Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF An Application to Approve Nova Scotia Power Incorporated's Demand Side Management Plan

Evidence of NSPI

January 31, 2008

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1.0 INTRODUCTION

Nova Scotia Power Inc. (NSPI) and its customers share a commitment to responsible energy use, energy efficiency and conservation. Reasonable efforts to reduce energy consumption, based upon a broad plan and well-designed programs, can bring benefits to customers, the Company, and the environment.

This document contains the Evidence of the Company and its consultants in support of a proposed energy efficiency and conservation program. This Evidence, together with the concurrently filed Collaborative Report and Demand Side Management (DSM) Programming Plan, provides the basis for the proceeding before the Nova Scotia Utility and Review Board (UARB) in which the Company seeks approval of:

1. The DSM Programming Plan;
2. Three early action DSM Programs; and
3. Recovery of DSM costs and a DSM Cost Recovery Mechanism

The DSM Programming Plan has been developed over a series of processes, beginning with an initial plan that was filed in the fall of 2005, and upon UARB direction, updated in September 2006. The Board further directed that DSM be considered in the context of the Company's Integrated Resource Planning Process (IRP). The IRP, based upon reasonable assumptions about future variables, considered scenarios to meet future electricity requirements and concluded that significant DSM spending should begin in the near term and continue in the longer term. NSPI supports the conclusions of the IRP calling for significant conservation programming to help meet future demand.

As an outcome of the 2007 IRP, the Company worked collaboratively with UARB staff and consultants in a consultative process with stakeholders to address outstanding administrative issues and further develop the Programming Plan.

The Company and customers can achieve success by implementing a portfolio of programs that meet a variety of needs and opportunities, and by continuing to work together with the input and advice of others having experience in the field. NSPI plans to continue to coordinate efforts and partner (as appropriate) with federal, provincial and municipal governments, as well as industry associations and non-governmental organizations involved in advancing energy efficiency and conservation in Nova Scotia.

The DSM Programming Plan filed with this Evidence proposes an expenditure in 2008 of $2.68 million targeting a reduction of 15.15 GWh, increasing annually to attain 978 GWh by 2013. This plan is designed to meet the IRP objectives.

NSPI proposes recovery of these expenditures from all customers using a cost recovery mechanism. The details of the proposed mechanism, and a proposed tariff, are included in this Evidence. Timely recovery of these expenditures is important to the success of the energy efficiency and conservation initiatives, and to the financial health of the utility.

This filing contains the testimony of the Company and its experts about energy efficiency and conservation programming, and evaluation, monitoring and verification of results. It also contains the evidence of the Company and its experts regarding the recovery of costs of energy efficiency and conservation, including the specific proposal for which the Company seeks approval of the UARB. The NSPI Programming Plan and the Collaborative Report on Administrative Issues, filed separately, are key elements of the evidence in this proceeding.

NSPI and its customers are ready for this Plan and for investment in a cleaner and greener future.

2.0 DSM PROGRAMMING PLAN

2.1. Introduction and Early Action

In 2007 NSPI completed its IRP analysis which showed DSM as a lower cost alternative to supply-side alternatives for meeting future customer load requirements. The resulting DSM Programming Plan, which has been revised from the version filed with the Board in September, 2006, is concurrently filed as a deliverable of the DSM Collaborative Terms of Reference. NSPI supports the Programming Plan and seeks UARB approval in this DSM process as an outcome of the hearing in April, 2008.

This DSM Programming Plan projects savings that achieve the five-year DSM goals included in the preferred plan of the 2007 IRP. The plan forecasts cumulative annual energy and demand savings through 2013 of 978 GWh and 148 MW respectively.

This plan represents the culmination of work which has been carried out since 2005. The plan has benefited from advice and ideas obtained through three stakeholder engagement processes, the most recent of which included several expert consultants and UARB staff.

The IRP calls for early action on DSM. NSPI has identified three programs that could be promptly initiated upon UARB approval:

1. Small Business Direct Install Lighting;
2. Low Income Households; and
3. Commercial and Industrial Custom Programs.

These three programs are described in the Programming Plan.

NSPI understands that the UARB is prepared to consider early approval, pursuant to a “paper review”, of significant DSM opportunities that are currently available. The three programs identified above meet the Board’s criteria. These programs have stakeholder support, strong results from the Total Resource Cost test, and will leverage partnerships and opportunities for collaboration with existing DSM initiatives. Therefore, the Company seeks early UARB approval of these three programs, for 2008.

Upon UARB approval, these three programs can be implemented beginning in the second quarter of 2008. It is important to the success of these programs that any early approval be based upon a commitment to the programs for all of 2008. Contractors will require commitments beyond the second quarter of 2008. Therefore, while the programs will be reviewed during the April hearing and evaluated for long term delivery, early approval is requested for delivery of the full 2008 requirements of each of the three programs.

The Programming Plan indicates spending of up to $2 million on these programs during 2008. The Company respectfully requests that the actual expenditures on these three programs be approved at this time for deferred, prompt recovery from customers. A deferral of these program costs could be recovered in a future General Rate Application, or in accordance with a DSM Recovery Mechanism if approved by the Board as requested by NSPI later in this Evidence.

NSPI respectfully suggests that the Board provide an opportunity for written input from stakeholders about this request for approval of three early action programs and deferred recovery of program costs. If this written input is provided by February 14, the Board can make a timely decision to allow these programs to be commenced.

In April, the Board will consider the testimony of NSPI, Board consultants and stakeholders about the details of these programs and others as contained in the Programming Plan. Since 2006, Summit Blue, a recognized expert in DSM, has been NSPI’s lead consultant for the development of this plan. The following testimony of Randy Gunn, Principal with Summit Blue explains the role of Summit Blue and its recommendations to NSPI on DSM Program design. This is followed by the testimony of Dr. Daniel Violette of Summit Blue, in respect of the evaluation, monitoring and verification elements of the Programming Plan.

The Company supports and adopts the Evidence of Mr. Gunn and Dr. Violette.

DIRECT TESTIMONY OF

Mr. Randy Gunn

SUMMIT BLUE CONSULTING LLC

2.2. Testimony of Randy Gunn, Summit Blue

INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Randy Gunn. My business address is 150 North Michigan Avenue, Suite 2700 Chicago, IL 60601

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a Member and Principal of Summit Blue Consulting, LLC. Summit Blue Consulting (or "Summit Blue") provides consulting services in the areas of energy efficiency and load management program performance monitoring and evaluation; program development and implementation; energy systems technology assessment and DSM potential studies; market research and market assessments; utility business management consulting, industry restructuring and deregulation strategies.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying for Nova Scotia Power Inc. ("NSPI" or "Company"), which provides electric utility service in the province of Nova Scotia, Canada.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received my Master's Degree in Planning from the University of Minnesota's Humphrey Institute of Public Affairs in 1995. My Master's coursework focused on energy, technology, and natural resources. In addition, I received a Bachelor of Arts degree in Physics from Carleton College in 1980.

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH PLANNING DEMAND SIDE MANAGEMENT PROGRAMS.

A. My consulting work for the past several years has focused on conducting DSM potential studies and DSM programs design studies. I have recently led DSM potential studies that were similar in scope to the work that Summit Blue conducted for NSPI for Duke Energy Indiana, the International Energy Agency (demand response programs), Jacksonville Electric Authority, Kansas City Power and Light, Missouri River Energy Services, and the Nebraska Public Power District. Previously I led other types of DSM potential studies for the Midwest Energy Efficiency Alliance, Otter Tail Power Company, and Xcel Energy.

I have led projects that included planning DSM programs for Commonwealth Edison, the Community Energy Cooperative, Duke Energy Indiana, Jacksonville Electric Authority, Kansas City Power and Light, the Nebraska Public Power District, NSPI, Northern States Power Company, Omaha Public Power District, Otter Tail Power Company, and Xcel Energy.

Q. PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL EXPERIENCE PRIOR TO ESTABLISHING SUMMIT BLUE CONSULTING.

A. Immediately prior to joining Summit Blue Consulting, I was employed as Manager of Utility Consulting for Sieben Energy Associates in Chicago, from 1998-2000. At Sieben Energy Associates, I led utility DSM program planning projects of various types, from program design projects to developing the DSM sections of utility integrated resource plans. Prior to joining Sieben Energy Associates, I was employed by Northern States Power Company as an internal consultant in their marketing department. At Northern States Power, I was responsible for DSM program planning and design projects, including DSM potential studies, developing the DSM aspects of the utility's integrated resource plans, developing DSM programs, and evaluating DSM programs.

Q. PLEASE DESCRIBE THE INDUSTRY ASSOCIATIONS IN WHICH YOU HAVE A LEADING ROLE.

A. I am currently the Vice Chair of the Midwest Energy Efficiency Alliance, and have served on MEEA's Executive Committee of its Board of Directors for two years.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to summarize Summit Blue Consulting DSM program design process and recommendations to NSPI.

Q. PLEASE SUMMARIZE SUMMIT BLUE'S DSM PROGRAM DESIGN PROCESS FOR NSPI.

A. In 2006, Summit Blue conducted a DSM potential study for NSPI and developed recommendations for a revised DSM program plan, both of which were submitted in September 2006. Summit Blue based its DSM recommendations in part on the results of a benchmarking analysis that examined the 2005 DSM program results (for seven utilities) or program plans (for one utility) for a group of eight utilities and energy agencies that are comparable to NSPI. Summit Blue normalized the organizations' DSM program results for their baseline sales, peak demand, and revenues. DSM energy and demand savings and spending as percentages of the baseline statistics were then developed. For example, each organization's 2005 energy savings were expressed as a percentage of their baseline 2005 energy sales. Typical data sources for the analysis were the organizations' 2005 DSM annual reports to their provincial or state regulators, as well as FERC Form 861 information for the baseline statistics.

For the organizations having the largest energy and demand savings as percentages of baseline sales and peak demands, Summit Blue collected additional information on the program structures and operating procedures using telephone interviews to supplement Summit Blue's existing information on those organizations' DSM programs. Program cost information was developed from the normalized DSM program cost data for the benchmarked organizations having the largest relative energy or peak demand savings and program costs that were at the median or lower.

Summit Blue's objectives in recommending the specified DSM programs to NSPI were to capture as much of the DSM opportunity identified in the 2006 DSM potential study as possible, to capture DSM "lost opportunities" as much as possible, and to structure programs so as to be as cost effective as possible. The main recommended programs that are focused on lost opportunities are the residential, and commercial and industrial ("C&I") new construction programs. Even though new construction was estimated to have modest DSM potential in the 2006 potential study, it is much more cost effective to install energy efficiency measures when buildings are being constructed than to go back after they are built and retrofit energy efficiency measures in them.

In 2007, NSPI asked Summit Blue to update the 2006 DSM program plan in two ways:

1. To eliminate DSM programming targeted specifically for pulp and paper customers, since a very recent DSM potential study indicated that these customers currently have limited DSM potential.
2. To provide additional details about how the programs could be implemented and operate beginning in 2008.

The revised DSM Programming Plan has been filed concurrently with this Evidence. The rest of my testimony provides a short summary of this plan.

Q. PLEASE SUMMARIZE THE REVISED DSM PLAN THAT SUMMIT BLUE RECENTLY DEVELOPED FOR NSPI

A. Summit Blue is suggesting that NSPI implement ten DSM programs in 2008-2010:

1. **Residential Efficient Products.** The initial focus for this program plans to promote compact fluorescent lamps to residential customers, as this technology is estimated to have the largest conservation potential of any single type of residential energy efficient product. In addition, this program will cover ENERGY STAR® refrigerators and other cost effective efficient products such as clothes washers and LED holiday lights, as well as facilitating the removal of unneeded secondary refrigerators from existing homes.
2. **EnerGuide for Existing Houses.** Through this program, NSPI plans to offer incentives to residential customers to improve the efficiency of their home's building shell, install more efficient electric heating systems such as heat pumps, and install efficient electric water heaters and water heating retrofit measures. NSPI hopes to partner with Conserve Nova Scotia and Natural Resources Canada (NRCan) to deliver this program in Nova Scotia.

3. **Low Income Households.** Through this program, NSPI plans to offer low income electric heating customers a free energy audit, as well as the no cost delivery of the largest impact and most cost effective energy conservation measures, based on the energy audit results. The program design would resemble NRCan's EnerGuide for Low Income Households program. NSPI intends to partner with Conserve Nova Scotia and subcontract program delivery to one or more third party agencies with experience helping low income households conserve energy.

4. **EnerGuide for New Houses.** This program plans to offer customers a reduced cost home energy rating, as well as provide financial incentives to customers and builders for designing homes to higher levels of energy efficiency, including installing higher efficiency electric heating systems such as heat pumps and high efficiency water heating equipment. The program builds on Natural Resources Canada's new home construction efficiency specifications.

5. **Commercial and Industrial Prescriptive Rebate.** The focus of this program would be on promoting energy efficiency measures to commercial and industrial customers through a standard program offering. A significant component would be focused on lighting, as lighting is estimated to have the largest energy efficiency potential of all of the C&I electric end uses. Through this program, NSPI will offer C&I customers information and financial incentives for efficient lighting, heating, ventilation, and air conditioning energy conservation measures. NSPI plans to work closely with equipment vendors, contractors, and distributors that sell the efficient products in Nova Scotia.

6. **Commercial and Industrial Custom.** The focus of this program would be on promoting energy efficient process and refrigeration measures to commercial and industrial customers through a custom program offering. Through this program, NSPI would offer C&I customers information and financial incentives for efficient refrigeration, motors, air compressors, and other types of process energy conservation measures. In addition, efficient lighting and heating, ventilation, and air conditioning (HVAC)

measures that are not covered by the C&I Prescriptive Rebate Program will be covered by this program. NSPI plans to work closely with consulting engineers, equipment vendors, contractors, and distributors that sell the efficient products in Nova Scotia.

7. **Small Business Direct Install Lighting.** This program would provide full service retrofit energy efficiency services to small businesses – a market that has little access to market-based expertise to identify energy savings opportunities or administer project implementation on their behalf. Competitively selected implementation contractors will recruit customers, assess efficiency opportunities, complete program applications, and install the equipment for the customers. NSPI plans to partner with Conserve Nova Scotia in delivering this program.

8. **Commercial and Industrial New Construction.** Through this program, NSPI plans to offer C&I customers (and their design teams) design assistance and financial incentives to install conservation measures when constructing new buildings to increase the efficiency. Most participating customers are expected to be constructing office buildings, retail stores, schools, and hospitals. NSPI expects to use NRCan's Model National Energy Code for Buildings as the performance standard for this program.

