

FortisBC Inc.
2005 Revenue Requirements Application,
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Q110.0 Reference: Volume 1, Tab 9, Appendix 9, p. 21

What benefits does FortisBC expect from the Computerized Maintenance Management System? Have these benefits been quantified? If so, please provide the analysis.

A110.0 The benefits of the Computerized Maintenance Management System are primarily associated with increasing the effectiveness and efficiency of FortisBC's maintenance programs. In the long term this will translate into improvements in reliability of individual pieces of equipment, as well as overall system reliability while reducing the possibility of premature spending on maintenance or capital activities. Our objective is to optimize the life of the asset. Performing just the right amount of maintenance at the right time ensures that operating costs will be as low as possible, while ensuring that assets are able to be utilized throughout their useful life. For details please refer to Volume 1, Tab 9, Appendix 9, Page 22 and 23. FortisBC has not quantified the benefits of a CMMS system as they are hard to quantify as outlined on lines 8 – 16 page 22 Appendix 9.

However, preventing failures creates value. To demonstrate this value, the prevention of a failure of one transformer could save the company in the order of \$250,000 to \$750,000. Preventing a transformer failure would prevent an extended outage of up to 12 - 24 hours depending upon the location and timing of such a failure.

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Q111.0 Reference: Volume 1, Tab 10.1, pp. 3-4

Please file the Semi-Annual Demand Side Management report for the period ending December 31, 2004, if available. If not yet complete, please indicate the expected filing date for the report.

A111.0 The Semi-Annual Demand Side Management report for December 31, 2004 will be complete and filed by March 15, 2005.

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112.0 Reference: Volume 1, Tab 10.1, pp. 5-6

FortisBC plans to update and file its Demand Side Management potential study and complete a new plan covering the period 2005-2014. It has attached the terms of reference for the update under Appendix D.

Q112.1 Please confirm that the study update and the new plan are understood to be part of the same terms of reference, or whether they are separate projects.

A112.1 The energy efficiency potential update and the PowerSense business plan are separate projects.

The potential update, once completed, will provide an identification of economic demand side management measures and technologies and their potential resource savings. An estimate of achievable savings will also be presented. That information will then be input to the development of the business plan, recognizing that the achievable potential represents the savings that are available at customer sites, buildings and households.

The FortisBC business plan must necessarily consider the electric system, forecast load growth, changes in customer accounts, and annual budgets over five years that will be available for PowerSense programs.

Q112.2 When does FortisBC expect the update and plan to be filed?

A112.2 The energy efficiency potential update is expected to be filed June 30, 2005. The business plan will be filed October 31, 2005. Both the potential update and the business plan will be developed with input, review and comment from the DSM Incentive Committee, a process that requires schedule considerations.

Q112.3 What are the costs of the update and plan and are these included in the 2005 Planning and Evaluation costs in the table on page 6 of Tab 10?

A112.3 The costs of the Energy Efficiency Potential Update and the 2005 Year Business Plan are \$26,000 and \$20,000 respectively. These are included in the 2005 planning and evaluation costs in the table on page 6 of Tab 10.

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113.0 Reference: Volume 1, Tab 10.1, pp. 7, 9-11

Q113.1 Please show the derivation of the planned and forecast costs and savings for 2004 and 2005, as summarized in Tables 10.1.2.4, 10.1.2.5 and 10.1.2.6. Please provide all assumptions used.

A113.1 Derivation of 2004 & 2005 plan costs and savings

Assumptions:

Target for General Service and Industrial based on:

- past years performance
- information derived from energy management committees
- discussion with and through experience of General Service Representatives.
- review of jobs in the job queue that are under consideration

Target for residential based on:

- past experience
- discussion with Residential Representatives. on economic activity within respective areas
- review of proposed projects in permitting reports

Costs:

Labour is based on staff count and allocated according to programs based on expected activity. Incentives are based on kW.h savings expected, and other costs are based on expected requirements.

Power purchase rates as per current BCH Schedule 3808 and rates per Tariff

No change in detailed calculations between both years i.e. Benefit Cost ratio, Levelised Cost

Q113.2 Please explain how the estimates of DSM savings account for investments by customers that may have occurred in the absence of any expenditures by FortisBC. Please provide a summary by program of such energy savings.

A113.2 The planning estimates of DSM PowerSense program savings have been derived from energy savings potential studies, the first completed in 1993 and the update completed in 1999. Planning for PowerSense bases the annual target savings on the estimated customer participation in our programs.

For those product-based programs, program evaluation methodology considers a portion of actual participation that may have occurred without the program. This has been done for the Residential Compact Fluorescent lighting (CFL) program.

For equipment efficiency improvement, such as increasing the Seasonal Energy Efficiency

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Rating (SEER) of new heat pump installations, the program is designed for those purchasers who would not have chosen the higher level of efficiency unless the PowerSense program was there to assist them.

For General Service and large customers, PowerSense works with customers' plans for capital improvement or expansion and upgrades the plans to higher efficiency levels for equipment and systems. For these participants it is readily assured that they would not have done the higher efficiency without the programs based on the extent to which their plans had proceeded.

Residential Lighting:

The 2002 review of our CFL program reduced reported program activity savings by 9% to account for those participants who would have purchased CFLs without the program's coupon. Annual program actual participation will be adjusted downwards by this amount beginning in 2004. This has been done to recognize the duration of the CFL program in FortisBC's service area and an estimate of the CFL replacement bulbs that are being purchased.

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Q113.3 Please show the derivation and summary breakdown of the planned and forecast costs for 2004 and 2005, as summarized in Table 10.1.2.7. Please provide all assumptions used.

A113.3

2004 Planning and Evaluation

	2004	2004	2005
	Plan	Actual	Plan
	(\$)		
Planning & Evaluation Labour	165,043	175,397	211,601
Travel customer, employee and technical	17,800	12,791	14,000
Telephone	5,400	5,520	6,000
Training (engineering, marketing)	9,500	1,262	8,000
Load Profiling Equipment -General Service	22,000	18,028	
Residential smart metering /evaluation	2,000	1,980	10,500
Website Research and development			11,000
Office and Administration	2,248	1,756	1,780
Consulting Resources	77,000		
Willis Energy Services		34,161	
AEEE project			2,500
DSM Committee liaison work			1,500
Technical research			1,000
2005 Potential Study and Business Plan			46,000
Lightstream Business services		30,780	31,000
Accounting and regulatory reporting			
Stantec Engineering		6,042	10,000
Project specific impact evaluation			
2003 Annual review	300,991	287,717	354,881

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114.0 Reference: Volume 1, Tab 10.1, pp. 7-12

Table 10.1.3 on page 12 “shows the costs associated with Demand Side Management as found at Tab 6 (Rate Base) of [the] Application.”

Q114.1 Please provide the reference to the respective Table and its associated Line item in Tab 6 within which these costs are included.

A114.1 The DSM costs in Table 10.1.3 are included in the Deferred Charges and Credits. The reference is found at Line 1 in Tables 1 – B (2002) through 1 – B (2005).

Q114.2 For each program in Tables 10.1.2.4 through 10.1.2.7, please provide a summary breakdown of 2004 and 2005 DSM additions and amortization.

