Ontario Energy Board

Ontario

IN THE MATTER OF:

A REPORT ON THE DEMAND-SIDE MANAGEMENT ASPECTS OF GAS INTEGRATED RESOURCE PLANNING FOR:

THE CONSUMERS' GAS COMPANY LTD.
CENTRA GAS ONTARIO INC. AND
UNION GAS LIMITED

E.B.O. 169-III

REPORT OF THE BOARD

JULY 23, 1993

EXECUTIVE SUMMARY
Report of the Ontario Energy Board
E.B.O. 169-III

During November and December of 1992, the Ontario Energy Board ("the Board") held an oral hearing on the generic issues involved in the demand-side management ("DSM") aspects of integrated resource planning ("IRP"). After evaluating the evidence and arguments submitted by the parties, the Board endorsed the need for formalized DSM planning by each of the three major gas utilities in Ontario, and concluded that these companies should implement their DSM plans as soon as possible. The Board's Report is attached.

Background

In its 1990 Decision in E.B.R.O. 462, the Board decided to call a generic hearing into Least Cost Planning or IRP. In preparation for the hearing, the Board's Technical Staff ("Board Staff") developed a draft list of issues in consultation with the three major gas utilities in Ontario, and comments on these issues were solicited from a broad range of interested parties. After reviewing the responses and consulting with the utilities, the Board determined that a discussion paper should be produced. Accordingly Board Staff, with the assistance of a consultant, prepared a draft report which was also circulated for comment. A final document, entitled "Report on Gas Integrated Resource Planning" ("the Discussion Paper"), was released by the Board in September, 1991.

On October 23, 1991, the Board requested written submissions from the Ontario gas utilities and other interested parties on the issues raised in the Discussion Paper. Forty-one parties responded to the Board's Notice of Hearing and were listed as intervenors in the E.B.O. 169 proceedings. Nineteen of these parties filed written submissions in response to the Discussion Paper.

After reviewing the responses, the Board announced that it would proceed using a building-block approach, starting with an investigation of the DSM issues, before considering supply-side issues and the integration of all aspects of IRP. The Board also stated that the issue of fuel switching would be deferred until the supply-side review.

To facilitate the DSM review, the Board encouraged the parties to reach consensus and reduce the scope and number of contentious issues to be dealt with at the hearing. This settlement phase of the proceedings consisted of two technical conferences to clarify DSM issues and consolidate the positions of the parties. During the conferences, the parties identified a list of DSM issues ("the Demand-Side Issues List") and submitted their positions on each issue. These positions were compiled in a consensus position summary and entered as evidence in the oral hearing.

During the oral hearing, all parties were given an opportunity to present evidence and expert testimony, and to cross-examine the witnesses brought forward by other parties. The utilities were heard first, followed by associations, municipalities and interest groups. At the conclusion of the oral hearing, in addition to their arguments, the parties submitted executive summaries of their positions which have been attached to the Report as Appendix "A".

Board Findings

The Board's guidelines for the implementation of demand-side management of natural gas in Ontario are set out in Chapter 15 of the Report. These guidelines are provided to assist the utilities in the development and implementation of their DSM plans. They address each of the major issues identified in the Demand-Side Issues List and are supplemented by specific conclusions on each issue, as described in Chapters 3 to 14. These conclusions are summarized below.

On the issue of the appropriate costing methodology for DSM, the Board determined that long-term avoided supply-side costs should be used, including avoided upstream tolls and demand charges. All other upstream costs should be identified, if known, but not included in the avoided cost calculations.

With regard to cost-effectiveness tests, the Board described an iterative screening process which it expects the utilities to follow when developing their DSM portfolios. This process incorporates the Societal Cost Test ("SCT") and Rate Impact Measure ("RIM") test. (These tests and other terms are defined in the Glossary which is Appendix "B" to the Report.) Programs which pass the SCT but fail the RIM test must pass a third test to ensure that any related rate impacts would not be excessive and that indirect costs would not exceed the net benefits of a program. Programs which fail the third test are to be evaluated once more before being discarded or deferred. All programs should be assessed quantitatively and qualitatively to determine the best candidates for a utility's DSM portfolio. All prospective programs must pass the SCT, but failure to pass the RIM test would not necessarily eliminate a program.

The Board concluded that those program externalities which involve significant environmental and social costs and benefits should be included in the cost analysis of DSM programs. When evaluating these externalities, the utilities are expected to use the Cost-of-Control method until the Damage Costing method is developed further. To expedite the evaluation process, the Board endorsed a consultative approach which would involve a diverse and non-duplicative Collaborative with a manageable number of participants. The purpose of the Collaborative would be to assess externalities and monetization methodologies and to recommend appropriate qualitative assessment processes for the screening of DSM programs and portfolios. It is expected to strive to issue a final report by February 28, 1994.

After reviewing the issue of the regulatory treatment of DSM investments, the Board determined that approved DSM costs should be treated consistently with prudent supply-side costs. Long-term DSM investments should be included in rate base and short-term expenditures expensed as part of the utility's cost of service. Any variance between the forecast and actual costs or benefits of a DSM program, which occurs in a test year, will be recorded in a deferral account for disposition at the utility's next rates case.

With regard to the question of who should pay for DSM, the Board concluded that the beneficiaries of a program should pay the direct costs of the program to the extent possible. However, customer contributions should not unduly restrict program participation or induce switching to less desirable fuels. Some level of cross-subsidization and rate impact may be acceptable to the Board, but the utilities should make every effort to work toward developing self-sustaining programs.

The Board did not see a need to require utility incentives or decoupling at this time. If utility incentives are shown to be required, the Board preferred the approach of shared savings, based on the nature or urgency of the program, the market being targeted and the degree of difficulty in program implementation.

The Board concluded that full decoupling was currently an inappropriate mechanism for use in Ontario. However, if a utility considers that a lack of revenue protection is a significant disincentive, it may propose a revenue adjustment mechanism, as differentiated from full decoupling, provided the impacts that the mechanism has on the utility's risk exposure and earnings are also considered.

The Board cited a need for effective monitoring and evaluation as a requisite to the efficient development and implementation of the utilities' DSM programs. As part of the evaluation process, the utilities are required to provide a base case forecast of their demand which will act as a benchmark when assessing the performance of subsequent DSM programs and portfolios. The base case should include all DSM programs started prior to the utility's fiscal 1995 test year. Natural Gas for Vehicles programs are to be included in the base case, and excluded from the DSM portfolio. Forecasts should also be provided for each DSM program and the overall portfolio showing the pessimistic, optimistic and most likely impacts relative to the base case forecast, based on achievable potential.

With regard to rate design, the Board concluded that there was little current justification for revising the utilities' rate structures. However, the Board recommended that energy efficiency impacts should be considered in any future review of rate design. The Board stated that the utilities should undertake, and periodically update, assessments of the impacts of interruptible rates on system costs and the use of alternate fuels. The Board also called for the provision of more explicit billing information to customers.

On the issue of jurisdiction, the Board concluded that the utilities should not delay or limit the DSM efforts pending a full resolution of jurisdictional issues. The Board also concluded that it has sufficient jurisdiction under the Ontario Energy Board Act to review DSM plans and to issue guidelines to the utilities. The Board indicated that it fully expects that, as IRP evolves in Ontario, the need for, nature and extent of appropriate legislative amendments will become clearer. The experience gained in the consideration of DSM planning in rates cases will furnish valuable guidance for any future legislative change.

On the issue of funding for the proposed Collaborative, the Board noted that it does not have jurisdiction under the Intervenor Funding Project Act to award advance funding prior to the filing of a specific application. Accordingly, the Board concluded the utilities should directly finance the consultative process. The Board stated that it is confident that prudently incurred consultation costs will be fairly considered for inclusion in the utility's cost of service by subsequent rates panels.

The Board asked the utilities to present their DSM plans no later than as part of their filings for their fiscal 1995 rates cases. In developing their plans, the utilities are encouraged to consult with appropriate parties and to use delivery channels such as those available through the energy service companies in Ontario. Where appropriate, programs should be designed to consider all energy conservation possibilities rather than just focussing on natural gas opportunities.

Once the utilities' DSM plans are implemented and sufficient experience is gained, the Board stated that it expects to proceed with a review of the utilities' supply-side policies, activities and expenditures, as well as the current policies on system expansion, to confirm that these are consistent with least-cost planning principles. Once the supply-side assessment is completed, the Board can proceed with the final phase of the IRP proceedings, i.e. the combination of DSM and supply-side management into an integrated resource plan.

In the interim, the Board recommended that government consider: regulation to establish carbon dioxide emission targets; further development of standards and fiscal measures to improve energy efficiency; establishment of a regulatory mandate for IRP; and clarification of the roles of government agencies to effectively coordinate IRP in all energy sectors.

The Board concluded that overall, notwithstanding the lively debate on many of the issues, it is encouraged by the apparent unanimity among the participants in the IRP proceeding on the underlying principles and objectives of the demand-side management of natural gas in Ontario.

July, 1993

E.B.O. 169-III

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c.O.13;

AND IN THE MATTER OF section 13(5) of the said Act;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to Integrated Resource Planning on the distribution systems of The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: Marie C. Rounding
Chair and Presiding Member

Carl A. Wolf Jr.
Member

Judith C. Allan
Member

Judith B. Simon
Member

REPORT OF THE BOARD

July 23, 1993

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1. INTRODUCTION AND BACKGROUND

1.0.1 In its April 9, 1990 Decision in E.B.R.O. 462 (the Union Gas Limited 1991 test year rates case), the Ontario Energy Board ("the Board") decided to call a generic hearing into Least Cost Planning. The Board stated that:

> Managing demand in the context of utility expansion in Ontario is a matter of interest to the Board. The Board is also of the view that Least Cost Planning, in its widest sense, must include the environmental aspects raised by Energy Probe as well as minimizing gas leakage and the subject of NGV [natural gas for vehicles].

1.0.2 In the same Decision, the Board also stated its intention to consult with the Ontario gas utilities and other interested parties as to the form of the generic hearing.

1.0.3 Following the E.B.R.O. 462 Decision, the Technical Staff of the Board ("Board Staff") developed, on behalf of the Board, a draft list of issues in consultation with the three major Ontario gas utilities. During this consultation, it was determined that the subject of the generic hearing should be renamed "Integrated Resource Planning" or "IRP". The Board, by a letter dated September 25, 1990, requested comments from a broad range of interested parties on this draft list of issues. Again, in consultation with the major gas utilities, the Board determined that it would initiate the investigation into IRP by producing a discussion paper based on the draft list of issues.

1.0.4 With the assistance of MSB Energy Associates Inc., Board Staff prepared such a draft discussion paper on behalf of the Board. After circulating the draft report for comments, the final document entitled "Report on Gas Integrated Resource Planning" ("the Discussion Paper") was released by the Board in September, 1991.

1.0.5 On September 13, 1991, pursuant to subsection 13(5) of the Ontario Energy Board Act ("the Act") the Board issued a Notice of Hearing into the matter of Integrated Resource Planning under Board File No. E.B.O. 169. The purpose of the Notice was to seek the public's comments in regard to the Discussion Paper as it applies to the natural gas distribution systems of the three major gas utilities in Ontario: The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc. The Notice indicated how a party could participate in the proceedings by becoming an intervenor and also outlined the procedure for intervenors to apply for funding under the Intervenor Funding Project Act, R.S.O. 1990, I.13 ("the IFP Act").

1.0.6 On October 23, 1991, the Board issued Procedural Order E.B.O. 169 No. 1 whereby, among other things, the Board solicited written submissions by the Ontario gas utilities and other interested parties regarding the issues raised in the Discussion Paper. Since this is a generic proceeding, the Board indicated that it would not examine specific utility, conservation or environmental proposals in this hearing. The preparation and submission of written responses to the Discussion Paper was subsequently designated as Phase I of the E.B.O. 169 proceedings ("Phase I").

1.0.7 The following parties answered the Board's Notice of Hearing and were listed as intervenors in the E.B.O. 169 proceedings:

- Alberta Petroleum Marketing Commission
- ANR Pipeline Company
- Association of Major Power Consumers in Ontario ("AMPCO")
- Beak Consultants Limited
- Canadian Association of Energy Service Companies ("CAESCO")
- Canadian Petroleum Association (now Canadian Association of Petroleum Producers)
- Centra Gas Ontario Inc. ("Centra")
- Centra Gas Manitoba Inc.
- The Coalition of Environmental Groups for a Sustainable Energy Future ("the Coalition" or "CEG")
- The Consumers' Gas Company Ltd. ("Consumers Gas")
- Consumers' Association of Canada (Ontario) ("CAC(O)")
- Direct Energy Marketing Limited ("Direct Energy")
- ECNG Inc.
- Ecosystem Approach Group ("EAG")
- Energy Brokers Canada Inc.
- Energy, Mines and Resources, Canada
- Energy Probe
- Gaz Métropolitain, inc. ("GMi")
- INCO Limited ("INCO")
- Industrial Gas Users Association ("IGUA")
- The City of Kitchener
- Mobil Oil Canada
- Municipal Electric Association ("MEA")
- Mutual Gas Association
- None Too Soon
- North Canadian Marketing Inc.
- Northridge Petroleum Marketing Inc. ("Northridge")
- NOVA Corporation of Alberta
- Ontario Association of Physical Plant Administrators
- Ontario Hydro
- Ontario Métis and Aboriginal Association ("OMAA")
- Pollution Probe
- A.E. Sharp Limited
- Rainer W. Stahlberg
- The City of Toronto

- TransCanada PipeLines Limited ("TCPL")
- TWG Consulting Inc.
- Unigas Corporation
- Union Gas Limited ("Union")
- Thomas Vladut
- Western Gas Marketing Limited ("WGML")

1.0.8 The following parties filed written submissions or comments in response to the Discussion Paper:

- AMPCO
- CAC(O)
- CAESCO
- Centra
- The Coalition
- Consumers Gas
- Direct Energy
- Energy Probe
- IGUA
- INCO
- The City of Kitchener
- MEA
- Northridge
- OMAA
- Ontario Deputy Minister of Energy
- Ontario Hydro
- Pollution Probe
- The City of Toronto
- Union

1.0.9 By Procedural Order E.B.O. 169-II No. 1, dated May 26, 1992, the Board announced that it would proceed via a "building block" approach whereby demand-side management ("DSM") issues would be investigated before considering supply-side management issues and, subsequently, the integration of all aspects of IRP. The Board also decided that the issue of fuel switching and its potential application to DSM would be considered at a later date as part of the review of the supply-side aspects of IRP.

1.0.10 To facilitate the proceedings, the Board established a process designed to encourage consensus and reduce the scope and number of contentious issues to be dealt with at the hearing. Therefore, as the second phase in the proceedings ("Phase II"), the Board announced its intention to hold two technical conferences to clarify DSM issues and consolidate the positions of the parties.

1.0.11 The two technical conferences were held, in the absence of the Board panel, on August 4-7 and September 21-24, 1992. The purpose of the first conference was to allow participants to state their positions and to better understand the positions put forward by the other parties regarding DSM options. At the meeting, presentation of the parties' summary statements was followed by an open discussion of the issues. A verbatim transcript of the first technical conference is available for public review at the Board's offices.

1.0.12 Following the first conference, and pursuant to Procedural Order E.B.O. 169-II No. 2, dated July 9, 1992, Board Staff circulated a summary document which grouped the various views of the parties into preliminary consensus positions. The parties were asked to comment on the consensus positions listed in the summary document so that their comments could serve as a basis for discussion at the second technical conference.

1.0.13 By the same Procedural Order, the parties were also required to submit a summary of their positions on the list of DSM issues ("the Demand-Side Issues List"), which is appended to that Order. Those submissions are also available for public review at the Board's offices.

1.0.14 The purpose of the second technical conference was to finalize the consensus positions of the parties using a consultative process. The parties were also asked to consider whether the issues on the Demand-Side Issues List should be refined. The second technical conference was not transcribed in order to facilitate a more open discussion of the issues.

1.0.15 At the conclusion of the second technical conference, the parties submitted their consensus position statements on the Demand-Side Issues List. These were compiled and issued to all participants on October 13, 1992. The consensus position summary ("the Consensus Summary") has been entered as evidence in the oral hearing of the demand-side issues in Integrated Resource Planning under Board File No. E.B.O. 169-III ("Phase III").

1.0.16 Board Staff took no position on the issues during either Phase I or Phase II of the proceedings.

1.0.17 Procedural Order E.B.O. 169-II No. 3, dated September 15, 1992, (subsequently renamed Procedural Order E.B.O. 169-III No. 1) fixed the date for the commencement of the oral hearing of DSM issues as Monday, November 9, 1992.

2. THE PHASE III PROCEEDING

2.0.1 The oral portion of the E.B.O. 169 Phase III hearing commenced on Monday, November 9 and concluded on December 8, 1992. During the hearing, all parties were given an opportunity to present evidence and expert testimony, and to cross-examine the witnesses brought forward by other parties. In general, each party was cross-examined in turn on all issues on the Demand-Side Issues List. The utilities were heard first, followed by associations, municipalities and interest groups.

2.0.2 During Phase III, Board Staff acted as an active party to the proceeding, and took positions on the issues on the Demand-Side Issues List. Other than cross-examining on a broad basis to assure a complete record, Board Staff acted autonomously. Board Staff did not call witnesses during the oral hearing.

2.0.3 Following the completion of the oral hearing, the active parties were directed to file argument-in-chief by December 23, 1992 and reply argument by January 22, 1993. The parties were asked to provide, in their arguments, their positions on each of the issues contained in the Demand-Side Issues List, as well as their recommendations on how the Board should proceed with the implementation of IRP and the guidelines it should consider.

2.0.4 Because E.B.O. 169 was a generic hearing convened at the Board's request, no specific party was identified as the applicant. Consequently, all parties were given the opportunity to reply to the arguments-in-chief submitted by the other parties.

2.0.5 In addition to their arguments, the parties submitted Executive Summaries of their positions, as directed by the Board. These Executive Summaries are attached as Appendix "A". A Glossary of Terms used in this Report is attached as Appendix "B".

2.1 APPEARANCES

2.1.1 The parties and their representatives who actively participated in the oral hearing were as follows:

Board Staff	I. Blue J. Lea
CAESCO	J.T. Brett
Centra	P. Jackson M. Penny
The Coalition	D. Poch K. Millyard
CAC(O)	R. Warren P. Lefebour
Consumers Gas	R.J. Howe
Energy Probe	M.O. Mattson T. McClenaghan N. Rubin
Farm Energy Association*	I. Mondrow

The City of Kitchener	A. Ryder
OMAA	M. Omatsu
Pollution Probe	M. Klippenstein
The City of Toronto	H. Poch
Union	B. Kellock

* At the commencement of the Phase III hearing, Mr. Mondrow indicated that the intervention of R.W. Stahlberg would now go forward under the name of the Farm Energy Association.

2.2 WITNESSES

For CAESCO:

A.W. Levy	President, CAESCO
J. Walrod	Principal, XENERGY Inc.

For Centra (Employees):

R.M. Bell	Manager, Environmental Affairs
J. Peverett	Manager, Corporate Planning
D.J. Gallagher	Manager, Marketing
R.W. Reid	Director, Gas Supply
P.J. Hoey	Manager, Regulatory Affairs

For the Coalition:

P.L. Chernick	President, Resource Insight, Inc.
W.B. Marcus	Principal Economist, JBS Energy Inc.

For CAC(O):

G. Edgar	Executive Director, Wisconsin Energy Conservation Corporation
P. Dyne	Chair, Energy Committee, Consumers' Association of Canada
C. Gates	Consultant, REIC (Consulting) Ltd.

For Consumers Gas (Employees):

W.B. Taylor	Director, Financial and Economic Studies
H.M. Lavergne	Director, Rates and Regulatory Proceedings
J.R. Hamilton	Director, Marketing Administration

For Energy Probe:

L. Ruff	Managing Director, Putnam Hayes and Bartlett Inc.
T. Adams	Utility Analyst, Borealis Energy Research Association

For Farm Energy Association:

R.W. Stahlberg	Principal, Farm Energy Association

J. Johnson	President, Canadian Renewable Fuels Association

For OMAA:

R. Swain	President, OMAA
M. Watkins	Professor, Economics and Political Science, University of Toronto
I. Goodman	Principal, The Goodman Group, Ltd.

For Pollution Probe:

J. Gibbons	Senior Economic Advisor, Canadian Institute of Environmental Law and Policy

For the City of Toronto:

D. Harvey	Associate Professor, Department of Geography, University of Toronto

For Union (Employees):

P. Shervill	Manager, Environmental Affairs
E. Merritt	Manager, Regulatory Projects
J. van der Woerd	Manager, Marketing
D.D. Bailey	Manager, Financial Studies

For Union (Other):

M. Lerner	President, Energy and Environmental Analysis Inc.

For Centra and Union:

R.S. Bower	Professor Emeritus, Finance and Managerial Economics, Amos Tuck School of Business Administration, Dartmouth College
V.L. McCarren	Assistant to the President, Special Projects, University of Vermont

2.2.1 A transcript of the public hearing and copies of all exhibits and submissions are on file for review at the Board's office.

2.2.2 While the Board has taken account of all the evidence and submissions on the issues in these proceedings, it has in this Report only summarized these to the extent needed. Because of the high level of interaction among the issues, parties, in their submissions, sometimes stated positions on one issue as part of their submissions under another issue. To the degree possible, the Board has attempted to amalgamate all the submissions on a particular issue under that issue.

2.2.3 The Board allowed the parties to include, in their arguments, submissions on issues beyond the Demand-Side Issues List as "Issue 12 - Other Issues". The Board has combined these submissions into its discussions on the most closely-related issues in the Demand-Side Issues List.

2.2.4 In succeeding chapters, the Board has dealt with each issue on the Demand-Side Issues List and, for the convenience of the reader, directly quoted (in italics) the pertinent segment of the Consensus Summary on each issue ("the Consensus Statement"). The Positions of the Parties are then presented, and are followed by Board Findings, which were reached after considering all the evidence and submissions. These findings are then summarized in the form of procedures and guidelines, in Chapters 14 and 15, respectively. The final chapter deals with cost awards.

3. ISSUE 1 APPROPRIATE COSTING METHODOLOGY FOR DEMAND-SIDE OPTIONS

3.0.1 In order to establish a portfolio of demand-side management programs, the first issue to be addressed is the selection of an appropriate methodology to define program costs and benefits in a consistent manner. Only then can candidate programs be compared effectively in order to construct an optimum portfolio.

3.0.2 This issue was included in the Demand-Side Issues List as:

> ***What is the appropriate costing methodology for demand-side options (e.g. avoided/marginal costs of supply-side options such as additional facilities, storage of gas supply)?***

and

> ***To what extent should the utilities use demand-side options when planning to meet their forecast demand?***

3.0.3 In response to the questions listed above, Board Staff, CAC(O), CAESCO, Centra, CEG, Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement. The City of Toronto agreed with paragraphs 1, 3 and 6 of the first six points of the Consensus Statement, and took no position on any other paragraphs of the Consensus Statement on this issue. Energy Probe presented its own position on this issue.

Consensus Statement

1. *The appropriate approach to determining the value of demand-side options is an avoided cost methodology.*

2. *Avoided costs should be calculated on the basis of the cost factors specific to each utility (e.g. load factor) except that it is appropriate that certain avoided costs be uniform between utilities when the costs are undifferentiated between them (e.g. CO_2 emissions).*

3. *Avoided costs include: utility capital, operating and energy supply costs; monetized environmental and societal externality costs; and incremental or decremental customer equipment and operating costs.*

4. *Avoided costs should be time-differentiated (e.g. annual, seasonal, monthly and/or daily; peak day) and system-differentiated. A "single valued" avoided cost approach is not considered adequate.*

5. *Avoided costs should be determined over the useful life of the DSM technology. It is recognized that uncertainty concerning the level of avoided costs will increase as the forecasting horizon lengthens.*

6. *Avoided externality costs should be included in the appropriate cost-effectiveness tests to the extent that these costs have been satisfactorily monetized. Externality costs which have not been monetized should be considered qualitatively during the cost-effectiveness screening of DSM measures or programs.*

7. *Different costs will be used in different cost-effectiveness tests as described in the definitions of cost-effectiveness tests at Issue 2.*

There are two ways in which this issue [To what extent should the utilities use demand-side options when planning to meet their forecast demand?] can be interpreted. The first perspective is how extensively the utilities should use demand-side options, in conjunction with supply-side options, in meeting their forecast demand. The second perspective is how the utilities should incorporate the effect of DSM programs into their demand forecast. Therefore, the following points address both perspectives.

1. *In terms of meeting future demand, DSM options should be given equal consideration as supply-side actions, and DSM initiatives should focus on barriers to wise energy use in a manner which provides valued services.*

2. *Supply plans should be based on the expected impact of DSM programs rather than a theoretical demand reduction target or goal. The expected results of DSM programs must have a corresponding impact on supply-side plans.*

3. *DSM programs which have passed the appropriate cost-effectiveness tests and form part of the utility's rate case proposal should be included in a utility's base case demand forecast. It is recognized that forecasting the volumetric effects of certain DSM programs involves significant uncertainties, so the utility's base case supply plan should be flexible enough to accommodate reasonable variance between forecast and actual DSM program results.*

4. *In certain cases utilities can rely on existing experience when forecasting DSM program effects, while in other cases it may be necessary to test-market programs initially in order to obtain more information. The expected volumetric effects of all adopted DSM*

programs, including test-marketed programs, should be included in the utility's demand forecast.

Positions of the Parties

3.0.4 Board Staff submitted that avoided costs provide the only practical means of comparing DSM programs. While Board Staff agreed that the use of avoided costs would also permit comparisons to supply-side options, it pointed out that to date only positive externalities (i.e. beneficial externalities such as increases in employment) have been considered in supply-side tests.

3.0.5 In addition to the avoided costs described in the Consensus Statement, Board Staff submitted that avoided costs upstream of the utility system and unabsorbed demand charges should also be included in the DSM avoided cost analysis. According to Board Staff, the use of long-run avoided costs as inputs for the cost-effectiveness tests would allow the utilities to evaluate their DSM programs and compare them fairly with supply-side options. Board Staff claimed that a DSM option would be valuable only if it reduced a utility's supply-side requirements.

3.0.6 While CAESCO agreed that the value of a DSM option should be based on avoided costs, it argued that this amount may exceed the direct value to the customer. It claimed that using avoided costs would hamper the efforts of energy service companies ("ESCOs") to structure DSM contracts on the basis of the direct value to the end user.

3.0.7 Centra agreed with Board Staff that the appropriateness of a DSM option will depend on a utility's unique system, gas supply characteristics and avoided costs. Centra argued further that marginal avoided costs were the most appropriate measure of incremental costs and benefits.

3.0.8 Centra disagreed with Board Staff's submission that forecast and actual avoided costs should be monitored on an on-going basis, since Centra's avoided costs would be calculated over a 10-year time frame and would vary by delivery area, load impact and supply-side alternative.

3.0.9 With regard to the inclusion of upstream avoided costs, Centra argued that only increased transportation rates and demand charges should be included, since these are costs which would in fact be avoided.

3.0.10 On the issue of the most appropriate time frame for the avoided cost analysis, Centra argued that the evaluation period should be the same as the expected life of the DSM program.

3.0.11 CEG argued that all DSM programs which are less costly than supply alternatives should be pursued. It rejected Union's submission that a DSM portfolio must not result in an increase in rates. The Coalition contended that such a policy would restrict the development of DSM, and lead to "cream-skimming" and lost opportunities.

3.0.12 The City of Kitchener disagreed with the Consensus Statement because it believed that the appropriate costing methodology should not be limited to avoided costs, but should also include the direct costs of a DSM program. While the City of Kitchener contended that the most appropriate costing methodology should include both costs and benefits, it argued that the benefits of externalities which were outside the utility's control should not be considered.

3.0.13 Energy Probe contended that the most appropriate measure of the net benefit, and indeed the only viable evaluation method, of a DSM program was a participant's willingness to pay, since individual customers are the best experts on what is of value to them. Energy Probe further submitted, and Board Staff concurred, that the avoided cost must reflect the marginal cost of supplying gas to each customer.

3.0.14 OMAA submitted that a full range of externalities, and in particular any social externalities, should be incorporated in the avoided costs of a DSM program. Its position was that all relevant external costs associated with the production, transportation and consumption of natural gas should be taken into account.

3.0.15 In its reply, OMAA submitted that the concerns raised by the City of Kitchener, regarding the inclusion of direct costs, were inappropriate since the costing methodology recommended in the Consensus Statement refers only to the benefits of avoiding unnecessary supply costs.

3.0.16 Although Union endorsed the Consensus Statement, it observed that its avoided costs are relatively low and, therefore, it submitted that each utility's particular circumstances should be considered when evaluating DSM options. While Union recognized that demand-side options should receive the same consideration in meeting demand as supply-side options, it emphasized that demand-side options differ fundamentally from supply-side options in that they provide special benefits to distinct customer groups, rather than providing a consistent level of service to all customers.

3.0.17 In its reply, Union submitted that a local distribution company ("LDC") should use its average avoided cost to evaluate programs since it is not possible or appropriate to "stream" costs to specific customers. Union also added that avoided costs must be adjusted frequently to accurately reflect changes in a utility's supply plan.

3.1 BOARD FINDINGS

3.1.1 In general, the Board endorses the Consensus Statement regarding avoided costs and costing methodologies. The Board concurs that avoided supply-side costs, including capital, operating and energy costs, should be used when measuring the benefits of natural gas DSM programs. The Board also concurs with the inclusion of demand-side costs such as incremental or decremental customer equipment and operating costs. However, the Board believes that attempts to incorporate the "upstream" avoided costs of TCPL and natural gas producers would impose an added layer of complexity to an already intricate problem. It is doubtful that the Ontario gas utilities now have the ability to accurately assess those upstream costs that are beyond the jurisdictional reach of the Board. However, the Board acknowledges that the full impacts of DSM measures will influence upstream activities.

3.1.2 The Board has concluded that, based on the current evidence before it, avoided upstream costs should be excluded from avoided cost calculations. However, where such costs are known they should be identified at the time that DSM programs are proposed.

3.1.3 While storage and transportation tolls and demand charges are costs which are incurred upstream, they are direct costs to a gas utility which are known and calculable. The Board sees merit in including any impacts that DSM may have on these costs when assessing avoided costs.

3.1.4 The Board concurs with the evidence of Dr. Lerner that there are significant differences between gas and electric utility costs. The Board cautions that these differences make it perilous to rely too heavily on electric utility models and experience as a basis for gas DSM planning.

3.1.5 The Board notes that experience with gas DSM is limited, and it has yet to be fully evaluated in any jurisdiction in Canada or elsewhere. Thus, there must be sufficient flexibility when assessing avoided costs to react to the experience gained as utilities proceed along their learning curves, and to accommodate the differences between individual gas utilities in Ontario.

3.1.6 The Board accepts that it is necessary that long-run avoided costs be considered when determining the net present value of DSM programs over their useful life. However, the likelihood of changes in the economy, in the relative prices of alternative fuels and in the levels of customer acceptance suggests that long-term forecasts are, at best, tenuous. This is compounded by the rapid pace at which new energy-efficient technologies are being developed.

3.1.7 When calculating avoided costs for long-term programs, emphasis should be placed on the performance in the early years of the DSM program and portfolio, since uncertainty in performance increases as the time horizon is extended and because of the disproportionate impact that performance in the early years has on net present value assessments. In general, the Board considers the early years to be the first five years of the DSM program.

3.1.8 In order to compare a program's costs and benefits with those of other DSM programs in an equitable manner, a break-even analysis based on net present values should be carried out for each program. The implications of the results of the break-even analysis for the program and the overall DSM portfolio should be provided.

3.1.9 The matter of how environmental and social costs should be incorporated into avoided cost determinations is dealt with under Issue 3.

4. ISSUE 2 COST-EFFECTIVENESS TESTS

4.0.1 A consistent method of determining the cost-effectiveness of each DSM program is necessary to assess the value of the program and to identify which programs should be considered as candidates for the utility's DSM portfolio. Different cost-effectiveness tests are required to factor in the various types of costs and benefits, and the Board must determine which test or tests are most appropriate.

4.0.2 This issue was included in the Demand-Side Issues List as:

> ***What are the appropriate cost-effectiveness tests (i.e. technical cost test, societal cost test, utility cost test, etc.) and methodologies to be used for demand side options? What costs should be included in this cost-effectiveness analysis? Should the E.B.O. 134 feasibility analysis be applied, and what modifications, if any, would be required?***

4.0.3 The Board's E.B.O. 134 Report, dated June 1, 1987, described the economic feasibility tests to be used in the analysis of supply-side options, e.g. transmission and distribution system expansions. The Board has appended the pertinent findings from that Report as Appendix "C".

