecast in the absence of future DSM.

Although this study addresses the same overall objectives as the 2008 assessment, the two studies differ in individual components considered, reflecting the changing landscape of demand-side management (DSM), both in Iowa and across the nation. Table 1 shows key components of each study. The 2012 study excluded the earlier study's primary data collection, assessments of new non-AMI demand response and renewable resources, and review of code compliance, while adding an assessment of market potential for energy efficiency.

1 *Assessment of Energy and Capacity Savings Potential in Iowa*, prepared for the Iowa Utility Association, prepared by Quantec, LLC, Summit Blue Consulting, Nexant, Inc., A-TEC Energy Corporation, and Britt/Makela Group, February, 2008.

Table 1. Key Components of 2008 and 2012 Assessments

Study Component	2008 Assessment	2012 Assessment
Primary Data Collection	✓	
Energy Efficiency—Technical Potential	✓	✓
Energy Efficiency—Economic Potential	✓	✓
Energy Efficiency—Market Potential		✓
Demand Response—Potential from Expansion of Legacy Programs	✓	✓
Demand Response—Potential from AMI-Enabled Options	✓	✓
Demand Response—Potential from New Programs without AMI	✓	
Renewable Resources	✓	
Effects of Free-ridership and Spillover	✓	✓
Code Compliance	✓	

The resources and technologies considered in this assessment are informed by the Chapter 35 rules and discussions with the Utilities and stakeholders. Assessments of DSM potential are naturally influenced by prevailing rules and considerations, as well as factors such as weather, customer demographics, and economic assumptions that will lead to differences between study results. Therefore, the results of potential studies may not be readily comparable across jurisdictions. The following points related to this study's scope should be considered in comparing results to other potential assessments:

- Emerging technologies (deemed not commercially available at the time of this study) are excluded from technical and economic potentials, but included in market potentials.
- Early replacement of end-use equipment is not considered in this assessment; equipment is assumed to be upgraded at the time of natural replacement.
- As the assessment covers 10 years, there may be remaining potential for long-lived equipment beyond the study's time horizon.
- Active generating options, such as renewable and combined heat and power (CHP) are excluded from the assessment.
- The identified technical and economic potentials represent gross savings and some measures may not be appropriate for inclusion in utility programs due to potentially high freeridership rates.

Although emerging technologies, equipment early replacement, and on-site generation are excluded from the technical and economic potential, this should not preclude the Utilities from considering these options in their program offerings.

Energy Efficiency

Technical and Economic Potentials

The energy-efficiency assessment quantified the amount of energy that could be saved in the Utilities' service territories from 2014 to 2023. The assessment included efficient technologies and practices widely commercially available at the time of the study,[2] accounting for known

[2] The market potential scenario considers emerging technologies.

changes in codes and standards, technical limitations (technical potential), and societal cost-effectiveness (economic potential).

Table 2 shows forecasted[3] 2023 baseline electric sales and potential by sector. Study results indicate 8,446 GWh of technically feasible electric energy-efficiency potential by 2023, the end of the 10-year planning horizon, with approximately 6,872 GWh of these resources proving cost-effective. Identified economic potential represents a reduction of 19% of forecasted load in 2023. The residential sector represents the largest portion of technical and economic potential, at 42% and 40%, respectively. The commercial sector represents the second-largest contributor to technical and economic potential, at 32% for each, while industrial potential accounts for 26% and 28% of technical and economic potential, respectively.

Table 2. Technical and Economic Electric Energy-Efficiency Potential (Cumulative in 2023) by Sector

		Technical Potential		Economic Potential	
Sector	Base Case Sales (MWh)	MWh	% of Base Sales	MWh	% of Base Sales
Residential	9,197,928	3,548,837	39%	2,772,993	30%
Commercial	7,857,412	2,702,650	34%	2,181,608	28%
Industrial	18,293,266	2,189,166	12%	1,910,047	10%
Total	**35,348,606**	**8,440,653**	**24%**	**6,864,648**	**19%**

Table 3 presents 2023 forecasted baseline natural gas sales and potential by sector.[4] As shown, study results indicate over 37 million therms of technically feasible natural gas energy-efficiency potential by 2023. The estimated economic potential of 25.5 million therms amounts to 24% of forecasted load in 2023, and over 2 million peak day therms.

Table 3. Technical and Economic Natural Gas Energy-Efficiency Potential (Cumulative in 2023) by Sector

		Technical Potential		Economic Potential	
Sector	Base Case Sales (Thousand therms)	Thousand Therms	% of Base Sales	Thousand Therms	% of Base Sales
Residential	671,594	274,172	41%	175,823	26%
Commercial	335,581	92,129	27%	73,649	22%
Industrial	62,616	5,591	9%	5,280	8%
Total	**1,069,791**	**371,892**	**35%**	**254,752**	**24%**

As with electric potential, the residential sector represents the largest portion of technical and economic potential, at about 74% and 69%, respectively. Almost all remaining potential lies in the commercial sector, with a small portion (5.3 million therms) deriving from industrial applications.

3 Forecasted sales have been based on baseline forecasts developed by Cadmus, as described in Section 1, and do not necessarily match official utility forecasts.

4 As specified in the Chapter 35 rules, gas transport customers are excluded from the analysis.

Market Potential

Assessment of market potential, a new component of this study, examined savings that might be achievable under an aggressive acquisition scenario where:

- Utilities offer incentives of 100% of incremental measure costs;
- Financing is available to further address first-cost barriers; and
- Additional economic potential becomes available from emerging technologies.

To address the first aspect, Cadmus analyzed publicly available data on recent energy-efficiency experiences for IOUs across the nation, conducting regression analysis to estimate relationships between increased incentive spending and savings levels achieved. Based on this analysis, and beginning with the Utilities' 2010 program activity, up to 90% and 65% of electric and natural gas economic potential, respectively, may be achievable, over the 10-year study horizon. However, acquisition of these resources would require significantly higher utility expenditures than those currently occurring in Iowa or elsewhere in the nation.

To assess financing's potential effects, Cadmus reviewed available literature regarding the success of such programs. It is important to note this financing would only apply to a subset of measures included in the economic potential, namely those with full costs differing from incremental costs. The research indicates the availability of financing, in addition to 100% incentives, likely will not significantly impact measure adoption.

Finally, Cadmus researched measures not currently widely available commercially, but that are expected to become available over the next five to 10 years. In most cases, these measures represent incremental improvements over measures already included in the technical and/or economic potential identified in this study. The analysis found emerging technologies may increase electric market potential by up to 3%, with no impact expected on natural gas potentials.

Results of the market potential analysis are intended to provide a realistic upper bound to the estimates of economic potential and do not necessarily represent "program" potential or utility targets. The estimated savings may be realized through market transformation or improved codes and standards and may not be available or suitable for inclusion in utility program offerings. For example, the electric potential includes a substantial amount of savings from LEDs and CFLs replacing minimum standard bulbs. However, if the new lighting standards cause CFLs to become the de facto standard, the amount of savings available for utility DSM program acquisition could be greatly reduced.

Comparison to 2008 Assessment

While the 2008 Assessment utilized the best available information at the time, much has changed over the past four years and, thus, many data and assumptions have been updated in this study. The key differences are these:

- Updated utility sales, customer, and avoided cost forecasts;
- Changes in building codes and equipment standards; and
- Increased measure saturations due to utility program accomplishments.

The 10-year technical and economic electric and natural gas potentials from each study, by sector, are presented in Table 4 and Table 5, respectively. As shown, electric technical potentials have decreased, largely driven by updated codes and standards, particularly with regard to residential lighting. However, due to increased electric avoided costs, the fraction of technical potential deemed cost-effective has increased, and system-wide electric economic potentials have increased by only 1% above 2008 levels. The natural gas technical potential has similarly decreased, with decreased avoided costs contributing to a corresponding decrease in economic potential.

Table 4. Comparison of 10-Year Electric Technical and Economic Potentials

	Technical Potential (GWh)		Economic Potential (GWh)	
Sector	2008 Assessment	2012 Assessment	2008 Assessment	2012 Assessment
Residential	4,937	3,549	3,215	2,773
Commercial	2,695	2,703	1,563	2,182
Industrial	2,136	2,189	1,999	1,910
Total	**9,767**	**8,440**	**6,777**	**6,865**

Table 5. Comparison of 10-Year Natural Gas Technical and Economic Potentials

Sector	Technical Potential (Thousand Therms)		Economic Potential (Thousands Therms)	
	2008 Assessment	2012 Assessment	2008 Assessment	2012 Assessment
Residential	265,320	274,172	186,540	175,823
Commercial	132,240	92,129	90,130	73,649
Industrial	8,970	5,591	8,970	5,280
Total	**406,530**	**371,892**	**285,640**	**254,752**

Demand Response

The 2008 Assessment estimated demand savings potential for a variety of demand-response program options, including firm (e.g., residential direct load control [DLC]) and non-firm (e.g., critical peak pricing) strategies. In addition to actual potential estimates, the study resulted in two key findings:

1. Large overlap occurs between eligible populations for similar programs, and implementing new programs may affect participation in demand-response programs currently offered by the two electric utilities.
2. Regarding billing systems in place in 2008, the study did not allow for implementation of price-based options, such as real-time or critical peak pricing. However, these strategies could become feasible if and when the Utilities move to an Advanced Metering Infrastructure (AMI).

Based on these findings, the Utilities have continued to offer their long-running, successful Residential DLC and Nonresidential Interruptible programs in their 2009–2013 Energy Efficiency Plans (EEPs). Building on the conclusions drawn from the 2008 Assessment, this study focused on two questions:

- What potential exists for expansion of utilities' current demand response programs?
- What opportunities would be available if and when utilities implement an AMI?

Expansion of Legacy Programs

As both electric utilities have operated successful demand response programs for many years, the assessment of demand response potential primarily focused on establishing the upper bounds of customer participation, based on the experience of utilities offering similar programs. Cadmus gathered data on comparable programs from across the nation to develop possible expansion scenarios for each of the current demand response programs.

The 2010 program accomplishments, 2008 study results, and potential under each scenario for Residential Direct Load Control (DLC) and Nonresidential Interruptible programs are shown in are shown in Table 6 and Table 7, respectively.

Table 6. Forecasted Residential DLC Impacts in 2023 (MW)

		10-Year Potential			
		2008 Study	2012 Study		
Utility	2010 Program Achievements	Base Case	Base Case	Moderate Expansion	Aggressive Expansion
Alliant	33	53	35	37	46
MidAmerican	31	72	32	35	43

Table 7. Forecasted Nonresidential Interruptible Impacts in 2023 (MW)

		10-Year Potential			
		2008 Study	2012 Study		
Utility	2010 Program Achievements	Base Case	Base Case	Moderate Expansion	Aggressive Expansion
Alliant	264	291	296	304	354
MidAmerican	193	170	238	422	492

As shown, based on updated benchmarking data, estimates of available 10-year potential for the Residential DLC program have decreased from those presented in the 2008 Assessment. Nonresidential Interruptible expansion scenarios indicate potential has increased since the 2008 Assessment, though it should be recognized that decisions around appropriate levels of load to hold under contract are heavily influenced by utilities' unique objectives and resource needs.

AMI-Enabled Options

Analysis of AMI-enabled demand programs was a qualitative exercise, given data quantifying impacts of AMI-enabled programs has been drawn almost exclusively from utility pilot programs, and may not be appropriate for extrapolation to larger markets. Consequently, potential energy and demand savings related to AMI cannot be reliably quantified at this time. Nevertheless, this study outlines a number of potential options that may provide viable savings sources if Iowa electric utilities implement AMI.

From initial pilot results, AMI appears to expand demand reduction capabilities of residential demand response programs, though the extent of this expansion remains to be seen, as program persistence issues have not been thoroughly studied. Additionally, studies of the reliability and security of these programs and enabling technologies remain in progress. Further, how AMI-enabled programs and traditional programs overlap, and how demand savings may shift, still must be understood before specific estimates of demand reduction can be determined.

From improving operability rates of existing DLC programs to offering new demand response programs to customers, who otherwise would not sign up for traditional DLC programs, AMI will likely expand utilities' demand reduction capabilities.

Assessment of the Net-to-Gross Ratio

In addition to estimating energy and capacity savings potential, the 2008 assessment investigated the use of net-to-gross (NTG) adjustments, specifically freeridership and spillover effects.[5] The assessment defined the freeridership and spillover concepts, discussed the background and policy implications of these concepts, and provided examples of studies that attempted to measure their magnitudes. The study concluded with a recommendation that Iowa's investor-owned utilities (IOUs) assume an NTG ratio of 1.0 across all programs for the energy-efficiency plans implemented during the 2009–2013 program cycle.

This report provides additional and more recent information to update findings from the 2008 study, seeking to determine whether the recommended NTG ratio of 1.0 remains appropriate.

As part of the current research, Cadmus reviewed treatment of freeridership and spillover in 32 jurisdictions, relying on regulatory filings, technical planning materials, and evaluation reports. The review resulted in the following key findings:

- Methods for measuring NTG elements are inexact. Despite considerable technical progress in measurement techniques for freeridership, spillover, and market effects, concerns exists about the potential bias in these methods and the reliability of their results.
- NTG estimates tend to have small impacts on the societal cost test (the basis for economic analysis of energy-efficiency programs in Iowa), and, therefore, likely do not affect cost-effectiveness of measures and programs.

[5] *Assessment of Energy and Capacity Savings Potential in Iowa—Appendix G*, prepared for the Iowa Utility Association, prepared by Quantec, LLC, Summit Blue Consulting, Nexant, Inc., A-TEC Energy Corporation, and Britt/Makela Group, February, 2008.

- Many jurisdictions have assumed an NTG ratio of 1.0 at the portfolio level.
- Of the 32 jurisdictions surveyed, freeridership is considered in most (60%), participant spillover in 11 (34%), and nonparticipant spillover in nine (28%). The incidence of cases where only freeridership is assessed suggests an asymmetrical treatment of spillover and freeridership effects. Should spillover be included, it is likely many NTG ratios will be near or greater than 1.0. More than two-thirds of all evaluation studies reviewed in a recent best-practices study had a NTG value of approximately 1.0.

Given these findings, it appears reasonable that gross savings be used as the basis for reporting and target compliance. However, utilities should design effective programs that minimize freeridership. This entails: (1) regularly monitoring the saturation of measures within their own service areas and in other jurisdiction; and (2) using this information to revise their programs and their incentive structures periodically.

1. GENERAL APPROACH AND METHODOLOGY

This assessment relies on industry best practices, analytic rigor, and flexible and transparent tools to accurately estimate the potential for energy and capacity savings in the Utilities' service territory between 2014 and 2023. This section outlines each step of the assessment process, with results presented in the following sections, and supplemental material provided in the accompanying appendices.

Energy Efficiency

This study distinguishes between three distinct types of energy-efficiency potential:

- **Technical potential**[6] refers to savings available from adoption of energy-efficiency measures and practices, considering physical constraints to installation, but not cost-effectiveness or market barriers. Measures must be widely commercially available and proven at the time of the study, and the study assumes equipment will be upgraded during natural replacement or through new construction.
- **Economic potential** serves as a subset of technical potential, containing only measures with a benefit-to-cost ratio greater than or equal to 1.0, based on the Iowa Societal Cost Test (as defined in the Chapter 35 Rules).
- **Market potential** represents a realistic upper bound to potential savings from cost-effective efficiency programs that could be achieved offering incentives up to 100% of incremental cost, availability of financing to cover additional up-front costs, adoption of emerging technologies, and other best practices for efficiency programs.

This section describes methods and data sources used to estimate each type of potential.

Base Case Forecasting

Estimating energy-efficiency potentials begins by establishing an accurate baseline forecast of energy sales in the absence of future demand-side management (DSM) activity. While each utility officially forecasts sales by rate class, this analysis requires forecasts at an end-use level, fully capturing effects of changing codes and standards. As such, utility customer forecasts have been combined with detailed end-use level data on equipment saturations, fuel shares, penetrations of efficient equipment, equipment replacement rates, and known codes and standards, producing alternate baseline forecasts from which to assess potential.

Characterizing base-case conditions requires extensive data collection. As this assessment did not include primary data collection, Cadmus began by cataloguing data collected and developed during the 2008 assessment. For end uses and segments, where the Utilities offered rebates for efficient equipment, Cadmus used data from the Utilities' DSM tracking databases to update saturations of efficient equipment. For example, the previous assessment included on-site visits to count light sockets and measure current compact fluorescent lamp (CFL) saturations. Since then, Alliant and MidAmerican have aggressively pursued savings from CFLs, considerably

[6] This definition is analogous to the "phase-in technical potential," described in the Chapter 35 Rules.

increasing this saturation. For each utility, the number of bulbs rebated was used to calculate a per-customer increase in saturation. These adjustments to current saturations of efficient equipment proved critical to avoid overstating remaining potential.

Additionally, the importance of accurately accounting for changes in codes and standards over the planning horizon cannot be overstated. Not only do these changes affect customers' energy consumption patterns and behaviors, but they establish which energy-efficiency measures will continue to produce savings over minimum requirements. This study captures current efficiency requirements as well as those enacted, but not yet taking effect.

The base case forecast particularly accounts for:

- Iowa's adoption of the 2009 International Energy Conservation Code (2009 IECC) for new construction;
- Provisions of the Energy Independence and Security Act of 2007 (EISA), affecting general service lighting and motors;
- The Department of Energy's 2009 rulemaking, setting standards for commercial fluorescent lighting, beginning in 2012; and
- Recent federal standards relating to residential heating, cooling, water heating, and appliances.

Creating a Database of Energy-Efficiency Measures

To estimate technical, economic, and market potentials for energy efficiency, this study relies on an extensive database of efficient equipment and practices. Measures considered in this study drew upon:

- Measures currently offered by the Utilities;
- Those included in regional and national database (e.g., California DEER and ENERGY STAR®); and
- Cadmus' internal library, compiled through our extensive experience conducting similar studies.

After compiling the initial list of measures, a qualitative screening process, as specified in the Chapter 35 rules, eliminated certain types of measures from consideration. Qualitative screening criteria included:

- Commercial availability;
- Applicability to Iowa's climate; and
- Effects on demand during peak periods.

The measures qualitatively screened out of the technical and economic potentials assessment, along with applicable sector, fuel, and reason for exclusion, are shown in Table 8. Emerging technologies were assessed as part of the market potential analysis.

