

DSM HANDBOOK

A DSM HAND BOOK FOR ONTARIO NATURAL GAS LOCAL DISTRIBUTION COMPANIES

APRIL 10, 2006

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Background

This Handbook has been prepared to assist natural gas local distribution companies (utilities) in meeting the filing requirements associated with their Demand-Side Management (DSM) programs. This Handbook sets out the regulatory framework and provides “prescriptive” rules and the basic requirements related to planning, delivering and evaluating DSM program offerings, with particular focus on the planning and evaluation elements. This Handbook will form the basis for natural gas utilities’ DSM activities starting in 2007 and is expected to be used until reissued by the Ontario Energy Board.¹

The development of prescriptive rules that can be applied across utilities and programs is applied because it provides some degree of consistency in approach between the utilities and serves to reduce the regulatory burden of DSM for all parties.

The original set of Guidelines that the natural gas utilities operated their DSM efforts under were laid out in EBO 169. This Handbook represents an update to EBO 169 and builds on the various arrangements and resolutions made through subsequent Board Decisions and proceedings. The development of this Handbook started with an examination of the various issues identified in the Board Procedural Order No. 1² (termed the Issues List hereafter) and extended that examination to include other issues that are relevant to DSM.

The structure of this document generally follows the categories as presented in the Issues List:

Section 1 identifies the specific filing requirements needed for Board approval of the utilities’ DSM activities.

Section 2 highlights the DSM Plan requirements.

Section 3 examines cost effectiveness and screening requirements for a DSM portfolio. It includes a discussion and description of the Total Resource Cost Test (TRC) test and the various inputs and components that make up the test.

Section 4 introduces the common DSM planning guide to be used by natural gas utilities in Ontario, including standardized assumptions and inputs for undertaking the TRC test.

¹ Changes to assumptions or amendments to multi-year plans are to be done within the rules established by this Handbook.

² “Natural Gas Demand Side Management Generic Issues Proceeding Procedural Order No.1”, Board File No. EB-2006-0021

Section 5 examines the requirements for establishing and clearing lost revenues through the Lost Revenue Adjustment Mechanism (LRAM).

Section 6 examines the requirements for establishing an incentive through the Shared Savings Mechanism (SSM).

Section 7 examines the requirements for using and clearing the Demand-Side Management Variance Account (DSMVA).

Section 8 examines the requirements for using and clearing the Electric Program Earnings Sharing Deferral Account (EPESDA).

Section 9 outlines the use of the stakeholder consultation process.

Section 10 identifies research requirements in support of DSM activities.

Section 11 examines the expected evaluation requirements and report(s) and the use and role of the third party Auditor.

Section 12 discusses how market transformation and lost opportunity programs are integrated into the DSM activities, including the nature and focus of program design and evaluation requirements.

Section 13 examines attribution and identifies rules for sharing claimed results when there are multiple parties (both regulated and non-regulated) delivering the programs. This section also outlines the role and ability for utilities to provide program delivery for external parties such as electric LDCs.

1. Ontario Energy Board Approval

The Ontario Energy Board (OEB) approves activities associated with natural gas utility delivery of DSM. The following DSM framework provides a more efficient and streamlined role for all Stakeholders including the OEB. In this framework, the role of the Board consists of approval of key elements of the utilities' multi-year plans and results, including:

- budgets;
- cost effectiveness of the plans;
- avoided costs;
- measures assumptions not previously approved;
- DSMVA, SSM, LRAM and EPESDA³ claims; and
- account clearance.

Table 1 shows the various aspects of Board input to the process. Each component is discussed in detail in the following sections. The framework shall follow the rules as approved by the Board in the EB-2006-0021 proceeding.

Table 1: Components of DSM for OEB Approval

	DSM Multi-Year Plan	Annual
Budgets	✓	
Plan Measure Assumptions	✓	
Portfolio TRC Test Results	✓	
Avoided costs	✓	
Measure assumptions not previously approved in the Handbook		✓
LRAM, SSM, DSMVA, and EPESDA approval for clearance		✓

³ Electric Program Earnings Sharing Deferral Account as approved in EB-2005-0001.