A114.2 Please see table below for a summary breakdown of 2004 and 2005 DSM additions.

	2004			2005		
	Incentives	General Program Costs	Total	Incentives	General Program Costs	Total
	(\$000)			(\$000)		
RESIDENTIAL: Table 10.1.2.4						
Heat Pumps	44	45	89	31	33	64
A/A Heat Pumps	106	144	249	76	152	228
New Home Program	260	85	345	70	20	90
Residential Lighting	86	59	146	116	54	170
Home Envelope	21	16	37	10	33	43
Water Savers	0	2	2	0	0	0
-	517	350	867	303	292	595
GENERAL SERVICE: Table 10.1.2.5						
Lighting	136	70	207	76	131	207
B.I.P. - Retro	69	74	143	81	122	203
B.I.P. - New	207	91	298	135	97	232
Water Handling Infrastructure	44	25	69	28	33	61
-	455	261	717	320	383	703
INDUSTRIAL: Table 10.1.2.6						
Industrial Efficiency	20	18	38	49	20	69
Pumps & Fans	25	18	43	36	31	67
Compressors	23	7	30	13	10	23
New Process Design	3	7	10	12	10	22
-	71	51	121	110	71	181
Program Total	1,043	662	1,705	733	746	1,479
Planning and Evaluation: Table 10.1.2.7						
	(see response 113.1)		290			355
Net Expenditure			1,995			1,834

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With respect to the amortization, it is calculated on the sum of DSM expenditures, net of income tax, for the year. The amortization rate of 12.5 percent is applied to this balance on a straight line basis.

Q114.3 Does the amortization period of each DSM program or measure correspond to the lifetime of the respective program or measure? Please provide the length of the amortization period for each DSM program or measure, and explain as necessary.

A114.3 All program costs are pooled and are amortized at 12.5 percent on a straight basis over eight years.

This treatment is in accordance with BCUC Orders G-55-95, item 6, dealing the amortization of Demand Side Management costs and G-73-96 dealing with a negotiated settlement item 1 (d) which changed the amortization period from 20 years to 8 years.

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Q115.0 Reference: Volume 1, Tab 10.1, p. 12

Please provide a copy of the report on DSM incentive mechanisms completed in November 1999 by David Nichols of the Tellus Institute.

A115.0 The report from the Tellus Institute is attached as BCUC A115.0.

Annex 1: Demand Side Management Cost
Recovery Mechanisms

A number of jurisdictions in North America have developed cost recovery and incentive provisions aimed at encouraging the pursuit of cost-effective demand-side management. This table lists jurisdictions in which three types of provisions were being applied to at least one investor-owned utility in 1999. These provisions are:

- Program cost recovery, referring to full recovery of utility expenditures for approved demand-side programs.
- LRAM or RevCap. LRAM refers to lost revenue adjustment mechanisms that make the utility whole with regard to fixed costs lost through sales reductions from energy efficiency. RevCap refers to revenue caps, which provide for a maximum level of revenues during a multi-year period, during which revenues are decoupled from changes in sales.
- Shareholder incentive, referring to additional profits provided to the utility based on demonstrated DSM performance. The cost recovery and incentive provisions for jurisdictions in this category are described in more detail in Annex 2.

This page reserved for Excel table

Annex 2: Shareholder Incentives for
Demand Side Management Performance

Shareholder Incentives for DSM Performance

Introduction

DSM incentives should be designed based on the policy and regulatory framework, utility structure, and economic and energy situation, that exist within the jurisdiction considering the incentives. Nevertheless, the nature of DSM mechanisms employed elsewhere is a matter of background interest. This annex synthesizes DSM incentives recently in place (1998-1999) in several North American jurisdictions. The summaries are limited to jurisdictions where there is some type of shareholder reward for DSM.

British Columbia

1998

General Treatment of DSM and its Costs: Recovery of program costs and shareholder incentives are currently in effect for investor owned utilities.¹ These are BC Gas Utility, Ltd. and West Kootenay Power, Ltd. (BC Gas and WKP).

DSM Funding: DSM expenditure levels are proposed by the distribution utilities and established by the BCUC when it approves the utilities' DSM Plans.

Recovery of Program Costs: Full DSM program cost recovery is allowed. The amortization period for the outstanding balance of deferred DSM costs for WKP is 8 years.²

Lost Revenues: There is no lost margin recovery for BC Gas or WKP. Within WKP's PBR framework, operating expense targets are largely based on the number of customers, a RevCap approach that can offset the need for an LRAM.³

Shareholder Incentives: BC Gas Utility Ltd. BC Gas receives a share of the net present value of benefits from DSM, based on the Total Resource Cost

¹ British Columbia Utilities Commission, *In the Matter of BC Gas Utility Ltd. Revenue Requirements Application 1998-2002*, July 23, 1997.

² Grant, W. J., BCUC, *Re: Proposed Settlement of Issues Concerning the February 26, 1996 Revenue Requirement Application of West Kootenay Power Ltd.* May 3, 1996.

³ WKP "Revenue Requirements Application Negotiation Worksheet," September 24, 1999.

Test. If the quantity of energy saved is 75% up to 100% of that forecasted at the start of a DSM plan, the share of savings to the utility is 3%. If the quantity of energy saved is 100% or more, the share is 5% of net benefits.

The BCUC states that results “from programs developed within the utility but which at some point are moved outside the utility will be included in the DSM calculation where those program results are tracked by the utility”.⁴

Shareholder Incentives: West Kootenay Power Ltd. WKP amortizes its DSM costs earning a return on the unamortized balances. This constitutes a positive shareholder incentive for DSM investment. WKP also has a DSM incentive plan with the objective of achieving cost-effectiveness while also encouraging the attainment of DSM energy savings targets. During 1996-1998, the DSM incentive was based on variable costs and energy savings. If the variable costs of providing DSM programs was lower than forecasted, while still achieving forecasted kWh savings, then the difference between actual and forecasted variable costs was shared equally with customers. The incentive was calculated by multiplying the actual kWh savings times the difference between the target and actual variable costs, and then dividing this product by two. Variable costs are those that fluctuate strongly as a function of DSM program delivery —advertising, rebates, marketing costs, travel expense, etc. WKP would receive this incentive if 90% of its forecasted energy savings was achieved.⁵

1999

WKP’s DSM incentive for 1999 adds two features to the structure described above. The incentive is calculated separately for the residential, general service, and industrial components of DSM, then summed. Additionally, a component related to fixed costs is added, and works as follows. If the Company would be due an incentive based on energy savings attained and variable costs reduced, as described above, then fixed cost variations are considered. The fixed cost base is the lower of 1997 or 1998 labour and training costs for delivery activities. The difference between 1999 fixed costs and the fixed cost base is added to the variable cost difference, increasing the incentive (if fixed costs have been reduced) or decreasing the incentive (if fixed costs have grown).⁶

⁴ Consolidated Settlement Document, *ibid.*, page 5.

⁵ *W. Kootenay Power Ltd. Semi-annual DSM Report*, December 31, 1997.

⁶ “Demand Side Management Incentive Mechanism for 1999,” Appendix A to *Commission Order No. G-123-98*, page 7.