4.0.4 In response to the questions on cost effectiveness, Board Staff, CAC(O), CAESCO, Centra, CEG, Consumers Gas, Pollution Probe and Union agreed to the following Consensus Statement. In argument, Energy Probe urged the Board not to adopt the Consensus Statement on this issue as Board policy.

Consensus Statement

The proposed methodology and set of cost-effectiveness tests to be used to evaluate demand-side management programs include the following criteria:

a) All DSM programs should be expected to pass the Societal Cost Test.

b) DSM programs under consideration that pass the Societal Cost Test and pass the Rate Impact Measure Test should be approved provided all reasonable steps to prevent lost opportunities have been taken and the programs do not violate any other more important utility or public interest objectives (examples might include system reliability or safety).

c) DSM programs that pass the Societal Cost Test but do not pass the Rate Impact Measure Test (not financially sustaining) should be approved providing the following conditions are met:

i) The resulting rise in rates after evaluating all programs in the DSM portfolio must not impose an undue burden on existing customers. Both short-term and long-term rate impacts should be considered;

ii) The resulting rise in rates must not entail second round net social costs that are expected to exceed the first round net social benefits of the demand management program (e.g. if higher rates cause customers to switch away from gas, the *resulting net social costs could exceed the net social benefits of the program that is being financed by the higher rates);*

iii) Customer contributions are appropriate to the extent that they do not seriously reduce overall participation or foreclose the participation of specific customer groups (examples might include low-income groups or rental customers). The Participant Test is one factor to be considered in establishing appropriate levels of contribution.

iv) Financially non-sustaining DSM programs may be included in the DSM portfolio. They will be considered on the basis of such factors as their social cost-effectiveness, a desire to maximize the breadth and quality of the conservation, preventing lost opportunities, and the desire to offer a broad menu of demand management programs.

The proposed evaluation process embraces the basic concepts established in E.B.O. 134, but introduces a new screening mechanism, plus added considerations and perspectives which are relevant to DSM programs.

Definition of Cost-Effectiveness Tests

The Societal Test incorporates all costs and benefits arising from the adoption of a program. These would include all direct costs borne by the utility such as commodity, transportation, storage, load-balancing, and distribution costs as well as system expansion costs. Also utility costs such as incremental administration, maintenance, and participant incentive costs would be recognized. In addition, all participant costs (net of incentives) should be included. In the case of programs that affect consumption of more than one fuel, all avoided costs of all fuels would be recognized. Finally, all externalities, including environmental and societal externalities, *would be included. Externalities which cannot be monetized should be treated qualitatively.*

Thus the Societal Test considers all costs and benefits accruing to society as a whole, and is not limited to the utility and its customers.

The benefits in the Societal Test are the reduction in energy supply costs (including externalities) plus any customer equipment and operating costs avoided by the participant due to the program. The costs are any increases in energy supply costs (including externalities) plus all of the program costs paid by either the utility or the participant.

The Total Resource Cost Test comprehends all costs and benefits included in the Societal Test, with the exception of externalities. The benefits and costs of the Societal Test are used except for environmental and societal externality benefits or costs.

The Participant Test includes only those costs and benefits borne by the participant, which could comprise capital, installation, and operating and maintenance costs, offset by energy cost savings measured at the rate paid by the participant, net of utility incentives.

The benefits include reductions in energy bills, incentives, and customer equipment and operating costs due to participation in the program. Costs include any increases in energy bills and out of pocket expenses that the customer pays to participate in the program.

The Rate Impact Measure Test (also referred to as the RIM Test or Non-Participant Test) includes all direct and indirect costs and benefits accruing to the utility mentioned under the Societal Test but also includes the reduced revenues collected by the utility as a result of energy savings. It therefore measures the impact of DSM programs on the utility's rates.

Benefits considered in the RIM Test are the reduction in utility supply costs and any increases in revenues. The costs are any increases in utility supply costs, revenue losses, program costs paid by the utility and any incentives paid to the participants.

The Utility Test is identical to the RIM Test, except that it does not factor in lost revenues due to DSM programs. It measures the relative impact of DSM programs on the utility's revenue requirements as a result of changes in cost.

The benefits in this test are the reductions in utility supply costs. The costs are any increases in utility supply costs, the program costs paid by the utility, and any incentives paid to the participants.

Positions of the Parties

4.0.5 Board Staff supported the use of cost-effectiveness tests which take into account a broad range of public interest factors and protect against an undue burden being placed on existing customers. The primary concern of Board Staff was the maintenance of reasonable rates for existing gas consumers. Board Staff contended that DSM rate impacts should not be greater than the rate impact that would have resulted from the alternative supply option, and that rate impacts should be minimized by selecting the least-cost option in all cases.

4.0.6 According to Board Staff, the portfolio approach is the most effective means of ensuring that a broad range of DSM programs are offered to all classes of customers. It stated that while a DSM portfolio should not be required to pass the Rate Impact Measure ("RIM") test, it should also not place an undue burden on any customer or customer class. However, Board Staff agreed that some amount of cross-subsidization is unavoidable, although it should be limited to reasonable levels.

4.0.7 Board Staff asked the Board to indicate whether the DSM cost-effectiveness tests should be applied in a consistent manner with the E.B.O. 134 supply-side tests, which consider both qualitative and quantitative externalities but do not recognize externalities which have negative impacts. It further submitted that, should the Board so desire, the framework for demand-side options can be used to refine or supplement the E.B.O. 134 methodology.

4.0.8 In the opinion of Board Staff, customer contributions are appropriate for DSM programs, as they could make financially non-sustaining DSM programs more profitable, and thereby reduce the need for a subsidy from non-participants. To be consistent, contributions should also be sought for fuel substitution programs, as well as other supply-side programs such as transmission projects. Wherever possible, the utility should strive to have a program pass the RIM test or have a minimum benefit/cost ratio of one.

4.0.9 CAESCO's position was that DSM programs should pass both the societal and ratepayer impact tests. CAESCO expressed concern that incentive levels may be unnecessarily high if programs are undertaken that do not pass a RIM test but pass a societal cost test, since Societal Cost Test ("SCT") evaluations may be driven by arbitrarily derived monetization factors. In most U.S. jurisdictions where IRP has been implemented, it is the Total Resource Cost ("TRC") test that is the ultimate determinant, and the SCT is used only in the initial screening process.

4.0.10 CAESCO submitted that all customer classes should have the opportunity to participate in the utility's portfolio of DSM programs. ESCO-linked programs, which focus on institutional, industrial and commercial customers, should be adopted by the utilities along with the programs that have been successful in the residential and small commercial markets. CAESCO advocated that ESCOs and the utilities should work together in the design and implementation of DSM rather than moving forward on parallel paths.

4.0.11 Centra emphasized paragraph (c)(ii) of the Consensus Statement, which cautions that rate increases must not entail second round net societal costs that exceed the first round net societal benefits of the demand management program. This, it claimed, might occur if higher rates cause customers to switch away from gas to less environmentally desirable fuels. Centra stated that the evidence indicates that there is more potential environmental and social benefit in fuel switching than will be realized through gas conservation. Therefore, while DSM action should encourage efficiency, it should not materially discourage fuel switching to gas or encourage fuel switching away from gas.

4.0.12 Centra noted the difficulty in forecasting the effect of price changes on fuel switching; the sensitivity in many markets to small price changes; and the environmental impacts of fuel switching. Because of these factors, it suggested that the degree to which prices should be allowed to increase as a result of a DSM portfolio will be an important limitation in the choice of an appropriate portfolio.

4.0.13 CEG argued that the benefits of aggressive DSM, even if it causes some rate increases, will lead to reduced energy bills and a least-cost energy economy. CEG expressed its support for the Board's ability to make a determination on what constitutes an undue rate impact. While CEG recognized the importance of keeping industrial gas prices competitive, it believed that the threat of the loss of industrial load, as a result of DSM rate impacts, was exaggerated and suggested that negative impacts could be offset by targeting specific DSM measures to industrial customers, and by allocating costs to other rate classes.

4.0.14 In CEG's view, utilities should not simply provide a single preferred plan. Alternatives should be presented in detail. In particular, utilities should identify and assess program alternatives; the cost of each alternative; alternative bundles of activities or measures for each program; alternative measure costs; and the results of the various cost-effectiveness tests for each measure, program, portfolio and any alternatives. CAC(O) indicated that it supported a similar approach, and OMAA agreed with CEG's proposed filing requirements. However, Centra argued in reply that a detailed proposal on filing requirements is premature and that, in any event, the cost of presenting such extensive analyses is likely to be prohibitive.

4.0.15 Consumers Gas agreed with Board Staff that it is appropriate to extend some portion of DSM costs to the system, as all ratepayers will benefit from the avoided costs of future supply, including externality costs. Consumers Gas also agreed that a balanced portfolio of DSM programs is warranted given the existence of significant market barriers to conservation.

4.0.16 Consumers Gas submitted that the analysis of future avoided system costs could reveal significant benefits for gas customers. It also suggested that some upward movement in current rates could be justified in recognition of the fact that current rates are based on a historic rate base which is not adjusted for inflation. Consumers Gas urged the Board to find that potential contributions from the electric power industry, as well as from governments, are appropriate when the results of the cost-effectiveness testing show a large net benefit to future electricity customers or to society in general.

4.0.17 Consumers Gas recommended that the E.B.O. 134 feasibility analysis be modified to be consistent with the DSM analysis, so that the SCT would serve as the primary screening, or Stage 1 test, for both the supply-side and demand-side analyses. Stage 2 would then consist of the RIM test and the Participant Test ("PT"), in order to address such issues as "who pays", cross-subsidization, and the need for customer contributions and/or incentives. Qualitative factors would be considered at Stage 3. Consumers Gas also noted in reply that externality costs must be included in supply options that are evaluated against DSM costs, in order to be consistent with the Consensus Statement.

4.0.18 Energy Probe submitted that the most appropriate cost-effectiveness test for DSM programs is the RIM test and that the SCT cannot be reliably applied or tested for accuracy in the presence of subsidized prices. The four conditions set out in the Consensus Statement under paragraph (c), for approving non-sustaining programs which fail the RIM test, were argued by Energy Probe to be too vague or weak to have any real value in the selection of programs. With regard to condition (c)(iv), Energy Probe endorsed an explicit ranking which would select the programs that produce the greatest social benefit for each dollar of subsidy needed.

4.0.19 Energy Probe did not support a portfolio approach, since offering a broad menu of programs will not transform the net costs of individual programs into an overall net benefit. Energy Probe further submitted that the evidence indicated only a "tiny" potential for "win-win" natural gas conservation in Ontario, "where everybody comes out paying less" than under the alternative supply-side option.

4.0.20 Energy Probe took the position that subsidized DSM measures or programs impose net financial costs on the system, and therefore, it urged the Board not to permit DSM activities that are subsidized by revenues from LDC monopoly activities. Energy Probe expressed its concerns about the negative social, equity and environmental impacts of raising natural gas prices; the regulatory complexity and arbitrariness of judgments about the cost-effectiveness of cross-subsidized measures; and the impacts that subsidized DSM activities might have on the non-monopoly suppliers of DSM goods and services.

4.0.21 Finally, Energy Probe recommended that the Board amend its E.B.O. 134 cost-effectiveness test for supply-side investments to make it more difficult to justify financially non-sustaining investments.

4.0.22 The City of Kitchener supported the staged screening and approval process outlined in the Consensus Statement and argued that subsidization may be appropriate if it is in the general interest of the system and its customers as a whole. It may also be appropriate, in the view of the City of Kitchener, for the portfolio to have some rate impact.

4.0.23 In the opinion of the City of Kitchener, no definition as to what constitutes "undue rate impacts" should be issued by the Board, as the acceptability of rate impacts will depend on the circumstances at the time of each rates case.

4.0.24 It further submitted that the principles which underlie E.B.O. 134 should not be applied to demand-side investment if they permit utilities to justify investment on the basis of incidental benefits which fall outside the mandate to provide utility services on an economic basis. The City of Kitchener also argued that unnecessary investment in utility services encourages an inefficient use of resources which is contrary to IRP principles.

4.0.25 Although the Consensus Statement contained many elements which OMAA could support, OMAA was concerned whether, in practice, externalities would be sufficiently considered in the SCT. Consequently, OMAA was not a party to the Consensus Statement. Moreover, other factors such as lost opportunities, equity, and the need for the sustained and orderly development of efficiency programs should be considered, in addition to the factors in the Consensus Statement's cost-effectiveness tests. Consideration of any of these factors, OMAA maintained, may on occasion justify inclusion of DSM measures that would otherwise be marginally cost-effective.

4.0.26 OMAA suggested that the SCT should be the principal standard in determining whether DSM should be implemented, subject to the considerations described in the Consensus Statement. OMAA argued that the short-term impact of investments in DSM may be negative under the RIM test, but analysis of avoided future system costs could reveal significant benefits, thereby justifying some cross-subsidization from present customers.

4.0.27 In OMAA's view, the utilities should treat ESCOs and other non-utility suppliers of DSM goods and services as strategic allies. The goal, according to OMAA, is to encourage the development of a vibrant DSM marketplace that will sustain a permanent transformation toward greater energy efficiency. While OMAA agreed that utility programs should not cavalierly undercut existing suppliers and markets, it was concerned that an overly restrictive response to these concerns may impede the levels of achievable DSM.

4.0.28 Union submitted that the most important principle underlying the tests to determine the desirability of DSM programs is the need to ensure that all considerations concerning societal, customer and participant impacts are included. The same methodology should be used to assess both DSM and supply-side options. However, rate impacts resulting from supply-side options, which produce benefits for customers as a whole, must be distinguished from rate impacts resulting from DSM program benefits which are enjoyed only by participating customers in targeted customer segments.

4.0.29 Union disagreed with the suggestions that rate impacts due to DSM which exceed the rate impacts of the avoided supply options are of little or no consequence. Union noted that such suggestions were contradicted by experience and published data concerning customer behaviour, and that they ignored the environmental benefits to be achieved by enhancing the competitive position of gas. Union also observed that, since new DSM programs would benefit targeted customer segments, rate impacts could influence perceptions of the overall fairness of the programs, thereby affecting customer response.

4.0.30 Union argued that, given its relatively low avoided costs and its preliminary assessment of new DSM initiatives, there is little chance it can develop a menu of new cost-effective DSM programs which focuses on market barriers and includes something for everyone without a rate impact.

4.0.31 Union argued in reply that its desire to develop a portfolio of DSM programs with no overall rate impact over the life of the project was based on sound principles.

4.1 BOARD FINDINGS

4.1.1 The Board supports a portfolio approach to DSM programs as the most effective means of ensuring that as many as customers as is reasonably possible are afforded the opportunity to participate and share in the benefits of DSM. A portfolio approach would allow groups, that might otherwise be precluded from participating, such as low-income customers, tenants, Aboriginals and farmers to participate in these programs, while minimizing the rate impact on existing customers.

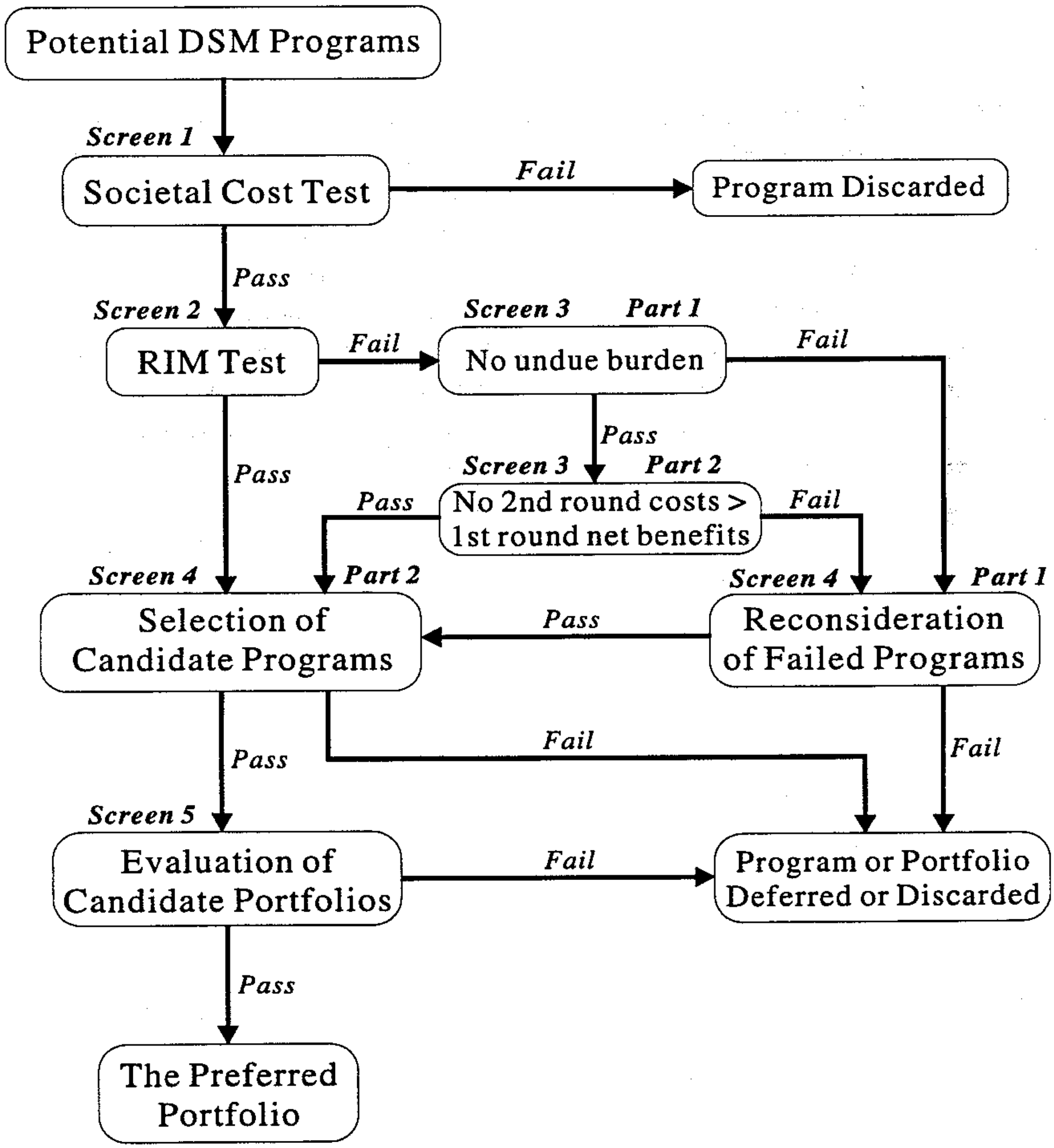
4.1.2 When developing a DSM portfolio, potential programs need to be identified for consideration. Some of the factors that should be considered in the selection of potential programs are: achievable potential; capture of potential lost opportunities; synergism among programs; and the breadth of the portfolio.

Program Screening

4.1.3 Once potential programs have been identified, screening is required to assure the development of a preferred DSM portfolio. In general, the Board endorses the Consensus Statement as constituting a reasonable approach for screening DSM programs. The screening process and steps that the Board expects the utilities to follow are summarized in Figure 1.

FIGURE 1

Recommended Screening Process for DSM Programs and Portfolios



4.1.4 Figure 1 conveys these steps in a linear fashion, but this is done only for illustrative purposes. The Board recognizes that the planning process may be non-linear and iterative. Consequently, the screening process should have sufficient flexibility to allow the utilities to return to earlier steps and to re-evaluate conclusions.

4.1.5 The Board considers that four major qualitative assessments should be incorporated in the screening process to avoid a mechanistic approach to the screening and to ensure that all appropriate considerations are included in the development of a DSM portfolio. The first qualitative assessment, which is discussed under Issue 3, provides an interim measure to complement Screen 1 until all significant externalities are monetized. The second assessment is incorporated in Screen 4, which selects programs from those that fail the third screen, and compares them to the other surviving programs. The third assessment occurs in Screen 5 when candidate portfolios are identified during the selection of a preferred portfolio. The fourth qualitative assessment is discussed under Issue 7 and deals with the evaluation of implementation strategies for the preferred DSM portfolio.

4.1.6 When carrying out the qualitative assessments, the Board expects the utilities to use an explicit evaluation process and to document the assumptions made as well as the process followed. To properly assess a DSM program, portfolio or plan, it is important to understand how the evaluations were carried out and how the conclusions were reached throughout the entire screening process.

The Societal Cost Test - Screen 1

4.1.7 The Board endorses the Consensus Statement that the Societal Cost Test be the first screen that all DSM programs must pass. The Board is of the view that the SCT provides a comprehensive approach to measuring the overall net benefit to society of a particular DSM program. The Board does not believe that it is reasonable for a utility to pursue a DSM program which does not have a net benefit to society.

4.1.8 The Board recognizes that the use of natural gas can contribute to environmental problems and that this cost is not fully captured in the price of natural gas. During the hearing, the Board was made aware of the negative impacts that natural gas combustion and leakage can have on communities, land and water, and upon the atmosphere through emissions of nitrogen oxides and volatile organic compounds. In particular, special attention was paid to the contribution of natural gas to the greenhouse effect. In the Board's opinion, it is appropriate to consider environmental costs. The Board believes that the SCT is an effective way of addressing these concerns.

4.1.9 In principle, the Board is supportive of initiatives that improve price signals to consumers, since imperfect price signals can lead to significant and unaccounted for societal costs or induce inappropriate actions. During the course of the hearing and argument, the Board was reminded of discussions at the Canadian federal level on emission taxes and tradeable emission permits, and the U.S. efforts through that country's Clean Air Act to use tradeable permits to control atmospheric pollution. The Board was also advised of the initiatives by the City of Toronto in cooperation with Consumers Gas and Ontario Hydro to reduce carbon dioxide ("CO_2") emissions by 20 percent from 1988 to 2005. In addition, the Board was reminded of the cautioning by the Government of Ontario regarding the negative impact that the internalization of societal costs via taxes could have on the competitiveness of Ontario industry.

4.1.10 The Board believes that initiatives to take account of natural gas externalities through energy prices and through planning approaches, such as the SCT, are complementary since it is unlikely that all externalities will ever be included in energy prices.

4.1.11 While using a strict SCT as the principal standard may be a laudable goal when determining whether a DSM program should be implemented, the Board believes that it is not currently possible to adopt this approach. Since the monetization of externalities as they relate to the gas utilities in Ontario is in its infancy, the full effect of internalizing these externalities cannot yet be assessed. In the interim, the Board concurs with the more cautious approach presented in the Consensus Statement which proposes the use of the SCT as the first screening test for a DSM program.

4.1.12 The Board notes that the Consensus Statement defines the SCT as including all costs and benefits. The Board has concerns that this could result in an infinite search. Accordingly, the Board expects the utilities to interpret this definition in a reasonable manner for both market-determined and monetized costs and benefits.

The Rate Impact Measure Test - Screen 2

4.1.13 The Board concurs with the Consensus Statement on the use of the Rate Impact Measure test as the second screen. The Board is of the view that the RIM test is an appropriate second screen because programs which pass this test will have a net societal benefit, without requiring cross-subsidization or causing any net rate impact, and therefore, should be considered further. However, the Board believes that it may not be prudent to implement only DSM programs that meet this second screen. Valid objectives (such as the avoidance of lost opportunities, the optimization of potential societal benefits, the improvement of safety and system reliability, and the need to broaden the DSM portfolio) may require the further consideration of some programs.

Consideration of Undue Burden & Second Round Impacts - Screen 3

4.1.14 The Board endorses the third screen described in the Consensus Statement. This screen requires that any increase in rates, resulting from programs that pass the SCT but fail the RIM test, not impose an undue burden on an individual or class of customers. Rate increases need to be considered both in the short and long term and assessed to ensure that they do not cause second round net societal costs that are expected to exceed the first round net societal benefits. These requirements are incorporated as Parts 1 and 2 of Screen 3.

4.1.15 The Board believes Part 2 of the third screen to be essential to ensure that DSM programs will not lead to customers switching from natural gas to less environmentally desirable fuels or reduce conversions and attachments to natural gas. The Board is aware that "dual-fuelled" gas customers are very price-sensitive and this must be taken into account. While it may be difficult to calculate the second round costs, the Board expects that utilities will undertake all reasonable efforts to do so. This would help to avoid the replacement of natural gas in applications for which the use of gas is preferable from a societal standpoint.

4.1.16 As part of the information requirements for carrying out the third screen, the Board expects the utilities to calculate the net societal benefit per dollar of subsidy for each program. This will provide further insight into the relative merits of individual DSM programs.

Final Program Screen - Screen 4

4.1.17 In addition to the three screens described in the Consensus Statement, the Board has added a fourth screen, which requires a qualitative assessment of those programs that have failed the third screen, as well as an overall evaluation of all of the surviving programs.

4.1.18 Part one of Screen 4 refines the screening process by permitting factors not covered in the initial three screens to be included in the selection of programs which have failed the third screen. These additional factors may include the magnitude and importance of avoided lost opportunities, the size of the net benefits associated with the implementation of the program, the improvement of safety and system reliability, and the contribution of the program to the breadth of the portfolio. Each program should be assessed from a pragmatic point of view regarding the likelihood of its acceptance and success, since even the most economically attractive DSM program can be useless unless customer acceptance is forthcoming.

4.1.19 Part 2 of Screen 4 involves the assessment of each program which has passed Screens 2, 3, or 4, to determine the program's suitability as a candidate for further consideration in comparison to the other surviving programs.

Identification of Candidate Portfolios - Screen 5

4.1.20 Candidate programs, once identified, should then be combined into candidate DSM portfolios. The candidate portfolios should be derived by examining the relative importance of the DSM plan objectives as well as the degree to which these objectives are met by the portfolio.

4.1.21 The final portfolio should result from an evaluation leading to the selection and combination of the preferred programs from each portfolio, or the selection of a preferred portfolio from among the candidate portfolios developed.

Customer Contributions

4.1.22 Since ratepayers who participate in DSM programs share in the direct as well as the broad societal benefits of these programs, the Board considers it appropriate that these ratepayers share in the costs of achieving these benefits. However, when considering the level of DSM contribution to be obtained from a customer class, the utilities are cautioned to be sensitive lest they impose hardships on low-income ratepayers or encourage industrial gas users to switch to less environmentally desirable fuels.

Accordingly, the Board endorses the provision in the Consensus Statement that: "Customer contributions are appropriate to the extent that they do not seriously reduce overall participation or foreclose the participation of specific customer groups". The Board also notes that customer contributions will reduce or eliminate the need for cross-subsidies.

4.1.23 The Board supports the provision in the Consensus Statement that the Participant Test is one factor to be considered in establishing appropriate levels of contribution, since this test provides an assessment of the direct costs and benefits to be accrued to those who participate in the DSM program.

4.1.24 The Board expects that the utilities will assess the required level of customer contribution on a case-by-case basis.

Rate Impacts of DSM Programs and the DSM Portfolio

4.1.25 The Board believes that rate impacts from DSM programs must be treated in a consistent manner with rate impacts from supply-side programs, since the costs and benefits of both types of programs can affect all gas customers. For example, supply-side programs may provide service benefits to all customers and may also provide specific benefits to certain customers in the vicinity of the new service. While most DSM programs are targeted to specific customer groups to realize certain benefits (although some information DSM programs may deal with all customers), these programs may also result in avoided system costs for all gas customers. Therefore, rate impacts caused by either demand-side or supply-side programs should be treated in an equivalent manner.

4.1.26 The Board recognizes that a portfolio of DSM programs may result in a rate increase. The Board will decide on the magnitude of any allowable rate impact on a case-by-case basis in rates cases.

4.1.27 The Board also recognizes the important role that the energy conservation programs of the gas utilities play in achieving the Government of Ontario's energy and environmental policy goals. In a letter to the Ontario Energy Board dated 28 February 1992, the then Deputy Minister stated that:

> Energy efficiency has been identified as the Government's top priority in the energy sector ...[and] as a key to achieving the Government's objectives of economic competitiveness, environmental protection, energy supply security and sound energy planning ... Natural gas utilities, in conjunction with other energy supply service companies within the province, are also expected to be central players in achieving these objectives through the delivery of energy efficient services and programs.

4.1.28 The Board concurs with these policy goals and, as a result, believes that a rate impact may be reasonable if DSM programs that survive the screening process can lead to gains in energy efficiency and environmental protection.

4.1.29 The Board also heard evidence that carbon dioxide and methane emissions due to the use of natural gas contribute to strengthening the greenhouse effect and, although there is scientific uncertainty regarding the amount and rates of warming and the resultant impacts, increased concentrations of greenhouse gases will lead to a warmer climate. The Board takes notice of a Discussion Paper prepared for Environment Ontario's Consultation on Global Warming, dated September, 1992. In this Discussion Paper, the Ministry of Environment and Energy adopted, as a starting point, a "no regrets" approach to global warming which provides insurance against potentially catastrophic outcomes by taking actions that make sense whether the warming predictions are right or not. Allowing a reasonable rate impact in order to support DSM initiatives which lead to significant reductions in the production of greenhouse gases is appropriate under a "no regrets" approach.

4.1.30 When considering a rate impact, the Board believes that the level of the impact should be based on questions such as:

- Will the immediate impact on customer bills be excessive?
- Is it likely that customer bills will, in the longer term, be unaffected or reduced even if rates increase?
- Will the impact on certain groups, such as low-income customers, be onerous?
- To what degree will the various stakeholders share in the benefits of a particular DSM program?
- Will improvements in the security or overall cost of operating the utility system create benefits beyond the first round impacts of the DSM program?
- Will the long-term net societal benefits of the DSM program override its immediate rate impacts?
- Are the net societal benefits of such magnitude and importance as to give priority to their attainment?
- Do opportunity costs demand prompt action?
- Will an important DSM program be left undone, or poorly done, if a ratepayer subsidy is not provided?
- Will the inclusion of the DSM program contribute to a broader menu of programs and thereby recognize the needs and perspectives of groups, such as low-income customers, Aboriginals and farmers, that might otherwise be precluded from participating?
- Will the inclusion of the DSM program take advantage of synergies among programs?

4.1.31 The Board expects the utilities to work toward developing strong, broad-based, self-sustaining DSM programs which continue to improve the level of energy efficiency. Thus, the Board also expects the utilities to be vigilant in their program design, and limit the level of rate impact, in order to minimize the need for cross-subsidization.

Using Existing Delivery Mechanisms for DSM Programs

4.1.32 When developing a portfolio of DSM programs, the Board expects the utilities to include successful non-subsidized approaches such as those used by the ESCOs. The ESCO approach for industrial, institutional, and large commercial clients is performance-based, contains measures with short, medium and relatively long payback periods, and often requires the client to accept the current level of utility bills until the DSM costs are fully recovered. The ESCOs also typically accept the risk that a program may not achieve its forecast savings.

4.1.33 The Board believes that it would likely be unproductive for the utilities to compete with or replace the effective DSM delivery mechanisms that are currently available from ESCOs or local providers of energy products or services. The Board feels that the use of these mechanisms is likely to be more cost-effective and efficient than the utilities developing their own. However, certain situations may require the utility to take a more aggressive role. The Board expects that the utility will justify, during its rates case, whatever approaches it uses for the delivery of DSM programs.

4.1.34 The Board also considers it preferable for a utility to design energy conservation programs which include all relevant energy forms, rather than just focusing on natural gas conservation measures in isolation. This more efficient, cost-effective and environmentally sound approach will require cooperation with other organizations such as Ontario Hydro and municipal electric utilities. The Board encourages such cooperation.

E.B.O. 134

4.1.35 With regard to the methodologies described in E.B.O. 134, the Board finds that the evidence provided at this hearing is insufficient to make a determination on what, if any, modifications are necessary. However, the Board recognizes the importance of having consistent treatment of supply-side and demand-side programs and the need to ultimately integrate the two types of programs. The integration phase and the next steps required in the IRP process, including the question of modifications to the E.B.O. 134 methodology, are discussed under Issue 10.

5. ISSUE 3 TREATMENT OF EXTERNALITIES - MEASUREMENT AND MONETIZATION

5.0.1 The distribution and use of natural gas have cost consequences for society which are not routinely accounted for in a utility's cost of doing business. Effective DSM programs should reduce these external costs. For example, improved efficiencies in the use of energy will reduce the emissions of combustion products. Given this potential for societal benefits, the Board has addressed the issue of how externalities should be factored into the analysis of DSM programs. The inclusion of externalities is an important issue because there could be substantial impacts on the costs and benefits of a specific DSM program, depending on how externalities are internalized.

5.0.2 This issue was included in the Demand-Side Issues List as:

> ***Should societal and/or environmental externalities be included in the cost analysis of demand side management ("DSM") programs? If so, how should these costs and benefits be included?***

5.0.3 In response to these questions, Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, Pollution Probe, and Union agreed to the following Preamble and Consensus Statement. The City of Toronto agreed to the Consensus Statement only.