2. DSM Plan Requirements

DSM Plans will be based on a multi-year planning horizon. The term of the Plan shall be for the duration of the incentive regulation term, if possible, but not less than 3 years. This approach represents best practice for DSM planning in North America.⁴ As shown in Table 1, certain aspects of a multi-year plan require Board approval.

The following defines the terms used in Table 1.

Budget Setting: Budgets shall be established by the utility, having regard to utility-specific circumstances, including programming needs, research and evaluation requirements and regulatory engagement. A bottom-up approach to Plan development is appropriate.

Measure Assumptions: Utilities shall apply to the Plan all key assumptions regarding savings, costs, free ridership and equipment life as defined in Appendix A. This information has been provided in the form of a standardized “Measures List”, similar to that used by the electric LDCs in Ontario.⁵ Measure assumptions for new programs are to be submitted to the Board on an annual basis, if required.

TRC Test Results: Utilities shall calculate and report the anticipated TRC results for the portfolio, based on standard assumptions regarding costs and benefits. See Section 3.

Avoided Costs: Utilities shall submit updated avoided cost estimates, including relevant documentation and rationale for use in the DSM Plan. See Section 4.

LRAM: The LRAM is a rate adjusting mechanism that captures the increase or decrease in a utility’s distribution margin due to the utility either underachieving or overachieving the DSM volumetric savings estimate included in rates for the first year of program implementation.

SSM: A Shared Savings Mechanism (SSM) is a financial tool that allows utilities and customers to “share” in the societal benefits that successful DSM programs generate. SSM can include both Resource Acquisition and Market Transformation incentives.

DSMVA: The existence and use of a DSM variance account provides a degree of flexibility for utilities as they undertake DSM investment. A DSM variance

⁴ The Canadian Gas Association identified a multi-year approach to planning as a best practice for DSM: “Canadian Natural Gas Distribution Utilities” Best Practices in DSM, IndEco Strategic Consulting and b. Vernon & Associates for Canadian Gas Association, 2005, pg 30.

⁵ Ontario Energy Board, September 8, 2005. “Total Resource Cost Guide”.

account may be used to rebate ratepayers at year end for unused budget allocation or to recover from ratepayers additional costs incurred for DSM programs.

EPESDA: The EPESDA is used to record half of the net revenue earned by a utility through delivering programs on behalf of an external party such as an electric LDC.

3. Screening of the DSM Portfolio

Background: DSM investments must be examined for their cost effectiveness, based on a methodology that provides similar economic evaluation to supply side investments. In practice, this cost effectiveness examination typically relies on a test known as the Total Resource Cost Test (TRC). EBO 169 established the TRC test as the key hurdle test for DSM investments by natural gas utilities. The application of this test has been affirmed for use by electric LDCs by the Ontario Energy Board through the publication of the “Total Resource Cost Guide”.⁶ Users of this Handbook are encouraged to review the Total Resource Cost Guide for a comprehensive discussion of the components of the TRC Test.

The TRC test is defined as a test that “measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant’s and the utility’s costs”.⁷ The TRC test measures the benefits and costs of DSM investments from a societal perspective. Under the TRC test, benefits are driven by avoided resource costs. Costs in the TRC test are the costs of the energy efficient equipment and the utility program support costs associated with delivering the equipment to the marketplace.

As indicated, the TRC Test examines streams of benefits and costs and uses discounting principles to express these future values as a single number. The NPV_{TRC} formula is as follows:

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

⁶ IBID.

⁷ California Public Utilities Commission, (2001) Standard Practices Manual: Economic Analysis of Demand-Side Management Programs and Projects.

$$B_{TRC} = \sum_{t=1}^N \frac{AC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^N \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and;

B_{TRC} = The benefits of the program

C_{TRC} = The costs of the program

AC_t = Avoided costs in year t

UC_t = Program costs in year t

PC_t = Participant cost in year t

d = Societal discount rate

As shown, the benefits stem from resource costs that are avoided. The costs that are included are the cost of the energy efficient equipment and the utility program costs. Subtracting the costs from the benefits provides the net benefits. For a program to be considered cost effective, the net benefits must be greater than zero.