9. **Education and Outreach.** Through this program, NSPI plans to offer a variety of energy efficiency educational services. These include free on-line energy audits, written energy conservation educational materials and newsletters, training seminars on various aspects of energy efficiency, working with schools on energy efficiency education, and outreach to low income customers on energy efficiency.

10. **Development and Research.** Through this program, NSPI plans to explore and evaluate opportunities for future DSM programming, including rate design, as well as the use of emerging technologies in the areas of lighting, smart metering, load monitoring, and load control. Specific program activities will include research studies, baseline evaluations, pilot programs, and program design. NSPI would seek partnership opportunities where appropriate.

These programs are described in more detail in the DSM Programming Plan.

Q. ARE DSM PROGRAMS SIMILAR TO THOSE PROPOSED HEREIN BEING SUCCESSFULLY CONDUCTED ELSEWHERE IN NORTH AMERICA?

A. Yes, similar programs are being conducted by many of the leading DSM organizations in North America. BC Hydro, Manitoba Hydro, MidAmerican Energy, National Grid, NYSERDA, Otter Tail Power Company, Efficiency Vermont, and Xcel Energy are all conducting similar versions of one or more of the programs proposed for NSPI to implement in Nova Scotia. Based on the results of our DSM benchmarking analysis, Summit Blue believes that these programs are tried and true, low risk programs that can be operated successfully in Nova Scotia.

Q. WOULD YOU RECOMMEND THAT THE BOARD APPROVE THE DSM PROGRAMS DESCRIBED IN THE DSM PROGRAMMING PLAN?

A. Yes, I would.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

DIRECT TESTIMONY OF

DR. DANIEL M. VIOLETTE

SUMMIT BLUE CONSULTING LLC

2.3. Evaluation, Monitoring and Verification – Testimony of Dan Violette, Summit Blue

INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Daniel Violette. My business address is 1722 14th Street, Suite 230, Boulder, Colorado, 80302.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a Member and Principal of Summit Blue Consulting, LLC. Summit Blue Consulting provides consulting services in the areas of energy efficiency and load management program performance monitoring and evaluation, program development and implementation; energy systems technology assessment and DSM potential studies; market research and market assessments; utility business management consulting, and industry restructuring, and deregulation strategies.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying for Nova Scotia Power Inc. ("NSPI" or "Company"), which provides electric utility service in the province of Nova Scotia, Canada.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned a MS and PhD in Economics in the fields of Industrial Organization and Econometrics from the University of Colorado.

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH DEMAND SIDE MANAGEMENT PROGRAMS AND MONITORING AND EVALUATION.

A. I have been working in the area of Demand Side Management (DSM) since the late 1980's when I led a state-wide evaluation of energy efficiency programs in New Jersey encompassing all the DSM programs at both the investor-owned electric and gas utilities. This involved almost 100 DSM programs. I have continued work in the area of assessing the impact of DSM programs on energy use by performing work for over 30 utilities and covering over 1,000 programs. This work has included serving as the project manager for a number of state-wide evaluations through multi-year, multi-million dollar efforts in Michigan, Wisconsin, and New Jersey. I am currently the project manager for a state-wide evaluation of New York's energy efficiency programs funded through the Societal Benefits Charge (SBC) and implemented as part of that State's industry restructuring and move to retail choice. That project addresses over 30 energy efficiency and demand response programs across five utility service territories. In addition, I am the project manager for a state-wide impact evaluation of demand response programs being implemented by the three California investor-owned utilities.

I have worked on policy issues surrounding DSM as a consultant to various state and utility DSM collaborative efforts in Massachusetts, California, Ohio, Kentucky, Utah, and Florida. I have testified in rate cases covering a wide variety of issues, including DSM incentives, and also addressed a range of rate case issues including cost allocation, tariff design, performance-based rates, and prudency issues.

I have presented papers at meetings of the National Association of Regulatory Utility Commissioners (NARUC), led workshops for the U.S. Environmental Protection Agency and NARUC related to energy efficiency, authored reports for NARUC on principles for regulating DSM programs, and been an invited speaker and contributor to NARUC Conference proceedings. I have developed guidebooks related to energy efficiency for regulators (through Oak Ridge National Laboratory), for the International Energy Agency (IEA), and for the California Measurement Advisory Council (CALMAC). In 2006, I completed a project on a procedures for valuing demand response resources (DRR) and the integration of DRR in planning for the IEA with approximately 12 countries contributing funds to this IEA Annex and 15 separate U.S. entities also contributing, including state commissions, utilities, independent system operators, associations (e.g., the Association of Western States' Governors) and the U.S. Department of Energy.

In 2006, I co-authored a report for the Canadian Association of Members of Public Utility Tribunals (CAMPUT) entitled “Demand Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing.” This led to three presentations at CAMPUT sponsored meetings. I have also given presentations in the past two years at meetings of the Ontario Electric Association, the Canadian Electric Association, and the National Energy Board of Canada. In recent years, I have conducted workshops on evaluation for BC Hydro, assisted Hydro One with program design and evaluation plans for new programs, authored white papers for the Ontario Power Authority on select programs and marketing processes, and I have provided assistance to Enbridge Gas Company in hearings before the Ontario Energy Board as an expert panelist addressing a number of issues in the Generic DSM Hearings that set program budgets and incentives for DSM.

I am currently serving as expert staff to the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) in CPUC in rulemaking R.07-01-041 on developing impact estimation protocols for demand response and pricing programs, as well as the development of cost-effectiveness methods for analyzing these programs. This year long project is scheduled to produce a decision in April of 2008.

Q. PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL EXPERIENCE PRIOR TO ESTABLISHING SUMMIT BLUE CONSULTING.

A. I have over 20 years of experience in the energy industry including over ten years as a Vice President and Director with Hagler Bailly Consulting. I also held officer-level positions with other major companies including serving as a Sr. Vice President with XENERGY, Inc., an energy services company, and with the Management Consulting Services Business Unit of Electronic Data Systems (EDS), one of the largest worldwide management services and technology companies.

Q. PLEASE DESCRIBE THE INDUSTRY ASSOCIATIONS IN WHICH YOU HAVE A LEADING ROLE.

A. I served three elected terms as President of the Association of Energy Services Professionals (AESP) International, and I currently serve on the AESP Board. I have held various positions on the AESP Board including servicing on the Executive Committee for three of the past four years, Chair of the Topic Committee on Evaluation and Chair of the Topic Committee on Pricing and Demand Response. I have served as Vice President responsible for the AESP topic committees. I have also been on the planning and steering committees for the National DSM Conference sponsored by the AESP, and was the chair for three conferences on pricing in the utility industry, as well as the co-editor of proceedings from two of these events.

Another industry association with which I have been involved is the Peak Load Management Alliance (PLMA). I have been elected to serve as the Vice Chair of the PLMA three times. I have also served on the Executive Committee for the PLMA for seven years and was the co-author of two white papers produced by the PLMA.

Q. HAVE YOU PROVIDED WORKSHOPS OR MANUALS IN THE AREA OF MONITORING AND EVALUATION?

A. I have authored guidebooks on the application of quantitative methods to supply-side and demand-side resource planning for electric and gas utilities. My work has been documented in handbooks authored for the Electric Power Research Institute, International Energy Agency, OECD, and the American Gas Association. I have conducted on-site workshops at nearly a dozen client sites and numerous workshops on planning, DSM and evaluation for EPRI, as well as training courses for the Association of Energy Services Professionals and the Peak Load Management Alliance. I was selected to teach the workshop on Necessary Statistics and Data Analysis for evaluation at the International Energy Program Evaluation Conference (IEPEC) for each of the three past meetings (2001, 2003 and 2005).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present the evaluation, monitoring and verification (EM&V) approach for the DSM programs contained in NSPI's program plan. My testimony contains one exhibit:

1. Exhibit DMV-1 (Appendix A) – Previous proceedings in which I have testified.

Q. CAN YOU SUMMARIZE SOME OF THE KEY POINTS CONTAINED IN THE EM&V APPROACH?

A. Yes. The revised DSM Plan referred to in Mr. Randy Gunn's testimony calls for the initiation of a number of energy efficiency programs. EM&V should take into account the status of the programs being evaluated. Programs that are in their first year of implementation typically have evaluations that provide early feedback to the staff implementing the programs to help determine if any adjustments are needed to help the programs achieve their objectives. Designing and introducing a new energy efficiency program to customers is similar to the introduction of any new product. Implementing a DSM program involves:

- Defining the program concept.
- Developing the marketing message.
- Implementing the marketing plan.
- Closing the sale (i.e., signing the participation agreement).
- Developing delivery channels and trade ally partnerships (i.e., create the needed infrastructure).
- Fulfillment (i.e., getting the product or service to the customer).
- Performing quality control and tracking.
- Financial accounting and disbursements.

Feedback on how well these processes are working and meeting the needs of the customers participating in the program is one important component of evaluation. As a result, evaluations of programs that are new to the market tend to place a greater emphasis on process and market evaluation with somewhat less emphasis on impact assessment in the first year.

The EM&V approach in the DSM Plan is divided into several components. The first introduces EM&V related activities. The second component presents concepts and the basic building blocks of an EM&V plan, including process evaluations, market evaluations, and impact evaluations – along with the key components of each of these evaluations. Also discussed is the evaluation framework. Next an annual savings verification process is presented.

The EM&V Plan is then presented with a focus for the initial evaluation efforts, the data collection approach, and how the overall evaluation budget should be allocated across programs. Assessing how best to allocate the EM&V budget to produce useful information is a key component of the evaluation effort. Factors that influence the budget allocation include:

- Complexity of the program delivery process.
- Number of participants in the program delivery chain.
- Indications that the program may not be meeting interim market targets.
- Uncertainty and range of potential savings based on participating sites and the technologies (e.g., if actual participants have different characteristics from the "planned" participants assumed in the program design then energy savings per site may also vary).

The EM&V Plan also discusses the EM&V infrastructure that is required for on-going evaluation work. This includes the development of a program tracking system that will support implementation and EM&V, as well as the elements of individual, program-specific evaluation efforts.

Section three of the DSM Plan presents the proposed program specific evaluations for the first program year.

Q. WOULD YOU RECOMMEND THAT THE BOARD ADOPT THE EVALUATION PLAN AS PRESENTED IN NSPI's DSM PROGRAMMING PLAN?

A. Yes, I would.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

3.0 DSM COST RECOVERY

3.1. Introduction

To be successful, DSM programs must have appropriate cost recovery mechanisms to avoid creating financial disincentives for a utility.

The traditional ratemaking process of setting rates through general rate applications is not the most appropriate platform for the recovery of DSM costs. General rate applications are not necessarily filed at regular intervals. Regulatory decisions may be made quite some time after the application is filed. There are also significant regulatory costs associated with the general rate application proceedings. Once the rate case decision is made, the approved annual expenses are fixed and embedded into the rates until the next rate case.

DSM-related costs should therefore be recovered by employing an alternate cost recovery mechanism. Use of this mechanism permits a cost-recovery process which makes it possible to implement new DSM programs and modify existing programs more effectively.

NSPI is proposing a DSM cost recovery mechanism which would allow changes to DSM programs and costs at the beginning of each year. In order to ensure accurate and timely recovery of costs, the mechanism is designed on a forward-looking basis with a later true-up to actual costs. The proposed DSM mechanism is to be applied to all rate classes served by NSPI and to be effective January 1, 2009

In the Programming Plan, the Collaborative has recommended that investment in DSM begin in 2008. NSPI proposes the cost of these programs be deferred until such time they can be recovered through the DSM Cost Recovery Mechanism or as part of a General Rate Application. This request includes deferred recovery of the costs of the three early action programs, if approved by the Board, as requested above.

The Company has retained Steve Seelye of the Prime Group to design a DSM Recovery Mechanism appropriate for NSPI and customers. Mr. Seelye has previously worked with NSPI and stakeholders to develop the Fuel Adjustment Mechanism and is familiar with the Company and the perspectives of the stakeholders. Nova Scotia Power supports and adopts the testimony of its expert, Steve Seelye. The Company seeks approval of the DSM cost recovery mechanism tariff provided in Appendix B.

DIRECT TESTIMONY OF

WILLIAM STEVEN SEELYE

THE PRIME GROUP LLC

3.2. Testimony of Steve Seeyle – The Prime Group

INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Steven Seelye, and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying for Nova Scotia Power Inc. ("NSPI" or "Company"), which provides electric utility service in Nova Scotia, Canada.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed cost of service and rate studies for over 130 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. A more detailed description of my qualifications is included in Exhibit WSS-1 (see Appendix C).

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH DEMAND SIDE MANAGEMENT (DSM) PROGRAMS AND COST RECOVERY MECHANISMS.

A. I have developed DSM cost recovery mechanisms for Louisville Gas and Electric Company, Kentucky Utilities, and Delta Natural Gas Company. I have assisted numerous utilities in the economic evaluation of their DSM, energy efficiency, and demand-response programs and have worked with utilities in maximizing the benefit derived from their existing demand side management programs. I have also developed time-of-use, interruptible, real-time pricing, cogeneration, and other rates designed to encourage customers to modify their demand and usage patterns.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe NSPI's proposed DSM Cost Recovery Mechanism. The proposed tariff for the DSM Cost Recovery Mechanism is included in Appendix B.

Q. PLEASE PROVIDE AN OVERVIEW OF NSPI'S PROPOSED DSM COST RECOVERY MECHANISM?

A. NSPI's proposed DSM Cost Recovery Mechanism is designed to provide for the recovery of DSM program costs and the recovery of a portion of revenues[1] from lost sales due to the implementation of DSM programs. NSPI will incur costs related to the implementation of DSM programs. NSPI's proposed DSM Cost Recovery Mechanism will provide dollar-for-dollar recovery of those costs.

The implementation of DSM programs will, by design, result in a reduction in sales to customers. NSPI's proposed DSM Cost Recovery Mechanism will provide for the recovery of revenues from lost sales due to the implementation of DSM programs. It is important for utilities implementing DSM programs to recover revenues from lost sales. Without the ability to recover lost revenues from the implementation of DSM programs, utilities would be penalized for their efforts in pursuing these alternatives.

[1] The portion of lost revenues to be recovered is that portion which contributes to the recovery of fixed costs.

NSPI's proposed DSM cost recovery mechanism will also include a reconciliation adjustment to ensure that there will not be any over or under-recovery of either DSM program costs or revenues from lost sales under the mechanism.