Table 8. Measures Failing Qualitative Screening

Sector	Fuel	Measure	Reason for Exclusion
Both	Electricity	Advanced Modulating HVAC Compressors	Emerging technology.
Both	Electricity	Heat Pump Dryers	Emerging technology.
Both	Electricity	Water Heaters - Tankless	Increased peak demand
Commercial	Electricity	Active Chilled Beam Cooling with DOAS	Emerging technology.
Commercial	Electricity	LED Replacement of Linear Fluorescent	Emerging technology.
Commercial	Electricity	Ventilation and Energy Recovery	Emerging technology.
Commercial	Electricity	Advanced Rooftop Packaged AC	Emerging technology.
Commercial	Electricity	Hot-Humid Rooftop Unit with Dual Enthalpy	Emerging technology.
Commercial	Electricity	Liquid Desiccant Hybrid AC	Emerging technology.
Residential	Electricity	Advanced All-Climate Heat Pump	Emerging technology.
Residential	Electricity	Hot-Dry Air Conditioners	Emerging technology.
Residential	Electricity	Multifamily Building Best Practices	Emerging technology.
Residential	Electricity	On-Demand Recirculation Pumps	Emerging technology.
Residential	Electricity	Optimized Residential Duct Work	Emerging technology.
Residential	Electricity	Robust Central Air Conditioners	Emerging technology.
Residential	Electricity	Water Heaters - Add-On Heat Pump	Emerging technology.
Residential	Electricity	Water Heaters - Ground Source Heat Pump	Emerging technology.
Residential	Electricity	Water Heaters - Northern Climate Heat Pump	Emerging technology.
Residential	Natural Gas	High-Efficiency Gas Fired Rooftop Unit	Emerging technology.
Residential	Natural Gas	Water Heaters - Condensing Tankless	Emerging technology.
Residential	Natural Gas	Water Heaters - Non-Condensing Gas Hybrid	Emerging technology.

For each measure passing the qualitative screen, Cadmus compiled several types of data necessary to fully characterize each measure. Whenever possible, these data drew upon Iowa-specific sources, such as primary data collection from the 2008 assessment, utility tracking databases, or other studies performed by utilities. When Iowa-specific data were not available, Cadmus utilized the most appropriate regional and/or national sources, tailoring the data to Iowa, when possible.

Each measure had the following key data elements:

- Efficient and baseline equipment, labor, and O&M costs;
- Annual energy savings;
- Effective useful life;
- Technical feasibility; and
- Current saturation.

For modeling energy-efficiency potential, measures were separated into two distinct classes:

- ***Equipment measures*** save energy by upgrading the efficiency of end-use equipment at the time of that equipment's replacement (e.g., high-efficiency gas furnaces). In the absence of early replacement of functional equipment, equipment turnover and replacement rates are defined by the equipment's average effective useful life. In a study spanning 10 years, long-lived equipment may not completely turnover during the planning horizon, and additional opportunities may exist beyond the study's close.
- ***Retrofit measures*** save energy by reducing end-use consumption without replacing end-use equipment. Such measures include: insulation, faucet aerators, and lighting controls. This study assumes these measures, in existing construction, have been installed in equal amounts during each of the 10 years. Retrofit measure installation rates in new construction are defined by the utilities' new construction forecasts.

Estimating Technical Potential

Technical potential represents total energy saved from all measures, only adjusting for physical constraints. For example, high levels of wall insulation can be placed in a certain percentage of homes, and, of those, a certain share may already have this insulation in place. Consequently, technical potential would only include technically feasible homes without measures in place.

Another important technical potential aspect assumes installation of the highest-efficiency equipment wherever possible. For example, this study examined SEER 14.5, 15, 16, and 18 central air conditioners in residential applications, with technical potential assuming that, as equipment fails or new homes are built, customers will install SEER 18 units, regardless of costs. Competing retrofit measures have been treated the same way, assuming installation of the highest-saving measures where technically feasible.

In estimating technical potential, one cannot merely sum up savings from individual measure installations, as significant interactive effects can result from installation of complementary measures. For example, upgrading a furnace in a home where insulation measures have already been installed can be expected to produce less saving than in an un-insulated home. The analysis of technical potential accounts for two types of interaction:

- **Interactions between equipment and non-equipment measures:** As equipment burns out, technical potential assumes it will be replaced with higher-efficiency equipment, which reduces average consumption across all customers. Reduced consumption causes non-equipment measures to save less than they would have, had the equipment remained at a constant average efficiency. Similarly, as non-equipment measures are installed, savings realized by replacing equipment decrease.
- **Interactions between non-equipment measures:** Two retrofit measures applying to the same end use may not affect each other's savings. For example, installing a low-flow showerhead does not affect savings realized from installing a faucet aerator. Insulating hot water pipes, however, would cause the water heater to operate more efficiently, thus reducing savings from either measure. The method in this assessment accounted for this interaction by "stacking" interactive measures—iteratively reducing baseline

consumption as measures are installed, thus lowering the savings from subsequent measures.

While theoretically, all retrofit opportunities in existing construction (often called "discretionary" or "instantaneous" resources) could be acquired in the study's first year, this would skew the potential for equipment measures, and provides an inaccurate picture of measure-level potential. Therefore, the study assumes realization of these opportunities in equal annual amounts over the 10-year planning horizon. Applying this assumption, natural equipment turnover rates, and other adjustments described above, annual incremental and cumulative potential is estimated by utility, fuel, sector, segment, construction vintage, end use, and measure.

Estimating Economic Potential

Economic potential represents the subset of technical potential that is deemed cost effective. Consistent with Chapter 35's definition of the Societal Cost Test,[7] a measure can be deemed cost-effective if its present-value benefits meet or exceed its present-value costs. The measure's cost results simply from the difference in upfront costs between the measure and the baseline technology. In some cases (such as retrofits), the cost used equals the measure's full cost.

Calculating a measure's societal benefits proves far more complex, relying on significant economic and load data such as:

- **End-use load shapes.** End-use consumption patterns by costing period are applied to electric and natural gas measures, capturing the time-differentiated value of energy savings and determining the amount of savings during peak periods.
- **Externality factors.** As specified in the Rules, an externality factor is applied to avoided energy and capacity costs, accounting for societal costs of supplying energy. This factor adds an additional 10% to electric avoided energy and capacity benefits, and an additional 7.5% to natural gas energy and capacity benefits.
- **Line losses.** Line losses represent energy lost between the generator and the customer meter. Thus, energy and capacity savings at the customer meter are grossed up, capturing the true value of savings. Such values vary by utility, fuel, and sector, and may differ for energy and demand.
- **Societal discount rate.** As specified in the Rules, the societal discount rate equals the 12-month average of the 10-year and 30-year Treasury Bonds rates at the time of this study, which uses a nominal discount rate of 5.63% for all utilities.
- **Utility avoided energy costs** are utility-specific projections of energy generating or purchasing costs. Electric costs are analyzed by season, weekday/weekend, and on- and off-peak periods, whereas natural gas costs are assessed monthly.

[7] This study did not assess other standard cost-effectiveness tests. The Utilities will consider these perspectives in developing the 2014–2018 Energy Efficiency Plans.

- **Utility avoided capacity costs** are utility-specific projections of the cost of supplying energy during peak periods, which is assumed to be the system peak hour for an electric utility, and the system peak day for a natural gas utility.
- **Values of other resources.** Some measures save non-energy resources, such as water or detergent. Value for these resources have been determined and applied consistently across utilities.

These data have been combined with measure-level data to calculate a variety of benefits for each measure. The benefits, described as follows, have been added and compared to the measure's costs to determine whether the measure proved cost-effective from the societal perspective:

- **Energy benefits:** The present value of conserved energy over a measure's life, calculated by applying the appropriate line loss and externality factor to avoided energy forecasts, spreading over the measure's load shape, and discounting back to present terms using the societal discount rate. For measures saving electricity and natural gas (e.g., insulation in homes with a gas furnace and central air conditioner), benefits from both fuels have been considered.
- **Capacity benefits:** The present value of conserved capacity over a measure's life, calculated by applying the appropriate line loss and externality factor to avoided capacity forecasts, and multiplying by the measure's savings in the peak period, and discounting back to present terms using the societal discount rate. As with energy benefits, for measures saving electricity and natural gas (e.g., insulation in homes with a gas furnace and central air conditioner), benefits from both fuels have been considered.
- **Non-energy benefits:** The value of applicable non-energy benefits, such as water or detergent, considered over the measure's life, and discounted back to present terms using the societal discount rate.

As evident from the information sources and methods used to quantify societal benefits, the measures' cost-effectiveness varies between utilities, based on projections of energy and capacity costs and line loss values. As such, this study calculated cost-effectiveness separately for each utility, leading to differences in economic potential, presented later in this report.[8]

Based on the results of the cost-effectiveness analysis, and using the same method described in the technical potential section, above, an alternate sales forecast the annual incremental and cumulative potential for each cost-effective measure has been calculated.

[8] Differences in economic potential across utilities are a function of customer characteristics and current saturations of end uses and efficiency measures.

Assessing Market Potential

Market—or achievable—potential generally is defined as the portion of economic potential expected to be reasonably achievable over the course of the planning horizon, given certain assumptions regarding market barriers and behavioral factors that may inhibit consumers' participation in utility-sponsored energy-efficiency programs. In this assessment, market potential is defined more narrowly, as the amount of savings that might be achieved, assuming: incentive payments up to 100% of incremental measure cost; financing availability; exemplary program design and implementation practices; and emergence of new technologies, currently not widely available in the marketplace.

Methods for estimating achievable potential vary across potential assessment studies. These methods fall into three general categories.

1. The first group of methods (such as those used in assessments of energy-efficiency potential in California) is based on a conventional market diffusion model, and assumes first-cost as the primary participation barrier. In this approach, market potential is hypothesized to depend on the return from energy-efficiency investments, and the effects of incentives on enhancing that return. Due to limited data available to establish the empirical relationship between consumers' expectations about returns on investments, this relationship often must be hypothesized.
2. The second group of methods typically rely on self-reports to determine consumers' willingness to participate in energy-efficiency programs. The approach involves asking a representative sample of potential participants about their willingness to adopt a measure or participate in a program, under given incentive amounts—generally expressed as a fraction of the incremental measure cost. These studies result in a demand curve for conservation measures, which relates willingness to participate as a function of respondents' shares of incremental measure costs.
3. Benchmarking, used in this assessment, provides the third method for determining market potential. This method incorporates certain elements from the first two method groups, but primarily relies on historical market penetration achieved by a representative sample of relevant programs to determine what might be achievable over a longer term.

In this assessment, Cadmus relied on the empirical statistical relationship between program expenditures (both incentive and non-incentive) and energy savings, based on historical performance data for a representative sample of utility-sponsored electric and natural gas programs in various jurisdictions. Cadmus used analysis results to estimate the likely maximum market potential for utility-sponsored electric and natural gas programs in Iowa under the study's specific assumptions. Data sources and analytic methods follow below, with results presented in Section 3.

The Effects of Increased Incentives

Form 861 of the Energy Information Administration (EIA) served as the primary data source for assessing electric market potential, providing energy savings, program expenditures, revenues, and retail sales reported by approximately 75 investor-owned utilities from 2004 through 2010.[9]

As natural gas utilities do not report energy-efficiency program results in universal datasets similar to EIA Form 861, Cadmus compiled publicly available documents from utilities and other program administrators reporting annual energy-efficiency results to create a comparable dataset. Performance data for 2010 programs for 14 portfolios were included in the analysis. The 14 selected portfolios represented those most relevant for informing market potential for Iowa utilities, using the following criteria:

- Portfolios operating for at least three years.
- Serving territories with at least 10 quadrillion Btu of annual sales.
- Portfolios in "Northern Tier" states, with climates most similar to Iowa. (As a practical matter, this criterion eliminated only two southern California utilities and one New Mexico utility from the data set.)
- Portfolios providing publicly available data, which, at a minimum, included the following information:
    - Natural gas spending separated from electric spending;
    - Spending differentiated between incentives and other costs; and
    - Annual energy savings.

Given these criteria, Cadmus developed a list of 14 portfolios spanning nine states, as shown in Table 9, below.

For each utility and program administrator listed in Table 9, data on natural gas sales, revenue, and average rates were collected from EIA Form 176, normalizing savings and spending across service areas of different sizes.

Using these data, Cadmus developed regression equations to estimate effects increased incentives would have on portfolio-level electric and natural gas savings for Iowa utilities. Data on current program activity and incentive spending were derived from the utilities' 2010 Annual Reports.

[9] Although Form 861 contains data for a larger number of utilities and a longer time series, back to 1999, the information tends to be incomplete and lack some variables of interest for this study.

Table 9. Natural Gas Utility Portfolios Included in the Benchmarking Analysis

Utility/Program Administrator	State
Pacific Gas & Electric	California
Public Service Co. of Colorado	Colorado
Yankee Gas Services	Connecticut
Connecticut Natural Gas	Connecticut
Southern Connecticut Gas	Connecticut
Avista Corp	Idaho
National Grid	Massachusetts
NStar	Massachusetts
Northern States Power	Massachusetts
Questar	Utah
Puget Sound Energy	Washington
Avista Corp	Washington
Cascade Natural Gas	Washington
Wisconsin Focus on Energy	Wisconsin

Effects of Financing Availability

Offering incentives covering full incremental costs may not be sufficient to offset first-cost barriers for all measures. For example, if a customer with low insulation levels chooses to upgrade to insulation exceeding minimum building code, a utility incentive may only cover costs above and beyond code-required levels. In this case, remaining cost could be substantial. Cadmus reviewed secondary literature on the success of financing programs to quantify the effect this option could have on market potential.

It should be noted that, in many cases, measures have the same full and incremental costs. Moreover, for equipment replacement, the study assumes equipment would be upgraded per its natural replacement cycles, and baseline costs would be incurred, regardless of whether an efficient unit would be installed.

Effects of Emerging Technologies

As specified in the Chapter 35 Rules, only measures commercially available were included in the technical and economic potential. However, the market potential is designed to include measures expected to become commercially available and cost-effective within the next five to 10 years, as these measures could provide savings over the course of the next round of EEPs. While these measures will increase available potential, their effects cannot merely be added to the identified economic potential for two reasons:

- First, many of these measures will supplant existing technologies; so only the incremental increase in efficiency creates new potential.
- Second, due to interactive effects, these measures will reduce potential from other measures included in the technical and economic potential. That is, emergence of a more efficient heat pump not only supplants the potential attributed to currently available technologies, but will reduce the potential attributable to shell measures.

To determine impacts on market potential, Cadmus developed a list of emerging measures drawn from secondary sources, such as DOE and ACEEE, providing estimates of efficiency levels and savings. Cadmus then determined how these measures overlapped with measures already considered in the study, and estimated incremental savings and potential from the emerging technologies. For measures without a complementary choice within the measure list, Cadmus apportioned estimates of national long-term potential to the Utilities' territory.

Demand Response

The 2008 Assessment estimated demand savings potential for a variety of demand-response program options, including firm (e.g., residential direct load control [DLC]) and non-firm (e.g., critical peak pricing) strategies. In addition to actual potential estimates, the study resulted in two key findings:

1. Large overlap occurs between eligible populations for similar programs, and implementing new programs may affect participation in demand-response programs currently offered by the two electric utilities.
2. Billing systems in place during the 2008 study did not allow implementation of price-based options, such as real-time or critical peak pricing. However, these strategies could become feasible if and when the utilities move to an Advanced Metering Infrastructure (AMI).

Based on these findings, the utilities continued to offer their long-running, successful Residential DLC and Nonresidential Interruptible programs in their 2009–2013 Energy Efficiency Plans (EEPs). Building on the conclusions drawn from the 2008 Assessment, this study focused on two questions:

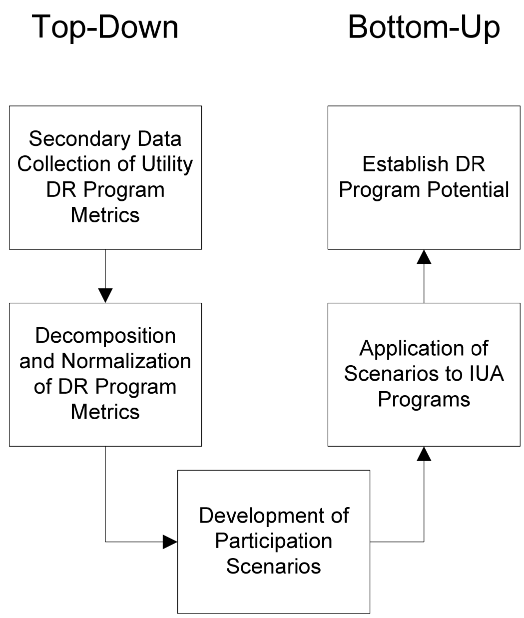
- What potential exists for expansion of utilities' current demand response programs?
- What opportunities would be available if and when utilities implement an AMI?

The methodology for assessing these questions follows this section.

Expansion of Legacy Programs

As both electric utilities have operated successful demand response programs for many years, the assessment of demand response potential primarily focused on establishing the upper bounds of customer participation, based on the experience of utilities offering similar programs. After developing a database of participation data from other, comparable utilities, a bottom-up methodology established the estimated market potential. Figure 1 illustrates the general process.

Figure 1. General Demand Response Potential Assessment Methodology



Secondary Data Collection and Analysis

The key metrics used to compare utility programs (and, subsequently, to estimate remaining potential) were current participation levels. As customer counts, peak loads, and program impacts can vary greatly across utilities, identified metrics sought to normalize for these effects. For residential DLC programs, "participation" was defined as the percentage of eligible customers (for example, residential customers with central air conditioners) currently enrolled in the program. Nonresidential interruptible programs used a metric of the percentage of nonresidential demand during the system peak under contract.

While calculating these participation rates for Iowa utilities proved relatively straightforward, greater difficulty resulted in collecting data on other utilities' program achievements due to reporting differences. Data on utility program achievements, customer counts, and peak demand derived from an array of sources, including:

- Federal Energy Regulatory Commission (FERC) 2010 Assessment of Demand Response and Advanced Metering Demand Response Survey Data;
- United States Energy Information Administration (EIA) Database;

- Utility integrated resource plans (IRP);
- Utility annual reports; and
- Utility demand response program evaluation reports.

Based on data collected from these sources, participation rates, defined above, were calculated for each utility program, based on 2010 data (with the most recent data available, in most cases).

Participation Scenario Development

Data collected indicated wide ranges of participation rates across utilities. The programs at the extremes (extremely high or low participation) were reviewed in additional depth, and some were removed as outliers, based on unique program differences or unreliable data.

Calculated participation rates allowed establishment of two potential expansion scenarios:

1. **Moderate expansion:** The amount of potential available if Iowa utilities' participation rates increased to the upper quartile of the reviewed utilities.
2. **Aggressive expansion:** The amount of potential available if Iowa utilities' participation rates increased to industry-leading participation rates.

These scenarios were compared to a "baseline" scenario, where Iowa utilities continued at current participation levels.

Under each expansion scenario, assumed participation rates were applied to Iowa utility customers, loads, and per-participant impacts to identify demand savings to be realized.

Though demand response strategies primarily focus on reducing demand during peak periods, reduced demand can also translate into energy savings. However, such energy savings cannot be calculated by merely multiplying demand impacts by an event's duration, as this neglects some or all demand may have shifted to off-peak periods, rather than be avoided entirely.