Use of the TRC Test: The TRC test is the sole test of cost effectiveness for programs and will be used for screening the portfolio of programs. The utilities will ensure that the entire portfolio has a positive net TRC. The utilities may reserve the right to invest in individual technology or program offerings that do not have appositve net TRC, if the utility believes there are compelling reasons to do so.

Due to the unique characteristics of market transformation programs they shall not be included in the Plan portfolio TRC test and shall be assessed separately. For these programs, utilities will develop metrics specific to the program, which will be approved by the Board (see section 12).

4. Assumptions and Inputs

Common Planning Guide: Input assumptions for unit measure savings for prescriptive measures, and for incremental equipment costs, measure life, and free ridership assumptions for both prescriptive and custom programs will be established for the entire planning horizon. These are common assumptions across the gas utilities. Updates to these assumptions that may arise based upon research or new information will be used only on a prospective basis (i.e. for the next multi-year Plan). Similar to the Measures List maintained by the OEB as part of the Total Resource Cost Guide⁸ for electric LDCs, the Board will also maintain an official list of assumptions for the natural gas utilities. A list of measure and program assumptions is provided in Appendix A.

Custom Projects. Custom projects are those projects where a utility facilitates the implementation of specialized equipment and technology not identified in the Measures Assumption tables in Appendix A. Savings for these project are to be calculated on a project specific basis and a free ridership of 30% is to be used in calculating net savings.

Avoided costs, Background: The TRC Test assesses DSM costs and benefits from a societal perspective. The benefits are defined as “avoided costs”. This represents the benefit to society of not having to provide an additional unit of supply. Avoided costs exist for all resources, including natural gas, electricity, oil, water, etc. Certain DSM programs will provide reductions in the use of these other resources and while these savings may not be the primary target of the program, it is appropriate to include these savings in the TRC analysis.

The TRC test requires an analysis over the life-cycle of the DSM measure. As such, long-term projections of avoided costs are required. As well, any DSM measures that are included in the analysis must have equipment life estimates along with the estimates of the savings and the costs.

Avoided costs are calculated using detailed projections of system load configurations and expected use. Utilities will calculate, report, and use new sets of avoided costs (natural gas, electricity and water) in preparation for the multi-year Plan submission, based on market values.

Avoided costs, Natural gas: For natural gas, supply costs include transportation, distribution, storage, and commodity costs. The utilities shall use a common methodology for calculating these costs. This shall include market values for commodity costs and utility specific transportation, distribution and storage costs.

All assumptions outlined in the Handbook are to be applied in the manner outlined in Table 2.

⁸ IBID

Table 2
Treatment of DSM Input Assumptions for the Purpose of Calculating SSM, LRAM and DSMVA

Measure Input Assumptions						
Program Type	Participants	Annual Unit Savings	Free Rider %	Measure Life	Unit Incremental Costs	Direct Program Costs
Prescriptive	Actual	Fixed	Fixed	Fixed	Fixed	Actual
Custom	Actual	Actual	Fixed	Actual	Actual	Actual

5. Lost Revenue Mechanism (LRAM)

Background: The LRAM is a rate adjusting mechanism that captures the increase or decrease in the utility's distribution margin due to the utility either underachieving or overachieving against the DSM volumetric savings estimate included in rates.

The LRAM is intended to compensate utility shareholders for margins lost as a result of greater than anticipated DSM performance and conversely, compensates ratepayers for any amounts built into rates where the utility does not meet the volumetric savings estimate that was included in rates.⁹

Approach: The calculation of actual volumes saved for the purposes of LRAM will be based on assumptions approved in the Plan. Improved savings assumptions shall only be used on a prospective basis. For a multi-year plan, prospective use means for use in the next multi-year plan. The actual savings that are used are those that are provided as part of the annual Evaluation Report (and Audit). Calculation of the first year impact of lost volumes on distribution revenues are to be calculated as 50% of the total annual savings and at 100% for each subsequent year. This reflects the average savings impact of measures that are implemented over the course of a full year.

The LRAM is to be calculated, reported and cleared annually as part of the annual evaluation and reporting efforts.