Preamble

All externalities (environmental and social) should be included in the societal cost-effectiveness test. However there are practical limitations on our current ability to identify, measure and monetize externalities.

There should be a distinction made when dealing with environmental externalities between the quantities of material emitted, the effects on the environment and the monetary values attached to them. All environmental externalities need to be measured first and then monetized. In some cases the first step is well understood and in others there has been progress in establishing a monetary value. Having both a measurement and a monetized value for environmental externalities requires further work.

The first step in this process will be to measure and monetize atmospheric emissions from fossil fuel use as impacted by DSM programs. The working group described below will be charged with this task along with evaluation of other externalities.

It should be noted that monetization of externalities will reflect considerable judgement and there may continue to be uncertainty with respect to the relative value of monetized externalities when considered in the same context as other economic factors.

The approach to measuring and monetizing externalities must be consistent with government policy and mindful of the ongoing debate in different jurisdictions.

Consensus Statement

1) All measured and monetized societal and environmental externalities should be individually accounted for in the Societal Cost Test once it *is possible to measure the externalities based on scientifically defensible data.*

2) *There is merit in conducting sensitivity analysis for monetized values of externalities in order to reflect the variance in potential impacts that they might have on society.*

3) *Those societal and environmental externalities which can be identified, measured but not monetized at this time should be given qualitative consideration by the utilities and the Board in their review of DSM programs during cost effectiveness testing.*

4) *The three utilities should adopt a consistent approach to the identification and measurement and valuation of societal and environmental externalities.*

Positions of the Parties

5.0.4 Board Staff submitted that the Consensus Statement provides the utilities with sufficient direction on the treatment of externalities, and that the monetization of all or even many externalities may not be necessary before the utilities can ensure that a particular program passes the SCT.

5.0.5 Board Staff stated that it supports DSM programs as a tool for reducing externalities such as greenhouse gas emissions. It supported the Consensus Statement because it recognizes such externalities on an equal footing with other costs and benefits when evaluating cost-effectiveness.

5.0.6 CEG submitted that the purpose of an externality valuation is to cause the customers who are currently enjoying the energy service benefits to gradually take responsibility for the costs of reducing the externalities they impose on others. It argued that monetized externalities should be valued equally with financial costs. If environmental impacts are certain to be created, but the amounts are uncertain, CEG stated that zero is clearly the wrong value to assign to those impacts. Externality estimates need not be perfect or completely accurate to be considered "scientifically defensible" and useful in energy planning.

5.0.7 In CEG's submission, including externality costs in the gas system planning process does not require the Board to become expert on all environmental issues in order to value impacts appropriately. Adoption of the Cost-of-Control approach leaves these decisions to the environmental regulators. Any reductions in pollutants which are achieved by a DSM activity are then valued at the cost of controlling them by an alternative method.

5.0.8 CEG further argued that the Board should not delay accepting the Cost-of-Control approach for natural gas in order to wait until this methodology is more broadly applied. The Board should take a leadership role, since monetization of externalities in the gas sector will surely speed the application of the Cost-of-Control approach to other fuels.

5.0.9 Energy Probe took the position that, since there is no market for externalities, the accuracy of monetized externality values cannot be tested and, therefore, cannot be considered reliable. Energy Probe stated that because externality cost estimates are highly uncertain, they should be given less weight than financial costs which are more certain. Moreover, in its view, the Cost-of-Control approach would be difficult to apply to CO_2 emissions which are not yet subject to government regulation.

5.0.10 A second problem Energy Probe identified arises from trying to internalize only the cost of externalities for natural gas while ignoring the environmental impacts that result from the use of competing fuels. It would not be in the best interest of the environment to subsidize DSM programs that will increase natural gas rates. In support of its argument, Energy Probe quoted its witness, Dr. Ruff, who testified that: "...even if the price of gas is too low because it does not include all the environmental impacts of gas production and use, it might be that the gas price should be decreased even more ... if other, dirtier energy forms cannot be priced to reflect their external environmental costs."

5.0.11 Consequently, Energy Probe recommended that the Board not try to internalize externalities for natural gas at all until equal regulatory treatment of less desirable fuel forms is assured. Energy Probe advised the Board to recommend that the federal government establish economically efficient, polluter-pay regulations, such as emission charges or tradeable pollution permits, which incorporate the costs of externalities in the price of all fuel forms. If the federal government fails to act quickly, according to Energy Probe, these regulations should be implemented by the Ontario government.

5.0.12 The City of Kitchener supported the Consensus Statement with one exception. It would exclude those externality benefits that fall outside the ambit of the utilities' mandate or responsibilities.

5.0.13 Although OMAA agreed with the intent of the Consensus Statement, it was not a party to the consensus. OMAA's position was that <u>all</u> relevant external costs associated with the production, transportation and consumption of natural gas should be taken into account. OMAA expressed concern that social and some environmental externalities will be given little weight in practice, unless there is a significant commitment of resources to effectively evaluate the full range of externalities. OMAA was concerned that giving less weight to monetized externalities than financial costs in the SCT could reduce the impact of the externalities on the planning process.

5.0.14 OMAA stressed that the identification and valuation of externalities must be comprehensive and accurate. Of particular concern is the issue of those externalities which are difficult to quantify and monetize. In such instances, the qualitative treatment in the planning process must be meaningful. OMAA submitted that its members should be consulted on this matter, since they offer a unique expertise that can assist in this process. OMAA also argued that justification should be provided for those externalities which are not monetized.

5.0.15 Union submitted that, in order to take account of social and environmental externalities, both the costs and benefits of supply-side and demand-side options must be considered and given appropriate weight. It noted the difficulties involved in trying to monetize externalities, and urged that judgment be exercised when attempting to compare the value of monetized externalities with economic costs determined by market transactions.

5.0.16 In Union's view, monetized externality values should not be treated in an equivalent manner with financial costs, since this could lead to adoption of a DSM program which causes a rate increase that would not have occurred had a less costly (in terms of real dollars) supply-side option been chosen.

5.0.17 Union pointed out that care must be taken to avoid the monetization of externalities in a way that makes gas appear less attractive than more environmentally detrimental fuels. In its submission, the environmental and other benefits resulting from the wise use of gas are far greater than the benefits associated with attempting to reduce the use of gas.

5.1 BOARD FINDINGS

5.1.1 In general, the Board views the Consensus Statement as a reasonable approach to the inclusion of externalities in the Societal Cost Test. However, the Board finds it appropriate to make refinements to the Consensus Statement to improve its effectiveness and ease of implementation.

5.1.2 The Board concurs with the Consensus Statement that, when dealing with environmental externalities, a distinction should be made between measuring and monetizing an externality. The Board believes that this explicit distinction is necessary to ensure that the monetized value is quantified appropriately. The derivation of the externality value should be documented properly so that it can be readily understood by the Board and other interested parties.

5.1.3 The Board notes that the preamble to the Consensus Statement focuses on the use of this distinction for atmospheric emissions. However, the Board expects that the distinction will be applied to the treatment of other environmental externalities and to social externalities.

5.1.4 In the Board's view, the first step when considering the measurement of any externality is to determine the significance of the externality in a qualitative manner. If the utility finds the externality to be significant, then the utility is expected to attempt to measure its effect (e.g. quantity of material emitted, change in water or air quality). Once the effect of the externality is measured, the next step should be the measurement of its impact (e.g. the damage to plant, animal and human health, the level of improvement in habitat or biodiversity). When it is not possible to measure the effect with sufficient precision for monetization, the externality should be incorporated into the qualitative component of the SCT.

5.1.5 The Board concurs with the Consensus Statement that all monetized externalities should be derived from scientifically defensible data, i.e. data that are valid and reliable. The Board also believes that, in order to apply the SCT properly as a planning tool, the dollar values of monetized externalities must be weighted equally with market-determined costs.

5.1.6 However, the Board is concerned that the SCT may be applied in an overly restrictive manner, and reminds the utilities that this test is only the first screen for the inclusion of a program into the DSM portfolio. When the utilities are deciding to include an externality in the SCT, the Board expects them to determine whether its inclusion is warranted after considering the trade-off between the limited quality of the data on which the externality is based and the benefit of including its avoided costs in the SCT. Ultimately, the question of whether or not an externality is included in the SCT must be defensible at a rates case.

5.1.7 The Board accepts that the monetization of externalities for natural gas utilities is a new field of endeavour with little direct or relevant experience in other jurisdictions, and this creates uncertainty. Accordingly, the Board concurs with the Consensus Statement that considerable judgement may be required. To address this uncertainty, the Board expects the utilities to conduct a sensitivity analysis for each monetized value for the SCT. However, as the utilities gain experience with monetization, the Board feels that the level of uncertainty, and therefore the need for the sensitivity analyses, will decline.

5.1.8 The Board is concerned about the qualitative assessment recommended in the Consensus Statement. It involves using two approaches to assess externalities which are not compatible, since the results cannot be directly summed to produce an overall net societal benefit. Moreover, the Consensus Statement does not provide direction on how to calculate an overall net societal benefit based on the two approaches. The Board prefers an approach to qualitative assessment which includes all of the significant costs and benefits of a DSM program and produces a non-monetary conclusion for the overall net societal benefit.

5.1.9 When the utilities are monetizing externalities, the Board prefers that, at this time, they use the Cost-of-Control method for calculating avoided costs. This method relies on an indirect valuation of damages based on the cost of compliance with existing regulations. It was endorsed by a number of parties during the hearing. The Board is of the view that this evaluation technique provides a relatively direct approach to monetization.

5.1.10 The Board notes that the Cost-of-Control method works best for regulated substances, but that it can be used for unregulated substances such as carbon dioxide by assuming a target of control and estimating the cost of compliance with that target. The Board believes that targets for emission control are most appropriately set by government and urges that this be done as soon as possible. However, the Board is prepared to accept assumed targets for DSM planning purposes in the absence of government regulation.

5.1.11 The Board views the use of the Cost-of-Control method as an interim measure until Damage Costing can be done in a straightforward and cost-effective manner. Damage Costing, which involves the calculation of the actual damage costs to society in dollar terms, is considered by the Board to provide a more accurate assessment of impacts. However, at present this evaluation method is extremely complex and costly to implement. The Board expects the utilities to keep apprised of developments on Damage Costing in other jurisdictions, and to keep the Board informed of any such developments at rates cases. A cooperative approach among the utilities on these activities would help to minimize costs.

6. ISSUE 3 TREATMENT OF EXTERNALITIES - CONSULTATION

6.0.1 As part of the discussion on externalities, the issues were raised as to whether the utilities should employ a consultative process when determining how externalities should be accounted for in their DSM plans, and how such consultation should be achieved. One proposed alternative was to form a working group to ensure that the affected parties have an early opportunity to contribute to the development of DSM plans.

6.0.2 Among the matters proposed to be considered by a working group were: which externalities should be included when defining avoided costs; what values should be ascribed to these externalities; and whether participation in the group should be funded, and if so, how should it be done.

6.0.3 Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, Pollution Probe, the City of Toronto and Union agreed to the following proposal in the Consensus Statement on Issue 3.

Working Group Proposal

A working group with representation from each of the utilities and other interested parties involved with DSM should report to the Board on a recommended methodology for treatment of those externalities to be *included in the LDCs' respective Societal Cost Test. If possible the Working Group will be convened prior to the DSM hearing. Its mandate will be to achieve consensus on the methodology for identification, measurement and monetization of externalities and the values themselves where possible. The anticipated result will be to establish a common basis for the LDCs to include monetized externalities as part of the DSM program evaluation.*

The Working Group will present its recommendations to the Board and report its conclusions to the E.B.O. 169-II interested parties.

Positions of the Parties

6.0.4 Board Staff argued that the proposed working group provides a means of ensuring that the monetization of externalities is done in a consistent manner for the three utilities, with input from interested parties. Board Staff submitted that the Board should recommend how the utilities should evaluate those externalities that cannot be monetized. The Board should also establish a time frame, such as six months, within which the working group should report its findings to the Board.

6.0.5 Board Staff concluded that funding would be required in order for interested parties to participate effectively in the working group. It submitted that early participation by interested parties is essential in order to develop broad support for the monetized values in future proceedings. Although Board Staff recognized that a larger group is potentially more unwieldy, it argued that there should be no discrimination against groups that may not have been active in the proceedings thus far.

6.0.6 CAESCO agreed that monetization of externalities should be researched through the working group. CAESCO noted that ESCO programs achieve their load-saving goals and reduce environmental externalities without the need for utilities to internalize any externality costs. This added benefit should be factored into the utilities' DSM plans.

6.0.7 Centra suggested that the working group is more likely to succeed if it develops, by agreement, its own specific objectives, work plan and timetable. These should be filed with the Board, with an initial report to be delivered within six months of the Board's decision in Phase III. Discussions within an ad hoc working group initiated by Centra indicated that the work plan would probably include: the identification of externalities that should be considered in an IRP context; a survey of approaches used in other jurisdictions; a review of relevant existing studies; a determination of the preferred approaches to quantifying and monetizing externalities; and a report of the working group's recommendations to the Board and the parties to E.B.O. 169.

6.0.8 Centra proposed that membership in the working group be open to any party from the E.B.O. 169 proceedings, as well as to any other appropriate interested party agreed to by the working group. Representation from the Ontario Ministry of Environment and Energy should also be sought to ensure the working group is kept apprised of relevant Ontario government policy and on-going studies of particular relevance. Centra supported funding of per diem and travel expenses, and suggested that "the group as a whole should determine the extent to which expert assistance is required and should jointly sponsor such assistance".

6.0.9 CEG stated that, while it prefers an informal approach, it is amenable to the working group being structured by the Board. CEG recommended that public interest group participation in the working group be funded. It suggested that, in the absence of legislative change, it would be appropriate to use the Board's Cost Award Guidelines when funding such participation. CEG recommended that the Board establish a reporting deadline, such as the six-month time frame suggested by several parties.

6.0.10 CAC(O) suggested that the Board should issue specific guidelines to the working group, directing it to provide: the best current control costs for emissions (other than carbon dioxide) arising from the use of natural gas; a survey of the monetary values which have been proposed elsewhere for the environmental effects of carbon dioxide emissions; a survey of the levels of carbon tax which have been proposed in other jurisdictions; and, an analysis of the reasons behind the wide range of values on these items.

6.0.11 Consumers Gas expressed the opinion that the working group's results would be produced most quickly and cost-effectively if an informal, consultative approach were employed. Consumers Gas indicated that it is prepared to fund the working group, provided the Board accepts these costs as eligible for consideration as a cost of service.

6.0.12 In Consumers Gas' view, original research or the extensive involvement of external experts would not be necessary or desirable. If external assistance is required, Consumers Gas agreed with Centra and Union that the working group should collectively engage consultants who would work on behalf of, and report to, the group as a whole. Consumers Gas also proposed that the Board direct the three utilities to submit a draft budget to the Board on behalf of the working group, after consultation with the other working group members.

6.0.13 Consumers Gas urged the Board to direct the working group to produce a status report within six months outlining recommendations for the Board to consider and a timetable for further work or reports.

6.0.14 The City of Kitchener encouraged the Board to recognize the working group's role in compiling and organizing the literature on monetization and determining the range of monetized values as evidenced by the literature. However, it argued that the Board should not expect the working group to reach a consensus on monetized values, and that task should be excluded from the working group's mandate. Moreover, the working group should not supplant the management decision-making role of the LDCs under regulation.

6.0.15 The City of Kitchener also submitted that the working group's membership should be broad, but should also avoid duplication in the representation of the environmental groups, customers and native peoples. These three distinct interest groups should each be obliged to select a single representative party to minimize costs and enhance consensus-building while encompassing all views without prejudice.

6.0.16 OMAA saw the working group as useful and supported such aspects as government representation, a six-month time frame, and a clear mandate. OMAA recommended that the mandate of the working group should be broadened to include the development of a methodology for the qualitative treatment of non-monetized externalities. It also recommended that the working group present its consensus and non-consensus positions at a separate oral hearing before the Board.

6.0.17 OMAA stressed that the identification and valuation of externalities must be accurate, particularly for those externalities which are difficult to quantify and monetize. In such instances, the qualitative treatment in the planning process must be meaningful. OMAA submitted that its members should be consulted on this matter, since they offer a unique expertise which can assist in the process.

6.0.18 Union recommended that the working group be limited to participants in the E.B.O. 169 hearing, with the addition of a government representative if desired. The group should be given a specific mandate to prepare a timely report indicating the extent to which the parties agree on the externalities to be considered, their measurable impacts, monetized values and the methodologies to be employed. The working group should also report on the extent of consensus within the group, but it should not be expected to negotiate a consensus if one does not exist after the survey, assessment and discussion of methodology are completed. Union also recommended that any consultants be retained by the group as a whole and be paid for by the three LDCs. Union agreed with the City of Kitchener that the mandate of the working group should not include the monetization of externalities.

6.1 BOARD FINDINGS

6.1.1 The Board concurs with the Consensus Statement that the three utilities should adopt a consistent approach to the identification, measurement, and valuation of externalities. This approach should foster cooperation among the utilities to develop a sound approach and should reduce the complexity of the regulatory process.

6.1.2 To develop a consistent approach, the Board expects the utilities to form a joint collaborative on externalities, and the review of qualitative assessment methodologies employed in other jurisdictions in order to recommend approaches to be used in the DSM planning process in Ontario ("the Collaborative"). The purposes of the Collaborative include those of the working group identified in the Consensus Statement.

6.1.3 When the utilities are forming the Collaborative, the Board expects them to seek representation which incorporates diverse perspectives (e.g. residential, commercial and industrial customers, special interest groups such as environmental and Aboriginal groups, and local and provincial government representatives) in a balanced, manageable and non-duplicative manner. Since the Collaborative is not a continuation of the E.B.O. 169-III proceeding, the utilities are not automatically bound or limited to the parties in these proceedings when selecting participants for the Collaborative.

6.1.4 To ensure the effective participation by diverse groups, the Board expects the utilities to provide funding in a manner consistent with the Board's

Cost Award Guidelines, but to consider the provision of financial compensation, possibly in the form of honoraria, which respect the value of the time being spent by employees and officers of the participants. When the services of experts are required, they should be retained on behalf of the group as a whole, rather than underwriting the costs of a number of experts representing the individual participants. The Board also suggests that the utilities consider the use of an independent facilitator to ensure the smooth functioning of the Collaborative. The reasonableness and prudence of the expenditures incurred by each utility will be tested at the rates hearing as a cost of service issue.

6.1.5 The Board is concerned that having the Collaborative focus initially on atmospheric emissions is too limited. It may lead to a lack of emphasis on other externalities and to insufficient attention being applied to the development of an appropriate approach to the qualitative assessments required in Screens 1, 4 and 5 (refer to Issue 2).

6.1.6 The Board expects the mandate of the Collaborative to include the preparation of a report that:

- identifies the range of Cost-of-Control costs being used in the SCT in other jurisdictions for air emissions as well as other environmental and social effects; explains the variance in the values used; and makes recommendations, where possible, on the most appropriate costs to be used in Ontario;

- carries out a survey of how non-regulated emissions and other effects from natural gas use (e.g. CO_2 emissions and effects on communities) currently are treated in the SCT in other jurisdictions, as well as proposals for their treatment in the future; explains the rationale for the approaches taken; and makes recommendations, where possible, on the most appropriate approach for Ontario, including the values to be assigned to the emissions and other effects;

- identifies other externalities which are not included in the SCT in other jurisdictions, but which should be included in Ontario; provides the rationale for the inclusion of other externalities; and makes recommendations, where possible, on the most appropriate approach for their treatment, including the values which should be assigned to them;

- reviews and assesses methods employed in Ontario and in other jurisdictions which can be used for the qualitative assessments required in Screens 1, 4, 5, and in the evaluation of portfolio implementation strategies; and makes recommendations, where possible, on acceptable approaches;

- identifies if and where there is a need to consider the unique characteristics of each utility; and

- describes and assesses the process of consultation that was used for the Collaborative.

6.1.7 The Board expects the members of the Collaborative to reach an agreement on the terms of reference, the timetable, budget, funding and work plan for the Collaborative and to report to the Board and the parties on these initial matters by September 30, 1993. Once the work of the Collaborative has been completed and the Board has received the final report of the Collaborative, the Board will determine how to proceed further. The Board encourages the Collaborative to strive to submit its final report to the Board and the parties by February 28, 1994 in order that the results can be incorporated in the examination of DSM plans for the fiscal 1995 test years of the LDCs.

6.1.8 In the event that the above deadlines are found to be unrealistic, the Board expects the utilities to make this known to the Board as soon as possible and, when doing so, to define the causes of delay and to jointly commit to a revised timetable.

6.1.9 The Board's endorsement of the consultative process is not limited to the issue of externalities. While there is an urgent need to apply a consultative effort to matters relating to externalities and qualitative assessment methodologies, the potential advantages of consultation on DSM matters extend beyond these issues.

6.1.10 The Board believes that formal ongoing consultation, of the type embodied in the Collaborative on externalities, could be an effective approach to addressing a number of DSM issues which are yet to be fully resolved. However, to be effective, other consultative groups will likely need to be formed to focus on specific issues, rather than creating an institutionalized, general forum.

7. ISSUE 4 REGULATORY TREATMENT OF DSM INVESTMENTS - COST RECOVERY

7.0.1 The regulatory and accounting treatment of DSM investments is a critical component of IRP. Of specific concern is the question of whether the costs and the accounting treatment of demand-side investments should be treated consistently with those of supply-side investments.

7.0.2 This issue was included in the Demand-Side Issues List as:

> ***How should investments in demand side options be treated for rate-making purposes? Are the cost recovery mechanisms for demand side options consistent with the accounting treatment of other utility expenditures?***

7.0.3 In response to these questions, Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement on the ratemaking treatment of DSM investment. Energy Probe agreed with the opening paragraph, point 4 and the last paragraph of the Consensus Statement on this issue.

Consensus Statement

Given the basic assumption that DSM programs are desirable and should be undertaken by utilities, then there is consensus among the parties listed below that the matching of costs and benefits of DSM programs is appropriate. There is also agreement that investment in demand-side options should be treated consistently with investment in supply-side options. In general, accounting treatment should be in accordance with GAAP.

1) *DSM programs should be divided into capital investments and operating expenses.*

2) *Capital investments would be those expenditures with longer term benefits. The capital investment portion of the DSM program costs should be treated in a similar manner as traditional rate base components.*

3) *Expenditures with shorter term benefits (one year or less) should be expensed. The utility should be allowed to recover the operating expenses in the year in which they are incurred through the cost of service.*

4) *The amortization of capitalized expenditures should attempt to match the expected benefits of the investment, with amortization over the lifetime of the technologies or over the period of the benefits to be realized. This method of cost recovery is consistent with the accounting treatment of other utility expenditures. Where the energy savings are realized over an uncertain or extended timeframe (e.g. informational programs), or where the benefits to be realized are the avoided costs of future supply-side options, the costs should be recovered on a timely basis.*

5) *The utilities should establish a deferral or balancing account for DSM operating, and if necessary, capital expenditures. The deferral account would be used to accrue the difference between actual DSM expenditures and forecast expenditures. The disposition of the balance would occur in the next rate period. There would be a carrying cost associated with the deferral account.*

There is agreement that due to the uncertainties surrounding any initial DSM program, the utilities should establish a deferral or balancing account for DSM (operating and/or capitalized) expenditures. This would allow the utility the opportunity to recoup all of the costs incurred with respect to DSM program implementation, and would give the utility greater flexibility to respond to a program's success or failure.

If the utilities did not have such a balancing account in place, they might have a disincentive to go over budget and spend additional resources on a program, regardless of its success or penetration rate. Since DSM investments are non-traditional utility assets, they do not generate revenue, and therefore the utility would simply stop spending once it ran out of resources. Therefore the use of a balancing account ensures continued DSM program implementation and fewer lost opportunities. Any over- or under-spending would be reviewed by the Board during the rate case, and the Board would judge the prudency of the expenditures. The balancing account also has the additional advantage of lowering the utility's new risk with respect to investing in non-revenue generating assets.

There was agreement that this type of deferral account was particularly useful in the early phases of DSM implementation. Therefore, the parties agreed that the deferral account may not be necessary in later years when the utilities were more experienced with DSM programs and the expected results; it was agreed that the necessity of a deferral account should be revisited or reviewed periodically in the individual utility rate cases.

What kind of expenditures should be considered DSM investments?

Again, given the basic assumption that DSM programs are desirable and should be treated in a manner consistent with supply-side options, any DSM program costs that should be considered as investments (and therefore eligible for rate base treatment) are those that are long-lived in nature and that have long-lived benefits. The basic principle behind the capitalization and the amortization of DSM investments is to match benefits and costs to the greatest extent possible. Any accounting treatment of program expenditures included in rate base should also be consistent with GAAP.

Those expenditures to be considered investments should include: hardware costs owned by the utility (such as high-efficiency gas equipment); and customer incentive payments (rebates, low-interest loans).

Other expenditures that may be included in rate base may be programs with costs of a "one-time" nature. The examples given were labour costs with respect to DSM program development and implementation, or a portion of overhead and administration costs. The guiding principle would be consistent treatment of supply-side and demand-side costs. Any expenditures of an ongoing nature would more properly be expensed.

The amortization period of capitalized expenditures should match the useful life of the asset or DSM program benefit. With respect to informational programs (and other programs with uncertain, and hard to attribute, benefits over an undefined period of time), those costs might be more prudently recouped in a shorter time frame.

Positions of the Parties

7.0.4 Board Staff submitted that the three key factors to consider when assessing this issue are the consistent treatment of demand-side and supply-side options, the ease of application and regulatory review, and the matching of costs and benefits.

7.0.5 Board Staff contended that the utilities' concerns regarding the recovery of DSM costs were legitimate and that resource selection would be biased in favour of less risky investments. Accordingly, Board Staff recommended the use of deferral accounts for DSM operating and capital expenditures in order to reduce the risk associated with investments in non-revenue generating assets.

7.0.6 In the opinion of Board Staff, the use of deferral accounts would also improve the utilities' ability to respond to variances in program performance, and reduce the incentive to abandon programs once budgeted funds run out. Early abandonment could result in lost opportunities and confusing market signals. Board Staff suggested that the need for deferral accounts, and the prudence of the actual expenditures, would be tested during the rates case proceedings.

7.0.7 In response to CAESCO's suggestion that joint utility/ESCO programs should be included in the deferral account, Board Staff argued that this was inappropriate since such accounts were designed to protect the utility, and not a private enterprise, from the risk of not recovering costs.

7.0.8 Centra believed that DSM capital expenditures are likely to be larger than DSM operating expenditures. Consequently, capital investments should be included in a deferral account to ensure that DSM development will not be constrained unreasonably by cost considerations, and that utility and consumer interests will be balanced in the event that DSM programs are more successful than anticipated.

7.0.9 Centra submitted that its support for the use of a deferral account was not inconsistent with its opposition to decoupling, (as discussed under Issue 6). Centra agreed to the use of a deferral account, but it did not consider such accounts as a necessary prerequisite for the implementation of DSM. The use of a deferral account would not, in Centra's opinion, involve a major regulatory change, nor would it lead to all the other disadvantages of decoupling.

7.0.10 CAESCO recommended that joint utility/ESCO programs should be included in the deferral accounts with periodic rebates based on the achieved load savings. This would remove the DSM financial risk from the utility and permit it to earn a return on program funds.

7.0.11 Consumers Gas submitted that the proposed cost recovery mechanism would ensure the equal treatment of demand-side and supply-side options and facilitate the implementation of large scale, cost-effective DSM programs. Consumers Gas also agreed with Board Staff that the proposal would provide utilities with greater flexibility when responding to a program's success or failure.

7.0.12 Energy Probe argued that, in order to protect customers from possible rate impacts due to the implementation of financially unsustainable programs, DSM investments should be recovered from the proceeds of those investments, and not from an authorized regulated return. Accordingly, DSM should be a deregulated activity which is separate from the utility to protect customers from the adverse rate impacts caused by unsuccessful programs (see also Chapter 8). Energy Probe also contended that activities which are not profitable should not be allowed into rate base, and that the Board should disallow future DSM costs if the expected benefits do not materialize.

7.0.13 Energy Probe recommended that subsidies should not be considered as assets. If subsidized DSM is permitted, however, customer contributions should be included as a separate item on customers' bills.

7.0.14 While Energy Probe agreed with the principle of equal accounting treatment of demand-side and supply-side investments, it argued that such agreement should not be used to justify the equal treatment of unprofitable and profitable investments for the purposes of including them in rate base or recovering their costs.

7.0.15 Energy Probe further submitted that the Board should treat monopoly activities and naturally competitive activities differently. Since DSM activities are not a monopoly, they do not require regulation to protect the consumer or to allocate resources efficiently.

7.0.16 The City of Kitchener considered the accounting treatment proposed in the Consensus Statement to be a continuation of the current treatment of DSM and NGV activities, except for the introduction of the deferral account. In its view, the advantages of the deferral account had been established.

7.0.17 Union supported the establishment of DSM deferral accounts to provide equal treatment to demand-side and supply-side expenditures. For the same reason, Union argued that demand-side "investments" must be amortized and included in rate base. In its opinion, a deferral account was necessary in order to reduce regulatory and forecasting risks.

7.0.18 In reply to Energy Probe's submission that subsidies and unprofitable investments should not be allowed in rate base, Union argued that participant incentives were important for the success of Union's DSM programs, but that the cost of these incentives would be recovered from the programs.

7.0.19 Union argued further that the LDCs have been promoting conservation, and thus DSM, for a substantial period of time and, accordingly, there is no reason to disallow these activities now.

7.0.20 Union also disagreed with the position put forward by Energy Probe and Pollution Probe that the Board should maintain the ability to disallow future costs of a DSM program if the expected benefits do not materialize. Union argued that to disallow an investment, the Board would have to find that the utility acted imprudently at the time the investment was made, not retrospectively after the program is in place.

7.1 BOARD FINDINGS

7.1.1 The Board endorses the positions put forward in the Consensus Statement. It believes that, when considering DSM efforts, it is desirable to the degree possible to maintain a consistent relationship between the treatment of supply-side and demand-side costs.

7.1.2 The Board, therefore, also endorses the proposal in the Consensus Statement that the costs of long-term DSM programs (i.e. those with a duration of more than one year) be included in rate base and amortized over the estimated useful life of the programs. This would match benefits and costs in a manner consistent with the treatment of supply-side investments. The costs that should be eligible for consideration for inclusion in rate base include "hardware" costs; longer-term incentives, rebates and loan costs; and associated labour, overhead and administrative costs. The Board also supports the proposal that expenditures with shorter-term benefits (one year or less) should be expensed and considered for recovery through the cost of service in the year in which they are incurred.

7.1.3 The Board is cognizant that the success of new initiatives, such as DSM efforts, is critically dependent on the initial use of information, attitude development and "market" research efforts. The Board considers such efforts to be a necessary preamble for an effective DSM plan.

7.1.4 The Board recognizes that information and associated programs incur costs that are often difficult to associate with particular benefits, and may depend on variables that are difficult to forecast, such as the level and degree of customer acceptance. Thus, the Board feels it is appropriate to consider broad-based DSM information and associated programs as a separate category of expenditure.

7.1.5 The Board, therefore, believes that prudent, broad-based information and associated programs should be considered for recovery as legitimate cost of service items without requiring the identification of specified benefits that will be obtained. The Board believes that, because of the pervasive nature of generic programs, such as information programs, the benefits that will be generated will be difficult, if not impossible, to quantify. Such programs will, however, almost certainly have a beneficial impact. Thus, future rates case panels will likely be prepared to consider prudent expenditures on generic programs to be justifiable costs of service, even if specific quantified benefits cannot be ascribed to them.

7.1.6 Given the fact that these broad-based programs will have inter-franchise benefits, the Board expects that the utilities will coordinate and cooperate when undertaking such programs.

7.1.7 Notwithstanding the above, when information and marketing efforts are specific to a particular DSM program, they should be accounted for as a cost of that program, and justified on the basis of the program benefits that are to be achieved.

7.1.8 The Board is aware that there will be greater uncertainty over the accuracy of initial DSM forecasts due to the lack of experience in such matters. In order to avoid exposing the utilities to undue risk, while assuring that DSM is aggressively pursued, the Board endorses the use of deferral or balancing accounts as proposed in the Consensus Statement. The Board anticipates that as forecasting experience is gained the need for such accounts will diminish.

7.1.9 When balancing accounts are utilized, the amounts accruing should attract carrying charges. While it remains for the rates case panels to define how such carrying charges should be calculated, the Board suggests that carrying charges for capital investments should be based on the average of their monthly averages and should earn the allowed rate of return on rate base. The Board also suggests that expensed items should earn simple interest on the monthly opening balances at the utility's authorized cost of short-term debt.