For example, in a central air conditioning DLC program, energy savings occur during the curtailment event, but temperatures in homes rise, and units must work harder after the event to achieve the desired temperatures. Similarly, if a commercial customer sheds load by temporarily adjusting processes (such as slowing production or shutting down some portion of a facility), it may have to increase production or use more of its facilities following an event. This phenomenon, commonly called "snapback," must be captured to reliably quantify energy savings attributable to these programs.

Quantifying snapback for a given demand response program proves quite difficult, as variations between demand response strategies and differences in participating customers can greatly impact snapback effects. For example, a region's temperature fluctuation greatly affects snapback. In climates where temperatures remain relatively high after the end of an event, a demand response program generally experiences a higher snapback amounts. If an event ends at a time of day when temperatures begin to decline, the snapback would be lower. Similarly, customers enrolled in nonresidential interruptible programs may retain on-site generation capabilities, and experience no snapback effects.

Consequently, Cadmus reviewed secondary data on observed and assumed snapback effects for utilities across the nation, providing estimates of the likely energy-savings range that could be realized from these demand response strategies.

AMI Enabled Demand Response

While the prevalence of AMIs has increased significantly since 2008's Assessment, few utilities have established AMI-specific demand response programs. Existing offerings primarily remain in pilot forms, and do not offer data that could be reliably extrapolated to quantify available potential for large-scale programs. Thus, this study presents a qualitative assessment of how utilities currently use AMI to reduce system peaks, and anticipates opportunities that may emerge in the next several years, if Iowa utilities implement AMI.

Freeridership and Spillover

This task largely updated the 2008 Assessment, reviewing current practices for assessing freeridership and spillover, and determining how jurisdictions across the country accounted for these effects. To provide a robust and complete assessment for use in future decisions regarding treatment of NTG in Iowa, and to provide the Utilities with recommendations for methods regarding mitigation of freerider effects, Cadmus conducted a thorough review of commission orders, legislative mandates, energy-efficiency program evaluations, and assumed values from jurisdictions across the nation, as described in Section 5.

2. ENERGY EFFICIENCY: TECHNICAL AND ECONOMIC POTENTIAL

Scope of Analysis

The assessment of energy-efficiency resources primarily sought to produce reasonable estimates of savings available in each utility's service territory over a 10-year planning horizon (2014-2023), thus informing creation of the 2014–2018 EEPs. Technical and economic potential for residential, commercial, and industrial[10] sectors were assessed separately for each utility, divided by fuel type. Within each utility's sector-level assessment, the study further distinguished among market segments or industry types, and their respective applicable end uses. Analysis included: 10 residential segments (existing and new construction for single-family, multifamily, manufactured, low-income single-family, and low-income multifamily); 24 commercial segments (12 building types within existing and new construction); and 18 industrial segments.

Analysis began by assessing the technical potential for 359 unique electric and 155 unique gas energy-efficiency measures passing the qualitative screening process, as described in Section 1 (and shown in Table 10), representing a comprehensive set of electric and natural gas energy-efficiency measures applicable to Iowa's climate and customer characteristics.

Table 10. Energy-Efficiency Measure Counts

Sector	Electric Measure Counts	Natural Gas Measure Counts
Residential	132 unique, 632 permutations	61 unique, 281 permutations
Commercial	164 unique, 1,580 permutations	71 unique, 657 permutations
Industrial	63 unique, 255 permutations	23 unique, 92 permutations

This list included measures analyzed in the 2008 Assessment (which may be active in current utility programs), and new measures that have become commercially available over the past five years. Considering all permutations of these measures across applicable customer sectors, market segments, fuels, and end uses, resulted in customized data, compiled and analyzed for over 4,000 measures. Appendix A.2 describes all measures analyzed, and Appendix A.3 presents technical details and economic potential for all permutations.[11]

The remainder of this section is organized into two parts:

- A summary of resource potentials by fuel; and
- Detailed sector-level results.

[10] The industrial sector includes sales and potential for agriculture and street lighting.
[11] Economic potential in Appendix A.3 has been aggregated to the state level.

Summary of Results: Electricity

Table 11 and Table 12 show forecasted[12] 2023 baseline electric sales and potential by utility and sector, respectively. Study results indicate 8,446 GWh of technically feasible electric energy-efficiency potential by 2023, the end of the 10-year planning horizon, with approximately 6,872 GWh of these resources cost-effective. Identified economic potential amounts to 19% of forecasted load in 2023.

Savings have been based on forecasts of future consumption, absent utility program activities. While consumption forecasts account for past savings each utility has acquired, estimated potential is inclusive of—not in addition to—current or forecasted program savings.

As shown in Table 11, though utility-specific technical and economic potential are a function of baseline sales, they are roughly comparable, when analyzed in percentage terms. Differences in technical potential as a percent of baseline sales are driven by differences in distributions of customers by segment, and other utility-specific customer characteristics. In addition to these differences, economic potential varies due to differences in utility avoided energy and capacity costs.

Table 11. Technical and Economic Electric Energy-Efficiency Potential (Cumulative in 2023) by Utility

Utility	Base Case Sales (MWh)	Technical Potential			Economic Potential		
		MWh	% of Base Sales	MW	MWh	% of Base Sales	MW
Alliant	15,465,326	3,839,043	25%	926	3,294,806	21%	803
MidAmerican	19,883,278	4,601,610	23%	1,110	3,569,842	18%	885
Total	**35,348,604**	**8,440,653**	**24%**	*	**6,864,648**	**19%**	*

* Due to differences in timing of utility system peaks, demand impacts could not be aggregated across utilities.

12 Forecasted sales have been based on baseline forecasts developed by Cadmus, as described in Section 1, and do not necessarily match official utility forecasts.

Table 12 provides each sector's technical and economic potentials. The residential sector represents the largest portion of technical and economic potential, at 42% and 40%, respectively. The commercial sector represents the second-largest contributor to technical and economic potential, at 32% of each, while industrial potential accounts for 26% and 28% of technical and economic potential, respectively.

Table 12. Technical and Economic Electric Energy-Efficiency Potential (Cumulative in 2023) by Sector

Sector	Base Case Sales (MWh)	Technical Potential		Economic Potential	
		MWh	% of Base Sales	MWh	% of Base Sales
Residential	9,197,928	3,548,837	39%	2,772,993	30%
Commercial	7,857,412	2,702,650	34%	2,181,608	28%
Industrial	18,293,266	2,189,166	12%	1,910,047	10%
Total	**35,348,606**	**8,440,653**	**24%**	**6,864,648**	**19%**

Table 13 shows the electric measures with the highest expected 10-year technical potential, and whether each is cost-effective in all, some, or no applications.

Table 13. Top Electric Technical Measures and Cost-Effectiveness Results[13]

Sector	Measure Name	Cost-Effective Applications
Residential	LED	All
Commercial	Fluorescent Reduced Wattage	Some
Industrial	Integrated Plant Energy Management	All
Residential	TV - ENERGY STAR	Some
Residential	ECM Motor - Air Conditioner/Electric/Gas Furnace	All
Industrial	High Bay Fluorescent High Output Packages	All
Commercial	Daylighting Controls	Some
Commercial	LED Lamp Package	All
Commercial	Induction Lighting Package	Some
Commercial	Retro-Commissioning	Some

Cost-effectiveness varies by utility due to differences in avoided costs, but can also differ by segment or construction vintage due to differences in savings and/or incremental costs. As shown, residential and commercial lighting measures represent six of the top 10 electric technical measures, with additional large savings opportunities for industrial plan energy management, ENERGY STAR televisions, efficient motors, and retro-commissioning. All of these measures were deemed cost-effective in at least some applications, with half economic in all instances.

13 Measure-by-measure economic potential is provided in Appendix A.3.

Table 14 compares identified 10-year technical and economic electric potentials to results from the 2008 Assessment.

Table 14. Comparison of 10-Year Electric Technical and Economic Potentials

Sector	Technical Potential (GWh)		Economic Potential (GWh)	
	2008 Assessment	2012 Assessment	2008 Assessment	2012 Assessment
Residential	4,937	3,549	3,215	2,775
Commercial	2,695	2,703	1,563	2,182
Industrial	2,136	2,195	1,999	1,916
Total	**9,767**	**8,446**	**6,777**	**6,872**

Residential potentials, both technical and economic, have declined, primarily driven by utility program activity as well as changes in minimum building codes and equipment standards. While the commercial sector has seen increased efficiency requirements, technical potentials have risen marginally compared to the 2008 Assessment due to availability of new advanced technologies, such as LED lighting. Economic potentials saw greater increases, driven by increased electric avoided costs and declining measure costs for certain measures. Industrial technical potential also increased in the 2012 assessment, while economic potential showed a marginal decrease.

Summary of Results: Natural Gas

Table 15 and Table 16 present 2023 forecasted baseline sales and potential by sector and utility, respectively.[14] As shown, study results indicate over 37 million therms of technically feasible natural gas energy-efficiency potential by 2023, the end of the 10-year planning horizon. The identified economic potential of 25.5 million therms amounts to 24% of forecasted load in 2023 and over 2 million peak day therms.

As with electric potential, technical and economic potential result as a function of baseline sales, and are roughly comparable across utilities when analyzed in percentage terms. Again, differences are driven by utility customer characteristics and avoided costs.

Table 15. Technical and Economic Gas Energy-Efficiency Potential (Cumulative in 2023) by Utility

Utility	Base Case Sales (Thousand therms)	Technical Potential			Economic Potential		
		Thousand Therms	% of Base Sales	Peak Day Thousand Therms	Thousand Therms	% of Base Sales	Peak Day Thousand Therms
Alliant	267,040	90,767	34%	732	61,574	23%	515
Black Hills	169,983	60,754	36%	486	42,507	25%	348
MidAmerican	632,769	220,371	35%	1,785	150,670	24%	1,262
Total	**1,069,791**	**371,892**	**35%**	**3,003**	**254,751**	**24%**	**2,125**

[14] As specified in the Chapter 35 rules, gas transport customers are excluded from the analysis.

Table 16 provides each sector's technical and economic potentials. As with electric potential, the residential sector represents the largest portion of technical and economic potential, at about 74% and 69%, respectively. Almost all remaining potential lies in the commercial sector, with a small portion (5.3 million therms) from industrial applications.

Table 16. Technical and Economic Natural Gas Energy-Efficiency Potential (Cumulative in 2023) by Sector

Sector	Base Case Sales (Thousand therms)	Technical Potential		Economic Potential	
		Thousand Therms	% of Base Sales	Thousand Therms	% of Base Sales
Residential	671,594	274,172	41%	175,823	26%
Commercial	335,581	92,129	27%	73,649	22%
Industrial	62,616	5,591	9%	5,280	8%
Total	**1,069,791**	**371,892**	**35%**	**254,752**	**24%**

Table 17 shows the natural gas measures with the highest estimated 10-year technical potential, and whether each is cost-effective in all, some, or no applications.

Table 17. Top Natural Gas Technical Measures and Cost-Effectiveness Results

Sector	Measure Name	Cost-Effective Applications
Residential	Duct Sealing	Some
Residential	Window Upgrades	None
Commercial	Retro-Commissioning	Some
Residential	Infiltration Reduction	All
Residential	Insulation - Basement Wall	All
Residential	Insulation - Attic/Ceiling	Some
Residential	Insulation – Floor	None
Residential	Home Energy Management System	Some
Residential	Water Heater - Tankless	None
Commercial	Green Roof	None

Cost-effectiveness varies by utility due to differences in avoided costs, but can also differ by segment or construction vintage due to differences in savings and/or incremental costs. As shown, most of the top measures are improvements to residential building shell, with commercial retro-commissioning also representing a large amount of technical potential. Only two of the top 10 measures are cost-effective in all applications, whereas four do not pass the economic screen in any instance.

Table 18 compares identified 10-year technical and economic natural gas potentials to results of the 2008 Assessment.

Table 18. Comparison of 10-Year Natural Gas Technical and Economic Potentials

Sector	Technical Potential (Thousand Therms)		Economic Potential (Thousands Therms)	
	2008 Assessment	2012 Assessment	2008 Assessment	2012 Assessment
Residential	265,320	274,172	186,540	175,823
Commercial	132,240	92,129	90,130	73,649
Industrial	8,970	5,591	8,970	5,280
Total	**406,530**	**371,892**	**285,640**	**254,752**

Economic potentials for all sectors have decreased in this assessment, largely due to significantly lower avoided energy costs.

Detailed Results

Residential Sector: Electricity

Residential customers in Iowa account for about one-quarter of forecasted electricity retail sales. The single-family, manufactured, multifamily, and low-income dwellings comprising this sector present a variety of potential savings sources, including: equipment efficiency upgrades (e.g., air conditioning, refrigerators); improvements to building shells (e.g., insulation, windows, air sealing); and increases in lighting efficiency (e.g., CFLs, LED interior lighting).

As shown in Table 19, based on resources included in this assessment, residential sector electric economic potential is estimated at 2,775 GWh over 10 years, corresponding to a 30% reduction (33% for Alliant and 28% for MidAmerican) in 2023 residential consumption,/

Table 19. Residential Sector Electric Energy-Efficiency Potential by Utility (Cumulative in 2023)

Utility	Base Case Sales (MWh)	Technical Potential			Economic Potential		
		MWh	% of Base Sales	MW	MWh	% of Base Sales	MW
Alliant	3,852,109	1,485,069	39%	443	1,275,181	33%	399
MidAmerican	5,345,819	2,063,768	39%	615	1,497,812	28%	497
Total	**9,197,928**	**3,548,837**	**39%**	*	**2,772,993**	**30%**	*

* Due to differences in timing of utility system peaks, demand impacts cannot be aggregated across utilities.

As shown in Figure 2, single-family homes represent 71% of total economic residential potential, followed by low-income, multifamily, and manufactured homes. Each home type's proportion of baseline sales serve as the primary drivers, but other factors, such as heating fuel sources, play important roles in determining potential. For example, manufactured homes typically have higher electric heating saturations than other home types, increasing their relative shares of the potential. Conversely, lower-use per customer for multifamily units decreases this potential, as some measures may not be cost-effective at lower consumption levels.

Figure 2. Residential Sector Electric Economic Potential by Segment (Cumulative in 2023)

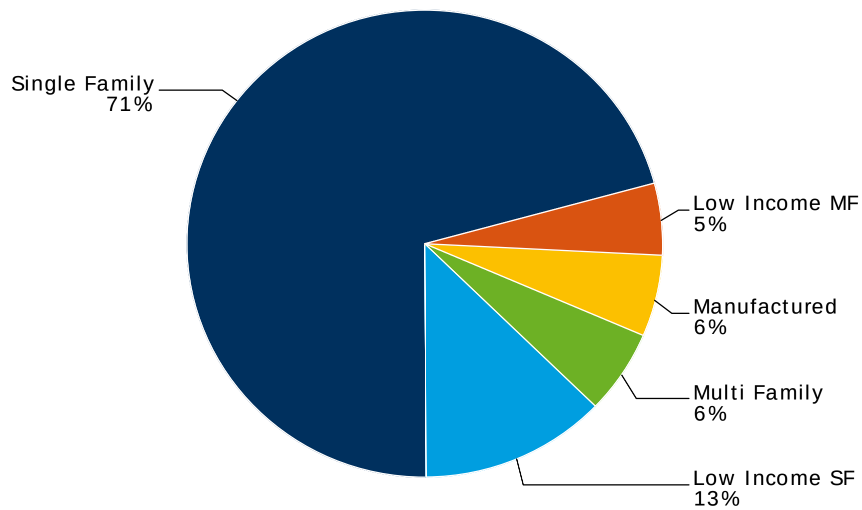
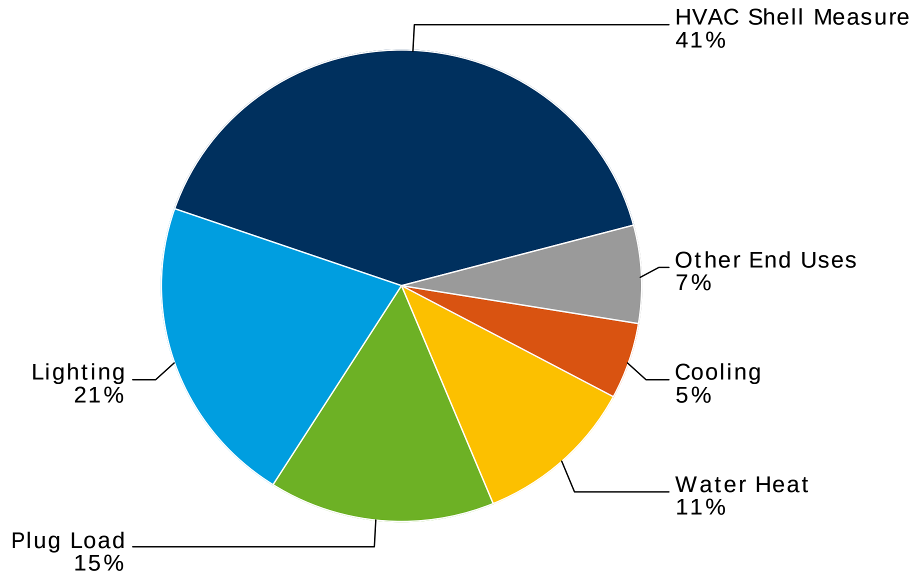


Figure 3 presents the distribution of electric economic potential by measure type.

Figure 3. Residential Sector Electric Economic Potential by Measure Type



Note: 'Other End Uses' includes:
Refrigerator: 3%, Freezer: 2%, Dryer: <1%, Pool Pump: <1%, Heat Pump: <1%

The largest portion of economic potential in the residential sector (41%) results from heating and cooling savings achieved through shell measures. Cooling measures account for nearly 50% of HVAC shell measure savings while ventilation and heating measures account for approximately 25% and 20%, respectively. A small amount of shell measure savings comes from homes with heat pumps. ECM motors, duct sealing, infiltration reduction, radiant barriers, and whole-house fans, account for over 60% of the identified shell measure savings. Lighting measures, primarily LED and CFL bulbs, account for the next largest slice (21%), followed by various plug load end uses and water heating. Table 20 provides technical and economic potentials by end-use category.

Table 20. Residential Sector Electric Energy-Efficiency Potential by End-Use Category (Cumulative in 2023)

End Use	Base Case Sales (GWh)	Technical Potential		Economic Potential	
		GWh	% of Base Sales	GWh	% of Base Sales
Computer	210	64	30%	64	30%
Cooking	296	33	11%	0	0%
Cooling	1,456	817	56%	699	48%
Dehumidifier	283	26	9%	26	9%
Dryer	596	59	10%	22	4%
Heat Pump	168	94	56%	85	50%
Heating	787	380	48%	221	28%
Lighting	817	588	72%	588	72%
Other Plug Load	1,164	191	16%	104	9%
Pool Pump	20	10	51%	10	51%
Refrigerators and Freezers	981	221	22%	148	15%
Set Top Box	206	113	55%	113	55%
Television	699	278	40%	116	17%
Ventilation and Circulation	682	273	40%	273	40%
Water Heat	834	403	48%	305	37%
Total	**9,199**	**3,550**	**39%**	**2,774**	**30%**

Residential Sector: Natural Gas

As shown in Table 21, based on resources included in this assessment, natural gas economic potential in the residential sector is estimated at about 176 million therms over the 10-year planning horizon, corresponding to a 26% reduction (27% for Alliant, 27% for Black Hills, and 26% for MidAmerican) in 2023 residential consumption.