Independent Auditor: An independent auditor shall review and verify the claimed volumetric and financial results.

⁹ In EBRO 495, the Board directed Enbridge to implement the LRAM as proposed in the Settlement Agreement for 1998 and described in the DSM Plan, EBRO 495, Ex 2, Tab 6, Sch 1, page V-4.

Rate Allocation: Rate changes that are a result of the change in distribution revenue due to the DSM programs will be allocated to the rate classes where the DSM volume reductions originated. Once the LRAM amounts have been verified by the Auditor and approved for clearance, they will be assigned to the various rate classes based on the volumes saved in the rate class.

6. Shared Savings Mechanism (SSM)

Background: A Shared Savings Mechanism (SSM) is a financial tool that allows utilities and customers to “share” in the societal benefits that successful DSM programs generate. The utility is thus rewarded for its delivery of services and programs to reduce energy use and is able to achieve a return on its human capital investment.

The SSM is an effective mechanism to encourage utilities to make resource and managerial commitments to optimize their DSM offerings. Shared Savings mechanisms are considered separately for resource acquisition programs and market transformation programs.

Resource Acquisition Programs: The resource acquisition Shared Savings Mechanism will be based on the TRC net benefits resulting from program implementation. The SSM calculation uses an increasing simple percentage of net TRC outcome based upon actual results. This is shown in Table 3 below.

Table 3: SSM Mechanism		
TRC (\$mm)	% Payout	Incremental %
1 to 50	1.5%	1.5%
>50 to 100	4.0%	2.5%
>100 to 150	7.5%	3.5%
>150 to 200	12.0%	4.5%
>200	17.5%	5.5%

Market Transformation Programs:

A Market Transformation (“MT”) incentive that addresses the unique characteristics of MT while ensuring that MT efforts maintain an equal footing with Resource Acquisition programs is required.

The incentive model shall assume that MT programs result in equivalent TRC benefits per dollar spent as the Resource Acquisition programs in the utility's portfolio. Further, in order to compete with Resource Acquisition spending, MT programs are to be incented at the highest marginal incentive rate achieved by the Resource Acquisition programs as defined above.

The incentive model shall use the product of the MT spending for the year and the actual DSM portfolio (resource acquisition) TRC net benefits/cost ratio times the percentage of the highest marginal incentive rate achieved for the resource acquisition portfolio of programs.

For example, assume

- A DSM portfolio of resource acquisition programs had a net TRC benefit of \$150 million based on expenditures of \$20 million in O&M.
- The portfolio had a TRC net benefits cost ratio of 7.5:1, or simply stated, for every dollar spent \$7.50 of benefits resulted.
- The Resource Acquisition SSM incentive rate for this level of benefit is 7.5%
- MT activities were undertaken during the year and the actual cost was \$3 million.

The MT incentive calculation is as follows:

$$\begin{aligned} & (\text{NET TRC} / \text{O\&M Spend}) \times (\text{MT Spend}) \times (\text{SSM Marginal Incentive Rate}) \\ & (\$150 \text{ million} / \$20 \text{ million}) \times (\$3 \text{ million}) \times (7.5\%) \\ & 7.50 \times \$3 \text{ million} \times 7.5\% \\ & = \$1.7 \text{ million MT incentive} \end{aligned}$$

The utilities will submit a detailed description of Market Transformation programs as part of the multi-year DSM plans.

Independent Auditor: An independent Auditor will review and verify results and the claimed SSM for both resource acquisition and market transformation programs.

Rate Allocation of Incentives: Incentive amounts that result from the operation of DSM programs will be assigned to the rate classes in proportion to the TRC net benefits received by the rate classes. Where TRC net benefits can not be defined across rate classes, the incentives are to be assigned in the same manner as program costs.

7. Demand-Side Management Variance Accounts (DSMVA)

Background: The existence and use of DSM variance accounts provides a degree of flexibility for utilities as they undertake DSM investment. A DSM variance account may be used to rebate ratepayers at year end for unused budget allocation or to recover from ratepayers additional costs incurred for DSM programs.