California

1998

General Treatment of DSM and its Costs: Electric utilities are in a transition period during which they administer DSM programs with funds collected at the distribution level through a Public Goods Charge (PGC) that is in effect.⁷ Recovery of program costs and shareholder incentives are currently in effect. After 2001 administration may shift to the California Energy Efficiency Board that was established by the Public Utilities Commission.

DSM Funding: Transitional funding levels are specified by law for San Diego Gas and Electric Co., Southern California Edison Co., and Pacific Gas and Electric Co.

Recovery of Program Costs: Electric utilities collect costs through the PGC. Gas utility DSM program costs remain fully recoverable through rates until the Public Utilities Commission (PUC) imposes a PGC for gas.

Lost Revenues: Utility revenues have been decoupled from sales through adjustment mechanisms that reconciled utility revenues to the amount authorized in the last rate case (adjusted annually for certain cost changes in an attrition proceeding). These have offset the need for LRAMs. Electric decoupling is being phased out, but gas utility revenues are still decoupled from sales and reconciled to the amount authorized in the prior rate case (adjusted for certain cost changes).

Shareholder Incentives: The PUC approved similar structures of shareholder incentives for 1998 for all four investor-owned utilities in the state.⁸ San Diego Gas and Electric's follows.

1. For programs that produce quantifiable streams of resource benefits, 5% of program expenditures plus a 15% share of net benefits, based on utility avoided costs only.

2. For programs that provide information and technical assistance, or promote market transformation without the benefits being readily quantifiable, 5% of program expenditures.

3. For Standard Performance Contract programs⁹ there are two types of performance incentives. One is a fixed set of dollar awards based

⁷ Per the electric restructuring statute known as Assembly Bill 1890.

⁸ Public Utilities Commission of the State of California, Decision 97-12-103, December 16, 1997.

achievement of program roll-out and management milestones. The other provides a share of net benefits provided that actual SPC activity yields at least 20% of expected benefits. The share ranges from 16 to 26%.

The total of all types of incentives is capped at 14% of SDG&E's total DSM program budget.

1999

Colorado

1998

General Treatment of DSM and its Costs: A demand-side cost recovery mechanism that includes recovery of utility costs and shareholder incentives is in effect for the Public Service Company of Colorado (PSCO).¹⁰ PSCO is the major utility in Colorado with DSM programs. Costs are recovered from ratepayers as a whole.

DSM Funding: Colorado emphasizes all-source or DSM-only bids to procure electric resources or their DSM equivalent. During the mid-1990s, PSCO also delivered several utility-administered DSM programs. Currently, DSM program costs consist largely of payments to successful bidders, plus the net costs of developing and administering bids.

Recovery of Program Costs: DSM program costs may be fully rate-based and earn a return while being amortized over 7 years.

Lost Revenues: There is no lost margin recovery for PSCO.

Shareholder Incentives: In addition to the return on rate-based DSM, a shareholder incentive applies. A base annual incentive is calculated as 5% of the price per kW of a representative supply-side investment displaced by DSM. This base incentive is then adjusted to reflect two factors. These are changes in the expected lifetime of DSM projects implemented, and deviations in the cost of DSM contracts signed from a target price per kW of DSM. This yields an adjusted DSM incentive which may be claimed as follows:

35% of the incentive may be claimed based on demonstrated efforts to establish the actual effects of DSM on the Public Service system.

⁹ SPC programs pay fixed prices for verified and measured energy savings as they are delivered over a multi-year contract period.

¹⁰ Public Utilities Commission of Colorado, *Decision No. C90-1551*, November 28, 1990.

65% of the incentive is available if actual DSM project performance turns out to be at least 90% of expected; below 90%, the 65% portion is itself scaled back.

1999

Provisions remain as described above.

Connecticut

1998

General Treatment of DSM and its Costs: Utility expenses for approved costs (called conservation and load management, or C&LM) are fully recoverable from ratepayers through a C&LM Adjustment Mechanism. Provisions for the largest utility, Connecticut Light and Power Company (CL&P), are described here.

DSM Funding: Before restructuring, the Department of Public Utility Control established annual budgets for C&LM programs. The 1998 law deregulating electricity generation established explicit Systems Benefit Charges to fund DSM beginning January 1, 2000.¹¹ The SBC is 3 mills/kWh, plus additional amounts collected for renewable energy programs and low-income programs.

Recovery of Program Costs: A portion of CL&P's C&LM expenditures have been placed in rate base where they earn a return based on the weighted cost of capital.

Lost Revenues: No lost margin recovery is in place for CL&P.

Shareholder Incentives: The Company is eligible for a bonus rate of return on its rate-based DSM. The bonus is based on a performance ratio which compares actual to budgeted life-cycle energy savings. Budgeted energy savings are those projected from the C&LM activity in the approved plan, while actual energy savings are those projected from the level of C&LM participation realized by the end of a year. CL&P's additional return on rate-based C&LM varies with 1998 performance ratios as follows:¹²

¹¹ Public Act No. 98-28, enacted April 29, 1998.

¹² Connecticut Department of Public Utility Control, Docket No. 97-10-23, *Decision*, March 25, 1998.

Ratio	Bonus
<.75	0 %
≥.75 < 1.1	1 %
≥1.1 < 1.25	2 %
≥1.25	3 %

The bonus rate of return does not take into account cost-effectiveness because cost-effectiveness was demonstrated in prior years.

1999

In 1999, new shareholder incentive structures are under consideration for the era of SBC funding of DSM. In the meantime provisions described above remain in effect.

Hawaii

1998

General Treatment of DSM and its Costs: Recovery of utility expenses for approved DSM plans, lost margins, and shareholder incentives have been available since 1994, and are enjoyed by the major electric utilities.¹³ Provisions for the largest utility, Hawaiian Electric Co. (HECO), are described here.

DSM Funding: DSM expenditure levels are proposed by the distribution utilities and established by the Public Utilities Commission when it approves the utilities' Plans as part of the overall Integrated Resource Planning process.

Recovery of Program Costs: DSM costs for residential programs are fully recoverable from HECO's residential rate classes, and costs for non-residential programs are fully recoverable from the non-residential rate classes.

Lost Revenues: An LRAM provides for full recovery of net lost margins.

Shareholder Incentives: HECO. HECO's shareholder incentives are, for most of its DSM programs, 10 percent, *post-tax*, of all electricity cost savings (measured from the utility perspective) expected to accrue over the lifetime of the DSM measures installed under HECO's programs, net of the direct costs of the programs themselves. This is equivalent to about 13.3% pre-tax. For a

¹³The cost recovery and incentive provisions were approved by the Public Utilities Commission in Decision and Order No. 14638, approved April 22, 1996, and Decision and Order No. 14730, approved June 5, 1996.

service program with less readily quantifiable resource benefits, the Company receives 5 percent, *post-tax*, of program costs as a shareholder incentive. The shareholder incentives are collected annually based on completed DSM activity. As with other DSM costs, shareholder incentives for residential programs are recovered from HECO's residential rate classes, and incentives for non-residential programs are recovered from the non-residential rate classes.

1999

Provisions remain as described above.