7.1.10 Given the current frequency of rates cases, the Board expects that the amounts accruing in balancing accounts will be manageable and of only minimal inter-generational concern. Should the interval between rates cases be extended, interim measures to dispose of significant balancing account balances should be considered.

7.1.11 Each of the major LDCs has Natural Gas for Vehicles ("NGV") programs. The Board considers NGV programs to be outside the scope of DSM as currently defined. Due to the scale and self-standing nature of these programs, the Board requires that they be kept separate and not incorporated into the utilities' DSM portfolios.

8. ISSUE 4 REGULATORY TREATMENT OF DSM INVESTMENTS - DSM AS A NON-REGULATED ACTIVITY

8.0.1 Energy Probe proposed a model which would separate DSM activities from the regulated aspects of the utilities' operations.

Positions of the Parties

8.0.2 Energy Probe submitted that the business of supplying DSM products is not a natural monopoly, rather it is an inherently decentralized activity. It recommended a stand-alone, for-profit DSM business set up as a non-regulated activity. In its view, stand-alone, for-profit businesses have powerful internal incentives to successfully identify and implement conservation investments. In addition, the issue of what investments should be considered as DSM need not arise as a regulatory issue.

8.0.3 Energy Probe also submitted that the creation of a non-utility division for DSM will ensure that investments in demand-side options are recovered from the proceeds of those investments and will protect customers from possible rate impacts due to the implementation of financially unsustainable programs. Energy Probe recommended that the appropriate way to internalize externalities is through the price system by emissions taxes and tradeable emissions permits, rather than merely monetizing them for planning purposes.

8.0.4 Board Staff submitted that Energy Probe's proposal should be rejected. In its view, the proposal would greatly increase the regulatory burden, as the Board would have to examine the extent to which the utility's resources are devoted to non-regulatory activities.

8.0.5 Board Staff further submitted that Energy Probe's position on cross-subsidization is inconsistent. It noted that Energy Probe is vehemently against allowing cross-subsidies between groups of utility customers and users of gas, but has no qualms regarding cross-subsidies from one utility affiliate to another. Board Staff noted that the Board has traditionally allowed some degree of cross-subsidization among gas users. In Board Staff's view, equity concerns with respect to DSM would be addressed by a DSM portfolio containing a broad array of programs to be offered to all classes of customers.

8.0.6 Finally, Board Staff submitted that Energy Probe's position is partly based on the assumption that gas externalities are so small that it would be more costly for the Board to consider them explicitly than it would be to live with the effects. In the view of Board Staff, it is reasonable to believe that externality effects are probably large enough to warrant some market intervention. It submitted that since a major component of IRP is the consideration of externality values, there is a fundamental weakness in Energy Probe's position.

8.0.7 Consumers Gas submitted that the strict user-pay position taken by Energy Probe is not consistent with the realities of today's marketplace and, if adopted, it would result in unwarranted constraints on the scope and benefits of societally cost-effective DSM programs. According to Consumers Gas, adequate evidence has been brought before the Board to demonstrate the existence of significant market barriers to conservation, and to provide a rationale for a balanced portfolio of utility DSM programs.

8.0.8 OMAA submitted that it is difficult to reconcile Energy Probe's position on this issue with its other positions. In OMAA's opinion, it is unclear why the entrance of unregulated utility subsidiaries into the DSM marketplace would improve the functioning of that marketplace which, based on Energy Probe's evidence, is performing reasonably well.

8.0.9 Energy Probe replied that it agrees with the desirability of applying the same regulatory principles to the supply side and the demand side, but insisted that the important logical distinction between the natural monopoly activities and naturally competitive activities not be blurred as a result. It noted that gas distribution services are a natural monopoly which must be regulated to protect consumers, whereas DSM services are not a monopoly, natural or otherwise, and therefore do not require (or benefit from) regulation to protect the consumer.

8.0.10 Energy Probe submitted that the purpose of the regulation of DSM, according to Board Staff and the other endorsers of the Consensus Statement on Issue 4, is apparently not to be a "surrogate for competition" but to tax customers to pay for "socially desirable" DSM goods and services that they would not have otherwise purchased. This, Energy Probe noted, is based on an effort to use "planning to improve the ability of market forces to allocate resources". It concluded that this sort of planning can destroy or diminish the ability of market forces to allocate resources.

8.1 BOARD FINDINGS

8.1.1 The Board sees the creation of a separate DSM business as being disruptive of, and likely to detract from, efforts to expedite the development and implementation of DSM plans.

8.1.2 The Board is also of the view that rather than simplifying the regulatory process, the formation of a DSM business would introduce regulatory complexities. The allocation and monitoring of the utilities' costs of supporting such businesses would be difficult, given that the line of demarcation between utility operations and the non-utility business will be less than precise due to the level of interplay between the two enterprises.

8.1.3 The Board notes that the utilities have already demonstrated, to a limited degree, that they can and have successfully pursued demand-side efforts as part of their utility operations. As a result, the Board does not concur with Energy Probe's contention that such efforts need to reside in a separate non-utility division.

8.1.4 The Board, therefore, concludes that the utilities' DSM efforts should properly remain as part of utility operations. Having now thoroughly considered this matter, the Board expects that it will not have to revisit this issue in future proceedings unless or until there is a marked change in circumstances, or significant new evidence is brought forward.

9. ISSUE 5 ALLOCATION OF DSM COSTS

9.0.1 Given that costs will be incurred in the development and implementation of DSM programs, a key question is how these costs should be allocated and recovered. Costs could be narrowly allocated to only those who directly benefit from a DSM measure, be shared across the broader base of a customer class, or be recovered from the ratepayers across the entire utility system.

9.0.2 This issue was included in the Demand-Side Issues List as:

> ***Who should pay for DSM programs? Should the principle of "user pay" apply to DSM programs?***

9.0.3 Two Consensus Statements were submitted on this issue. Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement.

Consensus Statement 1

The issue of who should pay for DSM programs encompasses:

a) the appropriate level of contribution/incentives for participants at a program level; and *b) the cost allocation of DSM program costs not recovered by the program after giving consideration to participant contributions.*

Participant Contributions and Utility Incentives

It is desirable that participants who are the direct beneficiaries of a DSM program should bear, to the extent possible, the direct financial burden of the program. Customer contributions should be sought where appropriate, to mitigate program cost impacts on other ratepayers. Providing utility incentives to customers will encourage participation by customers in DSM programs (i.e. increasing net societal benefits). In determining the appropriate level of contributions/incentives, several factors should be considered. These factors would include the impacts of the contributions/incentives on: non-participants, program cost-effectiveness, ability of special customer groups (e.g. low-income, renters, non-profit organizations) to participate, potential for lost opportunities, and the elimination of market barriers that inhibit customer participation.

The use of a DSM portfolio approach is appropriate, where financially self-sustaining DSM programs would support DSM programs which are not financially self-sustaining.

Cost Allocation

The allocation of DSM program costs not recovered from program participants should recognize and be proportional to the distribution of program benefits. These benefits may extend to the system as a whole. Customers outside the target group who benefit as a result of program implementation should bear a commensurate portion of the costs.

9.0.4 The Canadian Petroleum Association, Energy Probe and TWG Consulting Inc. agreed to the following Consensus Statement.

Consensus Statement 2

The principle of individual user-pay within the practical limits of cost allocation should apply to DSM programs.

Positions of the Parties

9.0.5 Board Staff submitted that it is appropriate to extend some portion of DSM costs to the system as a whole, since all ratepayers will benefit from the deferral of future supply-side options and the associated externality impacts. Demand-side and supply-side costs should be treated consistently for cost allocation purposes.

9.0.6 Board Staff suggested that incentives would increase participation and attract specific customer groups that might not otherwise participate in DSM programs. However, incentives should not be so high as to impair the cost-effectiveness of the programs, nor should the utilities simply give away DSM options. Conversely, contributions should be as high as possible without deterring participation.

9.0.7 Board Staff pointed out that the Board has traditionally endorsed rates that are cost-related rather than strictly cost-based, as long as the resulting rates do not place an undue burden on any customer or customer class. Board Staff further noted that the Board has also approved financially non-sustaining distribution and transmission projects for public interest reasons. Therefore, it submitted that some level of rate impact is acceptable, but in no circumstance should it be greater than the rate impact that would have resulted from the alternative supply option.

9.0.8 Board Staff submitted that, wherever possible, the costs of DSM should be allocated according to the impact the program has on peak, seasonal or annual costs. It recommended that the utilities be directed to analyze the cost causality of DSM programs.

9.0.9 Board Staff also submitted that the appropriate level of cross-subsidization should be at the utility's and the Board's discretion to be consistent with the manner in which the Board currently evaluates supply-side options. The diversity and widespread application of DSM programs across all customer classes would help ensure overall equity, as there would be relatively few non-participants. The goal is to find the appropriate level of customer contribution or incentive to ensure that the benefits are produced, while minimizing intra-class and inter-class subsidies.

9.0.10 CAESCO submitted that experience in the U.S. shows that cross-subsidization can become an issue and that the principle of user-pay should be followed. User-pay has always been the basis for ESCO/client contracts, where clients accept their current level of utility bills until the DSM investment has been fully recovered by the ESCO or until the contract expires.

9.0.11 Centra maintained that the cost allocation principles used to allocate DSM costs should be consistent with those used to allocate other expenditures. However, the nature of certain DSM costs may warrant the development of new cost allocation factors.

9.0.12 CEG submitted that customer DSM incentives in an imperfect market are in accord with the "polluter-pay" principle and are, therefore, entirely consistent with a broadly defined user-pay concept. In its view, those customers who choose not to participate in DSM programs impose the largest environmental costs on society and, therefore, should be paying the largest part of the costs of the programs intended to mitigate or offset some of the effects of their actions. It concluded that "the existing situation is rife with cross-subsidy in the form of externalized environmental insult".

9.0.13 Consumers Gas submitted that a strict user-pay approach, as recommended by Energy Probe, is not consistent with the realities of today's marketplace and, if adopted, would unduly limit the scope and benefits of DSM programs. Consumers Gas further submitted that adequate evidence has been brought before the Board to demonstrate the existence of significant market barriers to conservation, and to provide a rationale for a balanced portfolio of utility DSM programs.

9.0.14 Energy Probe recommended following the principle of user-pay for DSM programs to ensure that the twin goals of equity and efficiency are achieved. In its view, even without a fully arms-length relationship between gas distribution and DSM services, significant benefits can be achieved simply by the Board endorsing the broad principle of user-pay, encouraging unsubsidized utility DSM services, and exercising some vigilance to ensure fair cost allocation. Energy Probe noted that subsidies to DSM, like subsidies to supply-side activities, create distorted price signals and encourage inefficiency.

9.0.15 Energy Probe also submitted that "the question of whether society's support for the poor should be in the form of cash, or help with gas bills, or help with weatherization and low-flow showerheads, or food, or education is an important question of public policy, but not one ... which should be answered by the LDCs or by this Board (although ... a recommendation by this Board to the Ontario government could certainly be appropriate)". It concluded: "Much less should the socially preferred form of benefits be financed, in our view, from a tax or monopoly surcharge on gas".

9.0.16 The City of Kitchener stated that some degree of subsidization within and between classes has long been regarded as an acceptable way in which to recover costs and that some subsidization of DSM costs should be regarded as acceptable. It submitted that requiring a DSM portfolio to have no rate impact would confine the burden of subsidization to those who engage in DSM activities and that would tend to discourage participation in self-supporting programs by making these more expensive than they would otherwise be.

9.0.17 The City of Kitchener noted that incentives may be very difficult to justify, and that incentives in the form of "giveaways" and "life-line" rates may be counter-productive in IRP terms. It submitted that the appropriateness of any incentive must be determined on a program-by-program basis in rates hearings. In addition, the Board should not allow the utilities to pass the costs of their DSM programs on to other utilities.

9.0.18 OMAA replied to Union that the use of financial incentives must be combined with, and justified by, good program design, implementation, measurement and evaluation. On the other hand, it submitted that large financial incentives and "give-aways" are sometimes appropriate and necessary to accomplish socially cost-effective DSM. OMAA agreed with Consumers Gas that Energy Probe's position on user-pay is inconsistent with the realities of the Ontario gas marketplace and that the adoption of this position would pose an unwarranted constraint on socially cost-effective DSM.

9.0.19 Union considered it inappropriate to overcome alleged market barriers by "give-aways" or excessively large financial incentives. In Union's circumstances, these would lead to adverse rate impacts, undesirable cross-subsidization and unfair competition with other suppliers of goods and services. Union also rejected suggestions that such problems could be overcome by providing "something for everyone", and argued that this approach would only exacerbate the problems, particularly given its existing base of DSM activities and its relatively low avoided costs. Union further submitted that participation in a DSM program should be the result of the customer's "perception that something of value other than a gift or bribe is being provided".

9.0.20 Union replied that CEG's polluter-pay argument is flawed in that it assumes incorrectly that the use of gas has a net negative impact on emissions, that current DSM program non-participants are inefficient gas users and it also erroneously equates larger use with inefficient use.

9.1 BOARD FINDINGS

9.1.1 The Board endorses the positions put forth in Consensus Statement 1. The Board has traditionally espoused cost-related rates that, to the degree reasonably possible, reflect cost causality. The Board has, however, on many occasions recognized that the public interest is better served by some degree of cross-subsidization being allowed in particular circumstances, so long as it does not reach undue levels.

9.1.2 Given the Board's position on externalities (as set forth under Issue 3) some level of subsidy is likely to be unavoidable. Based on this, the Board is of the view that a strict adherence to user-pay principles as presented in Consensus Statement 2 would be inappropriate. However, the Board believes that the public interest will be best served when the direct beneficiaries of a DSM program bear, to the greatest extent possible, the direct financial burden of the program.

9.1.3 Since there will likely be an array of DSM program proposals, it is impossible to formulate an appropriate set of criteria regarding cross-subsidization that will cover all eventualities. As stated under Issue 2, the Board has concluded that, when determining whether a cross-subsidy is warranted, factors such as the following should be considered:

- Will the immediate impact on customer bills be excessive?
- Is it likely that customer bills will, in the longer term, be unaffected or reduced even if rates increase?
- Will the impact on certain groups, such as low-income customers, be onerous?

- To what degree will the various stakeholders share in the benefits of a particular DSM program?
- Will improvements in the security or overall cost of operating the utility system create benefits beyond the first round impacts of the DSM program?
- Will the long-term net societal benefits of the DSM program override its immediate rate impacts?
- Are the net societal benefits of such magnitude and importance as to give priority to their attainment?
- Do opportunity costs demand prompt action?
- Will an important DSM program be left undone, or poorly done, if a ratepayer subsidy is not provided?
- Will the inclusion of the DSM program contribute to a broader menu of programs and thereby recognize the needs and perspectives of groups such as low-income customers, Aboriginals and farmers, that might otherwise be precluded from participating?
- Will the inclusion of the DSM program take advantage of synergies among programs?

9.1.4 The Board concurs with the use of a DSM portfolio approach where financially self-sustaining DSM programs would support DSM programs that are not financially self-sustaining.

9.1.5 The Board considers it desirable that the portfolio of DSM programs be as broad as reasonably possible to allow as many customers as possible the opportunity to participate and share in the benefits of DSM. The Board suggests that, when structuring their portfolios, the utilities take particular care that ratepayers such as those with low incomes are not discouraged from participating.

9.1.6 When appropriate opportunities arise, for example, if there is a potential to significantly enhance penetration rates, consideration should be given to offering customer incentives. On such occasions the utility must be prepared to present evidence substantiating that the incentive is justified, has been thoroughly researched and will not require undue levels of subsidization from other ratepayers.

9.1.7 In the interests of fairness and competition, the Board believes that intra-class subsidization should be held to a minimum. In this respect, it is obvious that within each rate class there will be customers that have already undertaken conservation measures on a voluntary basis, and at their own expense. On the other hand, these early practitioners have benefitted by avoiding energy costs and thus have achieved some advantage. The Board has considered "grandfathering" and has rejected it due to the attendant administrative complexities. However, the Board would entertain any further proposals as to how to deal fairly with and recognize those who have already implemented conservation measures.

9.1.8 The Board sees value in disaggregating a DSM plan in order to more effectively recognize peak, seasonal and annual cost impacts for the allocation of demand and commodity charges. The Board further suggests that industrial and large commercial customers be grouped separately from small gas users when analyzing DSM program development and delivery mechanisms.

9.1.9 The Board encourages the utilities to make maximum use of energy goods and services suppliers, including ESCOs, when designing and delivering DSM programs. There appears to be little logic to proposals that would encourage a utility to compete with or supplant those existing experts in the field of DSM. Indeed, it would be prudent to investigate ways that the utilities might cooperatively expand the role of the ESCOs by, for example, assisting in the financing and publication of DSM opportunities to both the larger and smaller gas user groups.

9.1.10 The Board's views on customer contributions and on rate impacts are presented under Issue 2.

10. <u>ISSUE 6</u> <u>INCENTIVES AND DECOUPLING MECHANISMS</u>

10.0.1 Utility earnings are linked to throughput, i.e. deliveries of natural gas. Under current regulatory regimes, a utility's ability to earn above its authorized rate of return is, to the largest extent, dependent on two factors: the ability to restrain its costs to below forecast levels; or the ability to sell more of its energy commodity than anticipated. Given the latter linkage, there is a perceived systemic disincentive for a utility to promote energy conservation and thereby voluntarily limit its throughput.

10.0.2 The questions are, therefore, whether counter-balancing incentives or penalties need to be provided to assure that there is sufficient support for conservation efforts from a utility's management and shareholders, and/or whether a utility's profits need to be "decoupled" from its throughput before DSM can be effectively pursued.

10.0.3 This issue was included in the Demand-Side Issues List as:

> ***Should the utilities receive incentives to undertake DSM programs? If yes, what incentives should there be (i.e. shared savings, compensation for "lost revenues", or an accounting mechanism to unlink gas sales from profits)? Should the utility be rewarded for achieving DSM targets? Penalized for shortfalls?***

10.0.4 The parties subsequently divided this issue into two sub-issues: whether the utilities should receive incentives to undertake DSM programs; and whether the link between the utilities' throughput volumes and revenues should be decoupled. The need for penalties was included in the analysis of incentives.

10.1 INCENTIVES

10.1.1 Board Staff, CAESCO, Centra, the City of Kitchener, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe, the City of Toronto and Union agreed to the following Consensus Statement, which endorses the use of incentives.

Consensus Statement (Part 1)

1) *Incentives should be made available to the utilities to undertake DSM programs.*

2) *In principle, incentives which are meaningful to the utilities' shareholders and management will serve to encourage the utilities to aggressively undertake DSM programs and to deliver those programs in a cost-effective manner.*

3) *A number of incentive mechanisms are available. The shared savings mechanism is the preferred approach to incentives. However, any appropriately structured mechanism should have as its objective a defined financial reward for a utility whose DSM actions successfully produce net societal benefits in the most efficient manner.*

4) *Based on an assessment of its individual circumstances, in view of the above principle, each utility should have the option of proposing an incentive mechanism which supports its DSM activities. The proposal should be brought forward in the context of a utility rate case.*

5) *At the time a utility brings forward a proposed incentive mechanism for approval, the utility should address the issue of penalties associated with DSM activities.*

Positions of the Parties

10.1.2 Board Staff submitted that incentives are required to encourage the use of DSM programs in place of supply-side options which generate revenue and a return on rate base. Board Staff contended that incentives should be based on actual savings, rather than on the level of DSM expenditure, and that penalties should be used as a disincentive to poor performance or inactivity. According to Board Staff, a shared savings approach would reduce the risk associated with DSM programs.

10.1.3 In response to Consumers Gas' position that equity returns, not incentives, would provide the most appropriate shareholder reward, Board Staff submitted that any recognition of DSM risk should be addressed in the deferral accounts or by way of shareholder incentives.

10.1.4 CAESCO suggested that utilities should assess the benefits and feasibility of financial incentives as a business decision. The utilities should be kept financially whole and not be penalized. However, financial incentives should not discriminate between implementing a program directly through a utility or indirectly, such as when using an ESCO.

10.1.5 Centra submitted that incentives must be significant and obtainable if they are to be effective, and that the introduction of penalties would be counter-productive. Since an application to claim a subsidy will likely require supporting documentation, which can be supplied only by monitoring and evaluation, the utilities may be slow to apply for subsidies.

10.1.6 In its reply argument, Centra emphasized that the creation of a DSM infrastructure would not simply involve a reallocation of existing resources.

Rather, it submitted that there would be a need for additional resources and these would represent a real cost.

10.1.7 CEG argued that incentives are required to ensure that all appropriate DSM programs are developed, not just those that are the most lucrative, easiest, most obvious, or least threatening to the utility or its affiliates. According to CEG, incentives and penalties are necessary to overcome obstacles to conservation (institutional inertia, conflicting interests with gas supply affiliates and market impediments) and to recognize the government's policy on conservation. CEG argued that, although there is a long-run incentive to add rate base either for conservation or supply additions, the current experience is that, in the short run, conservation efforts are discouraged while supply additions are rewarded.

10.1.8 Consumers Gas advocated the use of incentives which would reward the utilities for the successful implementation of DSM. To be effective, an incentive must be meaningful to the utility's managers and shareholders, as well as to the financial institutions, while being fair from a customer's perspective. According to Consumers Gas, an incentive should also be tailored to the specific operating conditions of the utility and be flexible enough to accommodate a range of DSM initiatives. It further argued that a utility should not receive an incentive if its program failed to meet the required performance standards and that, with the possibility of an incentive loss, additional penalties were unnecessary and inappropriate.

10.1.9 In its reply argument, Consumers Gas submitted that a shareholder incentive mechanism could be designed to be equitable and reasonably simple to implement and administer. It argued further that using approved estimates of savings on a per-unit installed basis would expedite the implementation of cost-effective DSM.

10.1.10 Energy Probe submitted that DSM programs should not receive a higher regulated rate of return than investments in supply services. Energy Probe added, however, that subsidized DSM could be used to reduce throughput to a particular customer or class of customers if the marginal price paid by those customers is lower than the marginal cost of supplying them.

10.1.11 In response to the City of Kitchener's statement that regulated utilities have a strong incentive to expand investments in DSM, Energy Probe pointed out that this applies to all utility investment.

10.1.12 The City of Kitchener, while indicating support for the Consensus Statement, nonetheless recommended that proposals for shared savings or other mechanisms that tie penalties and rewards to a DSM program's success be rejected. It took the position that, in fact, the nature of regulation works against the use of a shared savings mechanism. Since measures of program success may not be known for a number of years, the City of Kitchener contended that rewards or penalties would discourage worthwhile investments, or the premature discontinuation of questionable programs. In its opinion, the most effective way to induce DSM investments is to restrict the current level of capital spending on supply-side measures.

10.1.13 The City of Kitchener, however, added that incentives which do not involve revenue compensation, such as deferral accounts or multi-year expenditure commitments, should be allowed in order to reduce the utility risk of not earning its allowed rate of return.

10.1.14 OMAA submitted that the evidence provides more than ample support for incentives, such as the shared savings mechanism. OMAA also stated its belief that a strong incentive structure was required to ensure a rapid evolution from the status quo to a broader spectrum of DSM programs.

10.1.15 Pollution Probe supported the use of a shared savings incentive in the event that the Board did not approve decoupling. However, it pointed out that, in the absence of decoupling, such a mechanism only acts as a contradictory incentive to the coupling of profit and throughput.

10.1.16 Union submitted that, to eliminate any potential disincentives to demand-side programs and ensure equal treatment for demand-side and supply-side options, the utilities would require confirmation that prudently incurred DSM costs could be recorded in a deferral account and recovered in rates. Union noted that bonus mechanisms would be problematic and could result in significant administrative and regulatory burdens. Also, if a utility were permitted to earn its allowed rate of return on DSM, no further bonuses would be necessary at this time.

10.1.17 In reply, Union identified three categories of incentives which currently exist and apply equally to demand-side and supply-side options. These were the opportunity to earn a return commensurate with risk; the desire to minimize costs to remain competitive; and the incentive to minimize the risk of regulatory oversight and scrutiny.

10.1.18 Union further argued that utility management would not consider investments in DSM in general to be less profitable than other investments. In Union's opinion, management would simply consider whether the expected return would be comparable at the time it makes the investment.

10.1.19 In reply, Union countered the argument that unplanned DSM during the rate year may result in a penalty. It contended that substantial variation was not likely within a one-year period, and that if unplanned DSM did occur, it could generate offsetting revenue. Union also pointed out that customer contributions to a successful program could offset any reduction in throughput.

10.1.20 In response to the concern that the utilities might manipulate program performance to maximize profits, Union submitted that such actions would be apparent to the Board and that the utility would be subject to the normal regulatory scrutiny. Union concluded that unplanned opportunities would not be frequent or significant and that it did not anticipate the need to seek recovery for lost revenues on a regular basis.

10.1.21 In response to CEG's assertion that Union was not committed to DSM, Union submitted that the evidence of its participation in DSM development and programs clearly supports the opposite conclusion.

10.1.22 On the issue of affiliate transactions, Pollution Probe described the disincentive that purchases of natural gas by an LDC from an affiliate could have on the aggressive pursuit of energy conservation. Energy conservation would result in a reduction in natural gas purchases from the affiliate, and everything else being equal, the profits to the affiliate, and the corporate organization as a whole, would fall.

10.1.23 Accordingly, Pollution Probe recommended that new affiliate gas supply transactions should be banned in order to ensure that the aggressive pursuit of energy conservation will not be contrary to the financial self-interest of the shareholders of the utilities. Alternatively, it recommended that all new affiliate gas supply transactions should have a "no displacement" clause (i.e. volumes would not be subject to displacement if the utility's requirements are diminished).

10.1.24 Board Staff and the three utilities rejected Pollution Probe's proposed remedies as unwarranted at this time. They noted that the Board and interested parties will have ample opportunity to review affiliate transactions during the public hearing process.

10.2 DECOUPLING

10.2.1 The parties were not in agreement on the issue of decoupling.

10.2.2 Board Staff, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe and the City of Toronto agreed to the following Consensus Statement on decoupling.

Consensus Statement (Part 2a)

1) Decoupling of profits and throughput volumes should be introduced to remove the existing disincentive to aggressive pursuit and implementation of cost-effective conservation DSM programs.

2) Decoupling mechanisms should recognize, and be tailored to, individual utility operating conditions, markets, and other circumstances. Individual utilities should propose specifics of a decoupling mechanism best suited to their respective circumstances. The proposal should be brought forward in the context of a rate case.

10.2.3 Centra and Union opposed the immediate introduction of decoupling and their Consensus Statement is shown below.

Consensus Statement (Part 2b)

1) Decoupling is not considered necessary at this time to eliminate financial disincentives or attitudinal barriers to the aggressive pursuit of new DSM programs.

2) Disincentives to the aggressive pursuit of new DSM programs can and should be removed through other measures which recognize the utilities business, financial and other risks associated with new DSM efforts and which ensure a fair return for DSM investments.

3) *The greater risks associated with forecasting the impacts of new DSM programs (i.e. program costs, customer participation, program impacts) and the concern of others that DSM effort will be deliberately limited for financial gain, can be addressed through the existing regulatory process and the implementation of a deferral account mechanism. Incentives to reward new DSM initiatives are also possible.*

4) *If in the future the lack of decoupling is considered to be a disincentive by the utility, and the consequences of decoupling are further understood, each utility should be expected to propose a decoupling scheme which suits its own circumstances.*

Positions of the Parties

10.2.4 Board Staff submitted that the current ratemaking process encourages a utility to sell more gas than forecast, and that decoupling would make the utility indifferent to the level of throughput. According to Board Staff, decoupling would benefit the ratepayer as well as the shareholder and permit demand-side options to compete fairly with supply-side options. Also, larger incentives would be required to encourage conservation if decoupling were not implemented.

10.2.5 Board Staff, therefore, argued that decoupling should be mandatory for all three gas utilities in Ontario or, alternatively, that decoupling should be implemented by Consumers Gas on a trial basis. In the presence of frequent rates reviews, Board Staff concluded that decoupling was not a necessary prerequisite for a successful DSM program. However, Board Staff added that decoupling was necessary if the Board wanted to encourage aggressive DSM development. As an alternative to decoupling, Board Staff suggested that a lost revenue adjustment mechanism ("LRAM") might be used to protect the utility against lost revenues associated with conservation.

10.2.6 However, Board Staff contended that the use of LRAMs, as employed in some U.S. jurisdictions, would still not eliminate the throughput incentive and would permit a utility to recover additional revenue from ratepayers, even when the utility was earning more than its allowed rate of return. Since decoupling would reduce revenue volatility and shift economic and weather risks to the ratepayer, Board Staff suggested that a utility's return on equity might need to be reduced.

10.2.7 CAESCO submitted that a decoupling mechanism would shift economic and weather risks from the utility to the ratepayer. CAESCO also argued that decoupling was relatively new and unproven, and that the rationale for decoupling in the electricity industry was not relevant to the gas industry.

10.2.8 CEG advocated full decoupling for all three utilities to eliminate the current disincentive against conservation. In reply to utility submissions that decoupling would have an adverse impact on load building and rate stability, CEG contended that the potential for this negative impact could be easily mitigated and that decoupling would eliminate the perverse impacts of weather and economic cycles on utility management.

10.2.9 CAC(O) agreed that decoupling should be employed in certain circumstances to promote IRP objectives, but it argued that decoupling should not outweigh the broader IRP issues. Accordingly, CAC(O) suggested that the Board should issue guidelines permitting the LDCs to voluntarily decouple if it can be established that doing so would promote the attainment of the goals of IRP in general, and the aggressive promotion of DSM in particular.

10.2.10 Centra contended that decoupling would impose significant changes on the method of regulation in Ontario and could cause more problems than it would solve. Centra concluded that the amount of experience with decoupling was not sufficient to determine that decoupling is appropriate in the current regulatory environment. Centra submitted that the U.S.

experience with decoupling was not useful since it is based on observations which are primarily limited to electric utilities.

10.2.11 According to Centra, the perceived disincentive for a utility to pursue conservation in the period between rates cases is insignificant given the frequency of rate reviews in Ontario. In contrast, decoupling could discourage beneficial gas sales, distort utility decision-making and create perverse incentives which would lead to adverse rate impacts, improper price signals and increased regulatory complexity.

10.2.12 In response to Pollution Probe's contention that decoupling reduces risk, Centra submitted that much of the evidence indicates that the introduction of decoupling could increase total risk to the utility, as it had in many U.S. jurisdictions.

10.2.13 Centra agreed with Union's assertion that the absence of decoupling will not interfere with the aggressive pursuit of cost-effective DSM measures. It also pointed out that CEG's witnesses had originally advanced the notion that full decoupling should be delayed to a later stage in the DSM implementation process.

10.2.14 Centra also agreed with CAC(O) that decoupling was not required in the initial stages of DSM development when one-year rates cases are the norm.

10.2.15 Centra disagreed with Pollution Probe's proposition that under decoupling rate impacts would not likely cause an undue burden on ratepayers and claimed that this was contrary to the evidence.

10.2.16 Centra concluded that decoupling is not required at this time and that, if such a need arises in the future, the utilities will likely be the first to recognize it.

10.2.17 Consumers Gas indicated that, in the course of the proceeding, its position evolved to support for "partial decoupling", i.e. a symmetrical revenue adjustment mechanism, as a response to the disincentive issue. In its view, partial decoupling would avoid the potential negative consequences of full decoupling and ensure that both the ratepayer and shareholder were equally protected against unexpected DSM consequences. Partial decoupling, to some extent, also would address the concerns of those who believe that a utility will not undertake conservation DSM if the existing link between profits and throughput volumes is maintained. In addition, partial decoupling would be consistent with the evolutionary development of DSM, which was endorsed by most participants in the proceedings.

10.2.18 Consumers Gas further submitted that some of the experience in the U.S. supports the idea that partial decoupling may be a more appropriate mechanism. It concluded that partial decoupling would remove the disincentive to pursue socially desirable additional sales, reduce a utility's deferral account balances, address rate variability concerns, reduce utility risk and eliminate concerns regarding changes to the return on equity.

10.2.19 In its reply, Consumers Gas urged the Board to reject the suggestion by Board Staff that decoupling be imposed on Consumers Gas.

10.2.20 Energy Probe submitted that the Board should reject the suggestion that increased conservation requires decoupling and recommended that the benefits of decoupling should be achieved through the further unbundling of gas services and rates.

10.2.21 The City of Kitchener contended that decoupling represents a fundamental regulatory change and that the evidence was not sufficient to force decoupling on a utility. Accordingly, it submitted that the Board should be willing to accept a decoupling proposal, but should not mandate one.

10.2.22 OMAA suggested that the best approach would be to implement decoupling for all three utilities, or, alternatively, to allow one utility to decouple as an experiment.