Table 21. Residential Sector Natural Gas Energy-Efficiency Potential by Utility (Cumulative in 2023)

Utility	Base Case Sales (Thousands of therms)	Technical Potential			Economic Potential		
		Thousand Therms	% of Base Sales	Peak Day Thousand Therms	Thousand Therms	% of Base Sales	Peak Day Thousand Therms
Alliant	142,565	62,444	44%	531	37,922	27%	345
Black Hills	105,983	44,238	42%	376	28,891	27%	258
MidAmerican	423,046	167,490	40%	1,422	109,010	26%	974
Total	**671,594**	**274,172**	**41%**	**2,329**	**175,823**	**26%**	**1,578**

As shown in Figure 4, single-family homes represent 73% of total economic residential potential, followed by low-income, multifamily, and manufactured homes, with results extremely similar to electric potential, with manufactured homes representing a smaller percentage due to lower saturations of gas heating equipment.

Figure 4. Residential Sector Gas Economic Potential by Segment

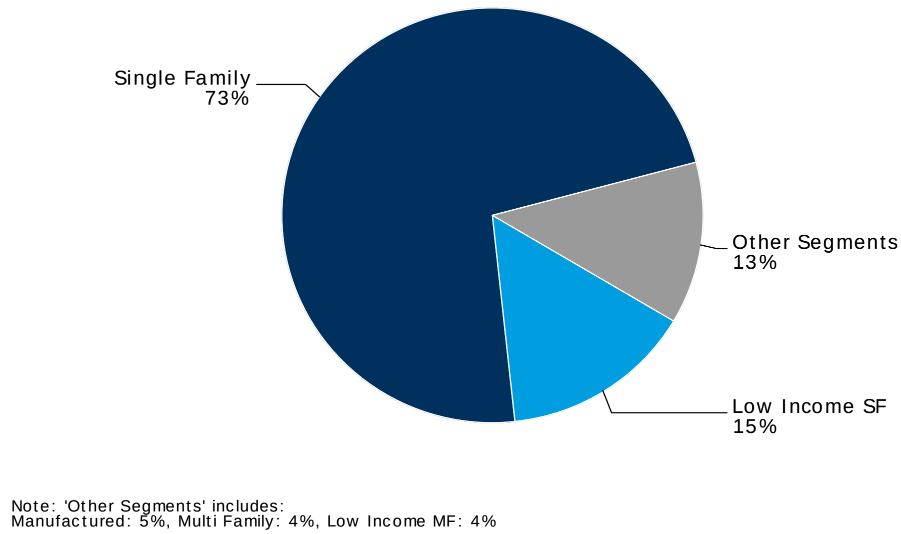


Figure 5 presents distributions of natural gas economic potential by measure type. The largest portion of economic potential in the residential sector (88%) comes from shell measures, followed by water heating (10%). Duct sealing, infiltration reduction, basement and attic insulation, and home energy management systems account for nearly 75% of shell measure savings.

Figure 5. Residential Sector Natural Gas Economic Potential by Measure Type (Cumulative in 2023)

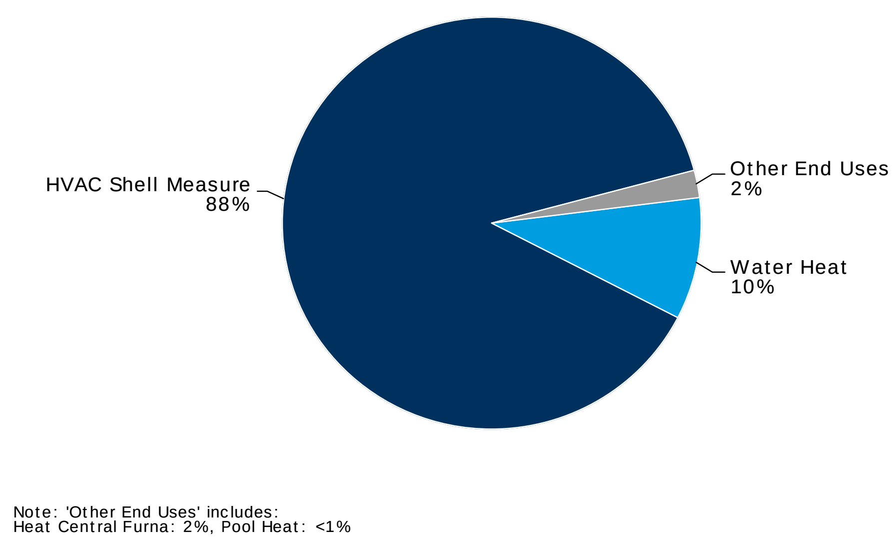


Table 22 provides technical and economic potential by end-use category.

Table 22. Residential Sector Natural Gas Energy-Efficiency Potential by End-Use Category (Cumulative in 2023)

End Use	Base Case Sales (Thousand Therms)	Technical Potential		Economic Potential	
		Thousand Therms	% of Base Sales	Thousand Therms	% of Base Sales
Cooking	15,526	1,579	10%	0	0%
Dryer	6,591	654	10%	0	0%
Heat Central—Boiler	24,758	9,889	40%	6,028	24%
Heat Central—Furnace	452,542	218,107	48%	152,577	34%
Other	64,002	0	0%	0	0%
Pool Heat	1,513	377	25%	340	23%
Water Heat	106,662	43,565	41%	16,877	16%
Total	**671,594**	**274,171**	**41%**	**175,822**	**26%**

Commercial Sector: Electricity

As shown in Table 23, based on resources included in this assessment, electric economic potential in the commercial sector is estimated at just over 2,180 GWh over the 10-year planning horizon, corresponding to a 28% reduction (29% for Alliant and 27% for MidAmerican) of forecasted 2023 commercial consumption.

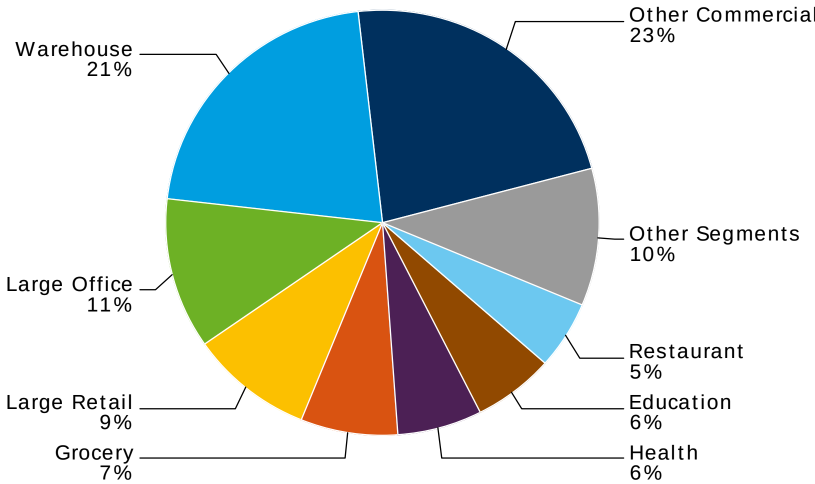
Table 23. Commercial Sector Electric Energy-Efficiency Potential by Utility (Cumulative in 2023)

Utility	Base Case Sales (MWh)	Technical Potential			Economic Potential		
		MWh	% of Base Sales	MW	MWh	% of Base Sales	MW
Alliant	3,969,210	1,377,058	35%	358	1,148,549	29%	292
MidAmerican	3,888,201	1,325,592	34%	343	1,033,059	27%	257
Total	**7,857,411**	**2,702,650**	**34%**	*	**2,181,608**	**28%**	*

* Due to differences in timing of utility system peaks, demand impacts cannot be aggregated across utilities.

As shown in Figure 6, miscellaneous buildings and warehouses represent the largest shares (23% and 21%, respectively) of economic potential in the commercial sector. The miscellaneous segment combines customers not fitting into one of the other categories and those that would, but do not having sufficient information to be classified. The commercial sector also provides considerable savings opportunities in offices (14%), retail (11%), and grocery (7%) segments. Moderate savings amounts are expected to be available in education, health, restaurants, and lodging facilities.

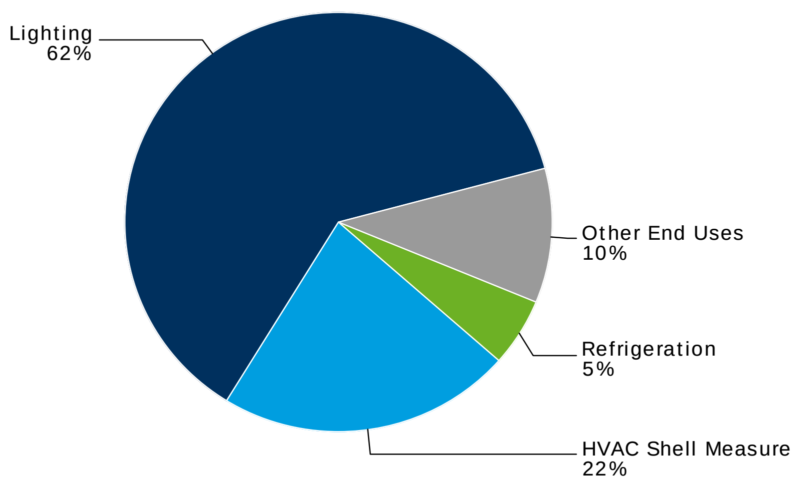
Figure 6. Commercial Sector Electric Economic Potential by Segment (Cumulative in 2023)



Note: 'Other Segments' includes:
Small Office: 3%, Convenience: 3%, Lodging: 3%, Small Retail: 2%

Figure 7 presents distributions of electric economic potential by measure types. The largest portion of economic potential in the commercial sector (62%) comes from lighting, followed by HVAC shell measures (22%). Cooling and ventilation each account for about one-third of shell measure savings, with heat pumps and electric heating accounting for 24% and 6%, respectively. Retro-commissioning, variable frequency drives, ECM motors, variable refrigerant flow systems for heat pumps, and programmable thermostats account for nearly 73% of the shell measure savings.

Figure 7. Commercial Sector Electric Economic Potential by Measure Type (Cumulative in 2023)



Note: 'Other End Uses' includes:
Plug Load: 5%, Water Heat: 4%, Cooling: 1%, Heat Pump: <1%, Other: <1%, Cooking: <1%, Dryer: <1%

Table 24 provides technical and economic potential by end-use category.

Table 24. Commercial Sector Electric Energy-Efficiency Potential by End-Use Category (Cumulative in 2023)

End Use	Base Case Sales (GWh)	Technical Potential		Economic Potential	
		GWh	% of Base Sales	GWh	% of Base Sales
Cooking	73	4	5%	1	2%
Cooling	844	304	36%	205	24%
Dryer	226	0	0%	0	0%
Heat Pump	366	153	42%	124	34%
Heating	352	82	23%	30	9%
Lighting	3,540	1,605	45%	1,353	38%
Other	25	2	8%	1	5%
Plug Load	974	121	12%	104	11%
Refrigeration	584	150	26%	115	20%
Ventilation and Circulation	680	191	28%	162	24%
Water Heat	192	90	47%	87	45%
Total	**7,856**	**2,702**	**34%**	**2,182**	**28%**

Commercial Sector: Natural Gas

The commercial sector represents about one-third of both technical and economic gas energy-efficiency potential. The 73.6 million therms of economic potential over 10 years, corresponds to a 22% reduction (23% for Alliant and Black Hills and 21% for MidAmerican) of forecasted 2023 commercial consumption, as shown in Table 25.

Table 25. Commercial Sector Natural Gas Energy-Efficiency Potential by Utility (Cumulative in 2023)

Utility	Base Case Sales (Thousand Therms)	Technical Potential			Economic Potential		
		Thousand Therms	% of Base Sales	Peak Day Thousand Therms	Thousand Therms	% of Base Sales	Peak Day Thousand Therms
Alliant	90,558	25,191	28%	193	20,683	23%	162
Black Hills	57,302	15,941	28%	109	13,076	23%	89
MidAmerican	187,721	50,997	27%	358	39,890	21%	283
Total	**335,581**	**92,129**	**27%**	**660**	**73,649**	**22%**	**534**

As shown in Figure 8, miscellaneous buildings and education facilities represent the largest shares of economic potential in the commercial sector (24% and 19%, respectively). As with the commercial electric sector, the miscellaneous segment is composed of a combination of customers not fitting into one of the other categories and those that would fit, but have insufficient enough information to be classified. Considerable savings opportunities are expected in the commercial sector's retail (15%), office (15%), and warehouse (12%) segments. Moderate savings amounts can be expected in health, restaurants, and lodging, and grocery facilities.

Figure 8. Commercial Sector Natural Gas Economic Potential by Segment

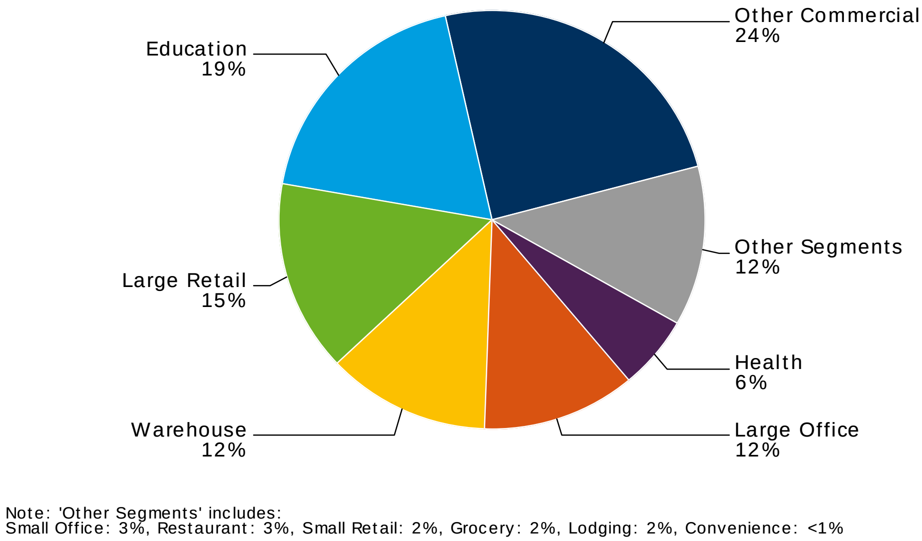


Figure 9 presents distributions of natural gas economic potential by measure type. The largest portion of economic potential in the commercial sector (64%) comes from HVAC shell measures, followed by water heating (26%). More than 63% of the shell measure savings comes from furnace applications, with the remainder attributable to boiler measures. Retro-commissioning, demand controlled ventilation systems, variable air-volume systems, boiler reset controls, and infiltration control account for nearly 95% of shell measure savings.

Figure 9. Commercial Sector Natural Gas Economic Potential by Measure Type (Cumulative in 2023)

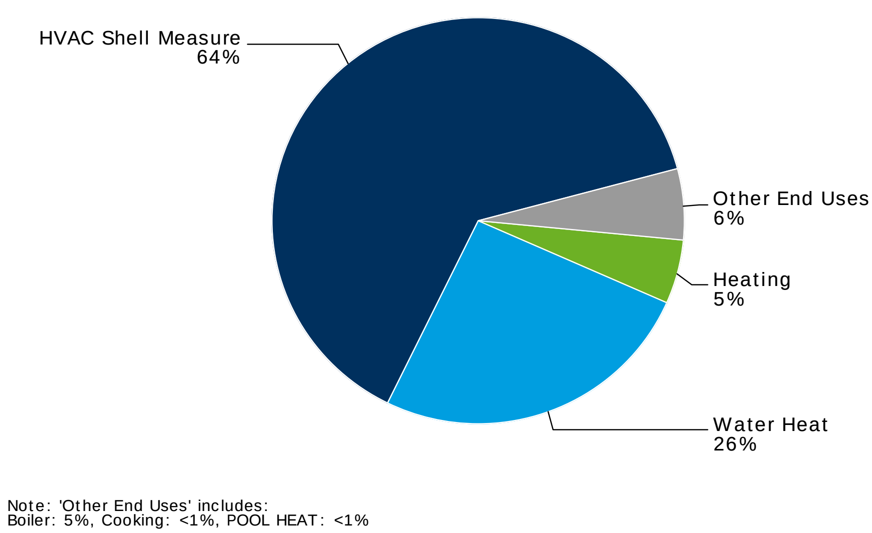


Table 26 provides technical and economic potential by end-use category.

Table 26. Commercial Sector Gas Energy-Efficiency Potential by End Use Category (Cumulative in 2023)

End Use	Baseline Sales (Thousand Therms)	Technical Potential		Economic Potential	
		Thousand Therms	% of Base Sales	Thousand Therms	% of Base Sales
Boiler	71,649	23,222	32%	20,644	29%
Cooking	14,149	556	4%	556	4%
Dryer	948	0	0%	0	0%
Heating	179,088	47,624	27%	33,527	19%
Pool Heat	240	34	14%	34	14%
Water Heat	69,507	20,692	30%	18,888	27%
Total	**335,581**	**92,128**	**27%**	**73,649**	**22%**

Industrial Sector: Electricity

Technical and economic energy-efficiency potentials were estimated for major end uses within 18 major industries, including agriculture and street lighting.[15] Across all industries, economic potential totals approximately 1,916 GWh over 10 years, corresponding to a 10% reduction (11% for Alliant and 10% for MidAmerican) of forecasted 2023 industrial consumption, as shown in Table 27.

Table 27. Industrial Sector Electric Energy-Efficiency Potential by Utility (Cumulative in 2023)

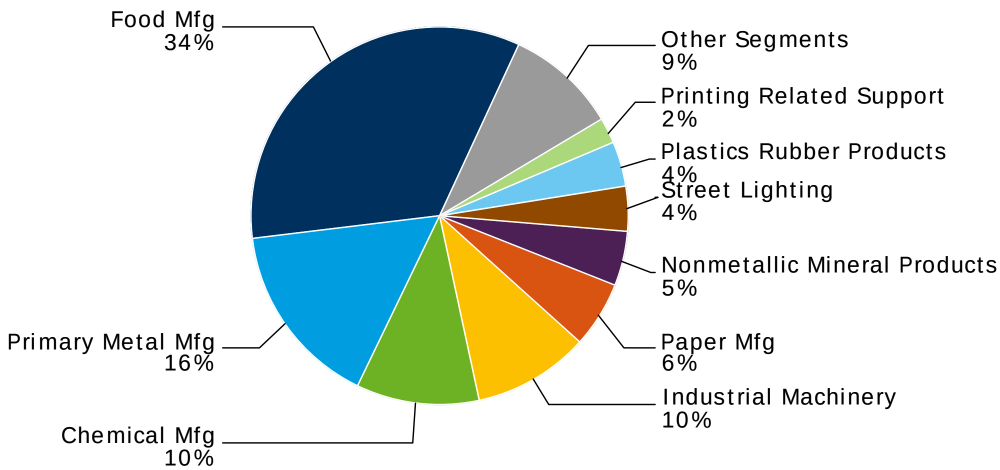
Utility	Base Case Sales (MWh)	Technical Potential			Economic Potential		
		MWh	% of Base Sales	MW	MWh	% of Base Sales	MW
Alliant	7,644,007	976,916	13%	125	871,076	11%	112
MidAmerican	10,649,258	1,212,250	11%	152	1,038,971	10%	131
Total	**18,293,265**	**2,189,166**	**12%**	*	**1,910,047**	**10%**	*

* Due to differences in timing of utility system peaks, demand impacts cannot be aggregated across utilities.