Kentucky

1998

General Treatment of DSM and its Costs: Recovery of utility expenses for approved DSM plans, lost margins, and shareholder incentives have been available since 1994.¹⁴

DSM Funding: Utilities may apply to the utility regulatory commission to implement a DSM Adjustment Tariff in order to recover costs and net lost revenues, and to receive incentives for the implementation of DSM programs. DSM costs, lost revenues, and incentives are collected from the customer classes that benefit from the programs.

Recovery of Program Costs: DSM program costs are fully recoverable through the DSM cost recovery mechanism.

Lost Revenues: The LRAM provides for full recovery of net lost margins from approved DSM programs.

Shareholder Incentives: Louisville Gas & Electric Co, American Electric Power, and Cinergy. Each of these utilities receives a shareholder incentive. The incentive is computed by multiplying the net resource savings expected from approved programs which are to be installed during the upcoming 12-month period by 15%.¹⁵ Net resource savings are defined as program benefits less the cost of the program, where program benefits are the present value of the utility's avoided costs over the expected life of the program, and include both capacity and energy savings.

¹⁴ Pursuant to 1994 Kentucky Acts, chapter 238, section 2.

¹⁵ There are no penalties in the shareholder incentives.

The DSM incentive amount is divided by the expected sales for the upcoming 12-month period and included in the DSM cost recovery mechanism. Reconciliation occurs subsequently. DSM incentive amounts are assigned for recovery purposes to the rate classes whose programs created the incentive.

1999

Provisions remain as described above.

Maryland

1998

General Treatment of DSM and its Costs: Maryland’s electric restructuring law, Senate Bill 300, passed in 1999, eliminated previous requirements for electric utility DSM programs. By the time the law was passed, the Public Service Commission (PSC) had ended gas and electric utility DSM. Provisions in effect for pre-1999 DSM programs are described here. Electric utilities recovered program costs, lost revenues, and shareholder incentives. Provisions for Potomac Edison Company follow.¹⁶

DSM Funding: Potomac Edison applies an Energy Conservation Surcharge (ECS) to designated Rate Schedules in order to recover eligible DSM program costs applicable to the customer classes served by those Rate Schedules. Eligible costs were approved by the PSC based on project descriptions as filed by Potomac Edison to the PSC. They are reconciled annually.

Recovery of Program Costs: All program costs are deferred and amortized over seven years.

Lost Revenues: The LRAM provides for full recovery of net lost margins.

Shareholder Incentives: Potomac Edison could earn a “performance-based shared savings incentive” by attaining specified goals. Achievement is based on aggregate energy saved by all active, approved DSM programs. The incentive is a share of the net savings from each program as calculated using the Total Resource Cost Test (TRC) filed by Potomac Edison and approved by the Commission. In 1998 the aggregate goals and Potomac Edison’s shared savings amounts, after tax, were:

<u>% Goal Achieved</u>	<u>% TRC</u>
Less than 80%	0%
80%-99%	6%
100%-119%	7.5%

¹⁶ Maryland Public Service Commission, *Electric P.S.C. Md. No. 53*, Approved Sept. 3, 1997.

120% & Over

10%

The pre-tax incentive rate for the 7.5% TRC level is 12.41%. The highest percent incentive determined above applies uniformly to the aggregate total of all net savings of all of the programs used in establishing the goal. Recovery of any incentive awarded through the ECS is based on the actual amount earned in the previous year.

1999

The 1999 restructuring law scheduled a study of the need for energy resource initiatives. The study is to be undertaken in 2001. There may be new DSM programs after the study is completed.

Massachusetts

1998

General Treatment of DSM and its Costs: The Massachusetts Division of Energy Resources (DOER) is to annually file a report with the Department of Telecommunications & Energy (DTE) on proposed funding levels for energy efficiency programs. The DTE will review and approve energy efficiency expenditures after determining that implementation of such programs will be cost-effective. There are several investor-owned utilities in Massachusetts. This description focuses on the two largest electric utilities and the largest gas utility.

Energy Efficiency Funding: A per kWh charge (SBC) was established by law to fund electric utility energy efficiency programs. The 5-year SBC schedule is as follows:¹⁷

<u>SBC Level</u>	<u>Duration</u>
3.3 mills/kWh	3/1/98-12/31/98
3.1 mills/kWh	1999
2.85 mills/kWh	2000
2.7 mills/kWh	2001
2.5 mills/kWh	2002

For gas utilities, DSM expenditure levels are proposed by the distribution utilities and established by the DTE when it approves the utilities' DSM Plans.

¹⁷ *Electric Utility Restructuring Act*, November 25, 1997.

Recovery of Program Costs: Electric utilities receive full program cost recovery for approved programs. DSM budgets are based on the mandated SBC charges multiplied by projected kWh sales. If revenues collected are over or under actual spending in any one year, that difference is reconciled in subsequent years. Gas utilities also receive full cost recovery for approved programs, generally through a non-bypassable per therm charge to all distribution customers that is subject to annual reconciliation. At Boston Gas Co., low income program costs are recovered from all customers, while other Residential, C/I, and Multi-family program costs are recovered on a sector specific basis.

Lost Revenues: Boston Edison and Massachusetts Electric Company do not collect lost margins. Boston Gas receives net lost margin recovery for three residential DSM programs only.

Shareholder Incentives: Massachusetts Electric Co.¹⁸ For programs resulting in measured savings, if MECO achieves at least 50% of targeted savings it receives a fixed incentive per lifetime kWh and kW saved. In addition, the amount of that volumetric incentive (at 100% of targeted savings) is scaled by the ratio of the target benefit-to-cost (B:C) ratio to the actual B:C ratio realized. This further amount is added to the volumetric incentive, unless the B:C ratio is under 1.0. If all targets and performance thresholds are met for program year 1998, the Company receives an amount equivalent to 7.5% of net benefits, after tax, with a maximum benefit of 8%.¹⁹ On a pre-tax basis the target incentive is equivalent to a 12.9% share of net benefits. There is no penalty. For programs less susceptible to measured savings, such as new construction, support for market-transforming technologies, and support for building codes, a variety of fixed dollar rewards are tied to program-specific performance indices such as the number of program participants.

Shareholder Incentives: Boston Edison Co. BECO can earn incentives on all of its energy efficiency programs. The maximum incentive BECO could earn for 1998 is \$2 million. This is based on 11.5% of eligible planned program expenses.

For 1998, if BECO's achievement of individual program metrics exceeds a performance threshold of 85%, then the maximum incentive for that metric will be earned. If less than 50% of the performance metric is achieved, then no incentive will be earned for that metric. If 50% of the performance metric is achieved, then 50% of the maximum incentive will be earned. If between 50% and 85% of the performance metric is achieved, then the incentive earned will be prorated between 50% and 100% of the maximum incentive for that metric.

¹⁸MECO is one of three NEES electric distribution utilities. The others, in New Hampshire and Rhode Island, receive shareholder incentives of similar design.

¹⁹Calculated from NEES, *Five Year Energy Efficiency Plan: Offer of Settlement*, March 18, 1998.