NSPI's proposed DSM Cost Recovery Mechanism will therefore consist of the following three components: (1) a DSM Program Cost Recovery (DPCR) component that provides for the recovery of DSM program costs, (2) a Revenue from Lost Sales (RLS) component that provides for the recovery of revenues from lost sales, and (3) a DSM Balance Adjustment (DBA) that reconciles for any over- or under-recovery of program costs, revenues from lost sales, and previous billings of the DBA.

Q. PLEASE DESCRIBE THE DPCR COMPONENT OF THE DSM COST RECOVERY MECHANISM?

A. The DPCR component of the DSM Cost Recovery Mechanism would be used to recover the cost of developing and implementing demand side management and energy efficiency programs. The DPCR component would recover all expected costs for demand-side management and energy efficiency programs for each twelve-month period that have been developed through a collaborative advisory process and approved by the UARB. These program costs ("DSM Program Costs") would include the cost of planning, developing, implementing, managing, monitoring, and evaluating DSM programs. In addition, all costs incurred by or on behalf of the collaborative process, including but not limited to costs for consultants, employees and administrative expenses, would be recovered through the DPCR component.

Q. HOW WILL DSM PROGRAM COSTS BE ALLOCATED TO THE VARIOUS CUSTOMER CLASSES?

A. NSPI is proposing to allocate DSM Program Costs using the cost allocation methodology for production plant in service approved by the UARB in the Company's most recent general rate case. Recognizing that DSM programs result in a reduction in both energy-related and demand-related costs, DSM Program Costs would be allocated to each customer class using both a demand (kW) and an energy (kWh) allocator in the same way that production plant is allocated in NSPI's cost of service study. Specifically, DSM program costs would be classified as energy-related and demand-related based on the relationship of energy and demand-related production plant in service from the cost of service study submitted in NSPI's last general rate case. In NSPI's last cost of service study, 67.4 percent of NSPI's production plant in service was classified as "energy-related" and 32.6 percent of NSPI's production plant in service was classified as "demand-related". Consequently, 67.4 percent of all DSM Program Costs would be allocated to the customer classes on the basis of an energy allocator, and 32.6 percent of all DSM Program Costs would be allocated to the customer classes on the basis of a demand allocator. The energy allocator used to allocate DSM Program Costs classified as energy-related would correspond to the production energy allocation factor from NSPI's most recent class cost of service study, and the demand allocator used to allocate DSM Program Costs classified as demand-related would correspond to the production demand allocation factor from NSPI's most recent class cost of service study.

Q. ONCE DSM COSTS ARE ALLOCATED TO EACH RATE CLASS ON THE BASIS OF ENERGY- AND DEMAND-RELATED ALLOCATION FACTORS, HOW WILL THE COSTS BE RECOVERED FROM EACH CUSTOMER CLASS?

A. Once the costs are allocated to the customer classes, the allocated costs would be converted to an energy charge (cents per kWh) by dividing the DSM Program Costs allocated to each customer class by the projected annual kWh sales for the customer class. Any over- or under-recovery of actual DSM Program Costs will be refunded or recovered through the application of the DBA.

Q. PLEASE DESCRIBE THE RLS COMPONENT OF THE PROPOSED DSM RECOVERY MECHANISM.

A. The RLS component is a lost revenue adjustment mechanism (LRAM) which would apply to all of the demand side management programs that NSPI would pursue. Implementing an LRAM for all demand side management programs would allow NSPI to recover the lost contributions to fixed costs associated with not selling units of energy because of the success of these programs in reducing electricity consumption on and after the effective date of the tariff.

For each upcoming twelve-month period, the estimated reduction in customer usage (measured in kWh) for the approved programs would be multiplied by the non-variable revenue requirement per kWh for purposes of determining the lost revenue to be recovered.

The non-variable revenue requirement for each customer class would be based on

(i) the average price per kWh from the application of energy charges and demand charges, where applicable, but excluding customer charges, to test-year billing determinants from NSPI's most recent general rate decision less

(ii) the variable costs, adjusted for the revenue to cost ratio, as determined from the cost of service study from NSPI's most recent general rate case. Variable costs would include fuel costs, the variable cost component of purchased power expenses, and variable operation and maintenance expenses related to NSPI's production facilities.

Next, the lost revenues for each customer class would be divided by the expected kilowatt-hour sales for the customer class for the upcoming twelve-month period to determine the applicable RLS rate. Recovery of revenue from lost sales would be included in the RLS until implementation of new rates pursuant to a general rate case.

Because the revenues collected by the RLS component would be based on engineering estimates of energy savings, expected program results and estimated sales, there would be a true-up at the end of the twelve-month period. Any difference between the lost revenues actually collected by the RLS component and the lost revenues determined through the measurement and verification process would be reconciled in future billings under the DBA component.

Q. PLEASE EXPLAIN WHY A TRUE-UP COMPONENT IS NEEDED AND HOW IT IS CONSTRUCTED.

A. A true-up component is needed to ensure that the DPCR and RLS components of the DSM Cost Recovery Mechanism neither over-recover nor under-recover costs. The DBA component of the DSM Cost Recovery Mechanism provides this true-up mechanism. The DBA component would be calculated on a calendar year basis and would reconcile the difference between the amount of revenues actually billed through the DPCR, RLS, and previous application of the DBA, and the revenues which should have been billed, as follows:

1. For the DPCR component, the balance adjustment amount would be the difference between the amount billed in a twelve-month period through the application of the DPCR unit charge and the actual cost of the approved programs during the same twelve-month period.
2. For the RLS component, the balance adjustment amount would be the difference between the amount billed during the twelve-month period through the application of the RLS unit charge and the amount of lost revenues determined for the actual DSM measures implemented during the twelve-month period.
3. For the DBA component, the balance adjustment amount will be the difference between the amount billed during the twelve-month period through the application of the DBA and the balance adjustment amount established for the same twelve-month period.

The sum of these three balance adjustment amounts for each customer class would be divided by the expected kWh sales for each customer class for the upcoming twelve-month period to determine the DBA.

Q. WOULD THE DEMAND SIDE MANAGEMENT COST RECOVERY TARIFF THAT YOU HAVE DESCRIBED ABOVE AID IN ACHIEVING THE POTENTIAL FOR DEMAND SIDE MANAGEMENT IDENTIFIED IN NSPI'S INTEGRATED RESOURCE PLAN?

A. Yes. NSPI's Integrated Resource Plan shows a significant ramp up in demand side management programs as one of the resources for meeting customer energy needs. The DSM cost recovery mechanism described above would provide a way to recover the program costs of implementing these demand side management programs and associated lost revenue without the necessity of continual general rate cases for this purpose. The cost recovery mechanism would provide the flexibility to pursue new programs or to change program direction rapidly as cost effective program modifications were identified. This flexibility with regard to cost recovery is needed to take full advantage of the demand side management opportunities identified in NSPI's Integrated Resource Plan.

The Demand Side Cost Recovery Tariff that I have described above would level the playing field between demand side and supply side approaches for meeting customer energy needs and should provide NSPI with the motivation to aggressively pursue demand side management and energy efficiency programs.

Q. WOULD YOU RECOMMEND THAT THE BOARD ADOPT THE DEMAND SIDE MANAGEMENT COST RECOVERY TARIFF THAT YOU HAVE DESCRIBED ABOVE AND WHICH IS ATTACHED TO THIS EVIDENCE AS APPENDIX B?

A. Yes, I would.

Q. HAVE THESE DEMAND SIDE MANAGEMENT COST RECOVERY COMPONENTS BEEN ADOPTED BY ANY OTHER REGULATORY COMMISSION PER YOUR RECOMMENDATION?

A. Yes. The DPCR, RLS, and DBA are standard cost recovery components included in DSM cost recovery mechanisms, are widely used in the industry, and have been adopted by a number of other regulatory commissions. DSM program cost recovery mechanisms have been adopted in at least 24 state jurisdictions in the U.S. Mechanisms providing for the recovery of lost revenues have been adopted in Kentucky, Minnesota, Iowa, Connecticut, Massachusetts, Oregon, Indiana, New Jersey, California, Maryland, Oregon, Vermont, New York, Missouri, and Georgia.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

3.3. NSPI’s DSM Cost Recovery Mechanism

As described in Mr. Seelye’s evidence, NSPI’s proposed DSM mechanism includes three distinct components: program cost recovery, recovery of lost revenues, and true-up. This mechanism is intended to recover the costs of the utility associated with implementing DSM. For the purpose of this filing the charge designed to recover DSM-related costs is being referred to as DSM Cost Recovery Mechanism (DCRM).

Please see Appendix B for NSPI’s proposed DSM Cost Recovery Mechanism Tariff. For the purpose of illustrating how the mechanism would function, Appendix D contains illustrative calculations of this tariff using hypothetical numbers

3.3.1. DSM Program Cost Recovery (DPCR)

NSPI’s Integrated Resource Plan identified DSM investment as an economic alternative to building new generation. DSM program costs are therefore proposed to be allocated to customer classes in the same manner in which fixed generation costs are allocated in NSPI’s cost of service model. The cost of service model to be used for annual allocation purposes is proposed to be the most recent cost of service study approved by the UARB.

Annual DSM program costs are proposed to be “functionalized” as 100 percent generation-related. These costs are then “classified” as energy- and demand-related using the weighted average classification applied to generation assets. The energy and demand-related DSM costs are then allocated among rate classes using the same mechanism as used for allocation of fixed generation costs. Energy-related costs are allocated using the relative shares of annual energy requirement of all rate classes. Demand-related costs are allocated using the relative shares of all class contributions to the 3 winter coincident peaks (3CP). Please refer to Table 1 of Appendix D.

DSM program costs are proposed to be recovered as a component of the DCRM charge expressed in cents per kWh. This component is calculated by dividing next year’s anticipated program costs, as allocated to each class using the Cost of Service Study

(COSS) methodology, by the forecast kWh sales for each class. The forecast kWh sales already reflect the anticipated effect of the DSM programs.

These calculations are illustrated in Tables 2 and 3 of Appendix D using hypothetical program costs projected for the years 2009 through 2013. The allocation of DSM program costs projected for the year 2009 is illustrated in detail in Table 2. The allocation of the remaining DSM program costs for the following 4 years are presented using the same methodology but in less detail in Table 3. As shown in Table 8 of Appendix D the DSM program cost recovery (DPCR) is the first of the three components of the DCRM.

3.3.2. Revenue from Lost Sales (RLS)

As DSM reduces energy consumption, the revenue previously associated with this energy is lost. For most classes[2] a portion of this lost revenue is required however, to recover fixed, rather than variable costs. In order to ensure that sufficient revenue is collected to fully recover all the fixed costs, the DSM mechanism includes an adjustment for revenue from lost sales (RLS). Lost sales accumulate year over year because each year's DSM programs are expected to have an ongoing and permanent effect. The RLS cost component therefore, grows cumulatively every year, reflecting the accumulated under-recovery of fixed costs. The RLS, similar to the DPCR component, is forward-looking and has a true-up adjustment. The RLS is calculated for relevant rate classes by multiplying their estimated non-variable unit fixed costs[3] (in cents per kWh) by their accumulated lost sales[4] as projected for the next year since the time the rates were last set pursuant to a general rate application. The unit non-variable fixed costs are calculated by dividing the relevant annual non-variable fixed cost of each class by its annual sales. The

[2] Three rate classes of NSPI: GRLF, 1P-RTP and Mersey Contract are excluded from the RLS cost calculations. The GRLF and 1P-RTP have only one rate component: an energy charge which is primarily made up of marginal fuel costs. The Mersey Rate is a contractual pricing arrangement with a cost-based true-up. Fluctuations in sales volumes of these classes have minimal impact on the recovery of fixed costs of NSPI.

[3] The non-variable unit fixed cost reflects costs of providing electric service only. Unmetered Class revenue includes other revenue designed to recover costs associated with capital and maintenance. This non-variable revenue is not accounted for in these calculations.

[4] The projected accumulated lost sales from each rate class in the following year is the total of the engineering estimates of the historical accumulated lost sales for a class and the projected reduction in the current and next year's sales for that class.

estimated relevant non-variable unit fixed cost is calculated for each class by subtracting variable costs, after they have been adjusted for the revenue to cost ratio, and customer charge revenue from its total revenue, and then dividing this remaining portion of class revenue by the class kWh sales. All inputs into these calculations are proposed to come from the most recent rate case as illustrated in Table 5 of Appendix D. Table 6 of Appendix D illustrates these calculations over the five year period from 2009 to 2013 using hypothetical information regarding the sales reduction due to DSM programs and cost of service information from the 2007 Compliance Filing.

3.3.3. DSM Balance Adjustments (DBA)

Because the DPCR and RLS components are set prospectively, DSM costs may not be recovered accurately. In order to ensure accurate cost recovery, the DPCR and RLS components include true-up adjustments. The actual DSM program costs and the results, as determined through the measurement and verification process, may differ from those assumed at the time the DCRM is calculated. Also, the actual energy sales for each class will differ from those which were assumed for the following year for the purpose of DCRM calculations.

The balance adjustment calculations for the DPCR and RLS components are prepared separately and lag two years behind the year for which they are calculated. This reflects the fact that the information and analysis required for true-up is not available until several months after year-end.

The recovery of the true-up costs themselves will be monitored for each class separately in the following years and included in future DBA adjustments. The DBA dollar amounts will be adjusted for the two year effect of the value of money using NSPI's weighted average cost of capital (WACC).[5]

[5] The residual DBA dollar amounts will be multiplied by a factor reflecting the weighted average cost of capital of NSPI, as assumed in the last rate case. Using the weighted average cost of capital of 8.25% from the 2007 Compliance Filing gives an adjustment factor of $(1.0825)^2 = 1.17181$.

Balance Adjustments for the DPCR Component

At the time of the DCRM submission, the actual amounts of revenue collected from each individual class' DPCR component in the previous calendar year will be subtracted from the actual program costs incurred in that year and then allocated to that class. These residual program cost amounts from individual rate classes will be adjusted for the time value of money using NSPI's average weighted cost of capital. Then these adjusted residual class amounts will be divided by the expected kWh sales from corresponding classes to arrive at a DBA-DPCR component for each class.

If actual costs incurred are lower than the amount of revenue collected, the DBA-DPCR component will be negative and will have an effect of a credit on future customer bills. If actual costs incurred are higher than the revenue collected, the DBA-DPCR component will be positive and will have an effect of an additional charge on future customer bills.

Table 4 of Appendix D illustrates the mechanics of the DBA-DPCR calculations. Table 8 of Appendix D shows all the components of the DCRM. These calculations are illustrated over the five year time period from 2009 through 2013.