10.2.23 Pollution Probe argued that, under the current form of regulation, a utility would be financially penalized if it promoted conservation, which is inconsistent with Government of Ontario policy, and contrary to the ratemaking principle that regulation should not penalize utilities for acting in the public interest. To resolve these problems, Pollution Probe recommended that decoupling should replace the current practice of tying profits to throughput volumes.

10.2.24 Pollution Probe argued further that penalizing a utility for promoting conservation is irrational if DSM options are expected to receive the same consideration as supply-side options. Since "status quo rules" motivate utilities to sell more gas, the first step towards improving the regulatory process is to decouple revenues and profits from gas sales volumes.

10.2.25 Pollution Probe disagreed with Centra's assertion that decoupling would lead to excessive rate variability for its large volume industrial customers. Pollution Probe submitted that had decoupling been used, Centra's deferral account balance would have been considerably lower. It was Pollution Probe's submission that Ontario's gas utilities would continue to aggressively promote fuel switching to natural gas if the Board allows decoupling. Pollution Probe also submitted that an LRAM is not superior to decoupling because it cannot completely remove the financial penalty for promoting conservation, and it would unnecessarily increase conservation and regulatory costs.

10.2.26 According to Pollution Probe, if the link between profits and sales volumes were to be severed, the costs of implementing conservation would be reduced. Decoupling would also lower the utility's rate of return, since its business risks would be reduced. Regulatory costs would also drop as a result of the elimination of the need for complex regulatory procedures.

10.2.27 Pollution Probe was not persuaded by the arguments of the three gas utilities that an LRAM was superior to decoupling for four reasons: coupling is a significant disincentive; an LRAM cannot completely remove the financial penalty for promoting conservation; an LRAM would increase the utilities cost of selecting conservation; and it would increase regulatory costs. With regard to the frequency of rates cases, Pollution Probe postulated that annual reviews were unlikely in the future due to the expectation of low inflation rates and the increased desire to reduce regulatory costs.

10.2.28 Union argued that the adverse impacts of decoupling were out of all proportion to any potential lost revenue problem. It maintained that frequent rate reviews of DSM forecasts and alternative accounting methods, such as LRAM, would mitigate any concerns regarding lost revenues between rates cases.

10.2.29 Union argued that decoupling would eliminate an incentive to promote the socially beneficial use of gas and that, in addition to the problems identified by Centra, it would negatively affect competitive gas markets. Union also objected to suggestions that support for decoupling was tantamount to a commitment to conservation. Virtually all gas utilities and most electric utilities that have pursued DSM are doing so without decoupling. Union did not consider that it has, to date, been financially penalized or discouraged from promoting conservation and efficiency due to the absence of decoupling.

10.2.30 Union contended that revenue losses due to unexpected DSM conservation would not be a major concern at this time, given that the promotion of energy conservation and efficiency involves the increased use of gas for new appliances or applications. In addition, Union agreed with Centra that it was highly unlikely that a significant unexpected DSM success would occur between rates cases on a regular basis.

10.2.31 In response to CEG, Union submitted that regulators who instituted decoupling where service quality standards were not in place did so to improve service quality, not to address the conservation disincentive.

10.3 BOARD FINDINGS

10.3.1 The Board notes the emphasis that a number of parties placed on "the perceived disincentive for utilities to aggressively pursue energy conservation". But, the Board also observes that the Ontario gas utilities have to date performed reasonably well in promoting energy efficiency without incentives or other measures to specifically remove the "perceived disincentive". The Board accepts the reasoning that underpins the theoretical perception of a disincentive. However, the Board also observes that the evidence indicates that the disincentive does not appear to be dissuading the utilities from promoting demand-side measures at this time. Having made this observation, the Board, nonetheless, is aware of the need to be vigilant to assure that shareholder interests do not constrain the pace at which DSM programs are identified and implemented in the future.

10.3.2 The Board realizes that, since the Ontario gas utilities are privately owned, it is not reasonable to expect that they should be driven by altruism. In fact, the opportunity for the utility shareholder to earn a reasonable return is essential to the health of the natural gas distribution system in Ontario.

10.3.3 The Board has already allowed that longer-term DSM investments should be included in rate base and thereby earn a return. The Board has also endorsed the use of balancing accounts to shield the shareholder from excessive risks due to uncertain forecasts of DSM costs in the initial years of a utility's DSM plan.

10.3.4 The question remains, however, whether the utilities will meet the Board's expectations and demonstrate at rates cases that their DSM plans are based on aggressive objectives and are being achieved through effective program design, implementation and monitoring.

10.3.5 The Board notes that, although the three major gas utilities were parties to the Consensus Statement on incentives, they were not unanimous in their assessments of the need for incentives and penalties. The Board has concluded that, at this time, it would be inappropriate to require incentive mechanisms or penalties as components of the regulatory regimen for DSM. To offer incentives when they are not requested would impose a needless expense on the ratepayer.

10.3.6 However, if the matter of shareholder incentives is to be pursued, the Board expects that it would be brought forward in the context of a rates case and that this would require a concurrent assessment of the need for penalties.

10.3.7 Should it be established that shareholder incentives are required in order for a utility to commit to an aggressive DSM effort, or to seize an immediate opportunity, the Board would favour the shared savings mechanism endorsed in the Consensus Statement on incentives. Under such an arrangement the Board believes that the shareholders' portion of the DSM program's savings should vary according to the nature or urgency of the program, the market being targeted and the degree of difficulty of implementation. When shared savings are offered, the level of sharing, as well as the method and timing of the determination of the actual savings achieved, should all be established at the time the DSM program is proposed. When it is difficult to segregate the results of the individual programs, sharing on a portfolio basis may be considered. In such an event, the utility's awarded share should be commensurate with the diversified risk of the portfolio.

10.3.8 With regard to the matter of affiliate gas supply transactions, the Board is of the view that, while Pollution Probe claimed a disincentive may exist in theory, there is no evidence that it exists in fact and that it is of sufficient magnitude to justify the proposed remedies. The Board notes that a utility's relations with its affiliates will continue to be scrutinized in the rates cases. Furthermore, the evidence showed that the utilities employ a public tendering process when acquiring new or replacement gas supplies. Having carefully considered the perceived disincentive to conservation that may arise as a result of affiliate transactions, the Board does not expect to revisit this issue unless or until there is a marked change in circumstances, or significant new evidence is brought forward.

10.3.9 On the issue of decoupling, the Board notes that by the conclusion of the hearing, Consumers Gas modified its position to endorse "partial decoupling", i.e. a revenue adjustment mechanism, and supported the consistent treatment of all the major Ontario gas utilities. The Board is of the view that it will be more equitable and less confusing to have a consistent policy across the province.

10.3.10 The Board further notes that the need for decoupling is most pertinent in situations where there are extended periods between rates case reviews. The Board also notes that experiences to-date have varied among the jurisdictions where such programs have been installed. The debate appears to be continuing as to the need for decoupling and which form of decoupling, if any, provides the most appropriate approach.

10.3.11 The Board accepts the evidence that there is only a remote potential for unexpected DSM activity of significance beyond that covered by deferral accounts in the interim between rates cases. Given this, together with the frequency of rates cases in Ontario and the complexities involved in decoupling, the Board is not convinced that full decoupling is warranted at this time.

10.3.12 The Board is of the view that, with the measures which have been accepted herein, the utilities will likely be sufficiently protected to allow them to fulfil their responsibilities to the shareholders, while still being encouraged to proceed with aggressive DSM plans. However, if a utility's lack of revenue protection is shown to be a significant disincentive, the Board is prepared to consider the use of a revenue adjustment mechanism as differentiated from decoupling. In the Board's view, a revenue adjustment mechanism is more consistent with the current regulatory framework in Ontario. As part of any such proposal, the Board will require the utility to fully describe the revenue adjustment methodology and the impact the revenue recovery program would have on the utility's risk exposure and earnings.

10.3.13 As all the stakeholders gain experience with the development, implementation and regulation of DSM efforts, the issue of requiring a revenue adjustment or decoupling mechanism may need to be revisited. The Board expects that if such a need arises it will be brought forward in the context of a utility's rates case.

11. ISSUE 7 MONITORING AND EVALUATION

11.0.1 Market research, monitoring and evaluation are crucial to the management of DSM, most particularly at the early stages when so much is still unknown about factors such as program potential, participation levels and load impacts.

11.0.2 This issue was included in the Demand-Side Issues List as:

> ***How should the utilities define and measure the technical and achievable potential of DSM programs? How should these assessments be incorporated into the forecast demand? How should DSM programs be monitored and analyzed after implementation?***

11.0.3 Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, the City of Kitchener, OMAA and Pollution Probe agreed to the following Consensus Statement. The City of Toronto agreed with paragraphs 2, 3, 6 and 8 in the Consensus Statement and took no position on the other paragraphs.

Consensus Statement

1. *The definitions of "technical potential" and "achievable potential", which appear at page 103 of the Board's Discussion Paper of September 16, 1991, should be adopted.*

2. *The utilities should attempt to consider as many DSM programs as possible (i.e. identify as much technical potential as possible). The extent of this identification process will be subject to the resources of the utility and the cost/benefit of such an effort. However, the utilities should work collaboratively with each other as well as seeking input from other sources wherever possible.*

3. *The potential programs which are identified should be screened using the appropriate cost-effectiveness tests.*

4. *Free-ridership must be addressed where it is believed to be an issue, and the pre-implementation analysis of a DSM program must account for the existence of free-riders in the context of the design and cost/benefit analysis of the program.*

5. *The utilities should develop estimates of the achievable potential for programs which are determined to be cost-effective. The estimates of achievable potential should be based on the best available information, which may be drawn from other programs undertaken by the same utility, similar programs undertaken by other utilities, and test marketing or pilot programs. The utility may determine that an analysis of the achievable potential is not appropriate for some cost effective programs. In those exceptional cases, the utility will provide the rationale it used to make this determination.*

6. *The utilities should attempt to maximize the achievable potential through program design and implementation, which will involve*

identifying and addressing market barriers. This can be enhanced through collaborative program development and effective monitoring and evaluation.

7. *End-use forecasts are necessary and beneficial, however, their development will take time due to the amount of data required. In the meantime, the utilities should incorporate program specific demand impacts into the existing forecasting methodologies. The utilities should present a discussion on expected activities which are likely to be required to affect end-use forecasting at the first rate case which includes DSM programs. This information should include the cost, data requirements, and time requirements for the proposed levels of end-use forecasting.*

8. *Monitoring and evaluation of DSM programs is necessary to examine the ongoing cost-effectiveness of the programs; to measure the impact on demand; and to determine whether changes to program design are necessary.*

9. *Monitoring and evaluation mechanisms may include one or more of the following: pilot programs, impact evaluation, process evaluation, end-use metering or any other valid monitoring and evaluation techniques. The development of an appropriate monitoring and evaluation plan will balance cost with the need for accuracy, and should be established at the time of program design.*

Positions of the Parties

11.0.4 Board Staff's view was that market barriers, and particularly lost opportunity situations, should be a priority when defining DSM programs. There is a trade-off between identifying DSM potential and keeping costs to a reasonable level. Board Staff cautioned that estimates of the achievable potential and the cost-effectiveness of most programs depend on the assumptions underlying forecasts of participation. Therefore, some sensitivity analysis should be performed. Identifying technical potential was felt to be of limited practicality.

11.0.5 Board Staff argued that Union's proposed method of identifying DSM potential, by addressing only known market barriers, carries a high risk of missing less obvious but still socially beneficial DSM opportunities. Board Staff expressed its belief that Union will not implement DSM beyond its current level.

11.0.6 Board Staff submitted that the Board, as part of its Report, should emphasize the need for the utilities to estimate the market response to their new DSM programs before they are fully implemented. This is especially important for programs which will be in direct competition with commercial suppliers. It was Board Staff's view that increasing a program's costs by raising the incentive level will not necessarily be offset by an equal or greater increase in benefits. Free ridership will not be a serious problem provided that a reasonable attempt is made to account for the effect of free riders when assessing program costs and benefits.

11.0.7 Board Staff also submitted that monitoring and evaluation are required to determine the success or failure of DSM programs. There is a serious risk that inadequate evaluation may allow costly DSM programs to remain in place. Board Staff advised the Board to direct the utilities to describe the monitoring and evaluation mechanisms they intend to employ in order that they can be scrutinized in subsequent rates cases. Specific filing protocols should include DSM program avoided cost analysis, demand forecast impacts and the actual impacts of existing programs on an individual program basis. Board Staff recommended that the utilities determine expected DSM savings under three scenarios (low, medium and high savings) and describe the corresponding impact on supply-side plans.

11.0.8 CAESCO pointed out that estimating the potential for load savings through energy efficiency in the commercial, institutional, and industrial sectors is different from determining the potential for DSM in the residential and small commercial sectors. ESCOs can help ensure that the introduction of new DSM measures are well-planned and coordinated.

11.0.9 CAESCO submitted that the expected load impacts of the DSM options should be incorporated into the utility's demand forecast for the test year, since demand-side measures can be used to meet a utility's forecast demand, particularly in areas where ESCOs are active. In its view, estimating the potential for load savings through energy efficiency in the commercial, institutional and industrial sectors should use an entirely different approach than that used in determining the potential for measures among residential and small commercial customers.

11.0.10 CEG submitted that the utility's filing should describe customer incentives, assumed market penetration, the impact of increased or decreased incentives on penetration and the results of various cost-effectiveness tests. It noted that Union's current approach is to analyze DSM potential only after cost-effectiveness testing and program design. In CEG's view, this approach will not allow the Board or intervenors to evaluate the degree to which the utility's programs are capturing all cost-effective DSM.

11.0.11 Consumers Gas suggested that, for programs which are determined to be cost-effective, utilities should develop estimates of achievable potential using test marketing, focus groups and similar programs conducted by the utility or by others. The best available point estimates of the volumetric impacts of DSM programs should be incorporated into the demand forecast in order to arrive at a "net" volumetric forecast.

11.0.12 Consumers Gas submitted that applying excessive resources to the monitoring function will impair program cost-effectiveness and inhibit the achievement of real results. As experience is gained, design, implementation, monitoring, and evaluation activities can be refined.

11.0.13 Energy Probe argued that the market for natural gas in Ontario (although imperfect) is functioning reasonably well. This market is not subject to market failures that can be overcome with the expertise, credibility, financing or good program design that is available to the LDCs; rather, the "flaw" is that many gas customers can only be induced to buy DSM products and services at below-market prices.

11.0.14 Energy Probe submitted that, in the absence of ratepayer subsidies for DSM programs, there is little need for elaborate follow-up monitoring or analysis. On the other hand, when subsidized DSM programs are involved, it was Energy Probe's belief that there will be many important and difficult questions that will have to be resolved.

11.0.15 The City of Kitchener recommended that the Board require the utilities to formalize a process for the sharing of research and development activities required to obtain the identification of the best possible portfolios. The utilities should also be required to report the results of this work to the Board at rates hearings.

11.0.16 OMAA took the position that it will be exceedingly difficult to realize estimates of achievable potential in the absence of preceding studies of technical potential. It submitted that Union's approach will lead to a scattershot approach which is likely to neglect certain market segments and opportunities.

11.0.17 Union submitted, that since DSM depends upon consumer acceptance, it is more important to focus on examining achievable potential, through consultation, information from other utilities and market research, rather than to conduct studies of technical potential in a vacuum. It adopted the evidence of CEG's witness, Mr. Edgar, that "the best way to learn about achievable potential is basically to develop things in the market and see how they work".

11.0.18 Union also noted that it had previously attempted to develop end-use forecasting models. However, after considerable time and effort, it concluded that such models will not be reliable or practical forecasting tools until there is considerably more detailed and reliable end-use customer and economic data.

11.1 BOARD FINDINGS

11.1.1 The Board agrees generally with the Consensus Statement, but prefers the definitions of achievable and technical potential shown in the appended Glossary. The Board concurs that monitoring and evaluation of DSM programs are necessary to examine the on-going cost effectiveness of the programs; to measure the impact on demand; to address free-ridership; and to determine whether changes to program design are necessary.

11.1.2 The Board notes that there was some disagreement among the parties as to the appropriate emphasis that should be placed on monitoring and evaluation. The Board recognizes that the over-allocation of resources to the monitoring and evaluation function, which includes market research and forecasting, could result in less DSM being undertaken. However, the Board is of the view that the initial results of DSM programs may differ from those forecast and that a lack of monitoring and evaluation could result in the continuation of unsuccessful or expensive programs. As well, the opportunity to learn from successful programs may be lost without credible monitoring and evaluation.

11.1.3 The Board recognizes that there are diminishing returns to the monitoring and evaluation function and that there are difficult technical problems associated with this function. There must be a balancing of the precision of monitoring and evaluation against the resources devoted to this function.

11.1.4 Each portfolio will be assessed initially during the rates case review process. The Board is of the view that the inclusion of the following characteristics in a portfolio is desirable:

- a broad range of programs;
- all programs assessed for their cost-effectiveness;
- appropriate emphasis on information and education programs;
- well-designed and cost-effective monitoring and evaluation of the expected costs and results;
- clear objectives for the individual programs and the overall portfolio; and
- market barriers identified and addressed and potential lost opportunities captured.

11.1.5 Various alternative implementation strategies, which include the monitoring and evaluation of individual DSM programs as well as the overall portfolio, should be identified and compared. The selected DSM portfolio, together with the preferred strategy for its implementation, comprise the DSM plan.

11.1.6 Successive DSM plans will consist of the sum of all existing and any new proposed DSM programs. Each plan should be brought forward for consideration at the rates case, where changes in the portfolio and in the underlying assumptions will be identified and tested. In addition to their individual analyses, new programs which are added to the portfolio in a year should be analyzed as a group, to show the overall impact on the portfolio's costs and results, due to the additions.

11.1.7 As well, each utility should submit an overview of its DSM plan, describing the goals of its DSM portfolio and the objectives for resource planning and customer service. This overview should include specific DSM savings objectives by class of customer. This overview should also include a discussion of the alternative implementation strategies considered for the DSM plan.

11.1.8 In order that forecasting accuracy and program performance can be monitored, the Board expects that each utility will prepare and present a "base case" demand forecast. The base case forecast, which is to accompany the filing of a utility's first DSM plan, should include the on-going impacts of any DSM-related program that was initiated prior to fiscal 1995. NGV programs are also to be included in the base case. The major assumptions underlying this forecast should be explained and price expectations should be described. As discussed under Issue 8, the Board also expects the utilities to provide estimates of alternate fuel consumption by interruptible customers.

11.1.9 Forecasts should be provided for each program and for the overall portfolio showing the pessimistic, optimistic and most likely impacts relative to the base case forecast. These analyses are to include assumptions on factors such as:

- demographics;
- technological change;
- trends in appliance or equipment saturation and use;
- target market;
- achievable potential;
- penetration rate;
- free ridership;
- expected life of the technology;
- delivery mechanism;
- human, hardware and financial resource availability;
- price elasticities;
- overlapping or synergistic efficiency impacts; and
- customer receptiveness and behaviourial changes.

11.1.10 The forecast impacts of each program should be displayed on an annual basis for the first five years of the plan, and at five-year increments to the twentieth year, or the life of the program. Reviews of DSM performance versus forecast, both on an individual program and on a portfolio basis, should be part of each utility's rates case. Estimates of technical potential are to be considered in the evaluation of programs for inclusion in the portfolio, but are not goals in themselves.

11.1.11 For each of the pessimistic, optimistic and most likely cases, the utility should provide estimates of the cost of each program in total and on a per unit of capacity and/or energy savings basis. A monitoring program to track the accuracy of the cost and savings estimates should be defined at the time that a program is proposed. The Board encourages the use of pilot programs, inter-utility collaboration and the other monitoring and evaluation techniques described in the Consensus Statement.

11.1.12 The Board is supportive of efforts by the utilities to improve their forecasting capabilities. Therefore, the Board concurs with the Consensus Statement that each utility should present a discussion on end-use models at the rates case when it files its DSM plan. This discussion should address the degree to which end-use forecasting can be made an integral part of its forecasting approach. It should also include the cost, data and time requirements for the implementation of end-use forecasting.

11.1.13 The Board expects that the utilities will consider and identify occasions when the presentation of forecasts and performance reviews are likely to result in any competitive disadvantage, and when such problems are anticipated, how they might be overcome.

12. ISSUE 8 RATE DESIGN AND DSM

12.0.1 Natural gas consumers, like consumers of virtually all products, react to prices. This raises the issue of whether rate structures can be designed explicitly to influence consumption in accordance with the goals of IRP. There is also the question of whether current rate structures provide appropriate price signals.

12.0.2 This issue was included in the Demand-Side Issues List as:

> ***How can rate design alternatives best be used to manage demand (seasonal, interruptible, declining block, etc.)?***

12.0.3 In response to this question, Board Staff, CAESCO, CAC(O), Centra, CEG, Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement. Energy Probe did not support the Consensus Statement.

Consensus Statement

1. *Rate design alternatives can be used to manage demand, and should be approached gradually on a test market basis. Various rate structures and levels can be used to encourage consumers to adopt different demand patterns. Changes to existing rate structures and*

levels must occur slowly so as to better monitor and evaluate results, and to make any necessary adjustments.

2. *Rates should continue to be cost-related. Any changes in rates should maintain accepted rate design principles, such as cost recovery, fairness, rate stability, and rate shock avoidance.*

3. *Competing objectives that may need to be addressed in rate design include:*

   - *remove any disincentives to energy efficiency and conservation;*
   - *promote energy efficiency and conservation through inverted rates or supporting users of efficient technology;*
   - *make rates more reflective of use, and societal and environmental externality costs, by reducing fixed charges and increasing commodity charges (without raising the total revenue recovery);*
   - *minimize cross-subsidization;*
   - *equity among members of individual rate classes;*
   - *any other utility or public interest objective.*

4. *Interruptible rates are useful in managing demand. The consequences of interruption must be taken into consideration, such as the environmental impact of alternate fuel use. This last factor would depend on the magnitude of alternate fuel use.*

5. *There may be potential risk consequences of changes to rate design, which will have to be evaluated at the time the rate design proposal is made.*

Positions of the Parties

12.0.4 Board Staff submitted that the explicit consideration of conservation objectives would be a new objective in rate design. However, caution is required since the redesigning of rates to encourage the conservation of natural gas may have a detrimental effect if users choose other less environmentally acceptable fuels as a result of increased gas prices at the margin.

12.0.5 It further submitted that seasonal rates are likely to encourage customers to make similar decisions as would be encouraged by the overall DSM portfolio. While equal billing may mute the price signal of seasonal rates, in Board Staff's view, this problem can be substantially mitigated by providing more information to customers.

12.0.6 Board Staff concluded that inverted rates are not a practical consideration at this time, due to revenue instability concerns and the lack of customer acceptance. It further submitted that inverted rates would create equity problems. Even in the relatively homogeneous residential sector, large families and customers who may use gas efficiently, but for more applications, might be penalized.

12.0.7 Board Staff submitted that the current use of interruptible rates should not be altered at present to try to further the goals of IRP. Increased interruptions of natural gas might increase the use of less environmentally acceptable fuels, such as heavy fuel oil. It recommended that the Board direct the utilities to track more closely the use of alternative fuels during interruptions, in order to provide information on the environmental impacts of curtailments.

12.0.8 Board Staff also recommended that the Board should direct the utilities to examine their existing rate structures now to see if they can be further enhanced to improve the efficiency of gas use.

12.0.9 Centra rejected Board Staff's submission on the review of existing rate structures as being premature and recommended that more complete reviews be undertaken as and when rate design alternatives are advanced.

12.0.10 Consumers Gas took the position that the issue of DSM-related rate design experiments is not a significant current concern to most of the active parties in the hearing. It submitted that existing rate design alternatives adequately provide for an enhanced and expanded DSM effort and, therefore, there is no need to alter existing rate structures. Consumers Gas further submitted that it would be imprudent to institute novel rate design alternatives before gaining substantially more experience, both directly and through the monitoring of developments in other jurisdictions.

12.0.11 Energy Probe did not support the Consensus Statement. It submitted that the most efficient demand management will result from a rate design that adheres to the principles of unbundling (i.e. disaggregation of services) and cost-based rates. Rate design should not, in Energy Probe's view, be used as a policy tool for achieving gas conservation. However, to the degree possible, rates should reflect the marginal financial cost of gas and gas services.

12.0.12 Energy Probe argued that rate design options such as inverted block rates ignore the real environmental risks that would result if they cause customers to switch away from natural gas to more environmentally harmful fuels. Energy Probe reiterated its view that instituting surcharges on natural gas rates to fund subsidized DSM is a move away from both the proper role of rate design and the Board's recent laudable tendency to remove from regulated control those aspects of a gas utility's business that are not natural monopolies and can be provided by competitive enterprises.

12.0.13 Union submitted that rate design is a relatively weak tool for promoting conservation, and that it is more important and productive to address the market barriers to wise energy use. Union indicated that it considered its existing rate structure for residential consumers to represent an appropriate balance between competing rate design objectives. Union agreed that it was important to provide customers with information concerning their consumption patterns and the attendant cost consequences.

12.1 BOARD FINDINGS

12.1.1 The Board agrees that accepted rate design principles of fairness, stability and cost recovery should be maintained and that rates must continue to be cost-related. The Board endorses the general consensus of the parties on these issues.

12.1.2 The Board also concurs with the comment in the Consensus Statement that the avoidance of rate shock is a principle of rate design. In addition, the Board notes its acceptance of cross-subsidization (Issue 2) as long as it is not undue, either among customers within a rate class or among rate classes.

12.1.3 With regard to inverted rates, the Board notes that, although this issue was not the subject of a specific proposal, the parties were generally in agreement that inverted rates are unfair in that they do not distinguish between efficient consumption of natural gas and low consumption of natural gas. The Board concurs, and considers inverted rates to be impractical unless there is greater homogeneity within the rate classes.

12.1.4 The Board notes that there is no evidence to suggest that, at present, rate structures are acting as a disincentive to the efficient consumption of natural gas. The Board is of the view that a review of rate structures is not required at this time. However, the Board would encourage the explicit consideration of energy efficiency impacts resulting from rates and rate structures in any future review of rate design. Furthermore, this review should be sensitive to how rate structures might enhance energy efficiency. The Board notes that, for example, seasonal or time-of-use rates have been implemented in other jurisdictions in support of DSM initiatives. Rate design and rate structures must not act as a barrier to energy efficiency measures.

12.1.5 The Board notes that it will be necessary to have information on the use of alternative fuels by interruptible customers in order to estimate the environmental impacts of interruptions. Since alternative fuel consumption may change over time, estimates will need to be updated periodically. In its comments on Issue 7, the Board has requested that this information be provided.

12.1.6 The Board is of the view that customers may be able to make better decisions regarding their energy consumption if they are provided with additional information on their energy use. The Board supports the provision of such information. Among the issues to be investigated are how billing information can be augmented by providing details on consumption in a prior period and to what extent bills can be broken down into capacity, customer and commodity charges.

13. ISSUE 9 JURISDICTIONAL CONSIDERATIONS

13.0.1 To proceed with IRP, the Board must determine its jurisdiction relating to the implementation of IRP by the natural gas utilities in Ontario, and whether legislative amendments may be necessary or desirable. This issue also encompassed the question of the Board's jurisdiction concerning funding for the consultative process.

13.0.2 This issue was included in the Demand-Side Issues List as:

> ***If the Board decides that DSM implementation is appropriate, are there any current jurisdictional constraints which need to be addressed in order to fully implement a DSM effort?***

13.0.3 In response to this question, Board Staff, CAESCO, Centra, the City of Kitchener, CEG, Consumers Gas, Pollution Probe and Union agreed to the following Consensus Statement regarding the Board's jurisdiction over gas utility DSM programs.

13.0.4 The Consensus Statement was supported by the analysis and opinion provided by Mr. Ian Blue, Board Staff counsel (contained in the Discussion Paper) and by the analysis and opinion provided by Osler, Hoskin & Harcourt in the Centra submission.

13.0.5 OMAA and CAC(O) did not support the Consensus Statement.

Consensus Statement

1) *The Board has the jurisdiction to approve the test year ratemaking implications of investments and expenditures made by a utility to pursue DSM programs.*

2) *Further, the Board has the jurisdiction to issue guidelines as to how it intends to evaluate DSM programs for ratemaking purposes within the context of a utility rate case. However, these guidelines cannot fetter the Board's jurisdiction to consider any matter before it, including a departure from the guidelines. The Board should be sensitive to the need for consistency, and the Board should also indicate its support for the longer term DSM programs proposed by the utilities in rate cases.*

Positions of the Parties

13.0.6 Board Staff took the position that the two legal opinions that were filed concluded that the Board has the jurisdiction to approve the rate implications of DSM programs and to issue guidelines for the evaluation of such programs. Board Staff observed, however, that there was a lack of unanimity concerning the issue of whether amendments to the Ontario Energy Board Act were required to provide the Board with the jurisdiction to implement a formal IRP process.

13.0.7 With respect to the implementation of IRP over the longer term, Board Staff noted that there are a number of areas which are not well enough defined to permit specific recommendations for amended legislation to be made. These areas include: whether the Board accepts the definition of IRP; the appropriate level of interaction with Ontario Hydro regarding fuel substitution issues; the time frame for an IRP plan; and the process for plan development. Board Staff took the position that, when determining the need for a formal IRP process, the Board will need to evaluate its experience with DSM and determine whether it will be practical, feasible, or necessary to amend the Act in order to achieve the goals of IRP.

13.0.8 Board Staff submitted that it is doubtful whether there is a legal basis for the Board itself to award funding for the consultation process. The existence of a proceeding and the granting of status to an intervenor are prerequisites to an award of funding under the IFP Act. In order to award funding under the IFP Act, the Board would therefore have to find that the consultation process is part of an ongoing IRP proceeding, or that a utility rate case proceeding continued throughout the consultation process. Board Staff recommended that the Board not make such a finding.

13.0.9 Board Staff also submitted that the most practical and legally sound approach would be to allow the utilities to pass through reasonable costs in connection with the consultation process as part of a utility's cost of service. If the Board were to determine that funding is not being appropriately provided by the utilities, it could then invoke the provisions of the IFP Act and assume responsibility for deciding these funding requests.

13.0.10 CAC(O) contended that under the present legislation, the Board does not have the jurisdiction to direct the LDCs to develop integrated resource plans in order to pursue DSM, conservation or load management programs. Nor, in CAC(O)'s view, does the Board have the authority to require either a collaborative working group or a consultative process. CAC(O) also argued that the Board does not have the jurisdiction to approve the cost consequences of some DSM measures or to impose sanctions on the LDCs that refuse to participate.

13.0.11 CAC(O) submitted that proceeding under the current jurisdiction would not achieve the goals of IRP for three reasons: the proposed Board guidelines would not be binding and could be challenged; all DSM measures could be evaluated only in relation to rates; and the maximum societal benefit may not be achieved. CAC(O) contended that a legislated IRP would not be burdensome or complex, and in fact it would simplify rates hearings without adding any more costs than pursuing DSM within the existing legislation.

13.0.12 According to CAC(O), there are several important benefits of a legislated approach to IRP. It would ensure that programs are implemented in a timely and cost-effective manner, which permits conflict resolution, and would provide authority to the regulator to resolve disagreements and ensure that IRP proposals are pursued effectively in the public interest. Legislation would also ensure that there is an opportunity for meaningful public input and that IRP pursuits will not be impeded by jurisdictional arguments. And finally, a legislated approach would reduce the regulatory, business and financial risks of the LDCs.

13.0.13 CAC(O) proposed a detailed legislative framework to address such issues as a definition of IRP, the requirement for consultation in the development of such plans, the use of incentives, the formal evaluation and approval of IRP plans by the Board, and the enforceability of the whole process.

13.0.14 CAC(O) concluded that, pending legislative changes, the Board should issue guidelines on DSM measures that would address the issues of consultation procedures, portfolio preparation, design and evaluation of DSM measures, treatment of DSM costs and intervenor funding and costs.

13.0.15 In reply to CAC(O), Centra observed that the Board already has considerable ability to encourage consultation and that it had not been shown that legislation was necessary to accomplish this goal. Centra also indicated that the pursuit of IRP goals should not be sidetracked by debates about legislative change and the considerable resources that legislative amendments would require. Centra reiterated its position that the best method of funding the consultation process would be for the utilities to voluntarily provide this support.

13.0.16 In its reply, CAC(O) continued to strongly advocate the enactment of legislation to address all aspects of IRP. However, in the interim, it submitted that the LDCs should be required to pursue DSM measures pending the enactment of legislative changes.

13.0.17 CEG submitted that the Board has jurisdiction to implement a DSM effort including decoupling, but it would be desirable to clarify the Board's jurisdiction to offer utility incentives and to adjust a utility's rate of return to foster DSM. The jurisdiction to provide advance funding for a collaborative process prior to a utility's application should be sought, and the ability to convene joint electricity and natural gas hearings should also be made explicit.