Rate Allocation: DSM costs are assigned to the rate classes that benefit from the operation of the programs. Similarly, variance expenditures that occur as a result of the operation of DSM programs will be assigned to the rate classes based on the rate class contribution to the variance.

DSMVA Clearance: The DSMVA is not subject to the DSM audit. Clearance of the DSMVA is done as part of the standard financial operations of the utility.

8. Electric Program Earnings Sharing Deferral Account (EPESDA)

Electric DSM program delivery - There is an opportunity for gas utilities to provide program services to another entity such as an electric LDC. All incremental electric program costs beyond a natural gas utility's traditional portfolio of programs shall be recovered through partnerships with electric LDCs so as to not impact gas ratepayers. The utilities shall share with Ratepayers, on an equal basis, any net revenues achieved through these program activities.

The EPESDA is used to record half of the net revenue earned by the utility delivering programs on behalf of an external party such as an electric LDC. On clearance of the account at year end, 50% of the net revenue is returned to ratepayers and the remaining 50% is distributed to the utility's shareholders.

9. Stakeholder Consultation

The primary purpose of stakeholder consultation is to provide value added insights and guidance with respect to the effectiveness of the DSM investment or related issues. This includes program breadth, direction and characteristics, success factors and stakeholder/customer perspective. While the utilities are solely responsible and accountable for their DSM efforts and are not mandated to undertake consultations, there may be merit, in certain situations, in seeking input and guidance from stakeholders, industry partners and customers.

The utility, which is ultimately responsible and accountable for its DSM program must decide the degree to which it involves stakeholders in the development and

operation of its DSM program. Stakeholder input is desirable but is not mandatory. The utilities are encouraged to pursue stakeholder engagement where it can provide greater efficiency and effectiveness.

10. Research

As part of their development and planning process, utilities should undertake research in support of both planning assumptions and to develop new information with input from the Board, stakeholders and other interested parties. Due to the variation by utility and by year, efforts per year or per planning cycle should be included within budgetary considerations established as part of the multi-year plan. The utilities shall determine the research requirements with the context of their overall DSM plans.

There may be opportunities to combine or share research efforts with other utilities. These should be explored where possible in an effort to reduce duplication. Utilities are encouraged to share their research plans where possible to make it known where opportunities for synergies may exist.

11. Evaluation and Audit

Background: Evaluations of DSM activities are typically undertaken to document and support savings and costs (impact evaluations). In addition, to identify future programming needs, research requirements, and potential new or unexpected barriers and/or opportunities, several types of evaluations are used, including impact and process evaluations as well as research supporting program assumptions.

Impact evaluation and audits are important elements in the determination of SSM, LRAM and the clearance of variance accounts. The documentation and verification component lends itself to an annual process using prescriptive guidelines, while other types of program evaluation can be done as required. The following proposition considers only impact evaluation needs.

Principles – Role of the Utility: Documentation and verification activities are developed under the following principles:

- The utility is responsible and accountable for the evaluation and audit process; and
- The utility shall decide the focus of the evaluation work and the associated budget.

An annual report will provide:

- Details of the program results (See Appendix B for Reporting templates); and
- The annual SSM, DSMVA and LRAM calculations.

Third Party Audit: The role of the Auditor shall focus on validation of the savings and costs with respect to the SSM and LRAM claims in accordance with the rules prescribed by the Board.

12. Market Transformation, Lost Opportunity Programs and Program Funding

Market transformation is defined as “A reduction in market barriers due to a market intervention, as evidenced by a set of market effects that last after the intervention has been withdrawn, reduced or changed.”¹⁰ Market transformation programs are inherently different than typical resource acquisition programs as their focus is shifted towards more upstream channel participants and there is often less reliance on the use of incentives paid to participants or customers. Ultimately, their goal is to increase the market share for energy efficiency products such that the market is transformed. This transformation is often accompanied by a code change that seals in the improved efficiency level (note that utilities may wish to participate in Code discussions as part of the program support).

Measuring the impacts of market transformation programs is more complicated than that of traditional programs, particularly in the absence of incentives. Market transformation evaluation typically relies on the use of “near” and “distant” indicators and measures, all of which require both base-line estimates and on-going tracking. It is also important to establish the indicators as part of the design of the program and to build in processes that ensure appropriate monitoring.