This incentive structure applies to all programs, whether performance is measured based on actual kWh savings or by a proximate indicator (such as the number of rebates awarded or completing a market assessment study).²⁰

75% of BECO's energy efficiency programs are traditional installation ("retrofit") programs where success is measured based on kWh savings. The remaining 25% of programs are new programs where proximate indicators based on program activity are used to measure success. In the long run, the measure of success for these programs is expected to switch from the proximate indicators to actual energy savings.

Shareholder Incentives: Boston Gas Co. For residential and non-residential DSM programs where lost margin recovery is not allowed, BG instead receives performance incentives. These incentives are based on a variety of indices of program activity and documented impacts on the market. Receipt of the full incentive for each indicator depends on actual vs. targeted results, as follows:

Actual v. Target	Portion of Full Incentive
<65%	0
65-85%	75%
>85%	100%

The maximum performance incentive for 1998 is \$600,000.²¹

1999

In 1999, new shareholder incentive structures are under consideration in the DTE's generic DSM cost-effectiveness proceeding. In the meantime provisions described above remain in effect.

Minnesota

1998

General Treatment of DSM and its Costs: Utilities file 2-year Conservation Plans with the Department of Public Services (DPS). The DPS makes recommendations on the Plans to the Public Utilities Commission (PUC),

²⁰ Boston Edison Company, *Five Year Energy Efficiency Plan*, July 1998.

²¹ Boston Gas Company, *Offer of Settlement*, March 19, 1997. The settlement was subsequently approved by the regulator.

which ultimately acts on the Plans. Full recovery of program costs for approved DSM plans, recovery of 75-100% of lost margins, and shareholder incentives are currently in effect for investor-owned utilities. Incentives vary by utility. Three examples are given here.

DSM Funding: The 1991 Omnibus Energy Act requires gas utilities to spend 0.5% of gross revenues on Conservation Improvement Plan (CIP) programs. Investor-owned electric utilities must spend 1.5% annually.

Recovery of Program Costs: Utilities are allowed full recovery of program costs for approved DSM programs.

Lost Revenues: Minnegasco and Great Plains Natural Gas Company both recover 100% of lost margins. Northern States Power Company recovers 75% of lost margins.

Shareholder Incentives: Minnegasco and Great Plains Natural Gas Co. Minnegasco and Great Plains both enjoy the same stepped bonus mechanism.²² The bonus allows the gas utilities to claim an additional 10% of their actual lost margins if their annualized savings are 75% to 100% of their DSM program savings goal. If annualized savings exceed 100% of the program goal, the utilities may claim an additional 25% of lost margins as a bonus.

Shareholder Incentives: Northern States Power. Northern States Power receives a shared savings incentive of 10% of the first 20% of actual net benefits in excess of 100% of planned benefits.²³

1999

Provisions remain as described above.

New Hampshire

1998

General Treatment of DSM and its Costs: Granite State Electric Co. (GSE) is the only utility in New Hampshire with DSM programs. GSE has been allowed program cost recovery and shareholder incentives since 1990.

²²Memo entitled "Gas Utility DSM Financial Incentive Work Group Report and Recommendations." November 20, 1995.

²³Northern States Power, *CIP Adjustment Rate, DSM Incentive, 1997 CIP Status Report*, April 1, 1998.

DSM Funding: Granite State is entitled to recover prudent direct costs of programs which are demonstrated to be cost-effective and consistent with least-cost integrated resource planning principles.

Recovery of Program Costs: GSE recovers DSM program costs through a per-kWh charge, allocating the costs of specific programs to the customer classes eligible to participate in those programs. Under- and overcollections are reconciled annually.²⁴

Lost Revenues: There is no LRAM.

Shareholder Incentives: GSE's shareholder incentive is a two-part shared savings mechanism. The first part, the maximizing incentive, is calculated separately for residential and commercial and industrial (C&I) programs. GSE may earn 5% of the total adjusted program value created by the utility's residential programs and 3.5% for C&I programs. Total adjusted program value is program value net of program evaluation costs and customer direct costs.

The second part, the efficiency incentive, is equal to 10% of total adjusted program value less the costs associated with producing those savings and less the amount of the maximizing incentive. The total program value created by GSE's DSM programs depends on both the number and type of kW and kWh saved by the programs.

GSE's incentives are subject to a threshold equal to 50% of projected value of DSM program net savings. Once the utility has achieved the threshold, it may earn the incentive based on the entire value achieved. GSE recovers incentives in the year following the year during which they were earned.

1999

Provisions remain as described above.

New Jersey

1998

General Treatment of DSM and its Costs: Recovery of utility expenses for approved DSM plans, lost margins, and shareholder incentives have been available under the NJ DSM rule adopted by the Board of Public Utilities (BPU) in late 1991. Approved costs are recovered from ratepayers as a whole.

²⁴ National Association of Regulatory Utility Commissioners, *Incentives for Demand-Side Management*, October 1993.

DSM Funding: DSM expenditure levels are proposed by the distribution utilities and established by the BPU when it approves the utilities' DSM Plans. Under the 1999 law providing for the restructuring of the electric and gas industries, minimum levels of statewide funding for energy efficiency programs are established for the period 2000 through 2008.²⁵ DSM funds are being and will be collected as a component of the Societal Benefits Charge levied at the distribution level. Initial SBCs were established for the electric utilities in the latter part of 1999.

Recovery of Program Costs: Full program cost recovery is effected through DSM cost recovery riders that are periodically reconciled, and now included as a component of utilities' SBCs.

Lost Revenues: Net lost revenue recovery is allowable for "performance-based" programs as discussed below.

Shareholder Incentives: Utilities may offer "performance based" DSM in two forms.²⁶

1. Shared savings. The utility may propose a share of net resource benefits. The state's second largest utility, GPU Energy, chose the shared savings alternative. That utility received a 25% share of all net benefits from performance-based programs under its first DSM Plan.²⁷ No share was included in its second Plan, now in effect, because of the very small expected net resource benefit. Performance-based programs have been the greater portion of the Company's DSM budget.

2. Standard pricing offer (SPO). Under the SPO, the utility pays a price to customers and ESCOs for verified DSM savings. This price is somewhat less than avoided costs plus environmental externality benefits. The utility's opportunity to profit comes from its ability to procure saved m³ of gas or kWh of electricity through its own for-profit conservation subsidiary. The largest utility, Public Service Electric & Gas Co., chose the SPO, depending on contracts with its energy conservation subsidiary as a source of shareholder profit from DSM. Expenditures for the SPO have been the greater part of the Company's DSM budgets.

1999

In 1999, new shareholder incentive structures are under consideration in the BPU's "Comprehensive Resource Analysis" proceeding. In the meantime, provisions described above remain in effect.

²⁵Electric Discount and Energy Competition Act, enacted February 9, 1999.

²⁶NJ also requires utilities to deliver certain "Core" public benefit DSM programs such as low-income services and new construction programs, for which no incentives other than program cost recovery are available.

²⁷NJAC 14:12, Chapter 3. There are no penalties in the NJ rule. However, if net resource benefits are negative the utility receives its share of negative benefits using the shared savings percentage in its approved plan.