13.0.18 In reply to CEG, Centra stated that the legislative changes recommended by CEG should await actual experience, that voluntary funding by the utilities would meet CEG's objectives, and that there is no indication of a disposition on the part of the Ontario government to amend the Act to provide for joint electricity and natural gas hearings.

13.0.19 Centra, in its argument, submitted that to undertake what would inevitably be a time-consuming, complicated and costly process of legislative amendment, would only be justified if there were a specific and necessary objective identified. The history of the Board's exercise of its jurisdiction demonstrates that it has considerable authority to enable the achievement of the DSM objectives that were identified in the hearing.

13.0.20 Consumers Gas contended that the Board has the jurisdiction to approve DSM expenditures and to issue DSM program guidelines for ratemaking purposes. However, Consumers Gas added that the guidelines cannot fetter the Board's jurisdiction to consider any matter before it, including a departure from the guidelines.

13.0.21 In Consumers Gas' opinion, two issues will ultimately require legislative attention. These are: whether DSM assets are considered used or useful in the same way as traditional assets; and whether DSM plans have longer-term stability, if future panels cannot be fettered by previous Board decisions. If DSM investments are open to challenge, the utilities will find it difficult to raise the necessary funds to finance these investments.

13.0.22 Consumers Gas recognized that legislative amendments will require time and, accordingly, it recommended that in the short term the Board should consider DSM proposals under the current legislation. Consumers Gas contended that actual experience with DSM would assist in identifying the necessary amendments. In the long term, however, it submitted that legislative change would be required.

13.0.23 Energy Probe submitted that the Board has sufficient jurisdiction to determine whether DSM activities should be removed from a utility's regulated operations and to insist that utilities should be guided by the principles of user-pay and rate minimization. However, if equal treatment of supply-side and demand-side options is a requirement of the regulatory process, a clear legislative mandate would be required.

13.0.24 With respect to the issue of DSM subsidies being outside the Board's mandate, Energy Probe took the position that the optimization of social welfare was a government function and that the Board should concentrate on consumer protection.

13.0.25 The City of Kitchener recommended that the Board proceed with the introduction of IRP without an alteration of its jurisdiction at this stage. The City of Kitchener also submitted that approvals for long-term DSM programs may be required in rates cases and that the Board should be willing to approve a program for a number of years, unless circumstances arise which warrant a reconsideration of the original approval.

13.0.26 OMAA reiterated its position that legislative change was necessary to ensure that IRP would take place, but indicated that, until the current legislation is revised, all parties should proceed with the IRP process. OMAA pointed out, however, that there are risks in a process that does not have clear legislative authority. For example, parties may not feel that they have adequate input in the planning process and this may lead to the process becoming contentious. If this happens, the Board may be asked to deal with disputes that it does not have authority to resolve.

13.0.27 Union asked the Board to endorse the need for consistency and to express support for longer-term DSM programs. Union stated that it supports amendments to the Act to indicate clearly that DSM deferral accounts, together with the cost of financing those balances, should be recovered in rates. However, Union submitted that, while it supports such changes to the Act, they are not a necessary condition precedent to its pursuit of new DSM programs.

13.0.28 Union submitted that neither need nor justification had been shown for the additional regulatory complexity or the cost that would result from the further formalization of IRP through legislative measures, particularly in view of the LDCs' support for virtually all of the important provisions of the Consensus Statements and for the goals of IRP.

13.1 BOARD FINDINGS

13.1.1 The Board concurs with the Consensus Statement as an accurate and reasonable statement of the Board's current jurisdiction to consider and evaluate DSM programs in rates cases.

13.1.2 The Board, like other administrative tribunals, can exercise only that jurisdiction which has been conferred on it expressly or by necessary implication by statute. There is currently no specific authority in the Ontario Energy Board Act, or any other statute, which would permit the Board to order Ontario LDCs to develop and file integrated resource plans according to criteria established by the Board. IRP, like the deregulation of natural gas markets, was not something that could have been contemplated when the Act was enacted in 1960.

13.1.3 The Board does, however, have the authority under section 19 of the Ontario Energy Board Act to receive evidence as to the prudence of investments and expenditures made by a gas utility in the implementation of DSM programs, and to evaluate those programs as part of an application to approve or fix just and reasonable rates and other charges.

13.1.4 Where DSM is an issue in a rates application, the Board has the jurisdiction to require evidence showing that the utility is prudently carrying out DSM planning and that such planning has regard to the guidelines issued by the Board, including those for consultation.

13.1.5 Further, the Board can issue guidelines as to how it intends to evaluate DSM programs for ratemaking purposes. Such guidelines cannot fetter the discretion of the Board to decide any matter that comes before it based on the facts adduced at the hearing. The Board recognizes, however, that consistency in Board decisions is desirable. The Board will strive to achieve consistency in the application of DSM guidelines without hindering the ability of any individual panel of the Board to reach its conclusions based on the evidence before it.

13.1.6 The Board also recognizes that some DSM planning is by its nature long term and that DSM expenditures and investments may be spread over several years. This gives rise to the possibility that the same DSM program may come before several panels of the Board. While no panel can fetter the discretion of a future panel, the Board supports long-term DSM planning and is confident that prudent long-term investments by gas utilities in DSM programs will be fairly considered and that panels in rates cases will take account of the need for consistency in the treatment of long-term plans.

13.1.7 The Board notes that a number of suggestions for legislative amendments have been made in this proceeding. For example, several parties would like to see the Act define "Integrated Resource Planning" and include provisions giving the Board explicit jurisdiction to order utilities to develop integrated resource plans and to bring these plans before the Board for approval. Other parties were concerned that existing legislation might not give the Board jurisdiction to provide incentives or adjust an LDC's rate of return based on DSM performance. Some concern was also expressed that the collaborative process envisaged in DSM planning might require legislative sanction to ensure compliance.

13.1.8 The Board recognizes that there is a need for certainty and clarity in IRP and that this may ultimately only be achieved by legislative change. At this stage, however, it is the Board's view that it is too early in the development of IRP to recommend such changes. The Board fully expects that, as IRP evolves in Ontario, the need for, nature and extent of appropriate legislative amendments will become clearer. The experience gained in the consideration of DSM planning in rates cases will furnish valuable guidance for any future legislative change.

13.1.9 However, the Board notes that, although it can make recommendations for legislative amendments, it is the Government of Ontario and the Legislative Assembly that will ultimately determine whether changes will be made, and what those changes will be.

13.1.10 It is the Board's view that it would not be wise to wait for legislative change before beginning to implement IRP. As has already been pointed out, the Board has sufficient authority under existing legislation to consider DSM programs in the context of a rates application. It is the Board's opinion that this is a satisfactory basis for beginning the process of implementing IRP.

13.1.11 Several parties raised concerns about the provision of advance funding for consultation with the utilities on DSM planning. The Board notes that the power to award funding under the Intervenor Funding Project Act is predicated on the existence of a proceeding before the Board, and at the time of the consultation process envisaged, there would not yet have been an application by a utility. Hence, the Board would have no jurisdiction under the IFP Act to award advance funding for consultation prior to the filing of an application.

13.1.12 It is the Board's view that the preferred funding mechanism is for the utilities to fund directly the pre-application consultative process, which they have indicated a willingness to do. The Board is confident that panels hearing rates applications will give fair consideration to the inclusion of costs prudently incurred for consultation.

14. ISSUE 10 IMPLEMENTATION OF IRP

14.0.1 In order for effective IRP plans to be developed and implemented, attention needs to be directed to the process that should be employed. When setting the scope for the overall process at the initiation of these proceedings, the Board announced that it would use a "building block" approach whereby the study of DSM planning would be investigated as the first step toward a fully integrated plan. The challenge at this time is to identify the process to be employed when developing demand-side management plans. This procedural question raises issues such as whether DSM planning should be a distinct activity or whether it should be part of the current rate review process.

14.0.2 This issue was included on the Demand-Side Issues List as:

> ***Should the Board proceed with the implementation of IRP and if so, how should it proceed?***

14.0.3 In response to this question, a number of different Consensus Statements were put forward by various groups. These statements were divided into two main parts, and the second of these was divided into three sub-parts.

14.0.4 Board Staff, CAC(O), CAESCO, CEG, Centra, the City of Kitchener, Consumers Gas, Pollution Probe and Union agreed to Consensus Statement (Part 1).

14.0.5 Board Staff, CAESCO, Centra, the City of Kitchener, Consumers Gas and Union agreed to Consensus Statement (Part 2a).

14.0.6 CAC(O), CEG, Pollution Probe and OMAA agreed to Consensus Statement (Part 2b).

14.0.7 Board Staff, CEG, CAC(O), Consumers Gas, OMAA and Pollution Probe agreed to Consensus Statement (Part 2c).

Consensus Statement (Part 1)

The Board should issue a report with DSM recommendations and guidelines upon the completion of this phase of the IRP proceedings.

One of the guidelines would be the expectation that each utility would come forward at its next rates case with DSM programs or plans. The scope of these plans will be dependent upon the time available to each utility.

Further, each utility would undertake meaningful discussion or consultations with representatives of its known interested parties or the representatives of known significantly affected parties in advance of filing a DSM proposal. These discussions are intended to improve program design, increase participation rates and reduce hearing time. These discussions would focus on how the plan should be developed based on the Board's guidelines, and would include such issues as program identification, cost effectiveness analysis, program design, program monitoring and evaluation, and proposed cost recovery.

At a utility specific rate case, the Board could approve the test year impacts of those aspects of the DSM program which it considered to be just and reasonable, with consideration given to the guidelines issued in E.B.O. 169-II. Ongoing cost recovery would be the subject of future rate cases. Pre-approval of the ratemaking impacts of a DSM program or plan beyond the test year is not possible, given the Board's current jurisdiction. Such pre-approval is also not advisable, as there should be ongoing scrutiny of the program's costs and results. This scrutiny will be achieved through the ongoing program monitoring and evaluation.

There may be potential changes in risk (e.g. forecasting, business, regulatory, jurisdictional) arising from the implementation of DSM or IRP, which will have to be evaluated at the time DSM or IRP proposals are made by the utilities.

Consensus Statement (Part 2a)

The Board does not have the jurisdiction to implement a formal IRP process under its current legislation. However, the necessity for a formal process cannot be determined yet. Given the difficulties associated with getting legislative change enacted, the Board should proceed to pursue the goals of IRP and at the same time continue to evaluate whether a more formal process is required.

It cannot be determined now whether further generic hearings on other aspects of IRP will be necessary in order to pursue the goals of IRP. The Board should proceed with issuing guidelines and examining DSM plans in individual utility rate cases, without making a determination in this proceeding as to the need for further generic proceedings.

After the first round of DSM plans is considered, it may become apparent whether further generic investigation into supply side or integration issues is required (e.g. fuel substitution, externalities). The Board should make this determination in consultation with the interested parties.

Consensus Statement (Part 2b)

The Board should pursue legislative change to ensure that it has the legislative authority to enact a full IRP process which would allow for the establishment of rules and regulations for IRP on a multi-year basis.

It is imperative that the Board have the jurisdictional authority at hand to fully implement a comprehensive IRP process. The existence of a clear legislative mandate will in and of itself increase the likelihood that IRP goals will be achieved.

Legislative authority supporting multi-year IRP plans would reduce regulatory risk and reduce the uncertainty of cost recovery for utility DSM expenditures.

Consensus Statement (Part 2c)

The Board should use its current legislative mandate to the fullest extent possible to pursue the goals of IRP.

Decoupling the link between distribution revenues and natural gas throughput volumes and the implementation of a strong DSM incentive structure will reduce the likelihood of needing to apply a formal, prescriptive IRP process to achieve IRP goals.

Positions of the Parties

14.0.8 Board Staff submitted that, with respect to the implementation of short-term DSM programs, the Board should set parameters in its guidelines to ensure broadly-based and meaningful participation by interested parties in the consultation process. The consultation process and results should be documented in a report to be included in the evidence supporting a utility's DSM plan at a rates case.

14.0.9 Board Staff submitted that the Board should indicate that any costs for undertaking consultations would be eligible for inclusion in the utility's cost of service after being subjected to examination in a rates case. The utility should be responsible for the control of these costs. The Board's current Cost Assessment Guidelines represent sensible criteria for the utilities to use when considering funding requests. Any party that is excluded from the consultation process through insufficient funding would still have the option of applying for intervenor funding in a rates case. In Board Staff's view, input from such a party would be one of the factors the Board should consider when determining whether the utility had properly undertaken its consultations.

14.0.10 CEG submitted that this proceeding has not adequately considered the supply-side and avoided cost aspects of IRP. Supply-side aspects will inevitably emerge as issues. By formalizing the full IRP process, the Board can ensure timely public involvement and encourage pre-submission collaboration. This, according to CEG, can minimize regulatory risks, as well as social and customer costs.

14.0.11 CAC(O) stated that for the consultative process to be successful, funding must be provided to the participants. CAC(O) suggested that funding should be provided under the IFP Act and should be recoverable by the LDCs in their rates.

14.0.12 Consumers Gas stated that effective consultation should tend to ensure a more efficient regulatory process with respect to DSM, and a higher prospect of success before the regulator. It recommended a structured consultative process that is practical, rather than one which encompasses extensive formal collaboration on all DSM-related issues.

14.0.13 It was Consumers Gas' view that attaining the benefits of IRP, which are predominantly related to DSM, can be fully accommodated within the context of a rates proceeding, both in the short term and in the long term. A separate IRP hearing would only add to the complexity and the cost since, to some extent, the examination of certain DSM and IRP issues would have to be repeated in a rates case. Separate IRP hearings would also not be conducive to getting on with DSM initiatives in the nearer term.

14.0.14 The City of Kitchener stated that, while the Board can expect the level of DSM investment to be increased in the future, it should be recognized that there are a number of limiting factors. First, there was no suggestion at the hearing that there were types of DSM programs which were being ignored by the utilities. Accordingly, the parties should not be surprised if the portfolios presented at the next rates cases contain programs similar to those which currently exist. Second, the initiative in the gas industry will be limited by the degree of IRP applied to other fuels. If all fuel prices do not reflect the cost of externalities to some degree, then the more harmful environmental fuels will prevail.

14.0.15 The City of Kitchener submitted that the requirement for consultation should not become a formal component of rates case preparation. The initiative and responsibility for developing programs of any kind, including DSM proposals, must reside with the utility's management. Consultation should be seen as part of the ongoing responsibilities of the marketing departments in each utility.

14.0.16 OMAA indicated that rates case hearings would be a limiting forum for the IRP process, since OMAA would be practically and financially unable to participate in each individual rates hearing. Also, it was concerned that insufficient attention will be paid to the IRP process in the midst of the numerous competing priorities in rates case hearings.

14.0.17 OMAA emphasized that its members are likely to be significantly affected by the outcome of this process, and can contribute a unique expertise and perspective to assist in the development of IRP. However, it does not have the resources to ensure that its concerns will be considered. In OMAA's view, its misgivings in this regard were illustrated by the experience to date with the ad hoc externality working group. While OMAA was invited to participate in this group, such participation has been effectively foreclosed by lack of financial resources. Based on its experiences, OMAA was uncertain whether meaningful consultation will actually take place in the development of the IRP process.

14.0.18 OMAA suggested that consultation should occur on three levels. First, the Board and the LDCs should make a special effort to understand OMAA's concerns and orientation, through consultation at the community level. Second, OMAA members who are gas-users should be consulted in the development and implementation of DSM programs, just as other groups of consumers are consulted. Third, the Board should establish a meaningful process for consultation with OMAA's members regarding the identification and valuation of social and environmental externalities.

14.0.19 OMAA argued that, for the IRP process to be effective, sufficient funding must be provided for consultation, as well as for legal and expert support to the affected parties.

14.0.20 In reply to OMAA, Board Staff submitted that meaningful consultation with OMAA's constituency will be very difficult to pursue as OMAA has not yet enumerated its membership. Therefore, in Board Staff's view, OMAA must help the utilities identify and communicate with the affected parties. Board Staff went on to submit that it is important that the Board receive OMAA's input on these matters, although direct consultation with individual Board members may not be appropriate.

14.0.21 Union, consistent with its approach to supply-side programs, proposed that it would provide funding where appropriate to facilitate participation by interested parties in the consultative process relating to DSM, and seek the recovery of costs in future rates cases. Union asked for the Board's endorsement of this approach.

14.0.22 Union suggested that future generic hearings on supply-side integration matters will not be required. It further noted that the major elements of IRP, with respect to the integration of plans, will also be in place through the process of estimating avoided costs and employing those estimates in DSM program evaluations. Union indicated, however, that subsequent workshops might be beneficial.

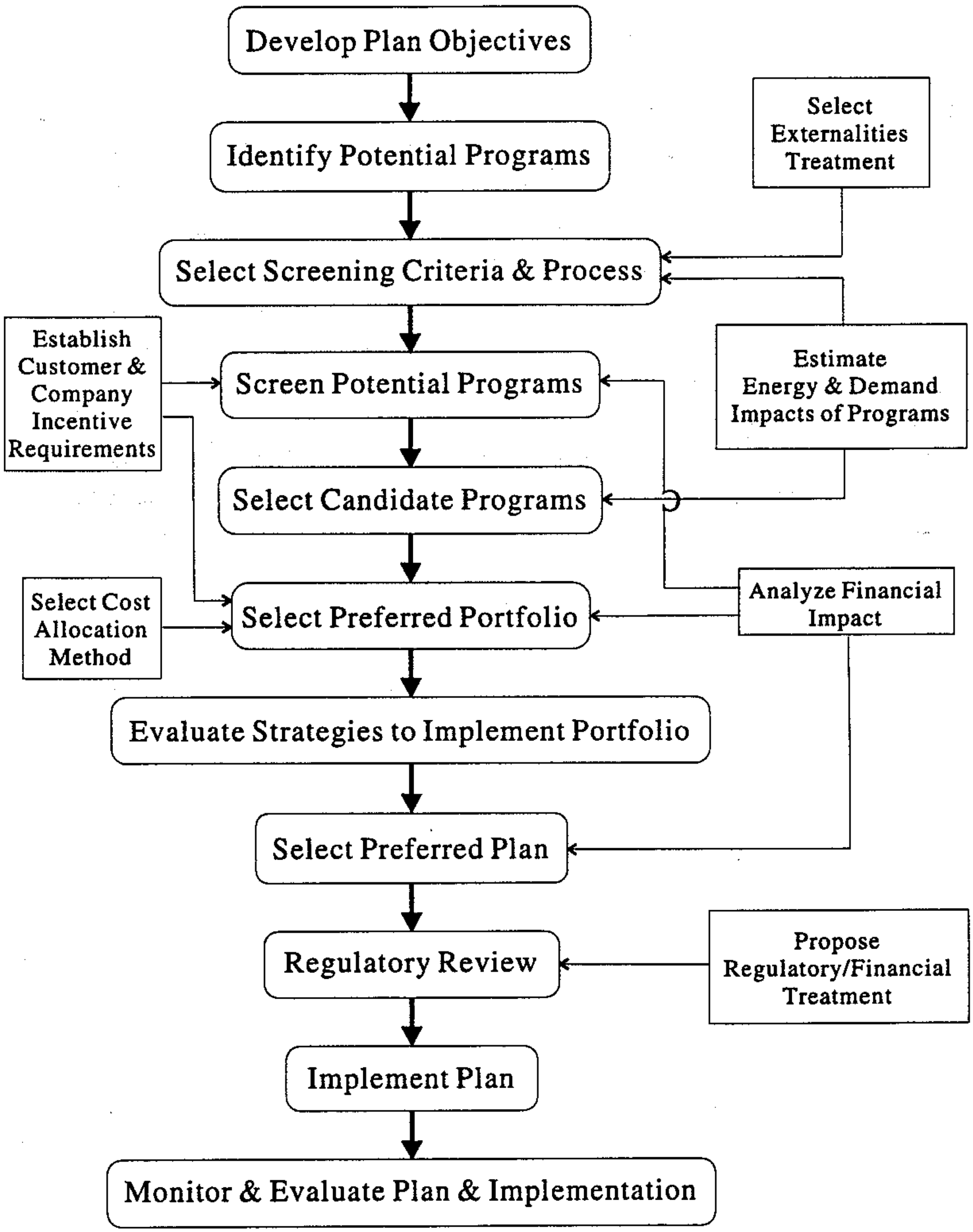
14.1 BOARD FINDINGS

14.1.1 In the preceding chapters of this Report, the Board has set out its views on the key elements of DSM as identified in the Demand-Side Issues List. The Board now expects the utilities to proceed with the development of their individual DSM plans for presentation at rates cases. The Board has set out guidelines for this process in Chapter 15.

14.1.2 In order to assist the utilities in the development of their DSM plans, the Board suggests a planning framework comprised of the major steps that the utilities should carry out. This framework, depicted in Figure 2, presents the planning steps in a linear fashion for illustrative purposes, but the Board recognizes that the process may be non-linear and iterative.

FIGURE 2

Major Steps in the Development of a DSM Plan



14.1.3 Using this framework, a utility should be able to select a preferred portfolio. The selected DSM portfolio, together with a strategy for its implementation, comprises the DSM plan.

14.1.4 The Board expects each utility to file its DSM plan no later than at the time of its fiscal 1995 rates case application. The Board recognizes that, given the timing of its fiscal year, Union, in particular, may find it difficult to comply with this timetable. Any request for extension should be made by a utility as soon as possible after receiving this Report. The utility should offer alternatives that can allow a DSM plan, or components of a full plan, to be implemented in advance of its fiscal 1996 rates case.

14.1.5 With regard to consultation, the Board encourages its use and has endorsed the formation of a joint Collaborative. While there is an urgent need to apply a consultative effort to the measurement and monetization of externalities, as well as the development of qualitative assessment methodologies, the potential advantages of consultation on DSM matters extend beyond that need. The Board expects the utilities to consult with appropriate parties in an effective manner to obtain meaningful input related to each of the major steps of the DSM planning process before irreversible decisions related to them are made. How consultation on the development and implementation of DSM plans, beyond the issues covered by the Collaborative, is to be carried out is left to the utilities to propose and justify. The Board's main concern is that there be meaningful and effective consultation.

14.1.6 With regard to the joint Collaborative, the Board expects that the utilities will move quickly to define what interests should be part of the Collaborative, and who should represent them.

14.1.7 The Board further expects that, once formed, the Collaborative will reach agreement on its terms of reference, timetable, budget, and workplan and that it will be able to submit its report on these matters by September 30, 1993 to the Board and the parties in the E.B.O. 169-III proceeding.

14.1.8 The Board encourages the Collaborative to strive to submit its final report to the Board and the parties by February 28, 1994 in order that the results can be incorporated in the examination of DSM plans for fiscal 1995.

14.1.9 In the event that the above deadlines are found to be unrealistic, the Board expects the utilities to make this known as soon as possible and, when doing so, to define the causes of delay and to jointly commit to a revised timetable.

14.1.10 The Board has considered the suggestion that plans be presented and reviewed at hearings that are specific to IRP or DSM, as opposed to incorporating these matters into rates cases. The Board has concluded that a utility's DSM effort must be viewed not only with regard to the external circumstances at the time, but also in relation to the utility's current operations. In the Board's view, a utility's DSM plan must be dealt with in the context of a rates case to assure that a proper perspective is maintained with regard to related matters such as rate impacts, human and capital resource availability, and working capital demands. Also, the Board does not see the added costs of separate hearings as being in the public interest. The Board also notes that there may be jurisdictional constraints to hearing IRP-related matters outside the context of a rates case.

14.1.11 The Board has also considered OMAA's recommendation that, in addition to the consultation on externalities, meetings be arranged to provide opportunities for the Board to gain insight into the orientation and needs of the Aboriginal community. The Board concurs that it would be valuable for it to increase its understanding of this segment of society. However, it is quite likely that other sectors might validly claim that their perspectives and needs are not fully appreciated. In the Board's view, it would be impractical to attempt to conduct meetings, of the type which OMAA proposes, with each interest group. Further, if the Board were to meet only with OMAA, this might give rise to claims by other parties that OMAA was being afforded unfair access to the decision-maker.

14.1.12 Thus, while it might be productive for OMAA to host occasions for the utilities, Board Staff and other parties to gain a better understanding of OMAA's "special concerns and orientation to gas related issues", it would be inappropriate for Board Members to meet individually with OMAA. The Board also notes that, if OMAA holds such meetings, the question arises as to whether it would be appropriate to require that natural gas ratepayers underwrite the cost, since the advantages to be realized by such meetings would be disproportionately to the benefit of OMAA and its constituents. Thus, the Board suggests that OMAA should investigate alternative ways to fund these meetings.

14.1.13 In conclusion, since the individual utilities will be held accountable for the development and implementation of their DSM plans, the Board feels it is proper to allow them the freedom to pursue these efforts in the manner that they feel is most appropriate. The wisdom, prudence and cost of the course of action they choose will, however, be subjected to future reviews by the interested parties and the Board.

14.2 FUTURE ACTIVITIES

14.2.1 The Board views the initiation of a formal DSM planning process as being only the first of many steps toward a fully integrated resource plan. The Board intended to convey this message when, at the outset of these proceedings, it referred to the study of DSM planning as the first of the "building blocks" of IRP.

14.2.2 Once the initial DSM plans have been filed by the utilities, and there is sufficient experience to assure that DSM planning is on a firm footing, progress toward a full integrated resource plan can continue. The next issue to be addressed is expected to be a review of the utilities' supply-side policies, activities and expenditures to confirm that these are consistent with least-cost planning principles.

14.2.3 A specific review of the methodologies prescribed in the Board's E.B.O. 134 Report will likely be required as part of the review of supply-side issues. Depending on the Board's calendar, this review may be undertaken as a separate generic hearing or as a part of the continuing IRP investigations.

14.2.4 Once both the demand-side and supply-side components of IRP have been investigated, the final phase of these proceedings, i.e. the combination of these elements into a formal integrated resource plan, can commence.

14.2.5 In the interim, and as further experience is gained, the Board recommends that government consider at least the following:

- government regulation to establish targets for allowable CO_2 emissions;

- additional provincial, inter-provincial and federal policies, standards and fiscal measures to further promote and coordinate efforts toward energy efficiency and the protection of the environment;

- legislative action to establish a regulatory mandate to oversee gas IRP and its underlying issues; and

- clarification of the roles of the involved government agencies in order to effectively coordinate IRP in the natural gas, electric power and, if possible, the alternate fuel industries.

14.2.6 It is the Board's hope that through the DSM efforts initiated in this proceeding, and the establishment of a consultative process, common perspectives will emerge to guide governments as they address the need for further action regarding wise energy use and environmental protection. Toward this end, the Board has been encouraged by noting that, notwithstanding the lively debate on a number of the specific issues, there appears to have been unanimity among the participants in this proceeding on the underlying principles and objectives of the demand-side management of natural gas use in Ontario.

15. GUIDELINES

15.0.1 At the conclusion of the Phase III hearing, the Board asked the parties to address an additional issue in their arguments. In order that the Board might have the benefit of the collective wisdom of all the participants when charting the future course of DSM, the Board asked that each party respond to the following question:

> ***If the Board were to decide to call for the development and submission of DSM plans by the utilities, what issues must be addressed by the Board in its E.B.O. 169 Report, and what specific guidelines must be provided?***

Positions of the Parties

15.0.2 All parties endorsed the need for the Board to provide clear guidelines to assist the utilities in the preparation and implementation of their DSM plans. The parties, in response to the above question, generally restated their submissions on the ten issues in the Demand-Side Issues List, which they recommended be incorporated into specific guidelines.

15.0.3 CEG recommended a detailed listing of information requirements to be included in utility filings. In CEG's view, utilities should not simply provide a single preferred plan. Alternatives should be presented in detail.

In particular, utilities should indicate how they intend to capture lost opportunities. They should also describe:

- program alternatives and their costs;
- alternative bundles of measures for each program;
- alternative measure costs;
- customer incentives by measure;
- the assumed penetration rate for each program and measure in each customer niche;
- an evaluation of the impact of increased or decreased incentives on penetration for each measure; and
- the results of various cost-effectiveness tests for each measure, program, portfolio and alternative.

15.0.4 CAC(O) indicated that it supported a similar approach, and OMAA expressed its agreement with CEG's proposed filing requirements.

15.0.5 Consumers Gas and Centra replied that a detailed proposal on filing requirements is premature. Centra further submitted that, in any event, the cost of presenting such an extensive analysis is likely to be prohibitive.

15.0.6 Union submitted that guidelines should be sufficiently flexible to allow each utility to pursue DSM in light of its own particular circumstances. As well, the guidelines should have sufficient flexibility to recognize that DSM should be permitted to evolve on the basis of experience.

15.1 BOARD FINDINGS AND GUIDELINES

15.1.1 The Board expects initial DSM plans to reflect the concerns and views which the Board has identified herein, or in the alternative, to clearly explain why acceptance of any of the Board's recommendations is considered inappropriate.

15.1.2 The Board considers the list of guidelines proposed by CEG to be too detailed and onerous for adoption at this phase of the process, and that the time and expenditure that would be required to respond to CEG's proposals would be excessive.

15.1.3 The following list summarizes the major concerns and views of the Board. It is being provided as a recommended guide for the utilities as they prepare their individual DSM plans, but does not supersede the previous chapters where each issue is discussed in greater detail.

15.1.4 Appropriate Costing Methodology for Demand-Side Options

- The benefits of DSM should be the avoided supply-side costs including capital, operating and energy costs.

- Avoided tolls and demand charges should be included as avoided costs of a DSM program.

- The avoided upstream costs of TCPL and natural gas producers should be identified when they are known, but should not be incorporated.

- Long-run avoided costs over the useful life of a DSM program should be used when defining DSM benefits.

- Emphasis in the analysis should be on the first five years of a DSM program and portfolio when evaluating costs and benefits, as well as their performance versus forecasts.

- A break-even analysis of each DSM program should be provided.

15.1.5 Cost-Effectiveness Tests

- When considering which potential programs should be screened for cost-effectiveness and incorporated in a DSM portfolio, consideration should be given to:

  - achievable potential;
  - the capture of potentially lost opportunities;
  - synergism among programs; and
  - the breadth of the portfolio.

- Once identified, potential programs should be subjected to a screening process which incorporates the following recommendations:

  - The Societal Cost Test should be a first screen (Screen 1) and used as a pass/fail hurdle (i.e. it would be unreasonable to pursue further a program that does not have a net benefit to society).

  - Social costs and benefits should be considered and treated in an equivalent manner to environmental costs and benefits.

  - Only those direct and indirect externality costs and benefits that are significant should be included in the SCT.

  - A qualitative assessment of each DSM program, including all program costs and benefits, should be carried out to produce a non-monetary conclusion on net societal benefit.

  - Programs that pass the SCT should next be subjected to Rate Impact Measure testing (Screen 2).

  - Programs that fail the RIM test may be further considered if the rate impact they would impose is not undue and if second round costs do not exceed the first round net societal benefits (Screen 3).

- The net societal benefit per dollar of subsidy should be provided for each program that fails the RIM test.

- Programs that fail Screen 3 should be further considered as candidate programs if they provide qualitative benefits such as: improved safety and system reliability; avoidance of lost opportunities; recognition of critical or important societal benefits; the need to broaden the DSM portfolio; or support for government policy (Part 1 Screen 4).

- Each program which has passed Screens 2, 3, or 4, Part 1 should be assessed to determine the program's suitability as a candidate for further consideration in comparison to the other surviving programs.

- All programs should be assessed from a pragmatic point of view regarding the likelihood of their acceptance and success.

- Candidate programs should be consolidated into potential portfolios, for evaluation. Each portfolio should be subjected to sensitivity analyses prior to the selection of the ultimate portfolio (Screen 5).

- The screening process and the assumptions used in carrying it out should be clearly documented and presented at the rates case.

• When assessing what constitutes a reasonable rate impact for programs that have failed the RIM test, consideration should be given to questions such as:

- Will the immediate impact on customer bills be excessive?

- Is it likely that customer bills will, in the longer term, be unaffected or reduced even if rates increase?

- Will the impact on certain groups, such as low-income customers, be onerous?

- To what degree will the various stakeholders share in the benefits of a particular DSM program?

- Will the security or the overall cost of operating the utility system create benefits beyond the first round impacts of the DSM program?

- Will the long-term net societal benefits of the DSM program override its immediate rate impacts?

- Are the net societal benefits of such magnitude and importance as to give priority to their attainment?

- Do opportunity costs demand prompt action?

- Will an important DSM program be left undone, or poorly done, if a ratepayer subsidy is not provided?

- Will the inclusion of the DSM program contribute to a broader menu of programs and thereby recognize the needs and perspectives of groups such as low-income customers, Aboriginals and farmers, that might otherwise be precluded from participating?

- Will the inclusion of the DSM program take advantage of synergies among programs?