Determining when and how to use market transformation programs requires a solid understanding of market dynamics and the potential. Ideally, this is done on a case by case basis where it is understood that some opportunities will inherently lend themselves to market transformation efforts.

Lost opportunity programs are those that focus on markets where the opportunity to make change is likely only to occur once or very infrequently. This would apply well to the new construction sectors where once energy use decisions are made; they are unlikely to be re-visited for many years. Utilities are encouraged to operate programs that address these lost opportunities to optimize the long term impact of DSM.

¹⁰ EB-2005-0001 Exhibit A7, Tab 3, Schedule 1

Program Funding. Market transformation and lost opportunity funding shall be based on the specific program goals and needs as identified by the utility in its multi-year plan.

13. Attribution of Benefits

Partnerships with Regulated LDCs (i.e. regulated by the OEB). For partnerships between OEB regulated entities, benefits will be allocated based on a negotiated agreement. Where such an agreement does not exist, the rules of the TRC Guide¹¹ will apply. Attribution assumptions made when the Plan is approved must remain constant when the results are assessed.

Partnerships with non-regulated entities. Utilities shall claim savings subject to the rule recently established by the Board in the EB-2005-0001 Partial Decision.

“the Company may claim 100 percent of the benefits associated with DSM programs in which it plays a central role in the marketing and delivery of the program with a non-rate-regulated third party.” (p. 8)

The Board also approved the definition of “central role” in the EB-2005-0001 Partial Decision:

“In the Company’s view it should be considered to have played a central role in a program if it initiated the partnership, initiated the program, funded the program, or implements the program.” (p. 7)

Attribution shall be established at the time that a multi-year plan is developed and approved. Any changes to these values are to be applied prospectively for the next multi-year plan.

Delivery of Electric Programs for Third Parties (e.g. LDCs). LDCs shall be able to enhance Ontario’s Conservation Culture and results through delivering cost-effective programs as outlined in Section 8 of this Handbook. Attribution of benefits will be dealt with within the contracts established between these parties.

In areas where LDC partnerships are not developed, the natural gas utilities shall continue to attempt to enhance electrical benefits associated with existing

¹¹ IBID

programs and should include any of the incremental benefits that can be demonstrated and substantiated in its actual results.

Appendix A: Measure Assumptions

RESIDENTIAL

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions			Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L		Customer Installed	Contractor Installed	
NEW CONSTRUCTION									
Basement Insulation (R-12)	OBC basement insulation levels	weather	93	-	-	25	-	\$700	0%
Energy Star Home	Home built to OBC	weather	800	1,000	-	25	-	\$3,020	0%
High Efficiency Furnace	Mid-Efficiency Furnace	weather	226	-	-	18	-	\$647	30%
High Efficiency Integrated Appliance	Mid-Efficiency Furnace / Storage Tank Water Heater	weather	287	-	-	18	-	\$850	0%
EnerGuide for New Houses	Home built to OBC	weather	450	0	0	25	-	\$2,000	0%
Programmable Thermostat	Standard Thermostat	weather	172	200	-	18	-	\$65	30%
R-2000	Home built to OBC	weather	800	0	0	25	-	\$4,000	0%
Tankless Water Heater	Storage Tank Water Heater	base	206	-	-	20	-	\$650	0%
Two-Stage Furnace with ECM	Mid-Efficiency Furnace	weather	245	580	-	18	-	\$1,563	30%
Waste Water Heat Recovery	No heat recovery	base	267	-	-	30	-	\$625	0%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions				Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L	Customer Installed		Contractor Installed		
EXISTING HOMES										
Condensing Boiler - up to 299 Mbtu/h	Standard Boiler	weather	925	-	-	25	-	\$1,300	0%	
Condensing Gas Water Heater	Storage Tank Water Heater	base	203	-	-	9	-	\$1,000	0%	
Energy Star Clothes Washer	Standard Clothes Washer	base	55	31	28,731	13	-	\$350	8%	
Energy Star Window	Standard Window	weather	13	16	-	25	-	\$52	20%	
Enhanced Furnace	Mid-Efficiency Furnace	weather	320	730	-	18	-	\$1,200	10%	
Faucet Aerator	Faucet w/o aerator	base	17	-	7,592	10	\$2	-	10%	
Heat Traps	Storage Tank Water Heater w/o heat trap	base	73	0	0	10	-	\$80	0%	
High Efficiency Furnace	Mid-Efficiency Furnace	weather	385	-	-	18	-	\$650	48%	
Home Rewards w/o Program. Thermo	Existing Home Sample	weather	1,321	300	0	25	-	\$2,708	8%	
Low-Flow Showerhead	Average Existing Stock	base	134	-	27,634	10	\$5	\$15	10%	
Pipe Insulation	Water Heater w/o pipe insulation	base	17	-	-	15	\$1	\$4	4%	