As shown in Figure 10, food processing and primary metal manufacturing facilities represent approximately one-half of the economic potential in the industrial sector (34% and 16%, respectively). Considerable savings opportunities are also expected in the industrial sector's chemical manufacturing segment (10%).

15 Industries analyzed varied by utility, based on customer and sales distributions

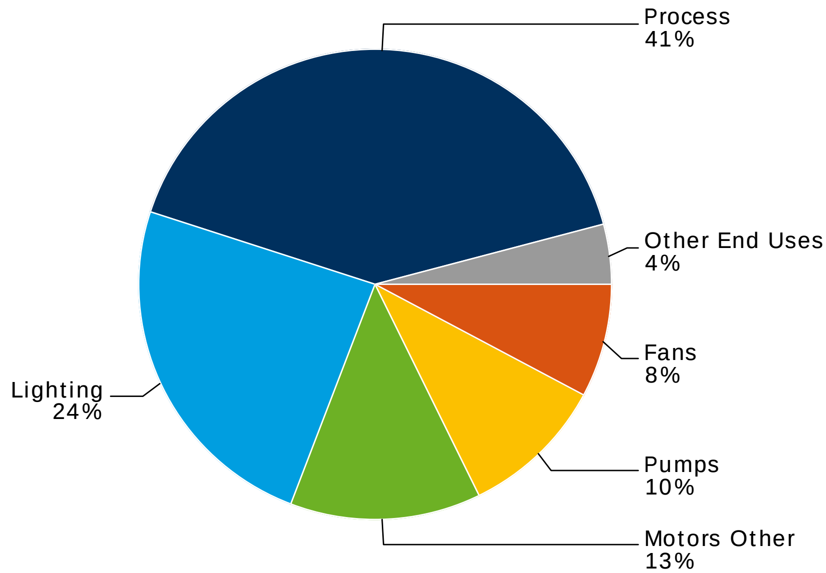
Figure 10. Industrial Sector Electric Economic Potential by Segment (Cumulative in 2023)



Note: 'Other Segments' includes:
Transportation Equipment Mfg: 2%, Fabricated Metal Products: 1%, Instruments: 1%, Wood Product Mfg: 1%
Miscellaneous Mfg: 1%, Electrical Equipment Mfg: <1%, Agriculture: <1%, Mining: <1%
Furniture Mfg: <1%

The majority of electric economic potential in the industrial sector (41%) can be attributed to gains in process efficiency (such as heating, cooling, and compressed air), followed by lighting improvements (24%) and motor system improvements (mainly fans and pumps). As shown in Table 28 and Figure 11, a small amount of additional potential exists for other facility improvements.

Figure 11. Industrial Sector Electric Economic Potential by Measure Type



Note: 'Other End Uses' includes:
HVAC: 4%, Other: <1%

Table 28. Industrial Sector Electric Energy-Efficiency Potential by End-Use Category (Cumulative in 2023)

End Use	Baseline Sales (GWh)	Technical Potential (GWh	Technical Potential % of Base Sales	Economic Potential GWh	Economic Potential % of Base Sales
Fans	1,056	162	15%	148	14%
HVAC	1,655	170	10%	77	5%
Indirect Boiler	219	0	0%	0	0%
Lighting	1,379	577	42%	463	34%
Motors Other	3,485	288	8%	251	7%
Other	585	2	0%	2	0%
Process—Air Compressor	1,099	248	23%	248	23%
Process—Electro Chemical	1,860	0	0%	0	0%
Process—Heat	2,676	70	3%	68	3%
Process—Other	234	3	1%	3	1%
Process—Refrigeration and Cooling	2,426	463	19%	461	19%
Pumps	1,622	206	13%	190	12%
Total	**18,296**	**2,189**	**12%**	**1,911**	**10%**

Industrial Sector: Natural Gas

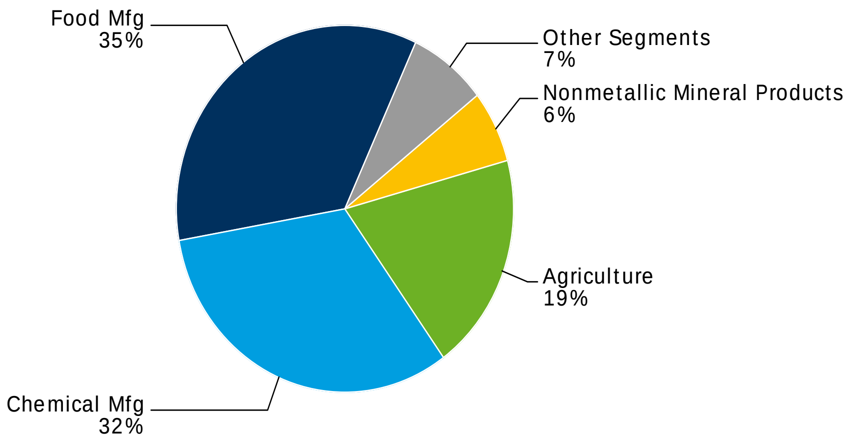
Most industrial processes and end uses rely on electricity; therefore, the industrial sector represents an extremely small portion of natural gas baseline sales and potential. As shown in Table 29, across all industries, economic potential totals approximately 5.3 million therms over 10 years, corresponding to an 8% reduction (9% for Alliant, 8% for Aquila, and 8% for MidAmerican) in forecasted 2023 industrial consumption.

Table 29. Industrial Sector Natural Gas Energy-Efficiency Potential by Utility (Cumulative in 2023)

Utility	Base Case Sales (Thousand Therms)	Technical Potential Thousand Therms	Technical Potential % of Base Sales	Technical Potential Peak Day Thousand Therms	Economic Potential Thousand Therms	Economic Potential % of Base Sales	Economic Potential Peak Day Thousand Therms
Alliant	33,917	3,132	9%	8	2,969	9%	8
Black Hills	6,697	575	9%	1	540	8%	1
MidAmerican	22,002	1,884	9%	5	1,770	8%	5
Total	**62,616**	**5,591**	**9%**	**14**	**5,279**	**8%**	**14**

Due to the composition of industries using natural gas in Iowa, over 67% of the economic potential lies in the food processing (35%) and chemical manufacturing (32%) segments. As shown in Figure 12, substantial savings opportunities also exist in agriculture (19%) and nonmetallic mineral products (6%).

Figure 12. Industrial Sector Gas Economic Potential by Segment



Note: 'Other Segments' includes:
Industrial Machinery: 2%, Primary Metal Mfg: 2%, Paper Mfg: 1%, Printing Related Support: <1%
Fabricated Metal Products: <1%, Transportation Equipment Mfg: <1%, Plastics Rubber Products: <1%, Wood Product Mfg: <1%
Miscellaneous Mfg: <1%, Electrical Equipment Mfg: <1%, Furniture Mfg: <1%, Instruments: <1%

Almost all baseline consumption occurs in boilers and process heating (87%); thus, these end uses account for 97% of the economic potential. As shown in and Figure 13, the remaining potentials result in HVAC improvements and other (non-heating) process improvements.

Figure 13. Industrial Sector Gas Economic Potential by Measure Type (Cumulative in 2023)

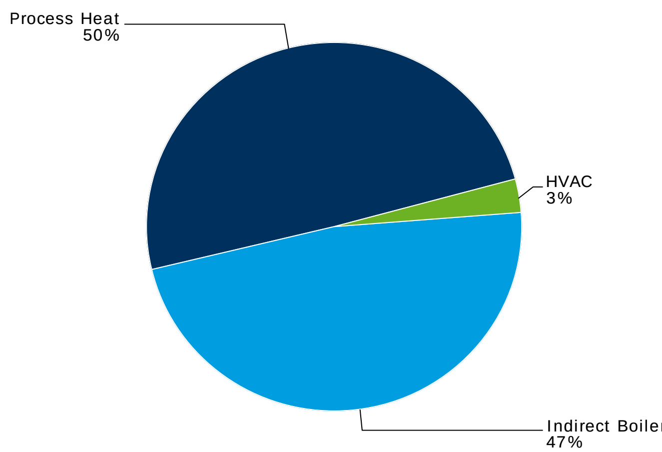


Table 30. Industrial Sector Natural Gas Energy-Efficiency Potential by End-Use Category (Cumulative in 2023)

End Use	Baseline Sales (Thousand Therms)	Technical Potential		Economic Potential	
		Thousand Therms	% of Base Case	Thousand Therms	% of Base Case
HVAC	3,694	210	6%	157	4%
Indirect Boiler	32,829	2,506	8%	2,506	8%
Other	1,919	0	0%	0	0%
Process—Heat	21,063	2,874	14%	2,616	12%
Process—Other	3,110	0	0%	0	0%
Total	**62,615**	**5,590**	**9%**	**5,279**	**8%**

3. ENERGY EFFICIENCY: MARKET POTENTIAL

Market potential, as defined in this study, represents savings that might be achievable under an aggressive acquisition scenario, assuming: incentive payments up to 100% of incremental measure costs; financing availability; exemplary program design and implementation practices; and emergence of new technologies, currently not widely available in the marketplace. This section presents research results in each of these areas, and examines its implications regarding realistic market potential levels in Iowa.

The results of the market potential analysis are intended to provide context to the estimates of economic potential and do not necessarily represent utility targets or "program potential." These savings may be realized through market transformation or improved codes and standards and may not be available or appropriate for utility programs. For example, the electric potential includes a substantial amount of savings from LEDs and CFLs replacing minimum standard bulbs. However, if the new lighting standards cause CFLs to become the de facto standard, the amount of savings available for utility DSM program acquisition could be greatly reduced.

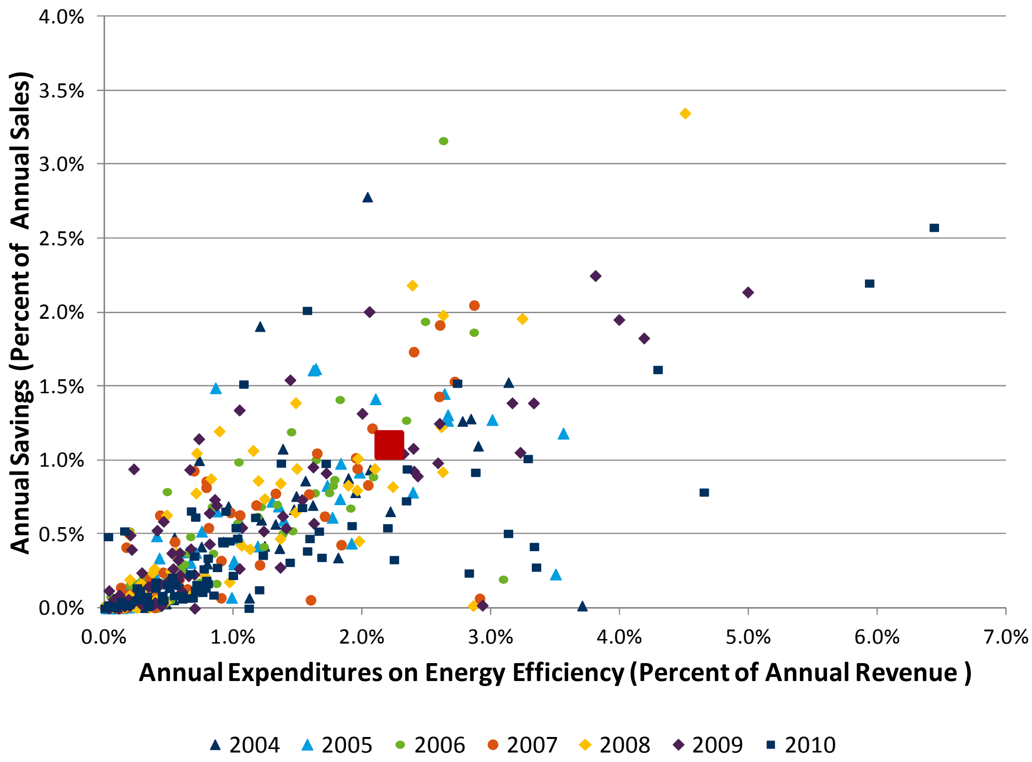
Effects of Increased Incentives

Due to key differences in measure characteristics and customer demographics, and the differing composition of programs and portfolios, one must separately assess incentives' effects on measure adoption for each fuel. While using similar methods, the two analyses adopted rely on fuel-specific potential and benchmarking data. The analyses' results follow.

Electricity

As described in Section 1, analysis quantifying the amount of electric market potential available, given incentives covering the entire incremental measure cost, has been based on portfolio-level data derived from EIA Form 861. Figure 14 shows relationships from 2004 to 2010 between savings (as a fraction of retail sales) and incentive payments (as a fraction of annual retail revenues) for the 75 utilities in the dataset. The figure suggests a generally linear relationship, with relationships that can be examined using regression analysis. The center of the larger red square indicates the average spending and savings for Iowa's electric IOUs in 2010.

Figure 14. Scatter Plot of DSM Savings and DSM Expenditures



The following regression equation estimated the statistical relationship between incentives and savings:

$$\log(\%\ \text{Savings}) = \beta_{0+}\ \beta_1 \log\left(\frac{\text{Incentive}}{\text{Revenue}}\right) + \beta_2 \log\left(\frac{\text{Other Costs}}{\text{Revenue}}\right) + \beta_3 \log(\text{Rate}) + \beta_4 \text{Log}(\text{Time})$$

This formulation states energy-efficiency savings is a function of: incentive payments (Incentive); non-incentive program expenditures (Other Costs), including program administration, marketing, and operating expenses; average per-unit cost of delivered energy (Rate); and time (Time). The rate term included in the equation accounts for the propensity to conserve energy and can be expected to run higher in jurisdictions with high rates. The time variable captures trends resulting from exogenous factors affecting program activity from 2004 to 2010. The equation parameters were estimated using a logarithmic specification with the panel data shown in Figure 14.

The analysis shows a relatively strong overall relationship between savings and the explanatory variables, indicated by a coefficient of determination (R^2) of 0.6, meaning 60% of the savings variation can be explained by the equation's explanatory variable (see Table 31). All estimated parameters have the correct sign, and are statistically significant at the 90% or higher level of statistical confidence, indicating a probability less than 10% that results might be due to chance. Coefficients for the incentive term and other expenditures are statistically significant at the 99% confidence level.

Table 31. Electric Model Terms and Coefficients

Model Term	Coefficient	Standard Error	P-Value
Intercept	0.94	0.54	0.08
Log (Incentive / Revenue)	0.44	0.05	< 0.01
Log (Other Costs / Revenue)	0.57	0.07	< 0.01
Log (Rate)	0.32	0.21	0.12
Log (Time)	-0.26	0.12	0.03

As the equation's terms are expressed in logarithmic form, estimated coefficients for each term in the equation represent the elasticity of savings with respect to that term. For example, as seen in Table 31, the estimated coefficient of incentives as a percent of revenue is 0.44, suggesting a 1% increase in incentives will likely lead to a 0.44% increase in savings. Using this parameter, one can estimate the maximum market potential achievable if incentives increase to 100% of incremental measure cost.

As the estimated coefficient on incentive amount measures the marginal impacts of higher incentives, a starting point for incentive amounts must be assumed. Available information on Iowa's electric utilities in 2010 indicates, on average, incentives covered approximately 40% of incremental measure costs across the energy-efficiency programs in their portfolios. A scenario assuming incentives at 100% of incremental costs thus requires a 150% increase ([100% - 40%] / 40%) increase in current incentive outlays.

Non-incentive expenditures, such as marketing, outreach, planning, and administration, have traditionally been assumed to be relatively fixed. This study's findings indicate this might not be the case. Indeed, the 0.57 estimated elasticity for non-incentive expenditures (shown in Table 31) suggests a positive and statistically significant correlation between non-expenditures and market penetration, and that these expenditures may even be more effective in expanding the market potential than incentives.

This finding is not surprising, given that first-cost is not necessarily the primary barrier in all sectors, and highlights that success in effectively promoting energy-efficiency programs depends on the total marketing effort, consisting not only of incentives, but of effective communication, education, and dissemination of information. Program administrators must examine and choose an appropriate mix of these investments, based on the unique characteristics of their service territories, customer needs, and characteristics of programs and products they offer.

In further analyzing EIA data, Cadmus found a statistically significant positive correlation between incentive payments and non-incentive expenditures of approximately 20%. That is, as incentives increase, so do non-incentive expenditures, and one cannot consider a scenario with drastically increased incentive payments without considering an accompanying rise in non-incentive costs.

Using 2010 reported portfolio savings and expenditures, revenues, and retail sales for the two electric utilities, Cadmus estimates that, if incentives for electric programs increase to 100% of incremental measure costs, up to 90% of estimated statewide economic electric potential will likely be achievable (see Table 32). As shown, however, budgets would need to increase by more than twofold at these incentive levels. As discussed, this increase in incentive spending would likely lead to additional spending on program administration, further increasing program budgets to over $113 million annually.

Table 32. Expected Electric Market Potential If Incentives Increase to 100% of Incremental Costs

Data Value	Statewide Value (2010)
Total Energy Efficiency Program Expenditures	$53,975,612
Total Energy Efficiency Program Expenditures % of Revenue	2.2%
Incentive % of Incremental Measure Cost	40%
Actual Savings % of Retail Sales	1.12%
Estimated Elasticity of Savings Relative to Incentives	0.44%
Actual Energy Efficiency Savings (MWh)	378,578
Change in % Savings at Incentives of 100% of Incremental Cost	66%
Projected Annual Energy Efficiency Savings (MWh)	628,440
Projected Annual Program Expenditures	$113,292,323
Estimated Annual Economic Potential (MWh)	687,221
Market Potential % of Economic Potential	**91%**

The analysis further shows the associated electric energy savings would likely produce statewide life-cycle benefits of approximately $450 million. The estimated costs and benefits do not account for potential future decreases in measure costs as energy-efficient technologies improve over time.

A market potential up to 90% of economic potential is extremely high, compared to results of other potential studies and market potential levels deemed achievable in other jurisdictions. Given economic potentials, relative to technical potentials, are also higher than in most jurisdictions, the identified market potential may not be realistically achievable.