Balance Adjustments for the RLS Component

At the time of the DCRM submission the actual amount of revenue collected under the RLS component from the previous calendar year will be subtracted from the actual forgone non-variable costs in that year. This will be calculated for each relevant class separately. This level of detail is required because rate classes have differing non-variable costs per kWh.

The residual dollar amounts calculated for individual rate classes will be adjusted for the time value of money using NSPI's average weighted cost of capital. Then these adjusted residual amounts from each class will be divided by the expected amounts of kWh sales from each class to arrive at the DBA-RLS component for each applicable class.

If the actual forgone non-variable costs are lower than the amount of revenue collected under the RLS components, the DBA-RLS component will be negative and will have an effect of a credit on future customer bills. If the actual forgone non-variable costs are higher than the amount of revenue collected, the DBA-RLS component will be positive and will have an effect of an additional charge on future customer bills.

Table 7 of Appendix D illustrates the mechanics of the DBA-RLS calculations. Table 8 of Appendix D shows all the components of DCRM. These calculations are illustrated over the five year time period from 2009 through 2013.

Balance Adjustments for the DBA Components

For the DBA-DPCR and DBA-RLS components, the balance adjustment amounts will be the difference between the amounts billed during the twelve-month period from application of the DBA and the balance adjustment amounts established for the same twelve-month period.

The DBA calculations are performed separately for the DBA-DPCR and DBA-RLS components of each rate class. They are labeled as DBA-DBA-DPCR and DBA-DBA-RLS in Tables 4 and 7 respectively in Appendix D. For the purpose of the DSM Tariff in Appendix B, as presented under item 3 of the DBA section, these two components are aggregated and treated as one DBA-DBA item in column G of the Table 8 of Appendix D. These calculations are illustrated over the five year time period from 2009 through 2013

4.0 CONCLUSION

Nova Scotia Power has worked with Board staff, consultants and its customers to develop an achievable plan for electric energy efficiency and conservation. The Company and customers are ready to commence this important work.

This document contains the Evidence of the Company and its consultants in support of a significant energy efficiency and conservation program. This Evidence, together with the concurrently filed DSM Programming Plan and Collaborative Report, provides a sound platform for successful energy efficiency and conservation.

The Company and customers will achieve success in this important area by implementing a portfolio of programs that meet a variety of needs and opportunities, and by continuing to work together with the input and advice of those with experience in the field.

With this Evidence, Nova Scotia Power Inc respectfully seeks:

1. Approval of the DSM Programming Plan;
2. Approval of three early action DSM Programs; and
3. Recovery of DSM costs and a DSM Cost Recovery Mechanism.

This plan is designed to be consistent with the IRP objectives. The plan is reasonable and achievable, and the outcomes are measurable. Timely recovery of these expenditures is important to the financial health of the utility and to the success of the energy efficiency and conservation initiatives. The Company's proposal is fair to Customers, and to the utility in the recovery and allocation of costs.

By working together to implement energy efficiency and conservation initiatives today and in the coming years, Nova Scotia Power and customers can build a brighter energy future for all Nova Scotians.

APPENDIX A

Previous Testimony by Dr. Daniel M. Violette

Daniel M. Violette -- Testimony / Litigation

- Served an expert panelist in the Generic DSM Hearings on Behalf of Enbridge in case EB-2006-0021 before the ONTARIO ENERGY BOARD in the matter of a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities. July 2006.

- Prepared Testimony on *Appropriate DSM Incentives and Alignment with Policy Objectives*, written rate case testimony submitted to the Hawaii Public Utilities Commission on behalf of Hawaiian Electric Company, HECO T-12, Docket No. 04-0113. August 2006.

- Assisting in the development of load management rates that are expected to be filed as part of Hawaiian Electric Company's current rated case before the Hawaiian Public Utilities Commission, Docket No. 04-0113.

- Expert Report prepared for Constellation NewEnergy, Inc. United Statues District Court Eastern District of Pennsylvania, Civil Action No. 02-CV-2733, May 2004 related to demand response / load management programs and technologies.

- Prepared testimony and testified before the New Jersey Board of Public Utilities concerning GPU's Restructuring Petition, Docket No. EO97060396, March 20, 1998. Corresponding report is entitled "Review of GPU's Restructuring Petition, GPU Energy Docket No. EA97060396, February 24, 1998.

- Prepared testimony and testified before the New Jersey Board of Public Utilities concerning GPU Energy Unbundled Rates Petition, Docket No. EO97070458," January 12, 1998. Corresponding Report is entitled "Review of GPU's Unbundled Rates Petition," GPU Energy Docket No. EA97060396, December 15, 1997.

- Prepared testimony in the Joint Application of Central Power and Light Company, West Texas Utilities Company and Southwestern Electric Power Company for Approval of Preliminary Integrated Resource Plans and for Related Good Cause Exceptions, before the Public Utility Commission of Texas, Docket No. 16995, January 1997.

- Participated in rate case testimony and support for Central Light and Power Company for the rate case, Docket No. 14965, before the Texas PUC, March 1996.

- Prepared testimony for three utilities in Iowa on DSM evaluation, incentives and IRP.

- Authored testimony on behalf of El Paso Electric Company examining the efficacy of its supply planning process as part of an ongoing rate case concerning in part, the cost recovery of the Palo Verde 3 Nuclear Power Plant.

- Prepared testimony for Peoples Natural Gas concerning the impact evaluation of five energy efficiency programs, November 1993.

- Provided litigation support for the Municipal Electric Association of Canada, in hearings in Ontario concerning Ontario Hydro's commitments to nuclear facilities, utility planning methods, and load forecasting. This multiyear assignment involved the most thorough review of Ontario Hydro's planning process, the future of nuclear power in Canada, and the role of independent power producers. The hearings were presided over by an Ontario Province supreme court justice. (1991-1992)
- Rebuttal testimony on behalf of Arizona Public Service Company involving utility planning and rate increase procedures, before the Arizona Corporation Commission, January 1991, Docket Nos. U-1345-900007 and U-1345-89-162.
- Prepared testimony on behalf of El Paso Electric pertaining to its planning and resource acquisition process, filed in October 1990 before the Texas Commission.
- Testimony on cost of service, innovative rates, and rate design before the Connecticut Department of Public Utility Control RE: United Illuminating Company, Docket No. 89-08-11 and 12.
- Surrebuttal testimony for the staff of the Delaware Public Service Commission, "Concerning the Power Plant Performance Program of Delmarva Power & Light Company," Docket No. 88-16, March 1989.
- Testimony for the staff of the Delaware Public Service Commission, "Review of the Delmarva Power & Light Company Power Plant Performance Program," Docket No. 88-16, November 1988.
- Testimony on Arizona Public Service Company, Cost of Service and Rate Design, for the staff of the Arizona Corporation Commission, Docket No. U-1345-85-150, January 1987.

Between 1983 and 1987, testified in eleven regulatory proceedings covering a wide-range of topics.

APPENDIX B

DSM Cost Recovery Mechanism Tariff

APPLICABILITY:

This schedule applies to all electric rate classes.

DEMAND SIDE MANAGEMENT COST RECOVERY MECHANISM:

The monthly amount computed under each of the rate schedules to which this Demand Side Management (DSM) Cost Recovery Mechanism Rider is applicable shall be increased or decreased by the DSM Cost Recovery Mechanism (DCRM) at a class-specific rate per kilowatt hour of monthly consumption in accordance with the following formula:

DCRM = DPCR + RLS + DBA

Where:

DPCR = DSM PROGRAM COST RECOVERY.

The DPCR includes all estimated costs for each upcoming twelve-month period for demand-side management and energy efficiency programs that have been approved by the Board (“approved programs”). Such program costs shall include the cost of planning, developing, implementing, monitoring, and evaluating DSM programs, including but not limited to costs for consultants, employees and administrative expenses. The DPCR shall be computed for each rate schedule using the cost allocation methodology for production plant in service as approved by the UARB in the Company’s most recent general rate case.

RLS = REVENUE FROM LOST SALES.

The RLS component does not apply to the following rate classes: Generation Replacement and Load Following Tariff, Extra High Voltage Time-of-Use Real Time Pricing Tariff, High Voltage Time-of-Use Real Time Pricing Tariff, Distribution Voltage Time-of-Use Real Time Pricing Tariff, and the Mersey System Tariff.

Revenues from lost sales due to DSM and energy efficiency programs implemented on and after the effective date of this tariff will be recovered as follows.

For each upcoming twelve-month period, the estimated reduction in each applicable customer class energy sales, as determined for the approved programs, shall be multiplied by the non-variable revenue requirement per kWh of each applicable rate class as determined from the last general rate case. The estimated lost revenues for each applicable customer class for the upcoming twelve-month period will be recovered through the class-specific RLS component. Recovery of revenue from lost sales calculated for a twelve-month period shall be included in the RLS components until implementation of new rates pursuant to a general rate case at which time the RLS components will be reset to zero.

RLS revenues for each applicable rate class will be calculated based on estimates of energy savings, expected program participation and estimated sales for the upcoming twelve-month period. At the end of each such period, any difference between the lost revenues collected hereunder and the lost revenues shall be reconciled in future billings under the DSM Balance Adjustment (DBA) component.

DBA = DSM BALANCE ADJUSTMENT.

The DBA will be calculated for each rate class separately on a calendar year basis and is used to reconcile the difference between the amount of revenues actually billed through the DPCR, RLS and previous application of the DBA and the revenues which should have been billed, as follows:

(1) For the DPCR, the balance adjustment amount will be the difference between the amount billed in a twelve-month period from the application of the DPCR unit charges and the actual cost of the approved programs during the same twelve-month period.

(2) For the RLS, the balance adjustment amount will be the difference between the estimated lost revenue in each applicable class based on the expected number of programs installed and the actual number of programs installed. The engineering estimates used to calculate lost revenues and the non-variable revenue requirement per kWh will not be trued-up.

(3) For the DBA, the balance adjustment amount will be the difference between the amount billed during the twelve-month period from application of the DBA and the balance adjustment amount established for the same twelve-month period.

Each change in the DCRM shall be placed into effect with bills rendered on and after the effective date of such change.

APPENDIX C

Exhibit of Steve Seeyle

WILLIAM STEVEN SEELYE

Summary of Qualifications

Bachelor of Science degree in Mathematics; completed 54 hours of graduate level course work in Industrial Engineering and Physics. Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service studies and developed rates for over 100 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Case No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Case Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

APPENDIX D

Illustrative DSM Mechanism Tables

Line #

TABLE 1 Illustration of Functionalization, Classification, and Allocation Factors (Source: COSS, Compliance Filing 2007)

Line #	COLUMN	A	B	C	D	E
2	COLUMN	A	B	C	D	E

Functionalization

Line #		Factor
7	Generation	100%
8	Transmission	0%
9	Distribution	0%
10	Retail	0%

Classification of DSM Costs

Line #		Factors[1]
15	Demand-related	32.6%
16	Energy-related	67.4%
17	Total	100.0%

ALLOCATION FACTORS

Line #	Rate Class	Determinants: 3 CP kW Demands [2]	Determinants: MWh Energy Requirement [3]	Allocators: Demand-related	Allocators: Energy-related
24	Residential Total	3,115,781	4,760,109	47.1%	36.7%
25	Small General	158,272	268,925	2.4%	2.1%
26	General Demand	1,290,542	2,654,677	19.5%	20.5%
27	Large General	180,995	446,765	2.7%	3.4%
28	Small Industrial	103,120	269,594	1.6%	2.1%
29	Medium Industrial	245,729	620,625	3.7%	4.8%
30	Large Industrial	392,418	1,122,003	5.9%	8.6%
31	ELI 2P-RTP	809,227	2,118,450	12.2%	16.3%
32	Municipal	119,033	206,123	1.8%	1.6%
33	Unmetered	75,090	124,904	1.1%	1.0%
34	Bowater Mersey	114,314	376,385	1.7%	2.9%
35	Gen. Repl./ Load Foll.	15,367	12,054	0.2%	0.1%
36	1P-RTP	-	-	0.0%	0.0%
38	Total	6,619,888	12,980,614	100.0%	100.0%

40 (1) The proposed classification is a weighted average of the fully classified total generation plant portion of the rate base as shown under the heading "Fully Classified Rate Base" on line 6 of schedule 2b of the COSS.

41 (2) Source: Exh 9c line (14) 3 Coincident Peak (3CP) demands COS

42 (3) Source: Exh 9a Annual column (3) Energy Requirement

TABLE 2 Illustration of Classification and Allocation of Hypothetical DSM Program Costs

Line #										
1										
2										
3	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
4										
5	**FORMULA**		**A x B (line 26)**		**C x D (line 26)**	**B + D**			**G - F**	**E / H x 100**
6										
7		**Demand-related Costs**		**Energy-related Costs**			**KWhs**			**DPCR**
8		**Allocation factors from table 1 (col D)**	**$ Amount**	**Allocation factors from table 1 (col E)**	**$ Amount**	**Total Allocated Costs**	**Sales Forecast without DSM Program**	**Engineering Estimate of DSM-related sales losses**	**Sales Forecast with DSM Program**	**cents/kWh**
9	**Rate Class**									
10	Residential non ETS						4,141,126,934	39,389,118	4,101,737,816	
11	Residential ETS						116,323,736	1,100,000	115,223,736	
12	Residential Subtotal [1]	47.1%	$2,456,615	36.7%	$3,953,343	$6,409,958	4,257,450,670	40,489,118	4,216,961,552	0.152
13									-	
14	Small General	2.4%	$124,788	2.1%	$223,346	$348,135	241,814,845	2,900,000	238,914,845	0.146
15	General Demand	19.5%	$1,017,519	20.5%	$2,204,750	$3,222,268	2,478,552,304	22,500,000	2,456,052,304	0.131
16	Large General	2.7%	$142,704	3.4%	$371,045	$513,749	421,375,291	4,000,000	417,375,291	0.123
17	Small Industrial	1.6%	$81,304	2.1%	$223,902	$305,206	253,264,006	2,000,000	251,264,006	0.121
18	Medium Industrial	3.7%	$193,743	4.8%	$515,438	$709,182	585,154,184	4,200,000	580,954,184	0.122
19	Large Industrial	5.9%	$309,399	8.6%	$931,841	$1,241,240	1,079,310,452	8,500,000	1,070,810,452	0.116
20	ELI 2P-RTP	12.2%	$638,029	16.3%	$1,759,405	$2,397,434	2,076,080,200	13,000,000	2,063,080,200	0.116
21	Municipal	1.8%	$93,851	1.6%	$171,188	$265,039	196,278,318	1,500,000	194,778,318	0.136
22	Unmetered	1.1%	$59,204	1.0%	$103,735	$162,939	112,382,536	910,882	111,471,654	0.146
23	Bowater Mersey	1.7%	$90,130	2.9%	$312,593	$402,724	367,920,000	-	367,920,000	0.109
24	GRLF	0.2%	$12,116	0.1%	$10,011	$22,127	11,789,000	-	11,789,000	0.188
25	1P-RTP	0.0%	$0	0.0%	$0	$0	-	-	-	-
26	Total	100.0%	$5,219,403	100.0%	$10,780,597	$16,000,000	12,081,371,806	100,000,000	11,981,371,806	0.134
27										
28	Classification Breakdown		32.6%		67.4%	100.0%				
29										
30										

31 (1) All residential rate classes will use the same unit fixed cost estimate.
(2) Note: DPCR is an acronym for DSM Program Cost Recovery.