Ontario

1999

General Treatment of DSM and its Costs: The Ontario Energy Board requested each regulated gas distribution utility to implement the demand-side aspects of integrated resource planning in 1993.²⁸ Approved costs are recovered separately from each major rate class.

DSM Funding: DSM budgets are set annually by the Board in the context of rate cases.

Recovery of Program Costs: Variance accounts are provided for utility program cost variations from the budgeted levels that were included in rates.

Lost revenues: An LRAM was approved in 1997 for Enbridge Consumers Gas and became effective with the utility's 1998 fiscal year.

Shareholder Incentives: An SSM for Enbridge Consumers Gas was approved in 1999 and became effective with the utility's 1999 fiscal year. The utility's reward or penalty is 35 percent of the difference of "actual" DSM benefits less the benefits targeted in the DSM Plan pre-approved in each year's rate case.²⁹ Benefits are calculated as the net present value of resource benefits based on the Total Resource Cost test. Actual benefits are projected on the basis of DSM activity through the end of the fiscal year.

Rhode Island

1998

General Treatment of DSM and its Costs: Recovery of program costs and shareholder incentives are currently in effect for investor owned utilities.

DSM Funding: By law, an SBC of 2.3 mills/kWh is to be collected by all RI electric utilities to fund energy efficiency and renewable energy resources. The charge is to be collected for a 5-year period, which began January 1,

²⁸ Ontario Energy Board, *A Report on the Demand-Side Aspects of Gas Integrated Resource Planning*. E.B.O. 169-III, 1993.

²⁹ Enbridge Consumers Gas, EBRO 497-01, Exhibit C, Section 9.0.

1997.³⁰ In 1998, the SBC was expected to raise \$19.9 million, of which \$1.3 million was to go towards renewables, and \$18.6 million towards energy efficiency.³¹

Recovery of Program Costs: Full recovery of costs for approved DSM programs is provided for.

Lost Revenues: No LRAMs are currently in place.

Shareholder Incentives: Shareholder incentives have been in existence since 1990. Utilities receive a small percentage of the savings that are achieved through DSM measures (SSM). The SSM is designed so that utilities are given an incentive to maximize the amount of savings achieved through their DSM programs as well as administer them as cost-effectively as possible. Provisions are similar to those for Massachusetts Electric Company (Massachusetts) and Granite State Electric (New Hampshire) as described above.

1999

Provisions remain as described above.

³⁰ *An Act Relating to the Utility Restructuring Act of 1996*, Approved August 7, 1996.

³¹ Kilmarx, Mary, RI PUC, Phone interview, August 14, 1998.

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Q116.0 Reference: Volume 1, Tab 10.1, p. 14

Please provide a summary, dating to the beginning of the Shared Savings Incentive mechanism, showing for each sector the planned and actual net benefits and the associated incentive calculation. Please provide the 2004 data if now available.

A116.0 Please refer to the appended file for a Shared Savings Incentive summary covering the period from 2000-2004.

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117.0 Reference: Volume 1, Tab 10.1, Appendix C

Please also apply and respond to the following questions in so far as they correspond to references in a December 31, 2004 Semi-Annual DSM Report, if such a report is now available.

Q117.1 Please provide the detailed calculations of all the figures reported in the table on page 4 of Appendix C. Please note all assumptions.

A117.1 Please see attachment BCUC A177.1.

Q117.2 Please provide the detailed calculations of the Net Benefits reported in the table on page 5 of Appendix C. Please note all assumptions.

A117.2 Please see attachment BCUC A117.2.

Q117.3 Please provide the detailed calculations of the Benefit/Cost Ratios and Levelized Cost summarized in the table on page 6 of Appendix C. Please note all assumptions.

A117.3 Please refer to the attachment BCUC A117.3 for a detailed calculation of the Benefit / Cost Ratios and Levelized Cost summarized in the table on page 6 of Appendix C.

Q117.4 Please comment on whether the calculations of either the Total Resource Cost test or Ratepayer Impact Measure test account for the earned return on DSM Rate Base items. Please explain why or why not, as the case may be.

A117.4 Neither the Total Resource Cost (TRC) test or the Ratepayer Impact Measure (RIM) test accounts for the earned return on the DSM rate base. We follow the definitions for TRC and RIM contained in the California Standard Practice Manual Earned return on DSM Rate Base includes the annual return on, and amortization of, the investment in DSM. The two tests include as a program cost, the cash capital cost and thus also including the annual earned return would be double counting.

Q117.5 Why is the Customer Incurred Cost in the table on page 6 of Appendix C equal to - \$17,000?

A117.5 The Customer Incurred Cost (CIC) is equal to -\$17,000 because we have included the benefit of not having to purchase 10 incandescent lightbulbs over the life of the compact fluorescent lightbulb (CFL) as a deduction from the customer's cost of the CFL.

The following example will demonstrate how a negative CIC can occur. The CFL program pays a rebate equal to the lesser of \$5 per CFL or ½ the product cost. If the customer pays \$8 for a CFL, the rebate is ½ x \$8 = \$4.00. In addition, over the rated life of the CFL, the customer will avoid the purchase of 10 incandescent lamps, which saves the customer \$5 (10 lights @ \$0.50 per light), for a net CIC of -\$1 (\$4-\$5).

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Q117.5.1 If the reason relates to the incentives offered customers, please discuss your view as to the level of the incentive given that the Total Resource Cost ratio equals 3.3.

A117.5.1 The average cost of a CFL in our service area is just under \$9. By replacing a 60 watt incandescent light with a CFL, the customer saves \$2.70 annually. Without our rebate the payback is about 4 years. With the rebate, the payback is just under 2 years. Our rebate brings the payback of this technology to an acceptable level for customers.

In spite of the longer life and lower energy costs of the CFL, customers still compare the \$8 cost of a CFL to the \$0.50 cost of an incandescent light. Our rebate program softens this first cost impact.

Q117.5.2 If the reason relates to the incentives offered customers, please demonstrate how FortisBC's calculation of the Total Resource Cost test ignores transfer payments, such as incentives, between the utility and customer.

A117.5.2 The appended CFL measure sheet demonstrates that FortisBC's calculation of the Total Resource Cost test treats transfer payments appropriately.