- The Participant Test should be used as one means of evaluating the appropriateness of a proposed customer contribution.

- A portfolio approach should be employed to allow as many customers as reasonably possible the opportunity to participate and share in the benefits of DSM.

15.1.6 Treatment of Externalities

- The utilities should consider the experiences gained in other jurisdictions, given the scarcity of data on externalities for natural gas DSM in Ontario.

- The significance of an environmental or social externality should be considered qualitatively before deciding whether its effect and impact should be measured.

- Monetization should not be attempted without first measuring the magnitude of the effect of the externality.

- When new studies on externalities and their monetization are required, the utilities should use judgement and recognize the dangers of "paralysis by analysis".

- Externality studies should not unduly usurp resources or delay the timetable for the initiation of DSM programs that can proceed in the absence of such studies.

- When monetizing externalities, avoided costs should be determined by the Cost-of-Control method until the Damage Costing method is further developed.

- The dollar values of monetized externalities should be treated in the same manner as market-determined costs, for planning purposes.

- At least in the near term, sensitivity analyses should be conducted for each monetized externality value.

- The utilities should cooperate when monitoring advances in Damage Costing in other jurisdictions.

15.1.7 Consultation on Externalities

- The utilities should employ a consultative approach toward the identification, measurement and, if possible, monetization of externalities.

- While the utilities are expected to give serious consideration to the views and proposals of the participants in the collaborative process, each utility will remain accountable for its entire DSM plan, including the proposed treatment of externalities.

- The utilities should form a joint Collaborative, which is constituted to:

  - assure that there is representation of the major diverse interests that will be affected;

  - avoid duplicative representation of these interests;

  - be constrained to a manageable number of participants;

- not be bound or limited to the parties in the E.B.O. 169 proceedings;

- provide participant funding in line with the Board's Cost Awards Guidelines;

- consider honoraria to compensate a participant for the value of the time of its employees and officers;

- employ an independent facilitator if this is deemed advisable; and

- utilize the services of experts retained on behalf of the group as a whole, rather than underwriting the costs of a number of experts representing the individual participants.

• The Collaborative should undertake, but not be limited to, the following tasks:

  - establish a self-defined mandate, work plan, budget and timetable;

  - identify the Cost-of-Control values being used in the SCT in other jurisdictions and, if possible, recommend pertinent Cost-of-Control standards for use in Ontario;

  - identify how non-regulated externalities (e.g. CO_2) are being valued in other jurisdictions and recommend how they should be dealt with and, if possible, valued in Ontario;

  - identify pertinent externalities that are not currently included in the SCT in other jurisdictions but which should be considered in Ontario and recommend their treatment and, if possible, their valuation;

- review the qualitative assessment methodologies employed in other jurisdictions and recommend approaches to be used in the DSM planning process in Ontario; and

- identify if and where there is a need to consider the unique characteristics of each utility.

- The Collaborative should, as part of its work plan, provide a preliminary report to the Board, and the parties to the E.B.O. 169-III proceeding, describing its agreed-upon mandate, composition, work plan, budget, consultant support and timetable. This initial report should, if possible, be scheduled to issue by September 30, 1993.

- The Collaborative should strive to issue its final report by February 28, 1994.

- In the event that the above deadlines are found to be unrealistic, the Board expects the utilities to make this known as soon as possible and, when doing so, to define the causes of delay and to jointly commit to a revised timetable.

- The utilities should prepare a description and assessment of the process used in the Collaborative and file this with the Collaborative's final report.

- The utilities should propose and justify the recovery of their share of the reasonably incurred costs of the collaborative approach as a component of their costs of service at subsequent rates hearings.

- The consultative approach to resolving DSM matters should be extended beyond the issues of externalities and qualitative assessment methodologies. The choice of how consultation on other issues will be achieved is left to the utilities to decide and justify.

15.1.8 Regulatory Treatment of DSM Investments

- To the degree possible, there should be consistency in the regulatory treatment of supply-side and DSM costs.

- The eligible costs of long-term DSM programs (i.e. those with a duration of more than one year), including "hardware", longer-term incentive rebates and loans, labour, overhead and administrative costs, should be proposed for inclusion in rate base.

- Eligible short-term costs expended over a period of one year or less should be proposed to be expensed and recovered through the cost of service in the year incurred.

- Reasonable broad-based information efforts and associated programs should be proposed as legitimate costs of service without necessarily identifying specific benefits that will be obtained, so long as prudence can be established.

- Information and associated programs that are specific to a DSM program should be accounted as a cost of that program.

- The utilities should cooperate in and, to the extent possible, co-ordinate their broad-based information and associated programs.

- The differences between actual and forecast DSM operating costs and, if necessary, capital expenditures should be proposed to be accrued in deferral or balancing accounts that, together with carrying costs, are to be disposed of at the utility's next rates case, or as directed by the Board.

- NGV programs should be kept separate and not incorporated into the portfolio of DSM programs.

- DSM efforts should be included as part of utility operations and not "spun-off" as a non-regulated affiliated business.

15.1.9 Allocation of DSM Costs

- To the extent possible, the direct beneficiaries of a DSM program should bear the direct financial burden of the program.

- Customer incentives, for purposes such as increasing penetration rates, may be considered when the utility is prepared to justify them.

- The utility should be wary of requiring customer contributions at levels that would restrict participation by groups such as low-income customers, or would induce conversions to less environmentally desirable fuels.

- So long as it does not reach undue proportions, some level of cross-subsidization for DSM programs may be proposed for recovery in rates.

- Rate impacts due to DSM programs should be treated consistently with the rate impacts from supply-side programs.

- While some level of cross-subsidization and rate impact may be acceptable, the utility should make every effort to work toward developing self-sustaining programs.

- DSM programs designed for large commercial and industrial customers should be identified separately from those directed toward small gas users.

- The utilities should disaggregate DSM plans to recognize peak, seasonal and annual cost impacts for the allocation of demand and commodity charges.

15.1.10 Incentives and Decoupling Mechanisms

- If a utility can establish that shareholder incentives are necessary in order to implement DSM programs effectively, it should apply for such incentives when it presents its DSM plan at a rates case and, at that time, also address the need for penalties to be imposed when performance is below expectations.

- If utility incentives are shown to be required, shared savings, based on the nature or urgency of the program, the market being targeted and the degree of difficulty in program implementation, should be viewed as the preferred approach to the provision of incentives.

- If shareholder incentives are proposed, on a program or portfolio basis, the level of the shareholders' portion of the savings should be determined on a case-by-case basis.

- Full decoupling should be viewed as an inappropriate mechanism for use in Ontario at this time.

- If a utility considers that a lack of revenue protection is a significant disincentive, it may propose a revenue adjustment mechanism, provided that the impacts that the mechanism has on the utility's risk exposure and earnings are also considered.

15.1.11 Monitoring and Evaluation

- The utilities should recognize the need to design effective monitoring and evaluation mechanisms into their DSM programs, in order to evaluate a program's on-going cost effectiveness and success, as well as any need for changes.

- When monitoring and evaluating a DSM portfolio, the utilities should provide assurance that the portfolio is fulfilling its expectations with regard to such matters as:

  - the breadth of coverage;
  - the effective use of information and education programs;
  - cost effectiveness;
  - achievement of intended objectives;
  - overcoming anticipated or emerging market barriers; and
  - the capture of potentially lost opportunities.

- The utilities should file base case forecasts of natural gas demand that would be expected in the absence of formal DSM plans.

- Initially, the base case forecast should include the impacts of NGV programs and of DSM programs initiated prior to fiscal 1995, together with the assumptions and price expectations underlying the forecast.

- The DSM plan and program forecasts should be based on achievable potential, derived to the extent possible from end-use models.

- The utilities should report on the degree to which end-use models can be integrated into their forecasts, at the rates case when they file their first DSM plans. The reports should also include the cost, data and time requirements for the implementation of end-use forecasting.

- Forecasts of the costs of programs and plans should be provided on both a total cost and unit cost (per unit of demand and/or savings) basis.

- For each program and for the overall portfolio, forecasts of the pessimistic, optimistic and most likely impacts on the base case forecast should be presented, along with a description of the major assumptions employed.

- Program performance forecasts should describe expected results in each of the first five years of the program and at five-year increments thereafter to the twentieth year of the plan, or the life of the program.

- Each utility should submit an overview of its DSM plan that describes:

  - the goals of its DSM portfolio and how these will be achieved;

  - the objectives for resource planning and customer service;

  - specific DSM savings objectives by class of customer; and

  - a discussion of the alternative implementation strategies considered.

- The utilities should cooperate in their use of pilot programs and in the development of standard monitoring and evaluation techniques.

15.1.12 Rate Design and DSM

- When developing DSM plans, the need for just, reasonable, stable, cost-related rates should be recognized.

- The potential for rate shock should be anticipated and avoided whenever possible.

- While there appears to be little current justification for revising rate structures, the utilities should explicitly consider energy efficiency impacts resulting from rates and rate structures in any future review of rate design.

- The utilities should undertake, and periodically update, assessments of the impacts of interruptible rates, since in addition to constraining system costs, such rates can affect the use of alternate fuels.

- More explicit billing information (e.g. displays of consumption patterns, as well as capacity, customer and commodity charges) should be provided to customers.

15.1.13 Jurisdictional Concerns

- The utilities should not delay or limit the development of their DSM plans pending a resolution of jurisdictional issues.

- DSM plans that extend beyond a given test year should be prepared under the assumption that, once their consequences are approved by the Board, panels in future proceedings will be sensitive to the need for consistency in the treatment of prudent long-term DSM plans.

- When funding is required for effective consultation, the utilities should directly provide such funding in the expectation that prudent expenditures will be recoverable in rates.

15.1.14 Implementation of DSM

- The utilities should present DSM plans in their filings no later than for their fiscal 1995 rates cases. Should this be onerous, a utility should request, as soon as possible, an extension of the timetable.

- The utilities should bring forward evidence on the development, implementation, monitoring and evaluation of DSM programs, portfolios and plans for review by the Board in the context of rates cases, rather than in parallel hearings.

- The utilities should consult with appropriate parties in an effective manner to obtain meaningful input related to each of the major steps in the DSM planning process.

- The utilities should report, when filing a DSM plan, on the planning process, including the consultative process, used to develop that plan.

- The utilities should take advantage of DSM delivery mechanisms, such as those available from ESCOs, rather than competing with, or supplanting them.

- Cooperation with ESCOs should extend to expanding their involvement with both the large and small user groups.

- Where appropriate, programs should be designed to consider all energy conservation opportunities, rather than just focussing on natural gas conservation measures in isolation.

- The utilities should cooperate with organizations such as Ontario Hydro and the municipal electric utilities to implement broad-based conservation programs.

15.1.15 The Board is aware that gas IRP is in its infancy across North America. As a result, the Board anticipates that the initial DSM plans and forecasts may require adjustments as experience is gained during their implementation. The Board feels it is appropriate to learn by doing, rather than wait until a higher level of certainty is achieved. Thus, while the Board will expect the utilities to commit to their DSM plans, and to work diligently toward their achievement, the plans should allow for the flexibility to make mid-course corrections and adjustments when necessary.

16. COST AWARDS

16.0.1 Section 28 of the Act states in part:

> (1) The costs of and incidental to any proceeding before the Board are in its discretion and may be fixed in any case at a sum certain or may be taxed.
>
> (2) The Board may order by whom and to whom any costs are to be paid and by whom they are to be taxed and allowed.
>
> (3) The Board may prescribe a scale under which such costs shall be taxed.
>
> (4) In this section, the costs may include the costs of the Board, regard being had to the time and expenses of the Board.

16.0.2 In addition to the Board's discretion to award costs, the IFP Act requires the Board to consider applications for intervenor funding in advance of a hearing. An intervenor funding hearing is held to determine if a funding request should be granted, modified or denied. The Board's funding decision also identifies a funding proponent, who is directed to pay any advance award. Any funds awarded under the IFP Act must by statute be deducted from any subsequent cost award ordered by the Board.

16.1 PHASE I COST AWARDS

16.1.1 On May 10, 1992 the Board issued a letter to all parties to the E.B.O. 169 proceedings wherein, inter alia, the Board announced that, since these proceedings were likely to be protracted, the Board would consider interim cost awards to alleviate the financial burdens that might otherwise be imposed upon the parties.

16.1.2 On May 26, 1992 the Board issued Procedural Order E.B.O. 169 No. 2, which invited parties to apply for an interim award of costs that were reasonably incurred to the date of that order (i.e. Phase I), due to their participation in the E.B.O. 169 proceeding. By that Order the Board further instructed those parties applying for an interim award of costs to submit a cost statement and to file an accounting of their use of the funds awarded by the Board's E.B.O. 169 Funding Decision (for Phase I) dated December 20, 1991.

16.1.3 By Procedural Order E.B.O. 169 No. 2, the Board also allowed that those parties that had been active in Phase I and expected to participate in future phases of the E.B.O. 169 proceedings might apply to recover their costs related to Phase I when the Board considers future applications for cost awards in these proceedings.

16.1.4 On August 14, 1992 the Board issued its Decision with Reasons which awarded 100 percent of their reasonably incurred costs for Phase I to all applicants. The last of the Board's E.B.O. 169 Phase I Cost Orders was subsequently issued on November 26, 1992. The table which follows lists the parties that were awarded costs and/or advance intervenor funding for Phase I.

E.B.O. 169 Phase I Awards		
Party	Intervenor Funding $	Cost Award $
CAC(O)	52,748	37,516
CAESCO	17,403	30,443
The Coalition	78,462	73,365
Energy Probe	77,690	81,497
OMAA	66,835	Deferred
Pollution Probe	15,630	15,680
City of Toronto	N/A	5,049
N/A Did not apply		

16.2 PHASE II COST AWARDS

16.2.1 On October 9, 1992 the Board issued Procedural Order E.B.O. 169-III No. 2, which invited the parties to submit applications for costs incurred between May 27, 1992 and October 9, 1992 inclusive (i.e. Phase II), as a result of their participation in the IRP proceedings. As previously allowed in Procedural Order E.B.O. 169 No. 2, parties that had deferred applying for costs incurred in Phase I were also eligible to apply to recover these costs. Parties that expected to continue to participate in future phases of the IRP proceedings were again given the option to apply to recover their Phase I and/or Phase II costs on a future occasion.

16.2.2 In its E.B.O. 169 Interim Costs - Phase II Decision with Reasons, issued on January 15, 1993, the Board dealt with the applications for costs that were filed pursuant to Procedural Order E.B.O. 169-III No. 2. The Board awarded 100 percent of the reasonably incurred costs of the parties that then applied for costs. The advance intervenor funding and cost awards authorized at the end of Phase II are shown on the table which follows.

E.B.O. 169 Phase II Awards		
Party	**Intervenor Funding $**	**Cost Award $**
AMPCO	N/A	$13,148*
CAC(O)	22,756	Deferred
CAESCO	28,942	47,221
The Coalition	29,822	39,814
Energy Probe	24,628	21,471
IGUA	N/A	9,098*
City of Kitchener	N/A	11,774
MEA	N/A	4,205
OMAA	27,297	119,131
Pollution Probe	24,941	29,969
City of Toronto	N/A	6,372

N/A Did not apply
* combined award for Phases I and II

16.3 PHASE III COST AWARDS

16.3.1 On December 4, 1992 the Board gave oral directions to the parties regarding applications for cost awards subsequent to the close of the evidentiary phase of the E.B.O. 169-III hearing. These directions were further contained in Procedural Order E.B.O. 169-III No. 4, which was issued on December 7, 1992.

16.3.2 In that Procedural Order the Board required as follows:

- Applications for cost awards for Phase III, and for deferred awards for outstanding costs incurred in Phases I and II, shall be made at the time of submitting argument-in-chief in the Phase III hearing.

- Objections to an award of costs to other parties shall be made at the time of reply argument, and replies to any such objections shall be filed on or before February 1, 1993.

- Applicants for cost awards shall file their statements of costs on or before February 8, 1993, and use the forms appended to the Procedural Order.

- Accountings of the use of any unreconciled funds awarded in the E.B.O. 169 proceedings pursuant to the Intervenor Funding Project Act shall be filed on or before February 8, 1993, and shall be segregated to separately account for the use of funds awarded in each phase of the E.B.O. 169 proceedings.

- There shall be no further carry-forward allowance for funding or costs incurred in Phases I, II or III of the E.B.O. 169 proceedings. All accounts will be closed to additional entries after the receipt of submissions filed up to and including February 8, 1993.

16.3.3 The intervenor funding awards and the cost claims for Phase III are shown in the table which follows.

E.B.O. 169 Phase III Awards and Claims		
Party	**Intervenor Funding Award $**	**Cost Claim $**
CAC(O) Phase II Phase III II & III Combined	22,756 26,508 49,264	29,549* 64,757 94,306
CAESCO	N/A	39,448
The Coalition	36,119	59,288
Energy Probe	51,197	111,833
City of Kitchener	N/A	38,392
OMAA	22,785	24,715
Pollution Probe	22,940	56,873
The Farm Association	Denied	14,111
City of Toronto	N/A	7,851
N/A Did not apply * Deferred from Phase II to Phase III		

16.3.4 In its reply argument, Consumers Gas noted that the City of Kitchener had described its interest in the IRP proceedings as being that of a utility and as a customer of Union. Consumers Gas submitted that, as a storage and transportation service customer of Union, the City of Kitchener, as a utility, was not substantially distinguishable from Centra and Consumers Gas. Further, Consumers Gas maintained that it would be inappropriate for the ratepayers of Union, Centra and Consumers Gas to subsidize an intervention put forward by the City of Kitchener as a utility. Consumers Gas, therefore, argued that it would be inappropriate for the Board to award costs to the City of Kitchener. The City of Kitchener did not reply to the objection by Consumers Gas.

16.4 BOARD FINDINGS

16.4.1 In its E.B.O. 116 Report the Board listed the considerations that generally will be taken into account when awarding costs. The three major considerations are that the intervenor:

> has or represents a substantial interest in the outcome of the proceeding of such a nature that the intervenor will receive a benefit or suffer a detriment as a result of the order or decision resulting from the proceeding;
>
> has participated in the proceeding in a responsible way; and
>
> has contributed to a better understanding of the issues by the Board.

16.4.2 When making its findings regarding the awards of costs in this proceeding the Board was guided by these considerations.

16.4.3 The Board has taken note of the conduct of each intervenor during the hearing, and has considered the quality of the testimony and written evidence presented. The Board has also taken into account the substance of the arguments filed by each party when deciding its award of costs.

16.4.4 The Board notes the objection filed by Consumers Gas with regard to an award of costs to the City of Kitchener. The Board does not accept Consumers Gas' submission that the City of Kitchener is indistinguishable from Consumers Gas or Centra on the basis that, as customers, they purchase the same type of service from Union. Nor does the Board accept the contention that the City of Kitchener is a "utility" on an equal footing with the three large gas distributors in Ontario. The Board has no difficulty distinguishing between the City of Kitchener and Consumers Gas, Union or Centra. Given that a pass-through of Union's IRP-related costs can have a significant impact on the City of Kitchener's costs, the Board finds that the City of Kitchener meets the test of the first of the E.B.O. 116 considerations set out above, and is, on that basis, eligible to be considered for a cost award.

16.4.5 With regard to the conduct of the parties at the hearing, the Board finds that all the witnesses and counsel acted responsibly in presenting their evidence and in cross-examination. The Board appreciates the cooperation and assistance that the parties provided in order to expedite this technically and administratively complex proceeding.

16.4.6 With regard to the substance of the interventions, the Board finds that each of the active parties in the Phase III hearing contributed to the Board's understanding of the difficult issues that were before the Board.

16.4.7 The Board recognizes that the Phase III hearing was the culmination of efforts that included work done over a period of more than a year in Phases I and II. The Board, therefore, will not segregate and focus in isolation on the contributions that were made by the parties in only the Phase III hearing.

16.4.8 The Board finds that 100 percent of their reasonably incurred costs applied for at the end of Phase III of the E.B.O. 169 proceeding shall be awarded, subject to review by the Board's Assessment Officer, to the following intervenors:

- CAC(O) (for both Phase II and Phase III)
- CAESCO

- The Coalition
- Energy Probe
- The City of Kitchener
- OMAA
- Pollution Probe
- The Farm Association
- The City of Toronto

16.4.9 In compliance with section 12 of the IFP Act, the Board directs that the amount of intervenor funding that was awarded to an intervenor for Phase III shall be deducted from the corresponding award of costs in Phase III of these proceedings. In the case of CAC(O), the total funding awarded under the IFP Act for Phases II and III shall be deducted from the amount awarded herein. In the event that the total amount funded to an intervenor for the entire E.B.O. 169 proceeding exceeds the total amount awarded for its costs in the proceedings, any outstanding difference shall be repaid, forthwith upon receipt of the Board's Phase III cost order, to the funding proponents in the same proportion as their funding payments.

16.4.10 As has been the practice in all previous phases of these proceedings, the Board directs that, subsequent to their review by the Board's Assessment Officer, the costs awarded herein shall be paid, forthwith upon receipt of the Board's costs orders, by Consumers Gas, Union and Centra in the following proportions:

Consumers Gas shall pay 3/6
Union shall pay 2/6
Centra shall pay 1/6.

16.4.11 The Board further finds that Consumers Gas, Union and Centra shall pay, in the proportions set out above, the Board's costs of and incidental to Phase III of these proceedings forthwith upon receipt of the Board's cost order and invoice.

Dated at Toronto July 23, 1993.

Marie C. Rounding

Marie C. Rounding
Chair and Presiding Member

Carl A. Wolf Jr.
Member

Judith C. Allan
Member

Judy Simon

Judith B. Simon
Member

APPENDIX A

EXECUTIVE SUMMARIES AS SUBMITTED BY THE PARTIES

* No Post-hearing submissions filed

APPENDIX A

EXECUTIVE SUMMARIES AS SUBMITTED BY THE PARTIES

EXECUTIVE SUMMARY OF BOARD STAFF

INTRODUCTION

Board Staff submits that the goal of IRP is to place DSM initiatives on an equal footing with supply-side resources as a means of meeting customer needs. DSM initiatives, for the purposes of this proceeding, are energy efficiency and conservation measures, and therefore do not include fuel substitution programs. Board Staff agrees with CAC(O) that the goal of DSM should be the development of effective and cost-effective programs that maximize savings or net societal benefits while minimizing the cost requirements of securing those benefits, both in the short term and the long term.

Wherever possible, demand-side options should be treated consistently with supply-side options. Board Staff submits that the Board should adopt the NARUC resolution which calls for the reform of regulation in order to make the successful implementation of a utility's least-cost plan its most profitable course of action.

There is a concern that DSM will cause rates to increase unnecessarily. The Board must ensure that cost-effective DSM options are used as resources; that is, used to replace supply resources. In no circumstances should the utilities be permitted to implement DSM programs if they have no provable intention of reducing supply-side resources. The rate impact of DSM must never be greater than the rate impact that would have resulted from the alternative supply option, and in all cases the utilities and the Board should try to keep it lower. The Board must not allow undue cross-subsidization between existing and new customers or between rate classes. Ultimately, the effect of DSM on rates for natural gas users will depend on how aggressive the Board wishes the implementation of DSM plans and portfolios to be, and how it evaluates these against supply options.

ISSUE 1

The use of avoided supply-side costs is the appropriate measure of benefits attributable to DSM programs. Components of avoided supply-side costs include capital, operating and energy costs, as well as externalities. There is a need for flexibility in the determination of actual avoided costs, as these costs must reflect both the timing and system differences which may be specific to each DSM program and unique to each utility. The Board should indicate which avoided costs it considers appropriate.

It is submitted that avoided costs provide a direct comparison to supply-side options. Avoided costs can be direct inputs into the cost-effectiveness tests, thereby allowing the utilities to evaluate the DSM programs. Further, the avoided cost methodology is consistent with the determination of costs and benefits outlined in E.B.O. 134 which allows for both quantitative and qualitative consideration of externalities on the supply-side evaluation. Public interest factors should be weighted consistently when evaluating demand and supply options.

Board Staff supports the inclusion of externalities as an avoided cost. The treatment of externalities in supply-side cases under E.B.O. 134 provides a guide to the utilities. Board Staff points out, however, that only positive externalities (those that increase the benefits of a project) have been included to date on supply-side projects. Externalities have not been accounted for as a cost on the supply-side.

Dr. Lerner for Union suggested that, in comparison to avoided supply costs for electricity, the avoided costs for the gas utilities will be lower and the justification of large numbers of new DSM programs will be difficult. Mr. Edgar for CAC(O) stated that "...in some cases the avoided costs for some gas utilities would be lower than the avoided costs for other utilities. It would really depend on the growth in their area." Board Staff believes that Dr. Lerner's and Mr. Edgar's points have merit especially in the determination of avoided facilities and operations costs in mature market areas. Board Staff submits that, given the variability in avoided costs among the utilities, it is necessary that DSM program monitoring and evaluation include an ongoing comparison of forecast and actual avoided costs. Without this monitoring, the Board will not have any accurate data on the costs actually avoided. Board Staff submits that the Board should direct the utilities to present a monitoring system for avoided costs with their proposed DSM programs.

Board Staff submits that in order to truly compare DSM programs on an equal footing with supply-side options, the Board should support the inclusion of long-run avoided costs, equivalent to those presently used in establishing the economic feasibility of the supply-side options.

To the extent that DSM programs reduce demand by a given increment, that increment will be reflected in upstream production and transmission systems. Therefore, the Board should direct the utilities to prepare studies of their avoided costs, with and without the avoided costs upstream of their own systems. The Board may wish to recommend that it be given provincial approval to request the National Energy Board to require TCPL to estimate these costs. The avoided costs of Union's transmission system are somewhat easier for the Board to obtain. Another avoided cost to consider is avoidance of unabsorbed demand charges.

Where DSM measures reduce reliance on supply-side requirements, the avoided cost must be considered a direct benefit attributable to DSM. Board Staff recommends that the Board require that the utilities identify the adjustments to the supply-side plans that they attribute to DSM programs. The utilities should file the expected DSM savings under different scenarios (low, medium and high savings) and the corresponding impact on supply-side plans. DSM options can only be successful when inclusion of DSM results in demand forecasting achieves a reduction in the supply-side requirements.

ISSUE 2

Board Staff supports the Consensus Statement on cost-effectiveness tests because the criteria take into account a broad range of public interest factors and protect against an undue burden being placed on existing customers. Board Staff submits that the portfolio approach is the most effective means of ensuring that a broad range of DSM programs are offered to all classes of customers. It allows low income groups, renters and tenants to participate in these programs. It also keeps the burden on existing customers in check.

Board Staff submits that the DSM portfolio should not be required to pass the RIM test, but that it should place no undue burden on any customer or customer class. The Board has traditionally endorsed rates that are cost-related rather than strictly cost-based, and has also approved financially non-sustaining distribution and transmission projects for public interest reasons. It is therefore submitted that some level of rate impact arising from the DSM portfolio is acceptable. However, in no circumstances should this rate impact be greater than the rate impact that would have resulted from the alternative supply option; in all cases, the Board and the utilities should try to keep it lower.

Board Staff submits that examination of the portfolio of DSM programs in a rate case may not provide sufficiently detailed information to determine the efficiency and effectiveness of individual DSM programs. The Board should direct specific filing protocols which address DSM program avoided cost analysis, demand forecast impacts and actual impacts of existing programs on an individual program basis.

Board Staff submits that there are significant differences between the regulated monopoly environment in which supply-side activities of the utilities are undertaken and the competitive environment in which the utilities will operate demand-side activities. If the utilities are to offer DSM goods and services that will compete with major commercial distributors, they will have to be at a lower price than that currently available in the market place, or the utilities will have to differentiate their product or service.

Board Staff submits that contributions from DSM program participants should be used to maximize the cost-effectiveness of all programs. The same effort should apply to contributions in aid of construction. Board Staff's primary concern is with maintaining reasonable rates for existing gas consumers. To maintain a positive balance in a portfolio of DSM projects, the utilities will have to undertake numerous cost-effective programs. The need for test marketing and pilot programs in areas where the utilities will be in direct competition with other commercial suppliers is critical. Board Staff submits that the Board as part of its report should emphasize the need for the utilities to establish a market response to their new DSM programs before franchise-wide implementation.

The Board must address the issue of the appropriate cost-effectiveness tests and screens, as well as which avoided costs should be included. The Board should indicate whether the utilities should apply the demand-side cost-effectiveness test in a consistent manner with the application of E.B.O. 134 tests for new capital expenditures.

ISSUE 3

The environmental and social impacts of gas usage are a real cost to society which has not been reflected in the price of gas usage to date. All the parties agreed that externality impacts should be included in establishing the feasibility of DSM programs. Board Staff submits that there should be consistent treatment of externalities among the utilities. As there is difficulty in monetizing values for individual externalities and in establishing the range of externalities to be considered in the cost-effectiveness of DSM programs, the working group proposal has been endorsed by all three utilities. Board Staff submits that it may not be necessary to monetize all or even many externalities before the utilities could ensure that a particular program passes the Societal Cost Test.

In Board Staff's submission, the Consensus Statement on Issue 3 provides the utilities with sufficient direction on the treatment of externalities, as it provides the framework for consideration of all identifiable externalities (societal and environmental) in both a qualitative and quantitative sense. Board Staff supports the Consensus because it recognizes externalities on an equal footing with other costs and benefits in cost-effectiveness testing. The Board has already recognized externalities as part of the quantifiable and non-quantifiable public interest factors considered in cases under E.B.O. 134. It is further submitted that, should the Board so desire, the framework for demand-side options can be used to refine or supplement the E.B.O. 134 framework. The use of sensitivity analysis would provide a range of values for externalities which could be applied as part of the Societal Cost Test.

The proposed working group is a means of ensuring that the monetization of externalities is done in a consistent manner amongst the utilities and with input from interested parties. Board Staff submits that the Board should approve the working group approach with the terms of reference as outlined by Centra Gas and CAC(O). The Board should also recommend how the utilities should evaluate those externalities that cannot be quantified. The Board should also establish a time frame, such as six months, within which the working group should report its findings to the Board. Should the Board endorse the working group, funding would be required for interested parties to participate effectively. Board Staff submits that participation from interested parties is essential to developing monetized values for externalities which will have the support of those parties during future proceedings.

ISSUE 4

The utilities have legitimate concerns regarding DSM program costs and their timely recovery. The underlying considerations in the Consensus Statement on Issue 4 include the importance of consistent treatment between demand-side and supply-side options, the ease of application and regulatory review, and an amortization period for DSM expenditures which is equitable in matching costs and benefits. If regulatory practices present utility planners with disparate financial risks and rewards for different resources, then resource selection will be biased in favour of options that are either more profitable or less risky. Spreading the costs over the lifetime of technologies, or the period of the benefits to be realized, reduces negative rate impacts in the earlier years of a program. Board Staff submits that the Board should endorse the consensus for the reasons stated above.

The main difference in accounting treatment for DSM expenditures compared to supply-side expenditures is that the utilities are looking for further reassurance that they will be able to recoup all of the costs incurred. As many DSM programs are of longer duration than one year, the utilities require approval for multi-year plans. Therefore, the utilities should establish a deferral account for DSM operating/capital expenditures, in order to alleviate the uncertainties surrounding DSM expenses, particularly in the early stages of new programs. The utility would be able to recoup all DSM costs incurred for program implementation and would have greater flexibility to respond to a program's success or failure.

Board Staff submits that the use of a deferral account in the early years of DSM implementation will prevent the utility from abandoning a program once the budgeted funds run out, which would result in lost opportunities, as well as mixed signals to the public. The balancing account has the additional advantage of lowering the utility's new risk with respect to investing in non-revenue generating assets. The deferral account would be examined at the next rate case proceeding to test the prudency of the expenditures. The deferral account has primary significance in the earlier years of DSM implementation. At each rate case, the necessity for the deferral account would be addressed.
The Board must describe how it intends to treat the DSM expenditures and whether it will allow the use of a DSM deferral account. Guidelines are necessary on how costs are to be amortized and recovered. The Board must also define what kinds of programs are eligible for inclusion in the DSM portfolio.

ISSUE 5

Participants who are the direct beneficiaries of a DSM program should bear, to the extent possible, the direct financial burden of the program. The remaining costs of the programs should be allocated to all existing gas customers on a system-wide basis.

Effective program design helps to minimize the costs and maximize the benefits of DSM. Board Staff submits that providing incentives to customers will encourage participation in DSM programs, improve the cost-effectiveness of programs and may increase the net social benefits. Incentives will also help target special customer groups that might not otherwise participate in DSM programs. Higher participation rates improve the financial performance of a DSM program, but the incentives should not be so high that they impair the cost-effectiveness of the program, or that the utilities simply give away DSM options.