TABLE 3 Illustrative Summary of DPCR Calculations for Hypothetical Program Costs, 2009-2013

COLUMN	A	B	C	D	E

Table 3.1 Forecast of Allocated DSM Program costs

Rate Class	2009	2010	2011	2012	2013
Residential non ETS					
Residential ETS					
Residential Subtotal	$6,409,958	$10,015,559	$12,018,671	$14,021,783	$16,024,895
Small General	$348,135	$543,960	$652,753	$761,545	$870,337
General Demand	$3,222,268	$5,034,794	$6,041,753	$7,048,711	$8,055,670
Large General	$513,749	$802,733	$963,280	$1,123,827	$1,284,373
Small Industrial	$305,206	$476,885	$572,261	$667,638	$763,015
Medium Industrial	$709,182	$1,108,096	$1,329,716	$1,551,335	$1,772,954
Large Industrial	$1,241,240	$1,939,437	$2,327,324	$2,715,212	$3,103,099
ELI 2P-RTP	$2,397,434	$3,745,991	$4,495,189	$5,244,387	$5,993,585
Municipal	$265,039	$414,123	$496,948	$579,773	$662,597
Unmetered	$162,939	$254,592	$305,510	$356,429	$407,347
Bowater Mersey	$402,724	$629,255	$755,107	$880,958	$1,006,809
Gen. Repl./ Load Foll.	$22,127	$34,573	$41,488	$48,403	$55,318
1P-RTP	$0	$0	$0	$0	$0
Total	$16,000,000	$25,000,000	$30,000,000	$35,000,000	$40,000,000

Table 3.2 Forecast kWh sales reflecting DSM-effect

Rate Class	2009	2010	2011	2012	2013
Residential non ETS	4,101,737,816	4,135,068,226	4,153,671,676	4,222,691,557	4,239,277,008
Residential ETS	115,223,736	116,153,548	116,676,116	118,614,876	119,080,759
Residential Subtotal	4,216,961,552	4,251,221,774	4,270,347,793	4,341,306,433	4,358,357,767
Small General	238,914,845	241,461,056	242,547,376	246,577,688	247,546,170
General Demand	2,456,052,304	2,474,926,039	2,486,060,598	2,527,370,461	2,537,297,205
Large General	417,375,291	420,758,795	422,651,766	429,674,799	431,362,431
Small Industrial	251,264,006	252,893,466	254,031,220	258,252,354	259,266,691
Medium Industrial	580,954,184	584,298,070	586,926,795	596,679,520	599,023,096
Large Industrial	1,070,810,452	1,077,731,359	1,082,580,014	1,100,568,808	1,104,891,508
ELI 2P-RTP	2,063,080,200	2,073,042,775	2,082,369,283	2,116,971,170	2,125,285,991
Municipal	194,778,318	195,991,151	196,872,905	200,144,263	200,930,368
Unmetered	111,471,654	112,218,114	112,722,977	114,596,049	115,046,148
Bowater Mersey	367,920,000	367,381,712	369,034,542	375,166,640	376,640,181
Gen. Repl./ Load Foll.	11,789,000	11,771,752	11,824,712	12,021,199	12,068,415
1P-RTP	-	-	-	-	-
Total	11,981,371,806	12,063,696,062	12,117,969,983	12,319,329,383	12,367,715,971

Table 3.3 Estimated DPCR Components in cents per kWh

Rate Class	2009	2010	2011	2012	2013
Residential non ETS	0.15200	0.23559	0.28144	0.32299	0.36768
Residential ETS	0.15200	0.23559	0.28144	0.32299	0.36768
Residential Subtotal	0.15200	0.23559	0.28144	0.32299	0.36768
Small General	0.14571	0.22528	0.26912	0.30885	0.35159
General Demand	0.13120	0.20343	0.24303	0.27890	0.31749
Large General	0.12309	0.19078	0.22791	0.26155	0.29775
Small Industrial	0.12147	0.18857	0.22527	0.25852	0.29430
Medium Industrial	0.12207	0.18965	0.22656	0.25999	0.29597
Large Industrial	0.11592	0.17996	0.21498	0.24671	0.28085
ELI 2P-RTP	0.11621	0.18070	0.21587	0.24773	0.28201
Municipal	0.13607	0.21130	0.25242	0.28968	0.32976
Unmetered	0.14617	0.22687	0.27103	0.31103	0.35407
Bowater Mersey	0.10946	0.17128	0.20462	0.23482	0.26731
Gen. Repl./ Load Foll.	0.18769	0.29370	0.35086	0.40265	0.45837
1P-RTP	0.00000	0.00000	0.00000	0.00000	0.00000

TABLE 4 Illustration of DSM Balance Adjustments to the DPCR Components, 2009-2013

Column	A	B	C	D	E	F	G	H	I	J
Formula	**Table 3.2**	**Table 3.3**			**B x C / 100**	**(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2**	**Col F / Col A x 100**	**Col C x Col G**	**(Prior 2 Year Col F - Col H) x (1 + WACC)^2**	**Col I / Col A x 100**
Year	**Forecast**		**Actual**			**DBA (DPCR Adjustment)**		**DBA (DBA(DPCR Adjustment))**		
	kWh Sales net of DSM	DPCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	DPCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustement amount	DSM Blance Adjustment on DBA (cents/kWh)
	Total for all rate classes									
2009	11,981,371,806		11,616,674,718	$19,000,000	$15,460,123	$0				
2010	12,063,696,062		12,289,716,074	$22,123,567	$25,487,890	$0				
2011	12,117,969,983		12,358,871,759	$28,000,000	$30,759,669	$4,148,050				
2012	12,319,329,383		12,116,980,419	$36,000,000	$34,281,834	($3,942,335)				
2013	12,367,715,971		12,053,059,257	$39,000,000	$39,064,056	($3,233,797)		$4,279,261	($153,754)	
	Residential (Non-ETS and ETS Combined)									
2009	4,216,961,552	0.15200	3,880,993,654	$7,611,825	$5,899,273		**-**			
2010	4,251,221,774	0.23559	4,310,998,436	$8,863,196	$10,156,388		**-**			
2011	4,270,347,793	0.28144	4,664,733,075	$11,217,426	$13,128,648	$2,006,780	**0.046993**			
2012	4,341,306,433	0.32299	4,010,941,703	$14,422,405	$12,954,753	($1,515,371)	**(0.034906)**			
2013	4,358,357,767	0.36768	4,293,342,732	$15,624,272	$15,785,846	($2,239,581)	**(0.051386)**	$2,192,114	($217,177)	**(0.004983)**
	Small General									
2009	238,914,845	0.14571	230,421,827	$413,410	$335,759		**-**			
2010	241,461,056	0.22528	248,615,109	$481,374	$560,077		**-**			
2011	242,547,376	0.26912	249,636,802	$609,236	$671,832	$90,992	**0.037515**			
2012	246,577,688	0.30885	257,163,223	$783,303	$794,238	($92,225)	**(0.037402)**			
2013	247,546,170	0.35159	236,434,427	$848,578	$831,269	($73,351)	**(0.029631)**	$93,651	($3,117)	**(0.001259)**
	General Demand									
2009	2,456,052,304	0.13120	2,560,041,860	$3,826,443	$3,358,699		**-**			
2010	2,474,926,039	0.20343	2,626,776,476	$4,455,504	$5,343,706		**-**			
2011	2,486,060,598	0.24303	2,422,259,542	$5,638,969	$5,886,700	$548,105	**0.022047**			
2012	2,527,370,461	0.27890	2,602,509,823	$7,250,103	$7,258,271	($1,040,801)	**(0.041181)**			
2013	2,537,297,205	0.31749	2,570,588,309	$7,854,278	$8,161,366	($290,293)	**(0.011441)**	$534,039	$16,483	**0.000650**

TABLE 4 Illustration of DSM Balance Adjustments to the DPCR Components, 2009-2013

Line #											
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
2											
3	**Formula**	**Table 3.2**	**Table 3.3**			**B x C / 100**	**(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2**	**Col F / Col A x 100**	**Col C x Col G**	**(Prior 2 Year Col F - Col H) x (1 + WACC)^2**	**Col I / Col A x 100**
4											
5	**Year**	**Forecast**		**Actual**			**DBA (DPCR Adjustment)**		**DBA (DBA(DPCR Adjustment))**		
6		kWh Sales net of DSM	DPCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	DPCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustement amount	DSM Blance Adjustment on DBA (cents/kWh)
7											
40		**Large General**									
41											
42	2009	417,375,291	0.12309	393,211,063	$610,077	$484,005		-			
43	2010	420,758,795	0.19078	455,062,427	$710,373	$868,179		-			
44	2011	422,651,766	0.22791	446,814,002	$899,061	$1,018,349	$147,732	**0.034954**			
45	2012	429,674,799	0.26155	420,111,983	$1,155,936	$1,098,815	($184,918)	**(0.043037)**			
46	2013	431,362,431	0.29775	471,791,624	$1,252,264	$1,404,750	($139,782)	**(0.032405)**	$156,177	($9,897)	**(0.002294)**
47											
48		**Small Industrial**									
49											
50	2009	251,264,006	0.12147	258,787,472	$362,432	$314,345		-			
51	2010	252,893,466	0.18857	256,953,598	$422,016	$484,541		-			
52	2011	254,031,220	0.22527	244,582,505	$534,111	$550,976	$56,349	**0.022182**			
53	2012	258,252,354	0.25852	254,338,483	$686,714	$657,520	($73,268)	**(0.028371)**			
54	2013	259,266,691	0.29430	261,837,180	$743,940	$770,580	($19,763)	**(0.007623)**	$54,253	$2,456	**0.000947**
55											
56		**Medium Industrial**									
57											
58	2009	580,954,184	0.12207	530,965,792	$842,153	$648,160		-			
59	2010	584,298,070	0.18965	612,090,999	$980,602	$1,160,805		-			
60	2011	586,926,795	0.22656	556,891,263	$1,241,068	$1,261,669	$227,323	**0.038731**			
61	2012	596,679,520	0.25999	601,963,557	$1,595,659	$1,565,073	($211,163)	**(0.035390)**			
62	2013	599,023,096	0.29597	542,228,420	$1,728,631	$1,604,857	($24,140)	**(0.004030)**	$215,690	$13,632	**0.002276**
63											
64		**Large Industrial**									
65											
66	2009	1,070,810,452	0.11592	1,147,384,403	$1,473,972	$1,330,001		-			
67	2010	1,077,731,359	0.17996	1,087,613,386	$1,716,291	$1,957,220		-			
68	2011	1,082,580,014	0.21498	1,146,307,616	$2,172,169	$2,464,326	$168,706	**0.015584**			
69	2012	1,100,568,808	0.24671	1,034,485,673	$2,792,789	$2,552,178	($282,323)	**(0.025652)**			
70	2013	1,104,891,508	0.28085	1,007,700,257	$3,025,522	$2,830,137	($342,350)	**(0.030985)**	$178,637	($11,637)	**(0.001053)**
71											

TABLE 4 Illustration of DSM Balance Adjustments to the DPCR Components, 2009-2013

Line #											
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
2											
3	**Formula**	**Table 3.2**	**Table 3.3**			**B x C / 100**	**(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2**	**Col F / Col A x 100**	**Col C x Col G**	**(Prior 2 Year Col F - Col H) x (1 + WACC)^2**	**Col I / Col A x 100**
4											
5	**Year**	**Forecast**		**Actual**			**DBA (DPCR Adjustment)**		**DBA (DBA(DPCR Adjustment))**		
6		kWh Sales net of DSM	DPCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	DPCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustement amount	DSM Blance Adjustment on DBA (cents/kWh)
7											
72		**ELI 2P-RTP**									
73											
74	2009	2,063,080,200	0.11621	1,952,143,495	$2,846,953	$2,268,518		**-**			
75	2010	2,073,042,775	0.18070	1,993,117,000	$3,314,987	$3,601,565		**-**			
76	2011	2,082,369,283	0.21587	1,944,796,624	$4,195,510	$4,198,212	$677,813	**0.032550**			
77	2012	2,116,971,170	0.24773	2,222,914,616	$5,394,227	$5,506,841	($335,814)	**(0.015863)**			
78	2013	2,125,285,991	0.28201	1,970,612,353	$5,843,746	$5,557,385	($3,167)	**(0.000149)**	$633,033	$52,474	**0.002469**
79											
80		**Municipal**									
81											
82	2009	194,778,318	0.13607	186,646,672	$314,734	$253,974		**-**			
83	2010	195,991,151	0.21130	206,463,357	$366,475	$436,251		**-**			
84	2011	196,872,905	0.25242	187,029,046	$463,818	$472,100	$71,199	**0.036165**			
85	2012	200,144,263	0.28968	217,891,741	$596,338	$631,183	($81,763)	**(0.040852)**			
86	2013	200,930,368	0.32976	190,476,768	$646,033	$628,125	($9,705)	**(0.004830)**	$67,639	$4,172	**0.002076**
87											
88		**Unmetered**									
89											
90	2009	111,471,654	0.14617	100,517,555	$193,490	$146,927		**-**			
91	2010	112,218,114	0.22687	113,071,822	$225,299	$256,529		**-**			
92	2011	112,722,977	0.27103	114,962,029	$285,143	$311,579	$54,562	**0.048404**			
93	2012	114,596,049	0.31103	106,371,778	$366,612	$330,849	(36594.92)	**(0.03)**			
94	2013	115,046,148	0.35407	123,638,590	$397,163	$437,771	(30977.64)	**(0.03)**	$55,646	($1,270)	**(0.001104)**
95											
96		**Bowater Mersey**									
97											
98	2009	367,920,000	0.10946	363,578,977	$478,234	$397,972		**-**			
99	2010	367,381,712	0.17128	367,881,712	$556,855	$630,112		**-**			
100	2011	369,034,542	0.20462	369,934,542	$704,766	$756,948	$94,052	**0.025486**			
101	2012	375,166,640	0.23482	376,166,640	$906,128	$883,306	($85,843)	**(0.022881)**			
102	2013	376,640,181	0.26731	371,640,181	$981,639	$993,443	($61,147)	**(0.016235)**	$94,281	($269)	**(0.000071)**
103											