Assumptions:

1. Costs are Actual to June 30, 2004 from the Accounting system, plus accruals.
2. Energy and capacity savings are from the energy management database
3. Customer costs are from the energy management database
4. Planning and evaluation costs are from the accounting system, and allocated to programs based on savings

5. Program lifespan is in Column R
6. Assumed discount rate is 8%
7. Deferred power purchases are computed at 2.6 cents per kW.h, capacity at \$29,680 per mw year and deferred capital construction cost at \$35,600 per mw year.
8. Customer savings are computed at tariff billing rates

BCUC A117.1

Fortis BC
PowerSense
For the Six Months Ending June 30, 2004

Adjustment to Capacity Benefits: 0.93

Benefits	Incentives	Program Planning & Customer				Total Cost	Benefit Cost Ratio	Energy Savings (kWh's)	Capacity Savings (kw's)	Levelized Cost (c's/kWh)	Customer Savings	Discount Rate	Cap. Amount	Life	PV	PV	PV	PV	Present Value	Present Value
		Costs	Evaluation	Cost	Cost										Capacity Rate	Energy Rate	Capacity Rate	Energy Rate		
(\$'000s)											8%	350		29.680	0.026		0.04			
RESIDENTIAL:																				
Heat Pumps	282	30	24	8	152	214	1.3	642,433	180	3.1	277	380	25	316.8	0.278	0	0.43	6,857,828	1,921	
A/A Heat Pumps	394	51	66	19	199	335	1.2	1,579,469	128	2.5	545	305	15	254.0	0.223	0	0.35	#####	1,096	
New Home Program	440	179	32	14	20	245	1.8	1,129,142	194	1.9	513	401	30	334.1	0.293	0	0.45	#####	2,184	
Residential Lighting	375	76	31	25	(17)	115	3.3	2,050,458	732	1.4	330	142	5	118.5	0.104	0	0.16	8,186,884	2,923	
Home Envelope	89	17	9	4	31	61	1.5	298,293	31	2.1	118	350	20	291.4	0.255	0	0.40	2,928,685	304	
Water Savers	2	0	1	0	0	1	1.8	11,264	0	1.5	3	239	10	199.2	0.174	0	0.27	75,582	0	
	1,582	353	163	69	385	970	1.6	5,711,059	1,265	2.2	1,785							#####	8,428	
GENERAL SERVICE:																				
Lighting	654	99	39	30	194	362	1.8	2,450,591	454	2.0	1,027	268	12	223.7	0.196	431.4	0.34	#####	3,421	
B.I.P. - Retro	80	18	38	3	24	83	1.0	275,606	24	3.1	135	350	20	291.4	0.255	562.0	0.44	2,705,940	236	
B.I.P. - New	651	109	51	24	286	470	1.4	2,000,449	295	2.4	1,050	350	20	291.4	0.255	562.0	0.44	#####	2,896	
Water Handling Infrast	93	36	13	3	25	77	1.2	277,118	45	2.8	148	350	20	291.4	0.255	562.0	0.44	2,720,785	442	
	1,478	262	141	61	529	993	1.5	5,003,764	818	2.3	2,359							#####	6,995	
INDUSTRIAL:																				
Industrial Efficiency	0	0	10	0	0	10	0.0	0	0	0	0	350	20	291.4	0.255	577.3	0.27	0	0	
Pumps & Fans	92	15	8	4	25	52	1.8	334,800	21	1.6	103	350	20	291.4	0.255	577.3	0.27	3,287,116	206	
Compressors	0	0	5	0	0	5	0.0	0	0	0	0	185	7	154.5	0.135	306.1	0.14	0	0	
New Process Design	0	0	4	0	0	4	0.0	0	0	0	0	350	20	291.4	0.255	577.3	0.27	0	0	
	92	15	27	4	25	71	1.3	334,800	21	2.2	103							3,287,116	206	
Program Total	3,152	630	331	134	939	2,034	1.5	11,049,623	2,104	2.2	4,248							#####	15,629	

Q117.2 Detailed Net Benefits Calculation

Benefits are calculated using projected energy and capacity savings discounted over the life of individual programs, at BCH Schedule 3808 power purchase rate.

Program Costs are actual costs from the accounting system, plus accrual expenses for the period.

Customer costs are obtained from, and as entered into, the energy management database.

Net Benefits is the difference between Gross Benefits and Total Costs.

The incentive mechanism defines total costs as all program costs excluding monitoring and evaluation.

The actual residential benefits detailed in the "Actual Tab" of this workbook are \$681k instead of \$536k and this revised amount is based on the figures reported in the table on page 4 of Appendix C. However, the June 30 residential net benefits for incentive purposes remains unchanged since it was calculated at the maximum amount of \$561k.

Q117.2 Detailed Net Benefits Calculation

Net Benefits Calculation
For the Six Months Ending June 30, 2004

	A	B	C	D	E
	<u>Benefits</u>	Program <u>Costs</u>	Customer <u>Cost</u>	Total <u>Cost</u>	Net <u>Benefits</u>
				B + C	A - E
	(\$'000s)				
<u>RESIDENTIAL:</u>					
Heat Pumps	282	55	152	207	75
A/A Heat Pumps	394	117	199	316	78
New Home Program	440	210	20	230	210
Residential Lighting	375	107	(17)	90	285
Home Envelope	89	26	31	57	32
Water Savers	<u>2</u>	<u>1</u>	<u>0</u>	<u>1</u>	<u>1</u>
	<u>1,582</u>	<u>516</u>	<u>385</u>	<u>901</u>	<u>681</u>
<u>GENERAL SERVICE:</u>					
Lighting	654	138	194	332	322
B.I.P. - Retro	80	57	24	81	(1)
B.I.P. - New	651	159	286	445	206
Water Handling Infrastructu	<u>93</u>	<u>49</u>	<u>25</u>	74	<u>19</u>
	<u>1,478</u>	<u>403</u>	<u>529</u>	<u>932</u>	<u>546</u>
<u>INDUSTRIAL:</u>					
Industrial Efficiency	0	10	0	10	(10)
Pumps & Fans	92	38	25	63	29
Compressors	0	5	0	5	(5)
New Process Design	<u>0</u>	<u>-11</u>	<u>0</u>	<u>(11)</u>	<u>11</u>
	<u>92</u>	<u>43</u>	<u>25</u>	<u>68</u>	<u>24</u>
Program Total	<u>3,152</u>	<u>961</u>	<u>939</u>	<u>1,900</u>	<u>1,252</u>

BCUC A 117.2

	Net Benefits			Net Benefits	% of	Incentive
	Actual to June 04	Target to June 04 (1)	Variance	For Incentive	Annual Target	Amount
		30-Jun				
Residential (3)	681	187	494	561	150%	33.7
General Service	547	647	-100	547	85%	0.0
Industrial	24	125	-101	24	49%	-0.7
Note 4	<u>1252</u>	<u>959</u>	<u>294</u>	<u>1132</u>		<u>33.00</u>

1. 2003 Net benefits target with TRC adjusted by 2.1% CPI increase
 2. For General Service, we assume that targets will be achieved and we will not incur a penalty as at year-end.
- kW.h Saving Summary:
3. Actual residential net benefits was previously shown as \$536 k in error
 4. There is no change in the incentive amount since the residential benefits in cell f6 is limited to 150% of the annual target which is \$561k as originally reported.