A review of over 100 electric energy-efficiency potential studies completed since 2000, across 37 states, shows the estimates of economic potential exceeded 80% of technical potential (as seen in this study) in only 10 cases. These 10 studies estimate a maximum achievable potential of less than 60% of economic potential, a level significantly below that estimated in this study. Planning study results in several regions with long histories of aggressive energy-efficiency resource acquisition programs also supports the supposition that, relative to the identified potential in this study, market potential up to 90% might be exaggerated.

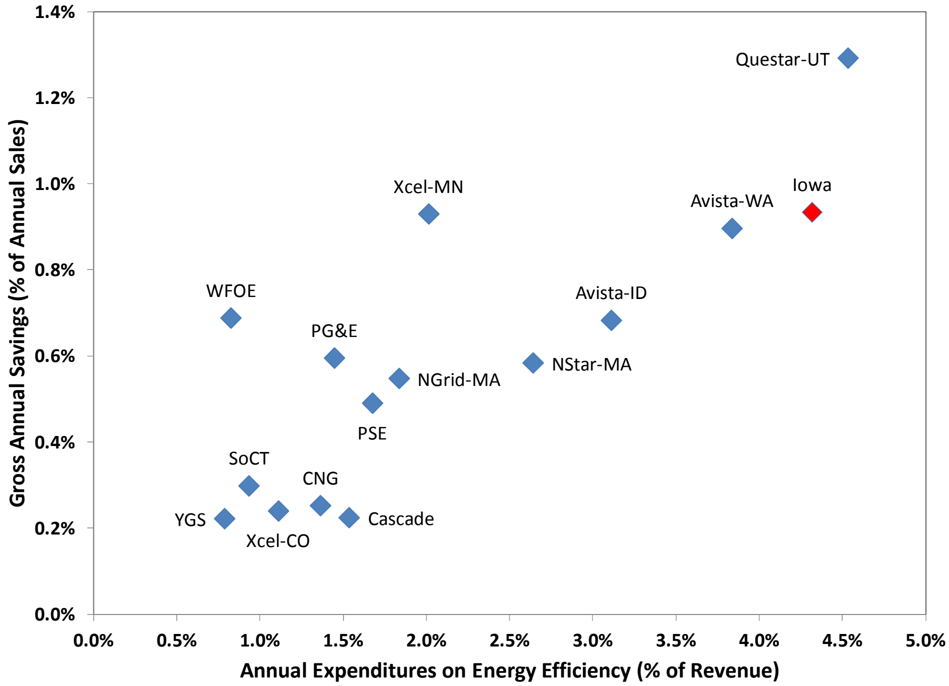
In the Pacific Northwest, for example, 85% of economic potential has been considered a maximum feasible level, which is consistent with findings of potential studies in California. In that state, a 2003 study of statewide electric energy-efficiency potentials estimated that, under the most aggressive scenario, assuming incentives of 100% of measures costs and total market awareness, 73% of the economic potential identified in the study would be achievable.[16]

[16] California Statewide Commercial-Sector Energy Efficiency Potential Study, Xenergy Inc, 2002.

Natural Gas

Due to the lack of centralized natural gas energy-efficiency portfolio data, Cadmus compiled information on 14 natural gas energy-efficiency portfolios, based on the criteria presented in Section 1. Cadmus used these data, presented in Figure 15, to perform a similar regression analysis (as described in the electric section, above).

Figure 15. Scatter Plot of Energy-Efficiency Savings and Expenditures



Cadmus specified a regression equation similar to that for electricity to estimate relationships between natural gas savings and incentives. As data were limited to 2010 results, the equation has no "Time" term:

$$\log(\%\ \text{Savings}) = \beta_{0+}\ \beta_1 \log\left(\frac{\text{Incentive}}{\text{Revenue}}\right) + \beta_2 \log\left(\frac{\text{Other Costs}}{\text{Revenue}}\right) + \beta_3 \log(\text{Rate})$$

As shown in Table 34, estimated coefficients for the incentive and other expenditure terms are positive, while the coefficient for the rate term has a negative sign, which appears counter-intuitive. This coefficient, however, also has a large margin of error and is statistically insignificant.

Table 33. Natural Gas Model Terms and Coefficients

Model Term	Coefficient	Standard Error	P-Value
Intercept	-0.89	1.15	0.453
Log (Incentive / Revenue)	0.49	0.16	0.009
Log (Other Costs / Revenue)	0.15	0.17	0.394
Log (Rate)	-0.62	0.54	0.272

Of the three estimated coefficients, only the incentive term (the critical term in the equation) is statistically significant at the 90% confidence level. The weaker overall performance of the estimated relationship for natural gas (as compared to electric) in the regression model is largely a result of the significantly smaller sample size.

As shown in Table 34, the estimated coefficient of incentives as a percent of revenue is 0.49, suggesting a 1% increase in incentive spending can be associated with a 0.49% increase in savings, a result generally consistent with the results found in the electric analysis. The coefficient for other spending is much smaller (and statistically less significant) than the electric result, suggesting, while savings also increase with other costs, first costs may be the primary barrier.

Table 34. Natural Gas Model Terms and Coefficients

Model Term	Coefficient	Standard Error	P-Value
Intercept	-0.89	1.15	0.453
Log (Incentive / Revenue)	0.49	0.16	0.009
Log (Other Costs / Revenue)	0.15	0.17	0.394
Log (Rate)	-0.62	0.54	0.272

Available information on Iowa's electric utilities in 2010 indicates incentives covered approximately 42% of incremental measure costs across all programs in the three utility's portfolios. A scenario assuming incentives at 100% of incremental costs thus requires an increase of 138% ([100% - 42%] / 42%) in current incentive outlays.

Using 2010 energy-efficiency program savings and expenditures, revenues and retail sales for the three natural gas utilities, Cadmus estimates that, if incentives for natural gas programs increase to 100% of incremental measure costs, the achievable fraction of economic potential might increase to approximately 65% of the estimated economic potential (see Table 35).

Table 35. Expected Achievable Natural Gas Market Potential If Incentives Increase to 100% of Incremental Costs

Data Value	Statewide Value (2010)
Total Energy Efficiency Program Expenditures	$37,851,535
Total Energy Efficiency Program Expenditures % of Revenue	4.1%
Incentive % of Incremental Measure Cost	42%
Actual Savings % of Retail Sales	0.92%
Estimated Elasticity of Savings Relative to Incentives	0.49%
Actual Energy Efficiency Savings (thousand therms)	9,682
Change in % Savings at Incentives of 100% of Incremental Cost	62%
Projected Annual Energy Efficiency Savings (thousand therms)	15,661
Projected Annual Program Expenditures	$74,951,818
Estimated Annual Economic Potential (thousand therms)	25,475
Market Potential % of Economic Potential	**65%**

As annual statewide savings relative to retail sales are currently lower for natural gas than electricity, the analysis projects a lower share of the economic potential as achievable, given it would be more difficult for natural gas programs to ramp up to maximal savings levels. As shown, however, budgets would need to increase twofold at these incentive levels. As discussed, this increase in incentive spending would likely lead to additional spending on program administration, further increasing program budgets to $75 million dollars annually. The analysis further shows the associated natural gas energy savings would likely produce statewide life-cycle benefits of over $100 million.

Effects of Financing Availability

Market potential depends on a number of factors, including retail energy rates, energy-efficiency measure costs, and the program's ability to overcome a host of market barriers recognized in the energy-efficiency literature to impede adoption of energy-efficiency measures and practices by consumers, including high first costs. These barriers tend to vary in severity, depending on customer sectors, local energy market conditions, and other, hard-to-quantify factors. Ultimately, market potential is a function of consumers' willingness and ability to participate in programs.

Financing options (in the form of loan programs) are mechanisms used to help mitigate effects from lack of capital—or high-cost financing—on consumers' ability to participate in energy-efficiency programs. Studies of financing and loan programs, including two recent reports by ACEEE, have found energy-efficiency loan programs have minimal effects on consumers' participation in energy-efficiency programs.

The findings of one ACEEE study[17] suggest participation rates tend to be generally low across programs. Compared to numbers of eligible customers in classes served by these programs, more than half the programs had participation rates below 0.5%. The highest participation rate was reported at 3%, experienced by only two surveyed programs. The report concludes these programs generally have not successfully achieved appreciable market penetration, and, importantly, sound program design does not appear to guarantee success.

A survey of on-bill financing programs found similar results. In a 2011 report, ACEEE examined 19 of 31 on-bill financing programs, structured as on-bill loans or on-bill tariffs in 20 states.[18] The study found less than 1%[19] of the eligible customers participated in these programs, despite several of these programs having been available for nearly 20 years.[20]

In light of extremely high economic potential levels assumed available under a 100% incentive scenario, and the performance of financing programs to date, it is unlikely availability of financing would increase market potential beyond that achievable assuming a 100% incentive.

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[17] Hays, Sara, et. al., *What Have We Learned From Energy Efficiency Financing Programs*, ACEEE, Report Number U115, September 2011.

[18] Bell, Catherine J., et. al., *On-Bill Financing for Energy Efficiency Improvements: A Review of Current Program Challenges, Opportunities, and Best Practices*, Report Number E118, December 2011.

[19] This number represents the average found by ACEEE for the programs reviewed. There have been cases where individual utilities have achieved higher penetration rates for on-bill financing programs, such as Cedar Falls Utility in Iowa.

[20] See also Byrd, D.J. and R.S. Cohen, A Roadmap to Energy Efficiency Loan Financing, Memorandum to U.S. Department of Energy, April 2011.

Effects of Emerging Technologies

In addition to commercially available technologies included in the assessment of technical and economic potentials, Cadmus considered the potential for emerging technologies in the context of market potential. Emerging energy-efficient technologies are those expected to become commercially available and cost-effective within the next five to 10 years.

The primary sources used to identify potential measures and corresponding savings data were reports published by ACEEE. Since the mid-1990s, ACEEE has published reports on *Emerging Energy-Saving Technologies and Practices in the Building Sector*.[21] In 2009 and 2011, reports focused on HVAC and hot water systems, respectively. ACEEE currently is investigating emerging lighting technologies, but, as results of this research are not available at this time, Cadmus referenced work conducted through DOE's CALiPER program.[22]

Generally, these technologies are higher-efficiency replacements for measures already included in the assessment. For example, Advanced Northern Heat Pumps (SEER 16/HSPF 9.6) are a more efficient variant of SEER 16/HSPF 9.0 heat pumps, already included. Active Chilled Beam Cooling with DOAS (dedicated outdoor air system) proves the exception: this measure represents an alternate building design, replacing standard duct systems with integrated features, combining lighting, water-cooled convective heat exchange surfaces, and ventilation. In short, it utilizes pumps to deliver cool water instead of fans to blow cold air.

The analysis assumes replacement measures for existing, cost-effective measures will, in turn, become cost-effective over the planning horizon. In these cases, Cadmus estimated additional potential savings for these measures relative to the comparable measure's economic potential. That is, using the example measure above, additional potential for the SEER 16/HSPF 9.6 heat pump is incremental to the SEER 16/HSPF 9.0 unit. However, if the measure supplanted by this emerging technology does not pass the economic screen, no additional economic potential is assumed for the emerging technology. That is, existing technology would first need to become economically feasible before being supplanted by an emerging technology. For example, as existing natural gas tankless water heaters do not pass the economic screen, it is assumed condensing tankless water heaters will not pass either.

Measures identified through this research, along with applicable sectors, fuels, and end uses, are listed in Table 36. Though ACEEE reports addressed more measures, only those in Table 36 achieved efficiency levels greater than economic measures already in the measure list.

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21 http://www.aceee.org/topics/emerging-technologies-and-practices

22 http://www1.eere.energy.gov/buildings/ssl/caliper.html

Table 36. Emerging Technologies

Sector	Fuel	End Use	Technology	Additional Market Potential (MWh or thousand therms)
Residential	Electric	Water Heating	Add-On Heat Pump Water Heater	27,426
Residential	Electric	HVAC	Optimized Residential Duct Work	763
Residential	Electric	Water Heating	Singe Family On-Demand Recirculation Pumps	1,615
Residential	Electric	HVAC	Multifamily Building Best Practices	43,599
Residential	Gas	Water Heating	Condensing Tankless Water Heater	0
Commercial	Electric	Lighting	LED Replacement of Linear Fluorescent	62,915
Commercial	Electric	HVAC	Active Chilled Beam Cooling with DOAS	2,338
Commercial	Electric	HVAC	Ventilation and Energy Recovery	34,214

The additional market potential from the emerging technologies is estimated at 73,403 MWh in the residential sector and 99,468 MWh in the commercial sector, assuming 90% of economic potential is achievable (given 100% incentives). If realized, these additional savings would increase the electric market potential, shown in Table 32, by about 3%. Cadmus did not identify additional natural gas potential from emerging technologies. Appendix A.5 describes each measure included in the analysis.

4. DEMAND RESPONSE POTENTIAL

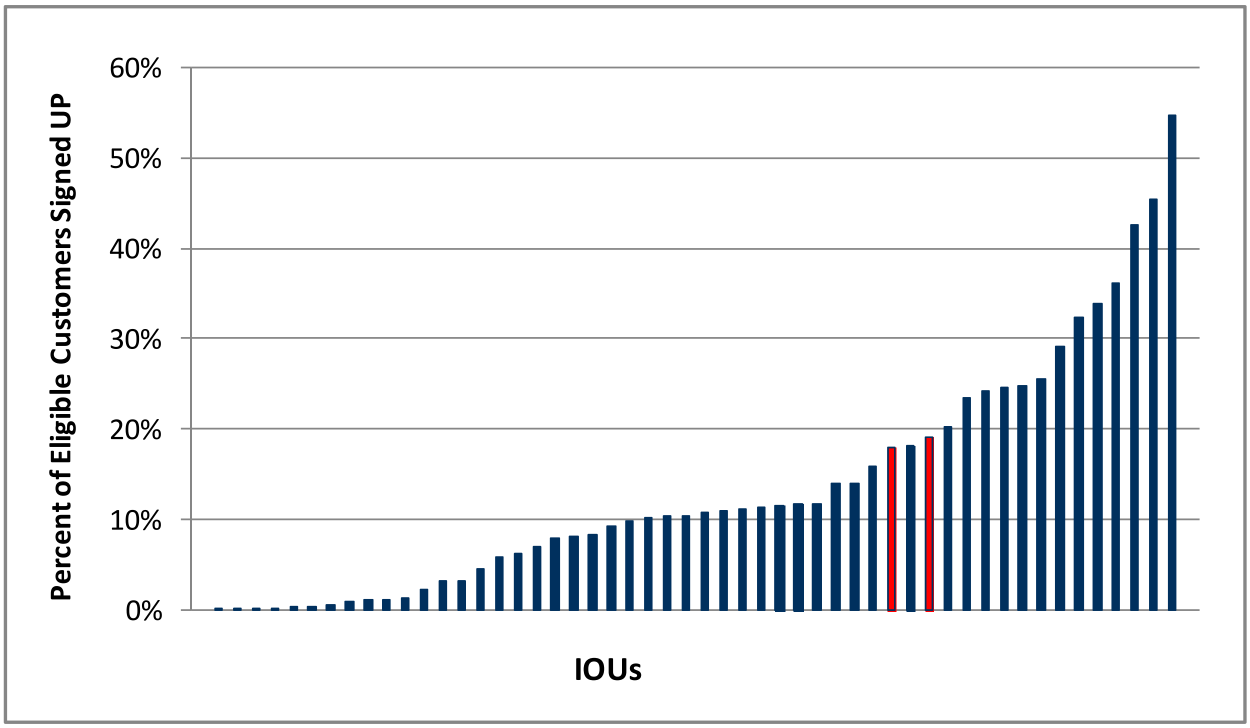
Potential for Expanding Legacy Programs

Residential DLC

As discussed in Section 1, the key metric for the residential DLC analysis was the fraction of eligible customers currently participating, with eligible customers defined as those with residential electric service and central air conditioners. Based on 2010 program activity, residential customer counts, and saturation data from the 2007 Residential Appliance Saturation Survey, Cadmus estimated similar currently participation rates for Iowa DLC programs: 19% and 18% for Alliant and MidAmerican, respectively.

Based on secondary data collected, Cadmus calculated participation rates for an additional 51 residential DLC programs for investor-owned utilities (IOUs) from across the nation. Figure 16 shows the calculated participation for each of these utilities in 2010, with Iowa utilities shown in red.

Figure 16. Participation Rates for 2010 IOU Residential DLC Programs



As program participation serves as the key driver of residential DLC impacts, Cadmus established three scenarios to quantify available potential for Iowa utilities, based on differing program participation levels. Participation levels in the moderate and aggressive expansion scenarios have been based on average participation in the upper-tier and industry-leading IOU programs, respectively.

Assumed participation rates are:

- Baseline: maintaining current program participation levels.
- Moderate expansion: achieving 20% program participation.
- Aggressive expansion: achieving 25% program participation.

To estimate peak demand impacts under each scenario, Cadmus multiplied participation rates by eligible customer forecasts for each utility, calculating the number of participating customers, then multiplying this number by per-participant values currently used by Iowa utilities, to calculate program-level demand impacts. Table 37 compares estimated 10-year potential under each scenario to the 2008 Assessment and each utility's 2010 accomplishments. As shown in Table 37identified potential is lower than in the 2008 Assessment, based on updated data on actual program achievements.

Table 37. Forecasted Residential DLC Impacts in 2023 (MW)

		10-Year Potential			
		2008 Study	2012 Study		
Utility	2010 Program Achievements	Base Case	Base Case	Moderate Expansion	Aggressive Expansion
Alliant	33	53	35	37	46
MidAmerican	31	72	32	35	43

Secondary research into snapback effects indicated residential DLC programs typically see energy savings reductions of 40% to 70% due to snapback.[23] Actual energy saved by these programs is a function not only of demand under contract, but also of the duration and frequency of events. However, based on the secondary literature, Cadmus expect per-hour MWh potential to be roughly half of the MW values presented in Table 37.

Nonresidential Interruptible

Participation in interruptible programs will vary greatly across utilities due to the following:

- The value of capacity savings;
- Eligibility requirements;
- Utility incentives;
- Prevalence of standby generation; and
- Who implements the program (utility vs. third-party aggregator).