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions				Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L	Customer Installed		Contractor Installed		
EXISTING HOMES CONT'D										
Power Comb. Boiler - up to 299 Mbtu/h	Standard Boiler	weather	659	-	-	25	-	\$500	51%	
Programmable Thermostat	Standard Thermostat	weather	212	100	-	18	-	\$65	11%	
Tankless Water Heater	Storage Tank Water Heater	base	203	-	-	20	-	\$650	0%	
Two-Stage Furnace with ECM	Mid-Efficiency Furnace	weather	332	535	-	18	-	\$1,563	30%	
Waste Water Heat Recovery	No heat recovery	base	267	-	-	30	-	\$625	0%	

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions				Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L	Customer Installed		Contractor Installed		
LOW INCOME										
Faucet Aerator	Faucet w/o aerator	base	17	-	7,592	10	\$2	-	0%	
Low-Flow Showerhead	Average Existing Stock	base	134	-	27,634	10	\$5	\$15	0%	
Pipe Insulation	Water Heater w/o pipe insulation	base	17	-	-	15	-	\$4	0%	
Programmable Thermostat	Standard Thermostat	weather	212	-	-	18	-	\$90	0%	

COMMERCIAL

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions			Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L		Customer Installed	Contractor Installed	
NEW BUILDING CONSTRUCTION									
Condensing Gas Water Heater	Storage Tank Water Heater	base	1,750	-	-	15	-	\$4,200	5%
Rooftop Unit	Standard Rooftop Unit	weather	1,275	-	-	20	-	\$1,250	0%
Programmable Thermostats	Standard Thermostat	weather	519	921	-	18	-	\$65	11%
Tankless Water Heater	Storage Tank Water Heater	base	825	-	-	20	-	\$2,200	0%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions			Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L		Customer Installed	Contractor Installed	
EXISTING BUILDINGS									
Condensing Gas Water Heater	Storage Tank Water Heater	base	1,750	-	-	15	-	\$4,200	5%
Faucet Aerators	Faucet w/o aerator	base	17	-	7,592	10	\$2	-	10%
High Efficiency Furnace	Mid-Efficiency Furnace	weather	385	-	-	18	-	\$650	10%
Low-Flow Showerhead	Average Existing Stock	base	134	-	27,634	10	\$5	\$15	10%

Efficient Equipment & Technologies	Base Equipment & Technologies	Load Type	Resource Savings Assumptions				Equipment Life Years	Incremental Cost		Free Ridership %
			Natural Gas m3	Electricity kWh	Water L	Customer Installed		Contractor Installed		
EXISTING BUILDINGS CONT'D										
Pre-Rinse Spray Nozzle	Average Existing Stock	base	2,434	-	432,800	5	-	\$100	5%	
Programmable Thermostats	Standard Thermostat	weather	519	921	-	18	-	\$65	11%	
Rooftop Unit	Standard Rooftop Unit	weather	1,275	-	-	20	-	\$1,250	0%	
Tankless Water Heater	Storage Tank Water Heater	base	825	-	-	20	-	\$2,200	0%	
Two-Stage Furnace with ECM	Mid-Efficiency Furnace	weather	332	535	-	18	-	\$1,563	30%	
Water Tank De-liming	Storage Tank Water Heater (with liming)	base	1,033	-	-	3	-	\$150	0%	