Line #	TABLE 4 Illustration of DSM Balance Adjustments to the DPCR Components, 2009-2013										
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
2											
3	**Formula**	**Table 3.2**	**Table 3.3**			**B x C / 100**	**(Prior 2 Year Col D - Prior 2 yr Col E) x (1 + WACC)^2**	**Col F / Col A x 100**	**Col C x Col G**	**(Prior 2 Year Col F - Col H) x (1 + WACC)^2**	**Col I / Col A x 100**
4											
5	**Year**	**Forecast**		**Actual**			**DBA (DPCR Adjustment)**		**DBA (DBA(DPCR Adjustment))**		
6		kWh Sales net of DSM	DPCR Components in cents per kWh	kWh Sales	DSM Program Costs allocated among rate classes[1]	Collected DSM Program Costs	Actual Adjustment Amount (Prior 2 Year)	DPCR (Cents / kWh)	Balance Adjustment Amount collected (Prior 2 year)	Balance adjustement amount	DSM Blance Adjustment on DBA (cents/kWh)
7											
104		**Generation Replacement / Load Following**									
105											
106	2009	11,789,000	0.18769	11,981,946	$26,276	$22,489		**-**			
107	2010	11,771,752	0.29370	11,071,752	$30,596	$32,518		**-**			
108	2011	11,824,712	0.35086	10,924,712	$38,722	$38,330	$4,437	**0.037525**			
109	2012	12,021,199	0.40265	12,121,199	$49,786	$48,806	($2,252)	**(0.018736)**			
110	2013	12,068,415	0.45837	12,768,415	$53,935	$58,526	$459	**0.003805**	$4,100	$396	**0.003279**
111											
112		**1P-RTP**									
113											
114	2009	-	-	-	$0	$0		**-**			
115	2010	-	-	-	$0	$0		**-**			
116	2011	-	-	-	$0	$0	$0	**-**			
117	2012	-	-	-	$0	$0	$0	**-**			
118	2013	-	-	-	$0	$0	$0	**-**	$0	$0	**-**

Note:
(1) The actual DSM Program costs are allocated among rate classes using the same methodology and coefficients as presented in table 2.

TABLE 5 Illustration of Fixed Unit Costs in cents per kWh Recovered under kWh and kW/kVA Charges (Source: COSS Compliance Filing 2007)

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M	N
5	FORMULA					C - D				F + G + H	I x A	J / J (line 24)	K x I (line 24)	E - L	M / B
8				Revenues			Variable Costs from COS[1]				Variable Cost adjusted for R/C Ratio			Fixed Costs recovered through energy and demand charges	
9	Rate Class	R/C Ratio	kWhs Sales	Total	Customer Charge	Net of Customer Charges	Fuel	O&M	Purchased Power	Total	Unbalanced	Relative Share	Balanced	Total	cents per kWh
11	Residential non ETS		4,141,126,934	$495,081,253	$53,335,342	$441,745,911		`							
12	Residential ETS		116,323,736	$9,147,919	$872,433	$8,275,486									
13	Residential Subtotal [2]	97.9%	4,257,450,670	$504,229,172	$54,207,775	$450,021,398	$163,085,000	$5,086,066	$6,619,000	$174,790,066	$171,100,289	37.0%	$171,254,535	$278,766,863	6.732
14															
15	Small General	101.2%	241,814,845	$29,425,174	$3,529,798	$25,895,376	$9,212,000	$287,383	$374,000	$9,873,383	$9,988,951	2.2%	$9,997,956	$15,897,421	6.574
16	General Demand	107.1%	2,478,552,304	$249,315,718		$249,315,718	$91,016,000	$2,836,367	$3,691,000	$97,543,367	$104,443,731	22.6%	$104,537,886	$144,777,832	5.841
17	Large General	98.8%	421,375,291	$34,404,251		$34,404,251	$15,309,000	$477,356	$621,000	$16,407,356	$16,203,841	3.5%	$16,218,448	$18,185,802	4.316
18	Small Industrial	102.2%	253,264,006	$24,072,764		$24,072,764	$9,245,000	$288,044	$375,000	$9,908,044	$10,125,540	2.2%	$10,134,668	$13,938,096	5.503
19	Medium Industrial	101.3%	585,154,184	$48,991,759		$48,991,759	$21,263,000	$663,141	$863,000	$22,789,141	$23,090,952	5.0%	$23,111,769	$25,879,990	4.423
20	Large Industrial	100.1%	1,079,310,452	$72,185,248		$72,185,248	$38,412,000	$1,198,899	$1,560,000	$41,170,899	$41,198,164	8.9%	$41,235,304	$30,949,944	2.868
21	ELI 2P-RTP	95.0%	2,076,080,200	$119,521,899	$496,800	$119,025,099	$72,560,000	$2,263,584	$2,946,000	$77,769,584	$73,881,104	16.0%	$73,947,708	$45,077,391	2.171
22	Municipal	97.4%	196,278,318	$15,723,725		$15,723,725	$7,059,000	$220,166	$287,000	$7,566,166	$7,369,015	1.6%	$7,375,658	$8,348,067	4.253
23	Unmetered[(3)]	100.0%	112,382,536	$11,677,628		$11,677,628	$4,270,000	$133,554	$174,000	$4,577,554	$4,577,502	1.0%	$4,581,629	$7,095,999	6.314
24	Total / Average	100.0%	11,701,662,806	$1,109,547,337	$58,234,372	$1,051,312,965	$431,431,000	$13,454,560	$17,510,000	$462,395,560	$461,979,089	100.0%	$462,395,560	$588,917,405	5.033

(1) Variable cost is made up of the following items in the cost of service studies:
1 Fuel costs (line 1, page 3, exh 6);
2 Variable Purchased Power (line 3, page 3, exh 6);
3 Variable O&M costs (16% of O&M - Steam (line 4, exh 5) allocated among rate classes using distribution pattern of O&M - Steam Energy-related (line 4, page 3, exh 6)

(2) All residential rate classes will use the same unit fixed cost estimate.

(3) The unmetered class revenue relfects only electric service costs. It does not reflect the maintanance and capital costs associated with unmetered fixtures such as lamp posts..

TABLE 6 Illustration of Calculation of the RLS Components, 2009-2013

Table 6.1 Forecast engineering estimates of DSM-induced kWh reduction (Columns B–F); Table 6.2 Forecast forgone recovery of fixed costs due to the DSM-effect (Columns G–K)

Line #	Column	A	B	C	D	E	F	G	H	I	J	K
5		Fixed Unit Costs in cents per kWh (Source: Table 5; Col N)	Table 6.1 Forecast engineering estimates of DSM-induced kWh reduction					Table 6.2 Forecast forgone recovery of fixed costs due to the DSM-effect				
7			2009	2010	2011	2012	2013	2009	2010	2011	2012	2013
8	**Rate Class**											
9	Residential non ETS	6.73	39,389,118	47,914,534	51,623,033	52,675,446	53,899,737	$2,651,544	$3,225,447	$3,475,091	$3,545,935	$3,628,351
10	Residential ETS	6.73	1,100,000	1,386,764	1,448,748	1,619,974	1,510,266	$74,048	$93,352	$97,525	$109,051	$101,666
11	Small General	6.57	2,900,000	3,351,652	3,810,418	3,626,152	4,121,117	$190,652	$220,345	$250,505	$238,391	$270,931
12	General Demand	5.84	22,500,000	25,600,751	28,529,233	30,815,599	31,924,195	$1,314,276	$1,495,398	$1,666,457	$1,800,009	$1,864,764
13	Large General	4.32	4,000,000	5,079,702	5,422,153	5,100,071	5,165,377	$172,633	$219,231	$234,010	$220,110	$222,928
14	Small Industrial	5.50	2,000,000	2,326,789	2,725,817	2,977,261	3,016,793	$110,068	$128,052	$150,012	$163,850	$166,026
15	Medium Industrial	4.42	4,200,000	5,429,505	5,352,036	5,520,196	6,565,594	$185,756	$240,134	$236,708	$244,145	$290,381
16	Large Industrial	2.87	8,500,000	10,916,287	9,874,574	11,856,074	10,982,841	$243,743	$313,032	$283,160	$339,981	$314,940
17	ELI 2P-RTP	2.17	13,000,000	14,978,498	18,103,038	17,466,188	19,108,988	$282,266	$325,224	$393,067	$379,239	$414,908
18	Municipal	4.25	1,500,000	1,756,341	1,939,215	2,176,582	2,358,621	$63,798	$74,700	$82,478	$92,574	$100,316
19	Unmetered	6.31	910,882	1,259,177	1,171,735	1,166,457	1,346,470	$57,514	$79,506	$73,985	$73,652	$85,018
20	Bowater Mersey	-	-	-	-	-	-	$0	$0	$0	$0	$0
21	Gen. Repl./ Load Foll.	-	-	-	-	-	-	$0	$0	$0	$0	$0
22	1P-RTP	-	-	-	-	-	-	$0	$0	$0	$0	$0
23	Total		100,000,000	120,000,000	130,000,000	135,000,000	140,000,000	$5,346,298	$6,414,421	$6,942,998	$7,206,937	$7,460,230

Line #	Column	A	B	C	D	E	F	G	H	I	J	K
28		Fixed Unit Costs in cents per kWh (Source: Table 5; Col N)	Table 6.3 Actual engineering estimates of DSM-induced kWh reduction					Table 6.4 Actual forgone recovery of fixed costs due to the DSM-effect				
30			2009	2010	2011	2012	2013	2009	2010	2011	2012	2013
31	**Rate Class**											
32	Residential non ETS	6.73	41,977,866	47,512,183	49,267,513	57,281,176	51,783,179	$2,825,810	$3,198,362	$3,316,525	$3,855,978	$3,485,871
33	Residential ETS	6.73	1,160,135	1,295,082	1,593,603	1,566,435	1,408,253	$78,096	$87,181	$107,276	$105,447	$94,799
34	Small General	6.57	3,107,178	3,243,775	3,597,577	3,569,315	3,726,396	$204,272	$213,253	$236,512	$234,654	$244,981
35	General Demand	5.84	24,041,215	25,441,211	28,167,897	33,458,686	30,992,455	$1,404,302	$1,486,079	$1,645,350	$1,954,397	$1,810,339
36	Large General	4.32	3,691,594	4,919,069	5,122,106	4,638,849	4,974,271	$159,323	$212,298	$221,061	$200,204	$214,681
37	Small Industrial	5.50	1,823,869	2,497,509	2,768,777	3,150,398	3,305,882	$100,375	$137,448	$152,377	$173,379	$181,935
38	Medium Industrial	4.42	4,103,587	5,836,080	5,605,206	5,659,374	6,735,294	$181,492	$258,116	$247,905	$250,301	$297,886
39	Large Industrial	2.87	8,946,939	10,777,544	9,456,497	12,167,353	11,058,892	$256,559	$309,053	$271,171	$348,907	$317,121
40	ELI 2P-RTP	2.17	14,121,164	14,261,992	16,375,824	16,781,355	19,767,627	$306,609	$309,667	$355,564	$364,369	$429,209
41	Municipal	4.25	1,430,239	1,899,858	2,127,051	1,997,148	2,506,605	$60,831	$80,804	$90,467	$84,942	$106,610
42	Unmetered	6.31	960,641	1,230,086	1,249,833	1,282,035	1,326,228	$60,656	$77,669	$78,916	$80,950	$83,740
43	Bowater Mersey	-	-	-	-	-	-	$0	$0	$0	$0	$0
44	Gen. Repl./ Load Foll.	-	-	-	-	-	-	$0	$0	$0	$0	$0
45	1P-RTP	-	-	-	-	-	-	$0	$0	$0	$0	$0
46	Total		105,364,425	118,914,389	125,331,885	141,552,125	137,585,081	$5,638,325	$6,369,929	$6,723,125	$7,653,528	$7,267,173

TABLE 6 Illustration of Calculation of the RLS Components, 2009-2013

Column	A	B	C	D	E	F	G	H	I	J	K

Table 6.5 Forecast cumulative engineering estimates of DSM-induced kWh reduction

Rate Class	2009	2010	2011	2012	2013
Residential non ETS	39,389,118	87,303,652	141,515,433	193,788,528	245,332,745
Residential ETS	1,100,000	2,486,764	3,995,647	5,523,939	7,179,060
Small General	2,900,000	6,251,652	10,269,248	13,787,524	17,695,799
General Demand	22,500,000	48,100,751	78,171,199	108,827,257	140,390,117
Large General	4,000,000	9,079,702	14,193,449	19,132,887	23,998,218
Small Industrial	2,000,000	4,326,789	6,876,474	10,024,456	13,084,209
Medium Industrial	4,200,000	9,629,505	14,885,128	20,811,899	27,630,663
Large Industrial	8,500,000	19,416,287	29,737,800	41,455,132	52,019,895
ELI 2P-RTP	13,000,000	27,978,498	47,202,700	63,952,382	81,334,155
Municipal	1,500,000	3,256,341	5,125,795	7,445,894	9,992,351
Unmetered	910,882	2,170,059	3,391,553	4,528,918	5,953,486
Bowater Mersey	-	-	-	-	-
Gen. Repl./ Load Foll.	-	-	-	-	-
1P-RTP	-	-	-	-	-
Total	100,000,000	220,000,000	355,364,425	489,278,814	624,610,699

Table 6.6 Forecast cumulative forgone recovery of fixed costs due to the DSM-effect