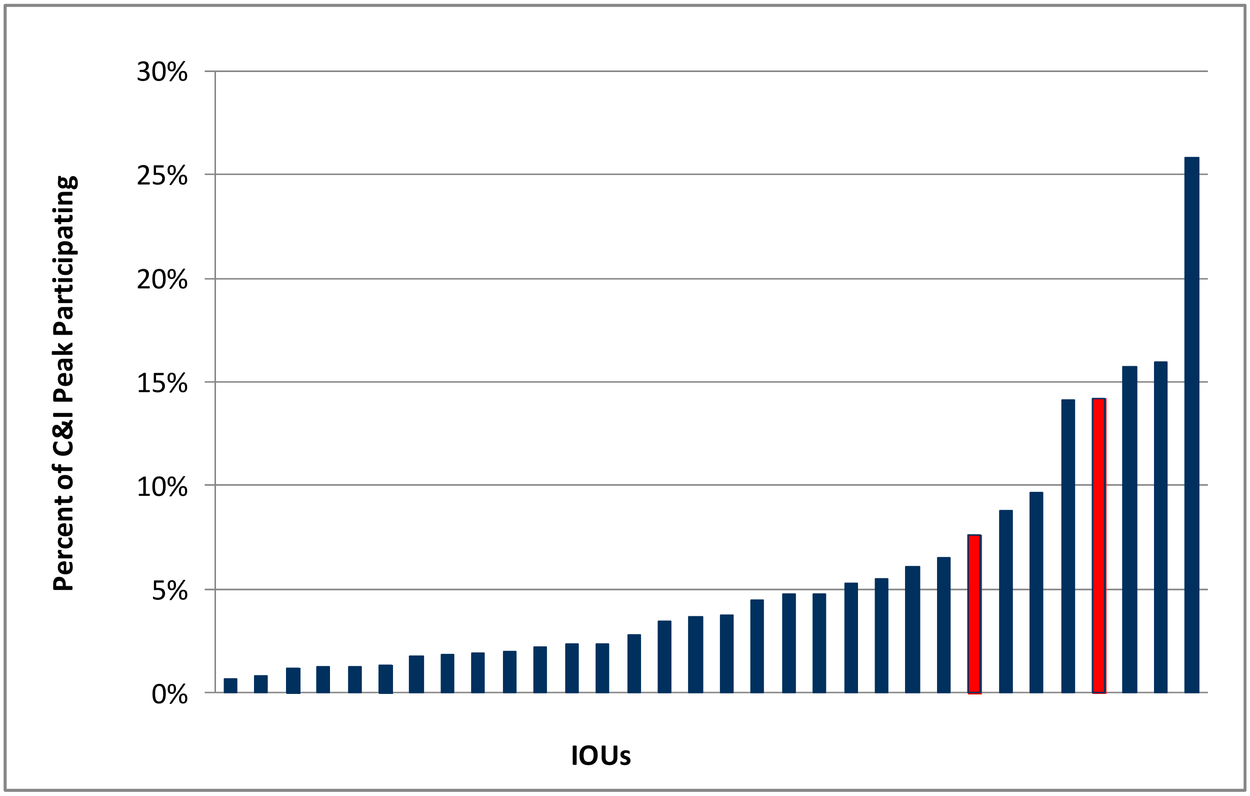
These caveats aside, Cadmus collected data on IOU programs similar to those offered in Iowa to assess opportunities for program growth.

Unlike the residential sector, due to large differences in demand between nonresidential customers, the percent of eligible *load* enrolled (rather than customers) serves as the key metric in assessing program participation. However, as data on eligible loads by utility are not readily

[23] Appendix B lists programs reviewed.

available for most utilities, Cadmus used total nonresidential demand during the system peak hour as a proxy. Using this metric and based on 2010 programs, Alliant and MidAmerican have currently enrolled 14% and 8% of eligible load, respectively. Figure 17 shows similar information collected for an additional 30 IOUs with similar programs, with Iowa utilities appearing as red bars.

Figure 17. Participation Rates for 2010 IOU Nonresidential Interruptible Programs



As program participation serves as the key driver of nonresidential interruptible impacts, Cadmus established three scenarios to quantify available potential for Iowa utilities, based on differing program participation levels. Participation levels in the moderate and aggressive expansion scenarios have been based on average participation in the upper-tier and industry-leading IOU programs, respectively, with the assumed participation rates:

- Baseline: maintaining current program participation levels.
- Moderate expansion: achieving 15% program participation.
- Aggressive expansion: achieving 17.5% program participation.

For each scenario, the percent increase in participation over 2010 activity has been used to calculate each utility's potential. As noted, utilities must consider their current and projected resource needs to determine whether these program participation levels are desirable and prudent.

Table 38 compares estimated 10-year potential under each scenario to the 2008 Assessment and each utility's 2010 accomplishments.

Table 38. Forecasted Nonresidential Interruptible Impacts in 2023 (MW)

		10-Year Potential			
		2008 Study	2012 Study		
Utility	2010 Program Achievements	Base Case	Base Case	Moderate Expansion	Aggressive Expansion
Alliant	264	291	296	304	354
MidAmerican	193	170	238	422	492

As in the residential sector, snapback effects, and thus energy savings attributable to demand response strategies, can vary greatly across utilities. Though literature on the likely snapback effects for nonresidential programs is limited, available data indicate that the effect may be around 50%.

Opportunities With AMI

Analysis of AMI-enabled demand programs was a qualitative exercise, given data quantifying impacts of AMI-enabled programs has been drawn almost exclusively from utility pilot programs, and may not be appropriate for extrapolation to larger markets. Consequently, potential energy and demand savings related to AMI cannot be reliably quantified at this time. Nevertheless, this study outlines a number of potential options that may provide viable savings sources if Iowa electric utilities implement AMI.

Overview of AMI-Enabled Demand Response

At the highest level, AMI's addition enables two-way communication for the mass-market of utility customers. Such two-way communication enables two primary opportunities. First, collection of near real-time interval meter data becomes possible as smart meters record interval meter reads, and send data back to the utility. Second, AMI enables communication from the utility to the customer, with the utility sending signals to the customer's meter, which can be used to specify changes in dynamic pricing or to control various appliances.

AMI technology does not present a new idea: many utilities have installed similar systems strategically for their larger C&I customers. Its strategic aspect arises regarding cost-effectiveness, as non-AMI systems have been inappropriate for installation in some situations, due to costs outweighing benefits. Such systems have often relied on dedicated Internet connections and advanced metering.

AMI enables a much lower per-meter cost for such advanced capabilities. By deploying system-wide communication networks, AMI systems reduce communication costs, and open doors to more cost-effective smart meter installations. Thus, as the C&I market has utilized various forms of advanced metering, the residential and small commercial market will likely realize much greater impacts from AMI.

Consequently, our research focused on residential, AMI-enabled opportunities. AMI can automate load reductions within a home or business through use of demand response enabling technology, which can be remotely signaled when utilities call demand response events, thus reducing an appliance's load through control strategies established by the utility or the customer. AMI-enabled demand response technologies include the following:

- **Smart thermostats:** Devices similar to programmable thermostats, but receiving and reacting to utility pricing and signals. Customers using smart thermostats typically program devices to react in specific ways when demand response events occur. For example, a customer may choose to raise the temperature set point by four degrees during an event to reduce load. Smart thermostats automate this process.
- **Smart appliances:** Smart appliances typically are very efficient versions of traditional appliances, equipped with AMI communication capabilities. They can receive event notifications or pricing signals, modifying operations to reduce demand during demand response events. For example, a smart refrigerator, when signaled with a relatively high electric price, may cycle its refrigerant compressor to reduce peak consumption. Other smart appliances include: water heaters, lighting, clothes washers and dryers, and dishwashers.
- **Load control devices:** AMI load control devices resemble traditional load control devices, except they communicate over AMI systems, and have an added benefit of communicating their status; so non-operable devices can be more readily repaired.
- **Home energy management systems (HEMS):** In advanced homes utilizing HEMS to control operations such as HVAC, lighting, appliances and security, adding AMI allows HEMS' to control systems to reduce demand when signaled through an AMI network.

In addition to demand response enabling technologies, other AMI-enabled technologies improve communication of energy usage from the utility to consumer. Traditionally, customers have received monthly utility bills that report consumption and charge customers for their aggregate monthly consumption, a system that somewhat disconnects customers from immediate connections between their actions and energy consumption. However, AMI enables near real-time feedback, informing customers of their energy consumption much more quickly. Examples of enhanced communication devices include the following:

- **Personal Web portals:** These portals offer customized Websites customers can use to monitor interval consumption. Such systems allow customers to analyze their consumption over time periods they choose to view. Increasingly, these systems employ advanced analytics to provide customers with even more useful information. For example, some systems allow customers to benchmark their performance against those of neighbors with similar homes. Some systems allow customers to specify what they wish their utility bills to be, and the portal provides recommended actions they should take to meet these goals.
- **In-home displays (IHD):** These are standalone devices, typically communicating with smart meters to show customers their energy consumption and current utility pricing. These devices allow customers to better understand their energy consumption.
- **Energy Orb:** These standalone devices, which change color as energy rates change or as demand response events are called, signal customers to take appropriate actions to reduce their electric demand.

Program Examples

AMI Enabled DLC

As noted, AMI adoption creates opportunities to control appliances within customers' homes and businesses. In some ways, they differ little from current DLC programs: individual load reductions from activities such as cycling central air conditioners may not differ from load reductions resulting from currently deployed DLC programs. However, AMI improves upon DLC by implementing two-way communication. Most residential DLC programs experience lower demand reduction capabilities due to malfunctioning DLC devices. As traditional systems cannot communicate their status to the utility, these devices often remain inoperable until discovered through inspections. Utilities typically experience 10% to 20% losses due to non-operable DLC devices. With AMI-enabled DLC, non-operable devices can be more readily detected, and inoperability rates can typically be decreased to between 2% and 5%.

AMI Enabled Dynamic Pricing

Dynamic pricing has encountered a limiting factor in that traditional utility meters cannot record or transmit the interval data required to reconcile customer consumption. However, as AMI enables such communication, it allows implementation of dynamic pricing programs. To date, the majority of dynamic pricing data have resulted from pilot evaluations, which have been plagued with potential bias, stemming from early adopters' reporting results, as these individuals may use AMI capabilities more than average customers. Nevertheless, preliminary pilot results have been somewhat promising.

The Brattle Group recently synthesized results of 109 AMI-enabled dynamic pricing pilots, finding the majority of pilots resulted in load reductions of up to 16%, with a 12% median demand reduction.[24] The majority of these pilots relied on customers taking action when prompted through signaling techniques such as telephone calls, e-mails, and text messages.

Brattle also examined 39 AMI-enabled dynamic pricing programs, utilizing various combinations of enabling technologies. These programs showed consistently higher savings than programs without enabling technologies, with a median demand reduction of 23%.

Summary of AMI-Enabled Demand Response Opportunities

From initial pilot results, AMI appears to expand demand reduction capabilities of residential demand response programs, though the extent of this expansion remains to be seen, as program persistence issues have not been thoroughly studied. Additionally, studies of the reliability and security of these programs and enabling technologies remain in progress. Further, how AMI-enabled programs and traditional programs overlap, and how demand savings may shift, still must be understood before specific estimates of demand reduction can be determined.

From improving operability rates of existing DLC programs to offering new demand response programs to customers, who otherwise would not sign up for traditional DLC programs, AMI will likely expand utilities' demand reduction capabilities.

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24 Ahmed Faruqui and Palmer, J. "Dynamic Pricing of Electricity and its Discontents." The Brattle Group. August 2011.

5. ASSESSMENT OF THE NET-TO-GROSS RATIO

Definitions

Net-to-gross (NTG) assessments primarily seek to determine energy savings attributable to energy-efficiency programs by explicitly accounting for ***freeridership*** (energy savings likely to have occurred in the program's absence) and ***spillover*** (energy savings induced but not subsidized by the program). Savings resulting from this calculation are the "net" program savings, and the ratio of net program savings to gross savings is the NTG ratio.

About Freeridership

Freeridership subtracts from gross energy savings likely to have occurred through adoption of energy-efficiency measures by participants, independent of the program. That is, participants are considered freeriders if they would have adopted the same energy-saving measures at the same time, in the same quantity, and at the same efficiency level, had the program not existed.

About Spillover

Spillover adjustment adds energy savings from adoption of high-efficiency measures outside the program, but likely induced by the program. These additional energy savings are assumed to derive from greater knowledge and awareness of energy-efficient options resulting directly from the program's availability and influence.

Spillover can occur within participant and nonparticipant populations. For example, participants in a program may be motivated to adopt high-efficiency measures beyond those subsidized by a program. Simultaneously, the knowledge, awareness, and availability of measures caused by a program may induce nonparticipants to adopt the same energy-efficient measures.

For most programs, the number of eligible nonparticipants far outnumbers participants; thus, potential exists for large spillover impacts within this population.

About Program-Induced Market Effects

A third possible adjustment is program-induced market effects[25]—that is, any change the program causes to operations of supply chains in energy-efficiency markets. For example, the programs may result in:

- Manufacturers changing the efficiency of their products;
- Wholesalers and retailers changing their stocking decisions, reacting to shifts in demand for more efficient goods caused by IOU programs; and/or
- Architects and builders adopting energy-efficient practices.

[25] Note that some literature includes nonparticipant spillover as part of market effects.

These market effects can be significant, especially in upstream programs implemented through point-of-sale discounts. Such transformational market effects are, arguably, the ideal achievements of energy-efficiency programs, and can have long-lasting impacts. However, it is broadly accepted that these impacts can be difficult to measure for at least two reasons:

- Identifying these consumers in the larger populations can be difficult, as they may not be aware they participated in a program.
- A large number of factors may influence consumers' purchasing decisions.

Thus, measuring and attributing these effects to particular energy-efficiency programs has been a significant measurement and evaluation challenge.

Treatment of Freeridership and Spillover

Depending on the relative magnitudes of freeridership and spillover, NTG may be less than, greater than, or equal to 1.0. However, in jurisdictions where freeridership is the only measured effect, NTG never takes a value greater than 1.0.

Applying NTG also affects the cost-effectiveness of IOU programs. The Iowa Chapter 35 rules specify the method and assumptions for cost-effectiveness tests, including the Societal Cost Test (SCT), the standard for determination of cost-effectiveness in Iowa. The rules have been based on the Standard Practice Manual (SPM) for Economic Analysis of Demand-Side Management Programs, established by the California Public Utilities Commission (CPUC).[26]

In calculating benefits for the Total Resource Cost (TRC) test, the CPUC observed: "…ratepayers, through the energy-efficiency revenue requirements collected to fund these programs, incur a cost for freerider participants that must not be ignored in the formulation of the TRC test."[27] (The same observation applies to the SCT, which is a variant of the TRC.)

Due to ambiguity regarding how to fold in freerider considerations on the equation's cost side, the CPUC (in its 2007 Clarification Memo) modified the original method for calculating TRC costs by adding a transfer incentive (INC) recapture term to the initial TRC cost equation, as follows:

$$\text{TRC Costs} = \text{PRC} + \text{NTG*PC} + \text{UIC} + (1.0\text{-NTG})\text{*INC}$$

Where,

PRC = program administrator costs

PC = participant device costs (*before* INC is received)

UIC = (for fuel substitution programs) utility increase supply costs

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[26] The SPM describes procedures for determining cost-effectiveness of energy-efficiency programs from five perspectives: resource allocation efficiency (Total Resource Cost); the utility (Utility Cost Test); participants (Participant Cost Test); society (Societal Cost Test); and ratepayers (Rate Impact Measure).

[27] 2007 SPM Clarification Memo, D.07-09-043, pages 154-158, California Public Utilities Commission, 2007.

NTG = net-to-gross ratio

INC = incentive costs, restricted to include only dollar benefits.

According to the CPUC, adding the INC term to the TRC formulation ensures removal of freerider costs does not remove program costs that become utility-revenue requirements, consistent with the test's intent and purpose. Given administrative costs normally represent only a small percentage of total resource costs, freeridership impacts on TRC (and SCT) results tend to be small.

Treatment of NTG Across Jurisdictions

The definition, measurement, and treatment of freeridership—and of NTG in general—vary across jurisdictions in the United States. Some jurisdictions include both freeridership and spillover in defining net savings, while others allow only freeridership to be counted. In several cases, freeridership and spillover are measured separately, and incorporated in NTG, while other jurisdictions estimate NTG without specifying freeridership and spillover individually. Finally, in some cases, measurement of NTG—or its components—may not be required. Instead, gross savings, adjusted for actual installation rates, are used as the measure of program impacts. This is also the case with regional transmission organization (RTOs), such as the New England independent system operator (ISO-NE), where verified gross savings serve as the basis for verification of energy-efficiency bids into the forward energy market.

Cadmus compiled data on 32 jurisdictions active in energy efficiency to determine how NTG is defined, and whether it is used as an adjustment to gross savings. The survey established the following highlights:

- All but six of these jurisdictions (81%) have energy-efficiency resource standards (EERS) in place, setting minimum performance requirements, either as legislative or regulatory mandates or voluntary goals.
- No requirements exist for NTG calculations in 12 jurisdictions (38%).
- In 17 jurisdictions (53%), freeridership is included in determination of program savings. In seven of these jurisdictions (41%), freeridership is applied at the measure level.[28]
- In 10 jurisdictions (31%), NTG calculations include freeridership and either participant or nonparticipant spillover effects.
- In the majority of cases where NTG is calculated, it is applied prospectively for planning purposes. In these jurisdictions, utilities rely on adjusted gross savings for reporting compliance with targets, but are required to use deemed freeridership values in their program plans.
- Participant spillover is measured in 12 jurisdictions (37%) in the sample, while nonparticipant spillover is taken into account in 10 (31%).
- The incidence of cases only assessing freeridership suggests asymmetrical treatment of spillover and freeridership effects.

[28] New Jersey applies freeridership only to appliance recycling programs.

For a list of jurisdictions reviewed, and the NTG activity in each, see Appendix C.

Examples of NTG Values

Table 39 lists deemed NTG values adopted by the CPUC for the 2009–2011 program cycle. Although these NTG values do not include spillover effects, the CPUC allowed evaluations of the 2006–2008 energy-efficiency programs to contain an examination and estimation of participant spillover. As seen, NTG estimates vary widely across market sectors and measures. On average, NTG ratios are lower in the residential sector than in the commercial and industrial sectors, mainly due to the high freeridership in upstream programs.