BCUC A 117.2

2004 Baseline	2003 Adjusted Gross Benefits			2003 Adjusted TRC			2004 Forecast Net Benefits Baseline		
	Plan	Productivity	Adjusted	Plan	Real CPI	Adjusted	Net Benefits	Min	Max
Residential	\$1,154	0%	\$1,154	\$764	2.12%	\$780	\$374	\$187	\$561
General Service	\$2,695	0%	\$2,695	\$1,371	2.12%	\$1,400	\$1,294	\$647	\$1,941
Industrial	\$512	0%	<u>\$512</u>	\$258	2.12%	<u>\$263</u>	\$249	<u>\$125</u>	<u>\$374</u>
	<u>\$4,361</u>		<u>\$4,361</u>	<u>\$2,393</u>		<u>\$2,444</u>	<u>\$1,917</u>	<u>\$959</u>	<u>\$2,876</u>

Target to
30-Jun-04
(50%)
187
647
125
959

BCUC A117.3

**Fortis BC
POWER SENSE SUMMARY
FOR THE SIX MONTHS ENDING JUNE 30, 2004**

Adjustment to Capacity Benefits: 0.93

	Total										Customer Savings Ratio														
	Financial		Total WKI		Customer Resource		% WKP	% Cust	Energy	Capacity	Levelized	WKP	Benefit	Utility	Impact	Customer	Discount	Cap. Com	Life	PV	PV	PV	PV	Present V	Present Value
	Incentives	Admin.	Cost	Cost	Cost	Savings			Savings	Cost	Benefits	Cost Ratio	Test	Test		Savings	Rate	Amount		Capacity	Energy	Capacity	Energy		
\$'000					(kWh's)	(kw's)	(c's/kWh)	(\$'000s)							8%	350	Rate	Rate	Rate	Rate	Rate	Rate	Capacity		
RESIDENTIAL:																									
Heat Pumps	30	24	54	152	206	26%	74%	642,433	180	3.1	282	1.3	5.2	0.83	277	380	25	316.8	0.278	0	0.43	#####	1,921		
A/A Heat Pumps	51	66	117	199	316	37%	63%	1,579,469	128	2.5	393	1.2	3.4	0.58	545	305	15	254.0	0.223	0	0.35	#####	1,096		
New Home Program	179	32	211	20	231	91%	9%	1,129,142	194	1.9	440	1.8	2.1	0.60	513	401	30	334.1	0.293	0	0.45	#####	2,184		
Residential Lighting	76	31	107	(17)	90	119%	-19%	2,050,458	732	1.4	375	3.3	3.5	0.81	330	142	5	118.5	0.104	0	0.16	#####	2,923		
Home Envelope	17	9	26	31	57	46%	54%	298,293	31	2.1	89	1.5	3.4	0.60	118	350	20	291.4	0.255	0	0.40	#####	304		
Water Savers	0	1	1	0	1	100%	0%	11,264	0	1.5	2	1.8	2.0	0.48	3	239	10	199.2	0.174	0	0.27	75,582	0		
	353	163	516	385	901	57%	43%	5,711,059	1,265	2.2	1,581	1.6	3.1	0.67	1,785							#####	8,428		
GENERAL SERVICE:																									
Lighting	99	39	138	194	332	42%	58%	2,450,591	454	2.0	654	1.8	4.7	0.55	1,027	268	12	223.7	0.196	431.4	0.34	#####	3,421		
B.L.P. - Retro	18	38	56	24	80	70%	30%	275,606	24	3.1	80	1.0	1.4	0.19	135	350	20	291.4	0.255	562.0	0.44	#####	236		
B.L.P. - New	109	51	160	286	446	36%	64%	2,000,449	295	2.4	651	1.4	4.1	0.53	1,050	350	20	291.4	0.255	562.0	0.44	#####	2,896		
Water Handling Infrast	26	13	49	25	74	66%	34%	277,118	45	2.8	93	1.2	1.9	0.46	148	350	20	291.4	0.255	562.0	0.44	#####	442		
	262	141	403	529	932	43%	57%	5,003,764	818	2.3	1,478	1.5	3.7	0.52	2,359							#####	6,995		
INDUSTRIAL:																									
Industrial Efficiency	0	10	10	0	10	100%	0%	0	0	#DIV/0!	0	0.0	0.0	0.00	0	350	20	291.4	0.255	577.3	0.27	0	0	0	
Pumps & Fans	15	8	23	25	48	48%	52%	334,800	21	1.6	92	1.8	4.0	0.71	103	350	20	291.4	0.255	577.3	0.27	#####	206		
Compressors	0	5	5	0	5	100%	0%	0	0	#DIV/0!	0	0.0	0.0	0.00	0	185	7	154.5	0.135	306.1	0.14	0	0	0	
New Process Design	0	4	4	0	4	0%	0%	0	0	#DIV/0!	0	0.0	0.0	0.00	0	350	20	291.4	0.255	577.3	0.27	0	0	0	
	15	27	42	25	67	63%	37%	334,800	21	2.2	92	1.3	2.2	0.62	103							#####	206		
Program Total	630	331	961	939	1,900	51%	49%	11,049,623	2,104	2.2	3,151	1.5	3.3	0.59	4,248							#####	15,629		
Planning and Evaluation								134																	
Net Expenditure								1,095																	

BCUC Report - Allocation Criteria for Planning & Evaluation:

Direct Information: Costs that are neither Incentives or Labour

Research, Admin. & Overhead: 30% of BAP & 50% of KAV (Aproximately 40% of Planning & Eval

Program Evaluation: Balance of Planning & Evaluation i.e. 60%

Allocation of Planning & Evaluation to Programs : Plan & Eval Research

Ground Source Heat Pump	642,433	6%	3.5%	2.3%
AAHP	1,579,469	14%	8.6%	5.7%
New Home Program	1,129,142	10%	6.1%	4.1%
HIP	298,293	3%	1.6%	1.1%
Water Savers	11,264	0%	0.1%	0.0%
Compact Fluorescents	2,050,458	19%	11.1%	7.4%
Appliances		0%	0.0%	0.0%

GENERAL SERVICE

Lighting	2,450,591	22%	13.3%	8.9%
B.I.P. - New	2,000,449	18%	10.9%	7.2%
B.I.P. - Retro	275,606	2%	1.5%	1.0%
Water Handling	277,118	3%	1.5%	1.0%
Destination Conservation		0%	0	0

INDUSTRIAL:

Motors		0%	0.0%	0.0%
Industrial Efficiency	0	0%	0.0%	0.0%
Pumps & Fans	334,800	3%	1.8%	1.2%
Compressors	0	0%	0.0%	0.0%
New Process Design	0	0%	0.0%	0.0%
	11,049,623	100%	60%	40%

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118.0 Reference: Volume 1, Tab 10.2, p. 21

Forced outage rates and incapability factors are shown for FortisBC and CEA.

Q188.1 Are the CEA statistics based only on hydro units, or are thermal units (and perhaps other unit types) included as well?

A118.1 Forced outage and incapability factors used for comparison to FortisBC's operating values are based on CEA values for Hydraulic units in the 5 to 23 megawatt range. The CEA produces statistics for all types of generation units including thermal and nuclear, etc. and in addition to breaking them down by capacity they also break down by year of service. We have found it most useful to compare to the 'capacity' values because all of our generation is within the 5 to 23 megawatt range.

Q118.2 If the CEA statistics are not for hydro units only, are hydro-only statistics available? If so, please provide them.

A118.2 Please see the response to BCUC IR1 Q118.1 above.

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Q119.0 Reference: Volume 1, Tab 10.2, p. 22

“The total Life Extension Program schedule has been re-worked due to the impacts of negotiating a go forward agreement with BC Hydro.”

What were the implications of this agreement for the Life Extension Program?

A119.0 The implications of the agreement for the Life extension program are that BC Hydro will support FortisBC in its applications to perform any future plant upgrades and/or life extension projects.