Rate Class	2009	2010	2011	2012	2013
Residential non ETS	$2,651,544	$5,876,991	$9,526,347	$13,045,198	$16,514,983
Residential ETS	$74,048	$167,401	$268,974	$371,853	$483,270
Small General	$190,652	$410,997	$675,122	$906,421	$1,163,359
General Demand	$1,314,276	$2,809,673	$4,566,156	$6,356,846	$8,200,503
Large General	$172,633	$391,864	$612,564	$825,741	$1,035,720
Small Industrial	$110,068	$238,120	$378,439	$551,684	$720,075
Medium Industrial	$185,756	$425,890	$658,334	$920,461	$1,222,039
Large Industrial	$243,743	$556,775	$852,751	$1,188,753	$1,491,705
ELI 2P-RTP	$282,266	$607,490	$1,024,900	$1,388,581	$1,765,987
Municipal	$63,798	$138,498	$218,009	$316,687	$424,993
Unmetered	$57,514	$137,021	$214,148	$285,963	$375,912
Bowater Mersey	$0	$0	$0	$0	$0
Gen. Repl./ Load Foll.	$0	$0	$0	$0	$0
1P-RTP	$0	$0	$0	$0	$0
Total	$5,346,298	$11,760,719	$18,995,744	$26,158,189	$33,398,547

Table 6.7 Forecast kWh sales reflecting DSM-effect

Rate Class	2009	2010	2011	2012	2013
Residential non ETS	4,101,737,816	4,135,068,226	4,153,671,676	4,222,691,557	4,239,277,008
Residential ETS	115,223,736	116,153,548	116,676,116	118,614,876	119,080,759
Small General	238,914,845	241,461,056	242,547,376	246,577,688	247,546,170
General Demand	2,456,052,304	2,474,926,039	2,486,060,598	2,527,370,461	2,537,297,205
Large General	417,375,291	420,758,795	422,651,766	429,674,799	431,362,431
Small Industrial	251,264,006	252,893,466	254,031,220	258,252,354	259,266,691
Medium Industrial	580,954,184	584,298,070	586,926,795	596,679,520	599,023,096
Large Industrial	1,070,810,452	1,077,731,359	1,082,580,014	1,100,568,808	1,104,891,508
ELI 2P-RTP	2,063,080,200	2,073,042,775	2,082,369,283	2,116,971,170	2,125,285,991
Municipal	194,778,318	195,991,151	196,872,905	200,144,263	200,930,368
Unmetered	111,471,654	112,218,114	112,722,977	114,596,049	115,046,148
Bowater Mersey	367,920,000	367,381,712	369,034,542	375,166,640	376,640,181
Gen. Repl./ Load Foll.	11,789,000	11,771,752	11,824,712	12,021,199	12,068,415
1P-RTP	-	-	-	-	-
Total	11,981,371,806	12,063,696,062	12,117,969,983	12,319,329,383	12,367,715,971

Table 6.8 Forecast RLS components by class and year (cents/kWh)

Rate Class	2009	2010	2011	2012	2013
Residential non ETS	0.06464	0.14213	0.22935	0.30893	0.38957
Residential ETS	0.06426	0.14412	0.23053	0.31350	0.40583
Small General	0.07980	0.17021	0.27835	0.36760	0.46996
General Demand	0.05351	0.11353	0.18367	0.25152	0.32320
Large General	0.04136	0.09313	0.14493	0.19218	0.24010
Small Industrial	0.04381	0.09416	0.14897	0.21362	0.27774
Medium Industrial	0.03197	0.07289	0.11217	0.15426	0.20401
Large Industrial	0.02276	0.05166	0.07877	0.10801	0.13501
ELI 2P-RTP	0.01368	0.02930	0.04922	0.06559	0.08309
Municipal	0.03275	0.07067	0.11074	0.15823	0.21151
Unmetered	0.05160	0.12210	0.18998	0.24954	0.32675
Bowater Mersey	-	-	-	-	-
Gen. Repl./ Load Foll.	-	-	-	-	-
1P-RTP	-	-	-	-	-

RLS CALCULATIONS

(1) For each year and each rate class Forecast forgone recovery of fixed costs due to the DSM-effect (Table 6.2) are calculated by multiplying Forecast engineering estimates of DSM-induced kwh reduction (Table 6.1) by Fixed Unit Costs in cents/kWh (column A).

(2) For each year and each rate class Actual forgone recovery of fixed costs due to the DSM effect (Table 6.4) are calculated by multiplying Actual engineering estimates of DSM-induced kwh reduction (Table 6.3) by Fixed Unit Costs in cents/kWh (column A) Note that fixed unit costs used here are the same as in step 1.

(3) For each year and rate class Forecast cumulative forgone recovery of fixed costs due to the DSM effect (Table 6.6) are calculated by adding Actual forgone recovery of fixed cost due to the DSM effect (Table 6.4) to Forecast forgone recovery of fixed costs due to the DSM effect from the current and next year (Table 6.2).

(4) RLS charges for each year and each class are calculated by dividing Forecast cumulative forgone recovery of fixed costs due to the DSM-effect (Table 6.6) by Forecast kWh sales reflecting DSM-effect (Table 6.7).

TABLE 7 Illustration of DSM Balance Adjustments to the RLS Components, 2009-2013

Line #														
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
2														
3	**Formula**	**Table 6.5**	**Table 5 Column N**	**Table 6.6**		**B X D / 100**			**C X G / 100**	**(Prior 2 Year Col F - Prior 2 yr Col H) x (1 + WACC)^2**	**Col I / Col A x 100**	**Col G x Col J**	**(Prior 2 Year Col I - Col K) x (1 + WACC)^2**	**Col L / Col A x 100**
4														
5														
6	**Year**	**Forecast**			**Actual**					**DBA (RLS Adjustment)**		**DBA (DBA(RLS Adjustment))**		
7			Cents per kWh		Forgone recovery of fixed costs			Collected forgone fixed costs						
8		kWh Sales net of DSM	Fixed Unit Costs	RLS components	DSM-induced reduction in kWh Sales	Amount	Cumulative Amount	kWh Sales	Amount	Actual Adjustment Amount	RLS (Cents / kWh)	Balance Adjustment Amount collected	Balance adjustement amount	DSM Blance Adjustment on DBA (Cents/kWh)
9														
10		**Total for all rate classes**												
11														
12	2009	11,981,371,806			105,364,425	$5,638,325	$5,638,325	11,616,674,718	$5,149,203	$0				
13	2010	12,063,696,062			118,914,389	$6,369,929	$12,008,254	12,289,716,074	$12,076,625	$0				
14	2011	12,117,969,983			125,331,885	$6,723,125	$18,731,379	12,358,871,759	$19,765,982	$573,156				
15	2012	12,319,329,383			141,552,125	$7,653,528	$26,384,908	12,116,980,419	$25,352,774	($80,117)				
16	2013	12,367,715,971			137,585,081	$7,267,173	$33,652,081	12,053,059,257	$32,933,982	($1,212,354)		$612,620	($46,244)	
17														
18		**Residential Non-ETS**												
19														
20	2009	4,101,737,816	6.732	0.06464	41,977,866	$2,825,810	$2,825,810	3,756,907,390	$2,428,631		**-**			
21	2010	4,135,068,226	6.732	0.14213	47,512,183	$3,198,362	$6,024,172	4,183,495,346	$5,945,818		**-**			
22	2011	4,153,671,676	6.732	0.22935	49,267,513	$3,316,525	$9,340,697	4,541,232,947	$10,415,210	$465,417	**0.011205**			
23	2012	4,222,691,557	6.732	0.30893	57,281,176	$3,855,978	$13,196,674	3,888,035,006	$12,011,340	$91,815	**0.002174**			
24	2013	4,239,277,008	6.732	0.38957	51,783,179	$3,485,871	$16,682,545	4,181,832,158	$16,291,194	($1,259,121)	**(0.029701)**	$508,844	($50,887)	**(0.001200)**
25														
26		**Residential ETS**												
27														
28	2009	115,223,736	6.732	0.06426	1,160,135	$78,096	$78,096	124,086,265	$79,744		**-**			
29	2010	116,153,548	6.732	0.14412	1,295,082	$87,181	$165,277	127,503,090	$183,758		**-**			
30	2011	116,676,116	6.732	0.23053	1,593,603	$107,276	$272,553	123,500,127	$284,705	($1,930)	**(0.001655)**			
31	2012	118,614,876	6.732	0.31350	1,566,435	$105,447	$378,000	122,906,697	$385,308	($21,656)	**(0.018257)**			
32	2013	119,080,759	6.732	0.40583	1,408,253	$94,799	$472,799	111,510,574	$452,548	($14,240)	**(0.011958)**	($2,043)	$132	**0.000111**
33														
34		**Small General**												
35														
36	2009	238,914,845	6.574	0.07980	3,107,178	$204,272	$204,272	230,421,827	$183,875		**-**			
37	2010	241,461,056	6.574	0.17021	3,243,775	$213,253	$417,525	248,615,109	$423,174		**-**			
38	2011	242,547,376	6.574	0.27835	3,597,577	$236,512	$654,037	249,636,802	$694,855	$23,902	**0.009855**			
39	2012	246,577,688	6.574	0.36760	3,569,315	$234,654	$888,692	257,163,223	$945,334	($6,619)	**(0.002684)**			
40	2013	247,546,170	6.574	0.46996	3,726,396	$244,981	$1,133,673	236,434,427	$1,111,139	($47,831)	**(0.019322)**	$24,601	($819)	**(0.000331)**
41														
42		**General Demand**												
43														
44	2009	2,456,052,304	5.841	0.05351	24,041,215	$1,404,302	$1,404,302	2,560,041,860	$1,369,922		**-**			
45	2010	2,474,926,039	5.841	0.11353	25,441,211	$1,486,079	$2,890,380	2,626,776,476	$2,982,062		**-**			
46	2011	2,486,060,598	5.841	0.18367	28,167,897	$1,645,350	$4,535,731	2,422,259,542	$4,448,972	$40,286	**0.001620**			
47	2012	2,527,370,461	5.841	0.25152	33,458,686	$1,954,397	$6,490,128	2,602,509,823	$6,545,836	($107,434)	**(0.004251)**			
48	2013	2,537,297,205	5.841	0.32320	30,992,455	$1,810,339	$8,300,467	2,570,588,309	$8,308,100	$101,664	**0.004007**	$39,252	$1,212	**0.000048**
49														

TABLE 7 Illustration of DSM Balance Adjustments to the RLS Components, 2009-2013

Line #														
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
2														
3	**Formula**	**Table 6.5**	**Table 5 Column N**	**Table 6.6**		**B X D / 100**			**C X G / 100**	**(Prior 2 Year Col F - Prior 2 yr Col H) x $(1 + WACC)^2$**	**Col I / Col A x 100**	**Col G x Col J**	**(Prior 2 Year Col I - Col K) x $(1 + WACC)^2$**	**Col L / Col A x 100**
4														
5														
6	**Year**	**Forecast**			**Actual**					**DBA (RLS Adjustment)**		**DBA (DBA(RLS Adjustment))**		
7			Cents per kWh		Forgone recovery of fixed costs			Collected forgone fixed costs						
8		kWh Sales net of DSM	Fixed Unit Costs	RLS components	DSM-induced reduction in kWh Sales	Amount	Cumulative Amount	kWh Sales	Amount	Actual Adjustment Amount	RLS (Cents / kWh)	Balance Adjustment Amount collected	Balance adjustement amount	DSM Blance Adjustment on DBA (Cents/kWh)
9														
50	**Large General**													
51														
52	2009	417,375,291	4.316	0.04136	3,691,594	$159,323	$159,323	393,211,063	$162,638		**-**			
53	2010	420,758,795	4.316	0.09313	4,919,069	$212,298	$371,621	455,062,427	$423,812		**-**			
54	2011	422,651,766	4.316	0.14493	5,122,106	$221,061	$592,682	446,814,002	$647,583	($3,885)	**(0.000919)**			
55	2012	429,674,799	4.316	0.19218	4,638,849	$200,204	$792,886	420,111,983	$807,363	($61,157)	**(0.014233)**			
56	2013	431,362,431	4.316	0.24010	4,974,271	$214,681	$1,007,567	471,791,624	$1,132,792	($64,334)	**(0.014914)**	($4,107)	$260	**0.000060**
57														
58	**Small Industrial**													
59														
60	2009	251,264,006	5.503	0.04381	1,823,869	$100,375	$100,375	258,787,472	$113,363		**-**			
61	2010	252,893,466	5.503	0.09416	2,497,509	$137,448	$237,822	256,953,598	$241,943		**-**			
62	2011	254,031,220	5.503	0.14897	2,768,777	$152,377	$390,199	244,582,505	$364,363	($15,220)	**(0.005992)**			
63	2012	258,252,354	5.503	0.21362	3,150,398	$173,379	$563,577	254,338,483	$543,324	($4,829)	**(0.001870)**			
64	2013	259,266,691	5.503	0.27774	3,305,882	$181,935	$745,513	261,837,180	$727,214	$30,275	**0.011677**	($14,654)	($663)	**(0.000256)**
65														
66	**Medium Industrial**													
67														
68	2009	580,954,184	4.423	0.03197	4,103,587	$181,492	$181,492	530,965,792	$169,773		**-**			
69	2010	584,298,070	4.423	0.07289	5,836,080	$258,116	$439,608	612,090,999	$446,148		**-**			
70	2011	586,926,795	4.423	0.11217	5,605,206	$247,905	$687,513	556,891,263	$624,644	$13,733	**0.002340**			
71	2012	596,679,520	4.423	0.15426	5,659,374	$250,301	$937,814	601,963,557	$928,613	($7,664)	**(0.001284)**			
72	2013	599,023,096	4.423	0.20401	6,735,294	$297,886	$1,235,700	542,228,420	$1,106,175	$73,670	**0.012298**	$13,030	$824	**0.000137**
73														
74	**Large Industrial**													
75														
76	2009	1,070,810,452	2.868	0.02276	8,946,939	$256,559	$256,559	1,147,384,403	$261,173		**-**			
77	2010	1,077,731,359	2.868	0.05166	10,777,544	$309,053	$565,613	1,087,613,386	$561,880		**-**			
78	2011	1,082,580,014	2.868	0.07877	9,456,497	$271,171	$836,784	1,146,307,616	$902,950	($5,407)	**(0.000499)**			
79	2012	1,100,568,808	2.868	0.10801	12,167,353	$348,907	$1,185,691	1,034,485,673	$1,117,375	$4,374	**0.000397**			
80	2013	1,104,891,508	2.868	0.13501	11,058,892	$317,121	$1,502,812	1,007,700,257	$1,360,488	($77,533)	**(0.007017)**	($5,725)	$373	**0.000034**
81														
82	**ELI 2P-RTP**													
83														
84	2009	2,063,080,200	2.171	0.01368	14,121,164	$306,609	$306,609	1,952,143,495	$267,088		**-**			
85	2010	2,073,042,775	2.171	0.02930	14,261,992	$309,667	$616,276	1,993,117,000	$584,068		**-**			
86	2011	2,082,369,283	2.171	0.04922	16,375,824	$355,564	$971,840	1,944,796,624	$957,190	$46,312	**0.002224**			
87	2012	2,116,971,170	2.171	0.06559	16,781,355	$364,369	$1,336,209	2,222,914,616	$1,458,073	$37,741	**0.001783**			
88	2013	2,125,285,991	2.171	0.08309	19,767,627	$429,209	$1,765,419	1,970,612,353	$1,637,463	$17,168	**0.000808**	$43,252	$3,585	**0.000169**
89														