Table 39. California Program Deemed NTG Ratios

Program	Average NTG	Maximum NTG (Measure)	Minimum NTG (Measure)
Residential			
Lighting	0.78	0.85 (Multiple)	0.60 (CFL ≤30 watt)
Appliance Replacement	0.70	0.85 (Clothes washer 15% above standard)	0.41 (Dishwasher EF>0.58)
Appliance Recycling	0.66	0.702 (Freezer)	0.614 (Refrigerator)
Water Heating	0.76	0.85 (multiple)	0.58 (Water Heater EF>0.62)
HVAC	0.67	0.85 (Programmable thermostat with direct install)	0.49 (Programmable thermostat with prescriptive rebate)
Multifamily	0.84	1.0 (Boiler controls)	0.76 (Lighting)
New Construction	0.53	0.62 (Lighting)	0.48 (Whole building single family RNC)
Residential Audits	0.80	N/A	N/A
Default Values	0.78	0.85 (New measures with <5% market share)	0.70 (New measures with ≥5% market share)
Nonresidential			
Lighting	0.78	0.85 (Multiple)	0.60 (CFL ≤30 watt)
HVAC	0.74	0.85 (Multiple)	0.50 (Multiple)
Refrigeration	0.68	0.82 (Refrigeration in NRNC)	0.46 (Strip door curtains)
Motors	0.84	N/A	N/A
Water Heating	0.64	0.82 (Water heating in new construction)	0.46 (Water heating in existing buildings)
Building Shell	0.93	N/A	N/A
Whole Building	0.70	N/A	N/A
Custom	0.75	0.85 (Multiple)	0.64 (Multiple)
Agricultural	**0.50**	**0.75 (Vacuum pump VSD)**	**0.26 (Plate cooler)**
Audits	0.41	0.48 (Lighting/cooling 20 to 100 kW)	0.29 (Lighting/cooling less than 20 kW)
Retrocommissioning	**0.95**	**1.0 (Gas measures)**	**0.90 (Electric measures)**
Local Govt Partnerships	0.68	N/A	N/A
Default Values	**0.78**	**0.85 (New measures with <5% market share)**	**0.70 (New measures with ≥5% market share)**

Source: 2008 Database for Energy-Efficient Resources (http://www.deeresources.com/deer0911planning/downloads/DEER2008_NTG_ValuesAndDocumentation_080530.zip) Version 2008.2.05 December 16, 2008

To date, only one evaluation (NYSERDA)[29] has estimated spillover effects for a new construction program. The evaluation showed a 46% freeridership rate (consistent with Table 39), and a combined participant-and-nonparticipant spillover rate of 54%, more than offsetting the freeridership estimate.

Measuring Freeridership and Spillover

A variety of methods and analytic techniques have been used to measure or to account for freeridership and/or NTG in general. Despite apparent differences, these methods and techniques tend to fall into one of two categories: statistical and self-report.

Statistical Methods

Statistical methods are based on the general difference-in-differences approach, where actual energy consumption is measured for program participants and a comparable group of nonparticipants in two time periods: before and after program implementation. Using statistical methods:

- Participants are exposed to program treatment in the second period, but not in the first.
- The comparison (nonparticipant) group is not exposed to treatment during either period.

Implemented properly, with a well-chosen control group, this approach removes potential biases related to the unique characteristics of participants, and biases from comparisons over time, which could result from non-program related trends (so-called "naturally occurring conservation"). Net program impacts are then calculated by subtracting the average change in nonparticipants' consumption from the average change in the participant group.

This approach is sometimes implemented within an econometric framework for the following reasons: (1) controlling for the residual difference between the two groups; (2) evaluating the sensitivity of savings to various factors; and (3) estimating savings for bundles of measures. It cannot, however, be used for measuring NTG for individual measures. Moreover, this approach does not provide estimates for the individual NTG components—freeridership, spillover, and market effects.

The approach is also not well suited to estimating NTG in large commercial and industrial energy-efficiency programs. Due to the heterogeneity of these customers, it often can be impractical to identify an appropriately comparable group of nonparticipants. Also, as energy savings in these programs are often a small fraction of total consumption, it can be difficult to isolate consumption changes resulting from implementation of energy-efficiency measures. Moreover, this method is not recommended for upstream programs or new construction programs (where the lack of a pre-program period limits the effectiveness of the approach).

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29 *New Construction Program (NCP) Market Characterization and Assessment*, prepared for New York State Energy Research and Development Authority, prepared by Summit Blue Consulting, LLC, August, 2008.

Self-Report Methods

Studies relying on self-reporting are more common than those relying on statistical methods. At a basic level, these methods directly involve asking participants questions about what they would have done in the program's absence. Responses are then scaled, weighted, and combined to produce a composite freeridership score (or index) for each respondent. Scores are then weighted (by savings) and averaged to produce a program-level freeridership fraction.

The self-report approach does not produce an NTG ratio. The other NTG components—spillover and market effects—must be estimated separately, and then be factored into the calculations. Surveys for determining spillover effects within groups of participants or nonparticipants are especially sensitive to variations in spillover scores. Small fractions multiplied by very large numbers of customers can dramatically boost savings.

Using surveys to assess freeridership raises concerns about response bias, particularly biases involving ***social desirability*** (the tendency of respondents to gauge their responses to conform to socially acceptable values). This well-recognized issue in social sciences has been discussed in a vast body of academic and professional literature.

Due to social desirability, respondents tend to offer what they think is the right answer, resulting in freeridership overstatement. Also, as some evaluation experts have noted, people have internal reasons—as explained by social psychology's attribution theory—motivating them to make certain decisions.

Another aspect is called the ***construct validity***. This issue stems from the fact that while survey respondents—by virtue of their participation in the program—are predisposed to conservation, the extent that their responses have been conditioned by the psychological effects of the conservation program remains unclear. Thus, what surveys measure may be the program's effect rather than what would have happened in its absence.[30] In areas with long histories of conservation programs and activities, it can be difficult to determine who is a freerider and who has been influenced by the program.[31]

In recent years, research methods have become more sophisticated, resulting in development of a series of questions and incremental answers designed to understand partial freeriders.

- In general, freerider questions ask interviewees about actions they would have taken had the program not been in place.
- For spillover, recent survey-based studies have focused mainly on participant and nonparticipant spillover. Participant surveys elicit responses about whether customers

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30 See Peters, Jane S. and Marjorie McRae., *Freeridership Measurement Is Out of Sync with Program Logic…or, We've Got the Structure Built, but What's Its Foundation*? Proceedings, ACEEE Summer Study Monterey, CA, August 2008.

31 Friedman, Rafael, Maximizing Societal Uptake of Energy Efficiency in the New Millennium: Time for Net-to-Gross to Get Out of the Way? Proceedings, International Energy Program Evaluation Conference, Chicago, August 2007.

have purchased additional energy-efficient measures of the same type without financial assistance.

- Nonparticipant spillover surveys ask customers if they purchased efficiency measures due to their awareness of the program.
- These developments have resulted in more systematic and transparent approaches, but results remain sensitive to evaluators' subjective assumptions.

Recall presents another problem, especially regarding spillover. Studies have found interviewees have difficulty self-reporting details such as usage, size, and efficiency levels.

Partly due to inherent biases, NTG results can vary sharply, based on the method selected. For example, two studies completed in the mid-1990s found self-reported freeridership estimates can be more than 50% higher than discrete choice approaches.[32] On the other hand, a recent study of several small commercial-sector programs in California found results, derived from more advanced statistical models (based on a nested logit model specification), were nearly identical to those obtained from self reports[33] (see Table 40).

Table 40. Freeridership Rates Differences Based on Research Approach

	Discrete Choice	Self-Reported
2010 California Small Commercial Programs	77%	78%
1995 Commercial Lighting Study	22%	32% to 38%
1994 PG&E Commercial Rebate	27%	42%

For these reasons, some experts have argued estimating freeridership and spillover can be too expensive, given considerable uncertainty about the results.[34]

32 Train, K. and E. Paquette, "A Discrete Choice Method to Estimate Freeridership, Net-to-Gross Ratios, and the Effect of Program Advertising," Energy Services Journal, Vol. 1, No. 1, 1995.

33 Grover, Stephen, et. al., *Free to Choose? A Comparison of a Nested Logit Model with a Billing Regression Model and Self-Report Analysis in a Commercial Impact Evaluation*, Proceedings, International Energy Program Evaluation Conference, Boston, August 2011.

34 Saxonis, William P., *Freeridership and Spillover: A Regulatory Dilemma*, Proceedings, Energy Program Evaluation Conference, Chicago, August 2007.

Cross-Program Research

The National Energy Efficiency Best Practices Study, an ongoing project sponsored by the CPUC, provides some insight into how the NTG issue has been handled in programs across the country.[35] The project seeks to identify best practices, and to communicate findings to program administrators for enhancing design of their programs.

In-depth interviews were conducted with managers of more than 100 programs in 2004 and 2005. Based on these interviews, program profiles were developed, and best practices were identified. Information was also provided regarding whether a program included a NTG adjustment, and whether this adjustment was based solely on freeridership, or if it also included spillover. Table 41 summarizes NTG values reported.

Table 41. NTG Values Identified Through the Best Practices Project

Program Area	NTG Value(s)	Freeridership Value(s)	Spillover Value(s)
Residential			
Lighting	0.57, 0.8, 1.27	5.7%, 6%	9.8%, 15%
Air Conditioning	0.8	N/A	N/A
Single Family Comprehensive	0.89, 0.93, 0.94, 0.97	3%, 4.4%	0%
Multifamily Comprehensive	0.78, 0.89	0%, 3%	N/A
New Construction	0.8, 1.0, 1.16	0%, 20%	N/A
Nonresidential			
Lighting	0.96, 1.0	N/A	N/A
HVAC	0.85, 0.96, 1.0	0%, 15%	N/A
Large Comprehensive	0.7, 0.8, 1.0, 1.06	N/A	N/A
New Construction	0.65, 0.67, 0.75, 0.81, 0.93	7%, 33%, 40%	N/A

See the Best Practices Website for detailed reports: http://www.eebestpractices.com/index.asp

More than 50% of studies reviewed either assumed or calculated an NTG value of 0.9 or greater. (In most cases, NTG values only included freeridership, or were based on a deemed NTG assumption.) Reported freeridership values varied significantly, even within program groups. Spillover effects were reported very infrequently.

Another cross-program study reviewed evaluation efforts of 50 resource acquisition programs and 31 information-only programs from the 2002–2003 California energy-efficiency programs.[36] That study found only 23 evaluations took freeridership into consideration.

Far fewer studies included efforts to account for spillover effects: three measured participant spillover, and three measured nonparticipant spillover.

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[35] This study is managed by Pacific Gas and Electric Company under the auspices of the California Public Utility Commission in association with the California Energy Commission, San Diego Gas and Electric, Southern California Edison, and Southern California Gas Company. The website address is: http://www.eebestpractices.com/index.asp

[36] *California 2002-2003 Portfolio Energy Efficiency Program Effects and Evaluation Summary Report*, prepared for Southern California Edison and the Project Advisory Group by TecMarket Works, January 16, 2006.

Although the study stated freeridership and spillover were important considerations that should be included in evaluation research, it provided no guidelines as to which effects may have greater impacts, or whether it was appropriate to assume freeridership and spillover effects essentially cancelled each other out. However, some specific program evaluation efforts were identified, which will be reviewed in the next section of this report.

Specific Programs

This section examines measurement results for specific program types, based on data available from evaluation reports assessing both freeridership and spillover. Selection of program types was based on their expected savings potential in Iowa.

Lighting Programs

Table 42 lists results from four evaluation efforts that assessed lighting freeridership and spillover effects.[37] The majority of these programs have an estimated NTG value is 1.0 or higher, as spillover estimates are higher than freeridership estimates.

Table 42. Residential and Commercial Lighting Programs with Spillover Estimates

Sponsoring Organization	NTG Values	Freeridership Values	Spillover Values
Residential			
Efficiency Vermont*	1.19	6%	25%
Energy Trust of Oregon**	0.75	51%	26%
Efficiency Maine***	1.10	20%	30%
Nonresidential			
NYSERDA****	1.10	39%	80%

* *Final Report: Phase 2 Evaluation of the Efficiency Vermont Residential Programs*, prepared for the Vermont Department of Public Service, prepared by KEMA, Inc, December 2005

** *Process and Impact Evaluation of the 2007-2008 Energy Trust of Oregon Home Energy Solutions Program Volume 2,* prepared for the Energy Trust of Oregon, prepared by Opinion Dynamics Corporation, January, 2010.

*** *Process and Impact Evaluation of the Efficiency Main Lighting Program*, prepared for Efficiency Main, prepared by Nexus Market Research, Inc., and RLW Analytics, Inc., 2007.

**** *New York's System Benefits Charge Program Evaluation and Status Report—Year Ending December 31, 2010,* prepared for the New York Public Service Commission, prepared by NYSERDA, March, 2011.

37 Note: the NYSERDA NTG value does not equal (1 - freeridership + spillover), which is the formula used by most programs, but uses (1-freeridership) * (1 + spillover). Note also that the efficiency Vermont values represent a more recent study than that identified in Table 39.

Nonresidential Large Comprehensive Programs

Programs in this category promote procurement and installation of high-efficiency energy technologies by providing incentive payments and design/audit assistance, in some cases, to partially offset incremental equipment costs. Customers can receive incentives for customized projects based on calculating the amount of kWh saved, or based on a measurement-and-verification procedure. Providing incentives to shorten payback periods and assistance to quantify equipment performance increases the adoption of new technologies (see Table 43).

Table 43. Nonresidential Large Comprehensive Programs with Spillover Effects

Sponsoring Organization	NTG Values	Freeridership Values	Spillover Values
Wisconsin Power & Light*	0.91	44%	34%
NYSERDA**	1.23	35%	58%
CA Standard Performance Contract	0.7	30%	N/A

* *Shared Savings Decision-Making Process Evaluation Research Results,* prepared for Wisconsin Power & Light by Summit Blue Consulting, April 11 2006

** *Commercial and Industrial Performance Program (CIPP) Market Characterization, Market Assessment and Causality Evaluation*, prepared for New York State Energy Research and Development Authority, prepared by Summit Blue Consulting, LLC, May, 2007.

The SPC program in California has a relatively low NTG value of 0.7. However, this NTG estimate contains adjustments only for freeriders, and does not include spillover effects.

Cadmus also reviewed evaluations estimating spillover effects from two similar programs. Much like the California SPC program, freeridership is large, with values of 35% for NYSERDA and 44% for Wisconsin. However, these high freeridership values are largely offset by large spillover estimates, with an adjusted NTG of 0.91 for Wisconsin and 1.23 for NYSERDA.

Refrigerator and Freezer Recycling Programs

NTG estimates for appliance recycling programs tend to be well below 1.0. As shown in Table 44, these estimates in California are 0.61 for refrigerators and 0.7 for freezers. This type of program likely does not lend itself to much (if any) spillover effect, as it is unlikely many participants or nonparticipants would dispose of additional qualified refrigerators and freezers beyond those they dispose of within the program. Therefore, these low NTG values may be appropriate.

Numerous studies investigating NTG ratios for refrigerator and freezer recycling programs have been completed recently. The results from these evaluations indicate consistently sub-1.0 NTG ratios, ranging from 0.31 to 0.79 for refrigerators, and from 0.38 to 0.82 for freezers (see Table 44).

Table 44. Reported NTG Ratios for Appliance Recycling Programs

Study	Study Year	Refrigerator NTG Ratio	Freezer NTG Ratio
Rocky Mountain Power Wyoming, The Cadmus Group	2011	0.57	0.58
Ameren Illinois, The Cadmus Group	2010	0.79	0.82
Pacific Gas & Electric, The Cadmus Group	2010	0.51	N/A
Ontario Power Authority, The Cadmus Group	2008	0.48	0.52
Statewide Residential Appliance Recycling Program, ADM Associates, Inc.	2008	0.61	0.71
Wisconsin Residential Appliance Turn-In Program, PA Consulting Group,	2008	0.57	N/A
Washington Refrigerator and Freezer Recycling Program, PacifiCorp, KEMA	2007	0.31	0.56
California Statewide Residential Appliance Recycling Program, KEMA-Xenergy	2004	0.35	0.54
Sacramento Municipal Utility District, Heschong Mahone Group	2003	0.55	0.68
Southern California Edison, Xenergy	1998	0.53	0.57
Southern California Edison, Xenergy	1996	0.42	0.38

Energy-Efficient Residential Clothes Washers

Many utilities offer programs promoting ENERGY STAR residential appliances, such as clothes washers. In recent years, however, evidence has appeared that the market for energy-efficient clothes washers is being transformed, with resulting low NTG estimates. Attribution for this market transformation may lie with the ENERGY STAR program, and not with local utility financial incentive programs. If so, this would indicate very little spillover (especially nonparticipant spillover) from this program.

Efficiency Vermont[38] has evaluated energy-efficient clothes washers as part of its portfolio of energy-efficient appliances, offered under the efficient products portion of its residential program. In 2001, Efficiency Vermont estimated the NTG ratio for this program element as only 0.38. In 2004, Efficiency Vermont re-estimated NTG, and results showed an even lower value of 0.17.

These studies did not specifically address spillover. However, the evaluation report noted the high saturation of ENERGY STAR clothes washers in the marketplace not as a local phenomenon, but as a national phenomenon, inferring attribution for spillover would require a national rather than local effort.

Despite this very low NTG value, Efficiency Vermont plans to continue administering rebates for ENERGY STAR clothes washers to maintain the good relationships with retailer channels built up over many years.

38 *Final Report: Phase 2 Evaluation of the Efficiency Vermont Residential Programs*, prepared for the Vermont Department of Public Service, prepared by KEMA, Inc, December 2005

Conclusions

Cadmus' examination of the methods, assumptions, and policies used to address NTG resulted in these key findings.

- ***Methods for measuring NTG elements, particularly spillover, are imprecise.*** The methods for calculating freerider and spillover effects exhibit considerable limitations, and little consensus exists among evaluation experts on best methods. Methods used to calculate NTG have inherent biases, particularly those based on self-reporting (the most common approach). These biases can significantly affect NTG analysis results.
- ***NTG estimates would have a small impact on the societal benefit test.*** If the benefit-cost tests were run with net impacts, programs with an NTG ratio of less than one would have administrative costs spread over fewer participants. Given administrative costs normally represent only a small percentage of program expenditures, this impact would be minor.
- ***Many states have assumed a NTG ratio of 1.0***. A review of NTG methods and application of NTG in 32 jurisdictions conducted by Cadmus found that 13 (40%) did not adjust savings for freeridership. In a recent decision by the CPUC, IOUs will report gross savings as the measure for compliance.
- ***A study of best-practices programs found more than two-thirds of all identified programs had an NTG value of approximately 1.0.*** Approximately half of the studies (49%) either assumed or calculated a NTG value of 1.0, and 68% of the studies had NTG values between 0.9 and 1.0. In most cases, NTG values, when used by a program, were only based on freeridership values. Consequently, an even higher percentage of programs would have a NTG ratio of approximately 1.0 if spillover were examined.
- ***Assuming a NTG ratio of 1.0 may be conservative in certain cases***. Research indicates some programs, particularly those for lighting, routinely achieve NTG ratios well over 1.0 when spillover is examined. Even in programs where high freeridership is reported, spillover effects are largely ignored. If properly accounted for, spillover effects may offset freeridership to a large extent.

Given these findings, it appears reasonable that gross savings be used as the basis for reporting and target compliance. However, utilities should make efforts to design effective programs that minimize freeridership through the following techniques:

1. ***Regularly track the saturation of measures within their own service areas and in other jurisdictions.*** For example, ENERGY STAR clothes washers continue to gain market share throughout the country, and freeridership will likely increase, resulting in an NTG of less than 1.0.
2. ***Carefully monitor market responses to particular programs, and set incentive levels that minimize freeridership.*** As programs mature and market shares for efficiency measures increase, program administrators may be inclined to reduce incentive levels. Paradoxically, however, freeridership tends to be higher in programs with low incentives, as lower incentives are less likely to motivate customers to adopt efficiency measures. Thus, incentive levels should be carefully reviewed and set at values that motivate a substantial number of participants to install efficiency measures.