TABLE 7 Illustration of DSM Balance Adjustments to the RLS Components, 2009-2013

Line #														
1	**Column**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
2														
3	**Formula**	**Table 6.5**	**Table 5 Column N**	**Table 6.6**		**B X D / 100**			**C X G / 100**	**(Prior 2 Year Col F - Prior 2 yr Col H) x (1 + WACC)^2**	**Col I / Col A x 100**	**Col G x Col J**	**(Prior 2 Year Col I - Col K) x (1 + WACC)^2**	**Col L / Col A x 100**
4														
5														
6	**Year**	**Forecast**			**Actual**					**DBA (RLS Adjustment)**		**DBA (DBA(RLS Adjustment))**		
7			Cents per kWh		Forgone recovery of fixed costs			Collected forgone fixed costs						
8		kWh Sales net of DSM	Fixed Unit Costs	RLS components	DSM-induced reduction in kWh Sales	Amount	Cumulative Amount	kWh Sales	Amount	Actual Adjustment Amount	RLS (Cents / kWh)	Balance Adjustment Amount collected	Balance adjustement amount	DSM Blance Adjustment on DBA (Cents/kWh)
9														
90		**Municipal**												
91														
92	2009	194,778,318	4.253	0.03275	1,430,239	$60,831	$60,831	186,646,672	$61,134		**-**			
93	2010	195,991,151	4.253	0.07067	1,899,858	$80,804	$141,635	206,463,357	$145,898		**-**			
94	2011	196,872,905	4.253	0.11074	2,127,051	$90,467	$232,102	187,029,046	$207,108	($356)	**(0.000181)**			
95	2012	200,144,263	4.253	0.15823	1,997,148	$84,942	$317,044	217,891,741	$344,769	($4,996)	**(0.002496)**			
96	2013	200,930,368	4.253	0.21151	2,506,605	$106,610	$423,655	190,476,768	$402,882	$29,288	**0.014576**	($338)	($21)	**(0.000010)**
97														
98		**Unmetered**												
99														
100	2009	111,471,654	6.314	0.05160	960,641	$60,656	$60,656	100,517,555	$51,863		**-**			
101	2010	112,218,114	6.314	0.12210	1,230,086	$77,669	$138,326	113,071,822	$138,063		**-**			
102	2011	112,722,977	6.314	0.18998	1,249,833	$78,916	$217,242	114,962,029	$218,401	$10,304	**0.009141**			
103	2012	114,596,049	6.314	0.24954	1,282,035	$80,950	$298,192	106,371,778	$265,440	$308	**0.000268**			
104	2013	115,046,148	6.314	0.32675	1,326,228	$83,740	$381,932	123,638,590	$403,988	($1,359)	**(0.001181)**	$10,509	($240)	**(0.000208)**
105														
106		**Bowater Mersey**												
107														
108	2009	367,920,000	-	-	-	$0	$0	363,578,977	$0		**-**			
109	2010	367,381,712	-	-	-	$0	$0	367,881,712	$0		**-**			
110	2011	369,034,542	-	-	-	$0	$0	369,934,542	$0	$0	**-**			
111	2012	375,166,640	-	-	-	$0	$0	376,166,640	$0	$0	**-**			
112	2013	376,640,181	-	-	-	$0	$0	371,640,181	$0	$0	**-**	$0	$0	**-**
113														
114		**Generation Replacement / Load Following**												
115														
116	2009	11,789,000	-	-	-	$0	$0	11,981,946	$0		**-**			
117	2010	11,771,752	-	-	-	$0	$0	11,071,752	$0		**-**			
118	2011	11,824,712	-	-	-	$0	$0	10,924,712	$0	$0	**-**			
119	2012	12,021,199	-	-	-	$0	$0	12,121,199	$0	$0	**-**			
120	2013	12,068,415	-	-	-	$0	$0	12,768,415	$0	$0	**-**	$0	$0	**-**
121														
122		**1P-RTP**												
123														
124	2009	-	-	-	-	$0	$0	-	$0		**-**			
125	2010	-	-	-	-	$0	$0	-	$0		**-**			
126	2011	-	-	-	-	$0	$0	-	$0	$0	**-**			
127	2012	-	-	-	-	$0	$0	-	$0	$0	**-**			
128	2013	-	-	-	-	$0	$0	-	$0	$0	**-**	$0	$0	**-**

Line #	TABLE 8 Illustration of DSM Tariff Components (in cents per kWh), 2009-2013									
1										
2	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
	FORMULA	**Table 3.3**	**Table 6.6**	**Table 4 Column G**	**Table 7 Column J**	**Table 4 Column J**	**Table 7 Column M**	**E + F**	**C + D + G**	**A + B + H**
3										
4		**2009**								
5		**DPCR**	**RLS**	**DBA**						**DCRM**
6	**Rate Class**			**DPCR**	**RLS**	**DBA**			**Total**	
7						**DPCR**	**RLS**	**Total**		
8	Residential non ETS	0.15200	0.06464	-	-	-	-	-	-	**0.21665**
9	Residential ETS	0.15200	0.06426	-	-	-	-	-	-	**0.21627**
10	Small General	0.14571	0.07980	-	-	-	-	-	-	**0.22551**
11	General Demand	0.13120	0.05351	-	-	-	-	-	-	**0.18471**
12	Large General	0.12309	0.04136	-	-	-	-	-	-	**0.16445**
13	Small Industrial	0.12147	0.04381	-	-	-	-	-	-	**0.16527**
14	Medium Industrial	0.12207	0.03197	-	-	-	-	-	-	**0.15405**
15	Large Industrial	0.11592	0.02276	-	-	-	-	-	-	**0.13868**
16	ELI 2P-RTP	0.11621	0.01368	-	-	-	-	-	-	**0.12989**
17	Municipal	0.13607	0.03275	-	-	-	-	-	-	**0.16883**
18	Unmetered	0.14617	0.05160	-	-	-	-	-	-	**0.19777**
19	Bowater Mersey	0.10946	-	-	-	-	-	-	-	**0.10946**
20	GRLF.	0.18769	-	-	-	-	-	-	-	**0.18769**
21	1P-RTP	-	-	-	-	-	-	-	-	**-**
24		**2010**								
25		**DPCR**	**RLS**	**DBA**						**DCRM**
26	**Rate Class**			**DPCR**	**RLS**	**DBA**			**Total**	
27						**DPCR**	**RLS**	**Total**		
28	Residential non ETS	0.23559	0.14213	-	-	-	-	-	-	**0.37772**
29	Residential ETS	0.23559	0.14412	-	-	-	-	-	-	**0.37971**
30	Small General	0.22528	0.17021	-	-	-	-	-	-	**0.39549**
31	General Demand	0.20343	0.11353	-	-	-	-	-	-	**0.31696**
32	Large General	0.19078	0.09313	-	-	-	-	-	-	**0.28391**
33	Small Industrial	0.18857	0.09416	-	-	-	-	-	-	**0.28273**
34	Medium Industrial	0.18965	0.07289	-	-	-	-	-	-	**0.26253**
35	Large Industrial	0.17996	0.05166	-	-	-	-	-	-	**0.23162**
36	ELI 2P-RTP	0.18070	0.02930	-	-	-	-	-	-	**0.21000**
37	Municipal	0.21130	0.07067	-	-	-	-	-	-	**0.28196**
38	Unmetered	0.22687	0.12210	-	-	-	-	-	-	**0.34897**
39	Bowater Mersey	0.17128	-	-	-	-	-	-	-	**0.17128**
40	GRLF.	0.29370	-	-	-	-	-	-	-	**0.29370**
41	1P-RTP	-	-	-	-	-	-	-	-	**-**
43										
44		**2011**								
45		**DPCR**	**RLS**	**DBA**						**DCRM**
46	**Rate Class**			**DPCR**	**RLS**	**DBA**			**Total**	
47						**DPCR**	**RLS**	**Total**		
48	Residential non ETS	0.28144	0.22935	0.04699	0.01120	-	-	-	0.05820	**0.56899**
49	Residential ETS	0.28144	0.23053	0.04699	(0.00165)	-	-	-	0.04534	**0.55731**
50	Small General	0.26912	0.27835	0.03752	0.00985	-	-	-	0.04737	**0.59484**
51	General Demand	0.24303	0.18367	0.02205	0.00162	-	-	-	0.02367	**0.45036**
52	Large General	0.22791	0.14493	0.03495	(0.00092)	-	-	-	0.03403	**0.40688**
53	Small Industrial	0.22527	0.14897	0.02218	(0.00599)	-	-	-	0.01619	**0.39044**
54	Medium Industrial	0.22656	0.11217	0.03873	0.00234	-	-	-	0.04107	**0.37979**
55	Large Industrial	0.21498	0.07877	0.01558	(0.00050)	-	-	-	0.01508	**0.30883**
56	ELI 2P-RTP	0.21587	0.04922	0.03255	0.00222	-	-	-	0.03477	**0.29986**
57	Municipal	0.25242	0.11074	0.03616	(0.00018)	-	-	-	0.03598	**0.39914**
58	Unmetered	0.27103	0.18998	0.04840	0.00914	-	-	-	0.05755	**0.51855**
59	Bowater Mersey	0.20462	-	0.02549	-	-	-	-	0.02549	**0.23010**
60	GRLF.	0.35086	-	0.03753	-	-	-	-	0.03753	**0.38839**
61	1P-RTP	-	-	-	-	-	-	-	-	**-**

TABLE 8 Illustration of DSM Tariff Components (in cents per kWh), 2009-2013

Line #										
1										
2	**COLUMN**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
	FORMULA	**Table 3.3**	**Table 6.6**	**Table 4 Column G**	**Table 7 Column J**	**Table 4 Column J**	**Table 7 Column M**	**E + F**	**C + D + G**	**A + B + H**
3										
63										
64		**2012**								
65		**DPCR**	**RLS**	**DBA**						**DCRM**
66	**Rate Class**			**DPCR**	**RLS**	**DBA**			**Total**	
67						**DPCR**	**RLS**	**Total**		
68	Residential non ETS	0.32299	0.30893	(0.03491)	0.00217	-	-	-	(0.03273)	**0.59918**
69	Residential ETS	0.32299	0.31350	(0.03491)	(0.01826)	-	-	-	(0.05316)	**0.58332**
70	Small General	0.30885	0.36760	(0.03740)	(0.00268)	-	-	-	(0.04009)	**0.63636**
71	General Demand	0.27890	0.25152	(0.04118)	(0.00425)	-	-	-	(0.04543)	**0.48498**
72	Large General	0.26155	0.19218	(0.04304)	(0.01423)	-	-	-	(0.05727)	**0.39646**
73	Small Industrial	0.25852	0.21362	(0.02837)	(0.00187)	-	-	-	(0.03024)	**0.44190**
74	Medium Industrial	0.25999	0.15426	(0.03539)	(0.00128)	-	-	-	(0.03667)	**0.37758**
75	Large Industrial	0.24671	0.10801	(0.02565)	0.00040	-	-	-	(0.02526)	**0.32947**
76	ELI 2P-RTP	0.24773	0.06559	(0.01586)	0.00178	-	-	-	(0.01408)	**0.29924**
77	Municipal	0.28968	0.15823	(0.04085)	(0.00250)	-	-	-	(0.04335)	**0.40456**
78	Unmetered	0.31103	0.24954	(0.03193)	0.00027	-	-	-	(0.03167)	**0.52890**
79	Bowater Mersey	0.23482	-	(0.02288)	-	-	-	-	(0.02288)	**0.21194**
80	GRLF.	0.40265	-	(0.01874)	-	-	-	-	(0.01874)	**0.38391**
81	1P-RTP	-	-	-	-	-	-	-	-	**-**
83										
84		**2013**								
85		**DPCR**	**RLS**	**DBA**						**DCRM**
86	**Rate Class**			**DPCR**	**RLS**	**DBA**			**Total**	
87						**DPCR**	**RLS**	**Total**		
88	Residential non ETS	0.36768	0.38957	(0.05139)	(0.02970)	(0.00498)	(0.00120)	(0.00618)	(0.08727)	**0.66998**
89	Residential ETS	0.36768	0.40583	(0.05139)	(0.01196)	(0.00498)	0.00011	(0.00487)	(0.06833)	**0.70519**
90	Small General	0.35159	0.46996	(0.02963)	(0.01932)	(0.00126)	(0.00033)	(0.00159)	(0.05021)	**0.77133**
91	General Demand	0.31749	0.32320	(0.01144)	0.00401	0.00065	0.00005	0.00070	(0.00678)	**0.63390**
92	Large General	0.29775	0.24010	(0.03240)	(0.01491)	(0.00229)	0.00006	(0.00223)	(0.04961)	**0.48824**
93	Small Industrial	0.29430	0.27774	(0.00762)	0.01168	0.00095	(0.00026)	0.00069	0.00500	**0.57703**
94	Medium Industrial	0.29597	0.20401	(0.00403)	0.01230	0.00228	0.00014	0.00241	0.01054	**0.51052**
95	Large Industrial	0.28085	0.13501	(0.03098)	(0.00702)	(0.00105)	0.00003	(0.00102)	(0.03906)	**0.37680**
96	ELI 2P-RTP	0.28201	0.08309	(0.00015)	0.00081	0.00247	0.00017	0.00264	0.00313	**0.36824**
97	Municipal	0.32976	0.21151	(0.00483)	0.01458	0.00208	(0.00001)	0.00207	0.01182	**0.55310**
98	Unmetered	0.35407	0.32675	(0.02693)	(0.00118)	(0.00110)	(0.00021)	(0.00131)	(0.02921)	**0.65161**
99	Bowater Mersey	0.26731	-	(0.01623)	-	(0.00007)	-	(0.00007)	(0.01631)	**0.25101**
100	GRLF.	0.45837	-	0.00380	-	0.00328	-	0.00328	0.00708	**0.46545**
101	1P-RTP	-	-	-	-	-	-	-	-	**-**

Note: DCRM is an acronym for DSM Cost Recovery Mechanism