Board Staff submits that customer contributions are appropriate for DSM programs, as they could make financially non-sustaining DSM programs more profitable, thereby reducing the subsidy from non-participants. Contributions should be as high as possible without deterring participation. To be consistent, contributions should also be sought for financially non-sustaining fuel switching programs or other supply-side projects, which are endorsed by E.B.O. 134 provided the social benefits exceed the costs. Wherever possible, the utility should strive to have the measure pass the RIM test or have a benefit/cost ratio of one.

Demand-side and supply-side costs should be treated consistently for cost allocation purposes. The allocation of DSM program costs not recovered from program participants should recognize and be proportional to the distribution of program benefits. Board Staff submits that it is appropriate to extend some portion of DSM costs to the system as a whole, as all ratepayers will benefit from the avoided costs of future supply and the avoidance of externalities.

Board Staff submits that the utilities should be directed to start their research on cost causality of DSM programs, and that they should share the costs of such research to the extent practical. The utilities should also be directed to work with the ESCOs, which may have valuable input regarding cost causality to share with the utilities for the commercial/industrial and institutional sectors.

Board Staff submits that the Board should approve the Consensus Statement on Issue 5(a). This would not require the DSM portfolio to pass the RIM test, as there may be some justified upward impact on rates. The Board has traditionally endorsed rates that are cost-related rather than strictly cost-based, as long as the resulting rates do not place an undue burden on any customer or customer class. The Board has also approved financially non-sustaining distribution and transmission projects for public interest reasons. It is therefore submitted that some level of rate impact is acceptable, but in no circumstances should it be greater than the rate impact that would have resulted from the alternative supply option.

Board Staff submits that while some degree of cross-subsidization is unavoidable, there should be some attempt to limit it to reasonable levels. The appropriate level of subsidy would be at the utility's and the Board's discretion, consistent with the manner in which the Board currently evaluates supply-side options. The diversity and widespread application of DSM programs across all customer classes would help ensure overall equity, as there would be relatively few non-participants. The Consensus Statement addresses the issue of intra-class subsidization by supporting customer contributions to DSM programs. The balance is in finding the appropriate level of customer contribution or incentive to ensure that the benefits are produced, but trying to reduce the amount of incentives in order to prevent intra-class and inter-class subsidies.

ISSUE 6

Board Staff submits that shareholder incentives should be made available to the utilities to undertake DSM programs to remove any disincentive to the aggressive implementation of cost-effective DSM programs. Board Staff submits that incentives are necessary to make the utility choose to implement DSM initiatives where they replace supply-side resources. Supply options generate revenue and a return on rate base; it is therefore submitted that DSM options should be made equally attractive to utility management. Financial incentive mechanisms should not only remove disincentives to DSM, but should also encourage positive action and align utility management objectives with those of societal objectives. Incentives must be earned, based on measured cost-effective savings rather than on the level of DSM expenditures. An added benefit of a shared savings plan is that it may help mitigate the short-term risk associated with undertaking DSM programs. Board Staff submits that the Board has the authority to implement a shared-savings mechanism. The Board should support the Consensus Statement on Issue 6, Part 1. If incentives are not available to utility shareholders, the Board must address how it intends to ensure that a sufficient amount of cost-effective DSM will be implemented by the utilities.

Board Staff submits that the use of a penalty mechanism (i.e. the reverse of shared savings, or disallowance of costs) is reasonable in cases where the utility's performance is poor or non-existent. This is to be dealt with at a rate case proceeding. The Board should also state whether it finds the use of penalties for poor performance to be appropriate.

Parties agreed that there is an inherent bias in the present rate-making system which provides an incentive to the utility to sell more gas than forecast during the rate year. Decoupling makes the utility indifferent to the level of gas sales during the period between rate cases. Board Staff submits that the Board should implement decoupling for all three utilities in Ontario. However, if the Board is not prepared to mandate decoupling for Centra and Union at this time, then full decoupling should at the very least be implemented for Consumers on a trial basis. Board Staff submits that the Board has the legal authority to implement a decoupling mechanism if it decides that one is in the public interest. If the Board perceives that decoupling will have public interest benefits, the Board need not have the utilities' consent for instituting appropriate policies. If decoupling is not adopted, the Board must indicate how the utilities are to recoup lost revenues.

Board Staff agrees that decoupling is not **necessary** for the implementation of successful DSM programs. The decision to implement decoupling or not must be based on how much the Board wants the utilities to achieve with respect to energy efficiency and conservation. Decoupling helps to break utility managers' preference for growth in sales and rate base. For this reason alone, it is submitted that decoupling may be appropriate for utilities with a focus on load building.

It is submitted that decoupling separates a utility's profitability from sales volume, and consequently, removes the disincentive to pursue energy efficiency as well as removing the incentive to increase sales in the rate year. Board Staff submits that the utility must be indifferent to the level of sales in order to place DSM options on an equal footing with supply options. Further, if the utility is protected from net revenue losses, then symmetry requires that the rate payers be protected from net revenue gains that would occur if the utility undertook less DSM than anticipated in the test year. Decoupling would provide this symmetry.

Lost revenue adjustment mechanisms may allow the utility to recoup additional revenue from ratepayers regardless of whether the utility is earning more than its allowed return. In addition, a lost revenue adjustment account will not take away the utility's perceived advantage associated with increased sales. This kind of account cannot capture the effects of informational DSM programs, and potentially other programs as well. There will also be considerable difficulty in estimating what the lost revenues are, giving rise to greater regulatory complexity than decoupling. Nor does this mechanism neutralize the incentive to sell more gas than forecast between rate cases.

Decoupling makes the utility neutral to sales promotion. Combining decoupling with deferred accounting for program costs will make the utility neutral to conservation and opposed to sales promotion. Board Staff submits that there are other incentives present for promotional costs, such as the incentive of rate base, the desire to satisfy customer needs, and the risk of regulatory scrutiny. If the Board wants the utility to promote certain types of sales, it could allow for deferred accounting of sales promotion costs. The advantage is that the Board, not the utility, determines which uses should be promoted, thereby ensuring that the public good is served.

Decoupling reduces volatility of revenues, and shifts the risk of weather and the economy onto rate payers. However, the risk is symmetrical and if the risk transfer is significant, it may be reflected in the cost of capital and the allowed rate of return, which would be a lower cost to the rate payers. It is submitted that this debate is best reserved for a rate case.

Without decoupling, shareholder incentives to make conservation the more profitable option will have to be larger than they would have to be with decoupling. Decoupling also makes it possible to try to mesh rate design with DSM programs, by allowing the utilities to move away from their dependence on fixed customer charges and focus more on commodity charges which are closer to marginal pricing. Decoupling could make the utility indifferent to the activities of ESCOs, allowing them to displace or at least reduce the need for utility involvement.

Board Staff submits that the revenue-per-customer approach on a customer class basis has merit. This methodology would have to be modified to take Centra's concerns regarding industrial customers into consideration. It is submitted that the Board should direct Centra and Union to evaluate some of the suggestions put forth by parties to this proceeding to reduce the variability of revenues.

ISSUE 7

The Consensus for Issue 7 addresses the need for careful research, monitoring and evaluation in order to take into account all of the factors which may affect the cost-effectiveness and net social benefits of each DSM program, while giving the utilities some flexibility of approach.

Board Staff submits that proper program selection is necessary to maximize the achievable potential of DSM. At the same time, there is a trade-off between identifying DSM potential and keeping costs to a reasonable level. As more research, analysis and monitoring are undertaken, the costs rise and the incremental benefits drop. Identifying technical potential is understood to be of limited practicality.

Board Staff submits that the goal of identifying achievable potential provides an explicit framework for developing and evaluating a DSM portfolio. Estimates of the achievable potential and the cost-effectiveness of most programs depend on the assumptions underlying participation rates, therefore some sensitivity analysis should be performed. Board Staff submits that it is necessary to identify the achievable potential, including expected participation levels, of any given program before one can determine the program's cost-effectiveness. Union's proposed method of identifying DSM potential by addressing only known market barriers, carries a high risk of missing less obvious but socially beneficial areas of DSM potential. Board Staff is concerned that Union does not intend to implement DSM beyond its current level.

Free ridership may be a possible obstacle to developing accurate estimates of program potential. Undetected free-ridership means that the actual benefits of a program relative to the costs are lower than they appear. It is submitted that free ridership will not be a serious problem provided that some attempt is made to account for the effect of free riders in assessing program costs and benefits. It is not apparent to Board Staff that increasing program costs by raising the incentive level will necessarily be offset by an equal or greater increase in benefits.

Board Staff submits that energy service companies are a valuable resource which the utilities should be encouraged to utilize. However, the types of programs in which ESCOs are involved differ substantially from those which are most logical for the utilities to adopt. While their expertise is almost certainly transferable to the utilities, the program emphasis and research methods of the ESCOs are not.

It is Board Staff's view that market barriers, and particularly lost opportunity situations, should and will be a primary focus for DSM programs. First-time costs and lack of information are the barriers to customer acceptance of DSM measures on which the LDCs expect to place their primary focus. While overcoming market barriers is important, avoiding lost opportunities is also an important consideration in designing DSM programs, to focus on those opportunities which arise only once or seldom, specifically appliance replacements and new construction.

There is a trade-off between accuracy and cost in choosing the types and extent of monitoring to undertake. Board Staff supports the use of pilot programs for any new or unfamiliar DSM program or which generates a relatively large degree of uncertainty concerning participation rates. Board Staff submits that monitoring and evaluation will ultimately determine the success or failure of DSM programs. There is a serious risk that inadequate evaluation may cause costly DSM programs to remain in place. The Board should direct the utilities to report on monitoring and evaluation mechanisms which will be scrutinized in subsequent rate cases.

ISSUE 8

The Board's traditional approach to rate-setting has been to support cost-related rates, allowing some cross-subsidization to meet qualitative policy objectives. In Board Staff's submission, a new objective in rate design is the explicit consideration of energy efficiency and conservation objectives. Redesigning rates to encourage conservation of gas may have a detrimental effect to the extent that users choose to use competing fuels as a result of increased gas prices at the margin. Rate structure changes must be approached cautiously, because they could create an atmosphere of instability and discontent if poorly designed or implemented too rapidly. Board Staff submits that rate stability should not be considered a problem. It is submitted that in the past, rate restructuring has occurred in such a way that any unavoidable negative impacts were mitigated by implementing the changes gradually. Staff supports the Consensus in setting aside the debate about risk in rate design measures to a future date when there are specific proposals to discuss.

Seasonal pricing is more economically efficient than current average cost pricing, by allocating costs more closely to the people who are imposing higher costs on the system. In theory, marginal cost pricing would also smooth the seasonal load peaks, supporting the goal of conservation as well as economic efficiency. Board Staff submits that there are many options for residential customers to improve the efficiency of their winter gas use, as well as adding summer applications of gas. Although equal billing may somewhat mute price signals, this problem can be substantially mitigated by providing more information to customers.

Board Staff agrees provisionally that inverted rates may be economically inefficient because they discourage socially desirable load-building activities. It should be noted, however, that precise estimates of negative load-building impacts versus conservation benefits would need to take into account the price elasticity of demand at the margin and the cross price elasticity of gas with respect to competing fuels, and the relative environmental impacts of each effect. Board Staff submits that inverted rates are not a practical consideration at this time, as they pose problems for the utility's revenue stability, because most of the cost recovery would occur at the margin. In addition, Board Staff submits that inverted rates would create equity problems even in the relatively homogenous residential sector, by penalizing large families and customers who may use gas efficiently but for more applications.

Board Staff submits that the use of interruptible rates should not be altered at present to try to further the goals of IRP. It is evident to Board Staff that information on the environmental impacts of interruptions would be helpful. Board Staff submits, however, that interruptible rates can be of great assistance to the utility in avoiding peak demand supply costs. It is therefore submitted that the Board should direct the utilities to track more closely the use of alternative fuels during interruptions.

ISSUE 9

The opinions provided by Ian Blue and Osler, Hoskin & Harcourt (Exhibit 1.11, Appendix D and Exhibit 3.1, Appendix A) outline the extent of the Board's jurisdiction in matters related to IRP and are also applicable to DSM programs. In each case, counsel reaches the conclusion that the Board has the jurisdiction to approve the test year rate making implications of DSM programs and to issue guidelines as to the evaluation of DSM programs.

Board Staff submits that no active party to the proceeding is in disagreement with the Consensus Statement. Rather, Board Staff submits that the lack of unanimity for the consensus statement arises from the issue of whether or not the Board should acquire jurisdiction, through legislative amendments to the Ontario Energy Board Act, to implement a formal IRP process. Board Staff submits that the Board should adopt the Consensus Statement on Issue 9 as being reflective of its jurisdiction in the area of DSM program approval.

ISSUE 10

The Board must indicate how it intends to pursue the implementation of DSM plans, and whether it intends to deal with the remaining issues of IRP (supply-side issues and the integration of demand and supply into a decision-making format). With respect to short-term DSM implementation, Board Staff submits that the Board should indicate its support for a consultative process among the utilities and intervenors, and should set parameters in its DSM guidelines to ensure a productive and efficient consultative process. Board Staff submits that the parameters should be: broadly based representation by interested parties; timing such that the interested parties are included in the process of DSM program development; the consultation structured so that all parties begin the process with an understanding of the content and expected results; and, a report on the consultation process and results included in the evidence supporting the utility's DSM plan at a rate case.

Board Staff submits that the Board should indicate that any costs for undertaking consultations are eligible for inclusion in the utility's cost of service subject to examination in a rate case. Without such funding interested parties will be excluded from the consultations and will be required to rely on intervenor funding and the rate hearing process in order to provide their input into DSM plans. This would be a less productive and probably more expensive outcome. Board Staff submits that the utility should be responsible for the control of these costs. The Board's current cost assessment guidelines represent sensible criteria for the utilities in considering funding requests. Any party which is excluded from the consultation through insufficient funding could still apply for intervenor funding in a rate case. Input from such a party would be one of the factors for the Board to consider as to whether the utility had undertaken its consultations appropriately.

Board Staff submits that the legal basis for the Board itself to award funding in the consultation process is doubtful. The existence of a proceeding and the granting of status to an intervenor are prerequisites to an award of funding to that intervenor under the Intervenor Funding Project Act ("the IFPA"). In order to award funding under the IFPA, the Board would have to find that the consultation process is part of an ongoing IRP proceeding, or that a utility rate case proceeding continued throughout the consultation process. Board Staff does not recommend that the Board make such a finding. The Board also has the power to award costs through section 28 of the OEB Act. Subsection 5 of that section does permit the Board to award costs in the form of advance funding. However, Board Staff submits that the prerequisites of the existence of a proceeding and the granting of status apply with equal force to this section of the OEB Act. Board Staff submits that the most practical and legally sound approach is to allow the utilities to pass through reasonable costs in connection with the consultation process as part of cost of service. If the Board ever determines that the funding is not being appropriately undertaken by the utilities, it could then invoke provisions of the IFPA and assume responsibility for deciding these funding requests.

Pollution Probe has recommended that affiliate gas supply transactions be banned on the basis that if an affiliate is supplying gas to a utility, this will result in a disincentive to the utility to pursue conservation. As an alternative, Mr. Gibbons recommended that all affiliate gas supply contracts should contain a provision whereby the volumes would not be subject to displacement if the utility's requirements are diminished. Board Staff submits that neither recommendation put forward by Pollution Probe is warranted at this time. While the identified disincentive may exist, there is not sufficient evidence on the magnitude of the problem to justify the proposed remedy. Board Staff notes that this disincentive will continue to exist, to the extent it is driven by the utility's parent, whether or not there is a sale between the affiliate and the utility.

With respect to long-term IRP implementation, Board Staff submits that the Board should adopt Parts 1, 2(a) and 2(c) of the Consensus Statement on Issue 10. The Board may wish to indicate whether it will pursue legislative change in the expectation of more extensive implementation of IRP. There are a number of areas in which not enough is known at this time to make specific recommendations for amended legislation. These areas include: whether the Board accepts the definition of IRP, the appropriate level of interaction with Ontario Hydro with respect to fuel substitution issues, the time frame for an IRP plan, and the process for plan development. Board Staff submits that by beginning a DSM process within the current jurisdictional limits, the Board will be able to determine whether or not a formal IRP process is required. As part of determining the need for a formal IRP process, the Board will need to evaluate, based on its experience with DSM, whether it will be practical, feasible, or necessary to expand the process in order to achieve the goals of IRP.

ISSUE 11

OMAA has requested that meaningful consultation with its constituency should occur. Board Staff submits that the majority of this consultation will be very difficult to pursue as OMAA has not enumerated its membership. Therefore OMAA must help the utilities identify and, communicate with, the affect parties. Further, Board Staff submits that it is important that the Board receive OMAA's input on these matters although direct consultation with individual Board members may not be appropriate. Other venues should be examined instead.

ENERGY PROBE

Energy Probe argued that rates should reflect the marginal cost of supplying gas. Board Staff agrees that in a perfect world, energy efficiency and conservation objectives would be achieved naturally through market forces. However, Staff submits that given the many inefficiencies and uncertainties in the markets for natural gas and competing energy sources, policy decisions and market intervention are required.

The thrust of Dr. Ruff's testimony is that the Board should focus exclusively on minimizing rates in evaluating resource options. Board Staff submits that to advocate the RIM test as the measure of cost-effectiveness requires the incorrect assumption of well-functioning energy markets. IRP recognizes that market barriers prevent customers from making efficient energy choices. Well-designed demand-side programs offer cost-effective choices to customers that cannot be or are not taken advantage of under market conditions. It is Board Staff's position that reliance on market forces and pricing will not be sufficient to ensure that an optimal or reasonable amount of cost-effective conservation is going to take place.

Board Staff submits that the proposal to establish non-regulated conservation divisions would greatly increase the regulatory burden and that the Board should reject Energy Probe's suggestion in this regard. Staff submits that Energy Probe contradicts itself by stating that no cross-subsidization is acceptable, and then suggesting the use of a DSM portfolio whereby financially successful programs are used to support non-sustaining programs. It is submitted that it makes no sense to allow cross-subsidization among affiliates.

Energy Probe submitted that the best way to treat externalities is to internalize them in the price of gas, but only after doing the same to other fuels. Board Staff submits that Energy Probe's position on externalities is partly based on the assumption that externalities of gas use are so small that it would be more costly for the Board to consider them than it would just to live with the effects. This explains why Energy Probe endorsed the reliance on market tests even though price signals are distorted by the exclusion of externality values. Dr. Ruff's evidence suggests that markets function best when left alone and the less intervention the better.

It is clear to Board Staff that Energy Probe's advice to the Board regarding externalities in the natural gas market boils down to: do nothing. Board Staff submits that such a course is inadvisable, as it is reasonable to believe that externality effects probably warrant some market intervention. Energy Probe's objection to an interpretation of Dr. Ruff's testimony on market imperfections to include externalities highlights the fact that the bulk of Dr. Ruff's testimony needs the qualifier: "in the absence of externalities." Considering that a major part of IRP is to consider externality values, this is a fundamental weakness of Energy Probe's position.

One of the basic tenets of Energy Probe's position is that raising gas rates will result in higher total emissions from energy sources in the aggregate, because the higher gas prices will discourage substitution to gas from more polluting competitive fuels at the margin. Energy Probe's argument that raising gas prices will increase total emissions from all fuel sources is only true if the cross price elasticity is high enough to offset the decrease in gas use. Board Staff submits that Energy Probe has not provided sufficient evidence to establish the validity of this proposition in the hearing. In the absence of supporting evidence, this proposition should not prevent the Board from considering DSM measures even if they may have small rate impacts.

FARM ENERGY ASSOCIATION ("FEA")

FEA presented evidence that the agriculture sector would like to be a player in any strategies for reducing its energy use. One example was the linkage between a small ethanol plant and a greenhouse operation to reduce natural gas use in the drying process. However, small ethanol plants, which support rural diversification, are financially viable only if they are linked to another operation, such as a greenhouse.

Dr. Stahlberg identified some financial and informational barriers to the implementation of these sorts of projects, and made a number of recommendations for utility actions to overcome such barriers. Board Staff recommends that the Board encourage the utilities to include representatives of the agricultural sector in its consultations and in the externalities working group. Board Staff further submits that the process is not sufficiently advanced at this point for the Board to determine whether regional offices to accommodate agricultural customers or specific guidelines for the utility to assess all agricultural linkages are necessary. These would be items for the utilities to consider when developing and conducting their consultations and DSM plan development.

EXECUTIVE SUMMARY OF CENTRA GAS (ONTARIO) INC.

I. INTRODUCTION

Centra Gas Ontario Inc. ("Centra") supports the pursuit of the goals of IRP in Ontario. Centra has been an active participant in all phases of the E.B.O. 169 proceeding and has found the consultative, cooperative approach adopted by the Board to be helpful in allowing the utility to develop its understanding of the issues and the positions of other parties.

Centra has based its positions on the issues which have been the subject of the E.B.O. 169 proceedings on the following important principles;

1. The implementation of IRP in the Ontario natural gas industry will be an evolutionary process.

2. IRP should be implemented in manner sufficiently flexible to accommodate the unique characteristics of each LDC.

3. IRP must recognize the LDC's obligation to balance the interests of each of its stakeholders.

4. Natural Gas must remain a cost competitive energy source, particularly in view of its environmental benefits.

IRP should focus on the implementation of cost-effective DSM programs. An appropriate set of feasibility tests will result in the consistent evaluation of demand and supply side options.

Centra believes that Ontario natural gas distribution utilities should move forward with additional demand-side efforts expeditiously. Recognizing that the introduction of DSM may introduce new uncertainties to the planning process, Centra is advocating a phased-in approach. This will permit the utility to develop the experience, information and systems required to forecast program impacts and will allow the careful testing of options through pilot programs. This in turn will manage the risk to which Centra and its customers may be exposed during the initial period of implementation.

ISSUE 1

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

The consensus statement notes that while the forecast load impacts of the DSM options proposed for implementation should be incorporated into the utility's demand forecast, the base case supply plan should be flexible enough to accommodate variance between forecast and actual DSM program results. Centra expects that the degree of supply flexibility required will decrease over time as the utilities develop the data bases and forecasting systems necessary to improve the accuracy of DSM program impacts. The potential to reduce the supply plan flexibility and to recognize the related savings is one reason why Centra supports a phased-in approach to IRP.

ISSUE 2

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

Centra would like to place particular emphasis on the portion of paragraph 2(c)(ii) of the Consensus Position Statement which notes that: "the resulting rise in rates must not entail second round net societal costs that are expected to exceed the first round net societal benefits of the demand management program (eg. if higher rates cause customers to switch away from gas, the resulting net social costs could exceed the net social benefits of the program that is being financed by the higher rates)".

Natural gas is the least environmentally damaging of the fossil fuels and is the preferred energy source for many end use applications. The evidence indicates that there is more potential environmental and social benefit in fuel switching than in gas conservation. Therefore, while DSM action should encourage efficiency it should not materially discourage fuel switching to gas or encourage fuel switching from gas. It is for this reason that the Consensus Position Statement highlights the concern about second round social costs if natural gas prices are allowed to rise excessively.

The competitive position of gas is a function of the relative unit cost of fuel and the relative capital cost of the equipment in each market in which it is sold. Given the difficulty of forecasting the effect of price changes on fuel switching, the sensitivity in many markets to small price changes, and the environmental impacts of fuel switching, the degree to which prices should be allowed to increase as a result of a DSM portfolio will be an important issue in the choice of an appropriate portfolio.

ISSUE 3

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

Centra suggests that the working group is more likely to succeed if it develops, by agreement, its own specific objectives, work plan and time table. Initial discussions within the working group on November 5, 1992 indicate that the work plan would probably include the following:

a) the identification of externalities that should be considered in an IRP context;

b) a survey of approaches used in other jurisdictions;

c) obtaining relevant existing studies on externalities; and

d) determining the preferred approaches to quantifying and monetizing externalities and reporting them to the Board and the parties to E.B.O. 169.

ISSUE 4

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

The Consensus Position Statement stipulates that a deferral account should be established for operating "and/or" capital expenditures. Centra believes that capital expenditures are likely to be the larger of the two types of DSM expenditure, and therefore should be included in the deferral account if the account is to meet its objective.

The deferral account achieves two objectives:

a) it reassures interested parties that the utilities will not be constrained from the aggressive pursuit of DSM programs by cost considerations; and

b) it balances the interests of the utility and the customers in the event that DSM programs are more successful than anticipated.

ISSUE 5

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

Centra maintains that cost allocation principles used to allocate DSM costs should be consistent with those used to allocate other expenditures. However, the nature of certain DSM costs may warrant the development of new cost allocation factors.

ISSUE 6 - PART I: INCENTIVES

Centra continues to support Consensus Position Statement of October 9, 1992 on incentives.

Centra believes that incentives must be significant and the potential to realize the incentives real if they are to be effective in motivating behaviour. The successful application to claim an incentive will likely require support which can only be supplied by measuring and monitoring systems not yet in place. For this reason that Centra has indicated that the utility may not apply for such incentives initially.

Centra believes that the introduction of penalties is counter-productive to a process which seeks to encourage the pursuit of innovative new programs. The additional risk imposed by the penalties may serve to dampen the enthusiasm of the utility to attempt unproven programs.

ISSUE 6 - PART 2: DECOUPLING

Centra continues to support the Consensus Position Statement of October 5, 1992 prepared jointly with Union.

Decoupling is a complex and troublesome regulatory mechanism which will require significant adjustments to the method of regulation in Ontario. There is good reason to suppose it raises many more problems than it solves and that it may be counter-productive to its objectives. There is little experience with this mechanism in other jurisdictions, and such experience as there is does not support the conclusion that decoupling is appropriate in this regulatory environment at this time.

Decoupling is intended to address a perceived disincentive for the utility to pursue conservation in the period between rate cases. Between rate hearings, the utility is seen as having a disincentive to reduce sales below forecast levels and therefore not to pursue conservation programs which would reduce sales.

Under the existing regulatory regime in Ontario, which utilizes a forward test year and allows for annual rate applications, this issue is small in relation to the scale and complexity of the solution proposed. The Ontario regime does not discourage conservation. It provides a disincentive to the utility to aggressively pursue planned conservation programs during the rate year after the case has been decided. However, there are many other factors that indicate that the disincentive is insignificant:

a) The extent to which the revenue incentive dissuades the utility from conserving beyond the levels forecast as an alternative to gas sales which do not represent cost effective energy usages is limited.

b) The perceived disincentives do not operate other than between rate hearings and do not and are not seen to discourage utilities from planning aggressive DSM programs.

c) In reality the "trade-off" between conservation and increase sales really occurs, because both can and do go on simultaneously.

The evidence indicates that the introduction of decoupling into the regulation of natural gas utilities in Ontario today can be anticipated to result in a number of significant problems, the cost and complexity of which can be expected to significantly outweigh the impact of the issue decoupling is intended to address. Decoupling can be expected to result in:

a) Advantageous sales of gas being discouraged;

b) Distorted decision making and perverse incentives;

c) Adverse rate impacts and perverse price signals;

d) Increased regulatory complexity.

Centra submits that U.S. experience with decoupling does not provide a foundation on which this Board should conclude that decoupling is necessary or desirable. With the exception of California, it has been introduced only for some electric utilities in three states, within the last two years.

Centra submits that the Board should be cautious in drawing any conclusions about the need for and impact of decoupling on the basis of U.S. experience related to electric utilities, because of the significant differences between gas and electric markets. These include the fact that electricity is not generally as vulnerable to competition as natural gas so that the concern about the rate impact of decoupling may not be so marked.

ISSUE 7

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

ISSUE 8

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

ISSUE 9

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

ISSUE 10

Centra continues to support the Consensus Position Statement of October 9, 1992 on the issuance of guidelines, consultations on DSM programs, and consideration of DSM programs in specific rate cases.

The issue which remains in contention with respect to Issues No. 9 and 10 is the question of the need for an extension of the Board's jurisdiction.

Centra submits that to undertake what would inevitably be a time-consuming, complicated and costly process of legislative amendment would only be justified if there were a specific and necessary objective identified. The history of this Board's exercise of its jurisdiction demonstrates clearly that the Board has considerable authority to enable the achievement of the DSM objectives which have been identified in this hearing.

EXECUTIVE SUMMARY OF CAESCO

INTRODUCTION

CAESCO believes that Energy Service Companies ("ESCOs") and gas utilities have complementary strengths and should work together to implement demand side measures among natural gas consumers in the institutional, commercial, industrial and multi-family residential sectors. CAESCO's view is shared by each of the major gas utilities in Ontario, who have all testified that they would be prepared to work with CAESCO and that they consider CAESCO to be a strategic ally in the delivery of demand side programs. (Transcript: Centra at p. 263; Consumers at p. 660; Union at p. 920) These complementary strengths are set out under Issue 12 ESCO/Utility Cooperation. The Government of Ontario also calls for ESCO/utility collaboration in its policy document, "A Framework for Energy Efficiency & Conservation in Ontario".

ISSUE 1 DSM COSTING METHODOLOGY AND INCLUSION IN THE DEMAND FORECAST

While CAESCO is a party to the Consensus position it reiterates a previously stated concern: that the <u>value</u> of DSM, based on avoided costs, does not become the <u>cost</u> of DSM thereby leading to inappropriate or unnecessary financial incentives. This has the potential to not only cause distortions in the market place that affect customers' decisions, but it also hampers the ESCOs' efforts to structure DSM contracts on the basis of market value.

If utilities design programs that allow a financial incentive to cause program costs to rise to the level of then avoided costs estimates, it would not only upset the equilibrium and financial structure of ESCO projects, but could also result in unnecessary costs to non-participating ratepayers.

With respect to the use of demand side measures to meet utilities forecast demand, CAESCO has testified that in the sectors with which it was familiar, fuel savings (gas or oil) normally accounted for about 45% of total dollar savings generated by the retrofit project, (with the balance electricity). There is, therefore, the potential for gas savings in the sectors where ESCOs are active.

ISSUE 2 APPROPRIATE COST-EFFECTIVENESS TESTS

CAESCO's position on this issue is that of the majority; that is, DSM should pass the societal and ratepayer impact tests. However, the current variation in monetization factors for externalities should be thoroughly researched and evaluated through the working group, as decided during the hearings. Again, CAESCO's concerns involve incentive levels that may be unnecessarily high, which can happen when programs are undertaken that do not pass a ratepayer's test but pass a societal test, which may be driven by arbitrarily derived monetization factors. In most U.S. jurisdictions where IRP has been implemented, it is the Total Resource Cost Resource Cost Test that is the ultimate determinant. The Societal Test is used in the initial screening process only.

It is noteworthy that ESCO programs achieve their load-saving goals and successfully reduce environmental externalities without the need for utilities to internalize any externality costs. This added benefit should be factored into the utility's DSM plans.

ISSUE 3 INCLUDING EXTERNALITIES IN THE COST ANALYSIS OF DSM Programs

Societal and environmental externalities to the extent that they can be identified, quantified, and monetized with a satisfactory level of confidence, should be a factor in determining the cost effectiveness of programs vis-a-vis the Societal Test.

ISSUE 4 RATEMAKING TREATMENT FOR DSM INVESTMENTS

CAESCO is a party to the consensus statement on the cost recovery issues. In keeping with generally accepted accounting principles, any DSM operating expenses, or one-time costs that occur in a current period should be expensed while longer term DSM investments should be capitalized and included in the utility's rate base.

CAESCO is also in agreement with the concept of a deferral account and would even take it one step further for the sectors in which they operate. Joint utility/ESCO programs could be included in these accounts with the rebate funding occurring at periodic intervals after the load savings are realized and documented. In this manner any potential DSM financial risk is removed from the utility, while it potentially earns a return on the program funds. At the same time the risk associated with the lack of information on persistence is mitigated.

ISSUE 5 WHO SHOULD PAY FOR DSM PROGRAMS

The U.S. experience indicates that cross-subsidization can become an issue and the principle of *user pay* should be followed. This has always been the basis for ESCO/client contracts, where clients accept their current level of utility bills until the DSM investment has been fully recovered by the ESCO or the contract expires. CAESCO prefers to see the gas utilities' programs for commercial, institutional, and industrial customers structured similarly. The CAESCO membership is offering to work with the utilities to design programs with benefits that not only outweigh costs but also provide a means of serving the energy efficiency needs of these sectors, without a financial investment until the savings are realized. This provides the utilities the opportunity to implement programs in all sectors; prescriptive programs in the residential and small commercial markets, and customized comprehensive programs for the larger commercial institutional and industrial facilities.

ISSUE 6A SHAREHOLDER INCENTIVES

It is CAESCO's position as a party to the consensus, that utilities should determine the benefits and feasibility of financial incentives to implement DSM as a business policy decision; they should be made whole and not be penalized. However any financial incentives that are developed should maintain a level playing field between the utility's implementing a program directly or working through ESCOs.

ISSUE 6B DECOUPLING

CAESCO offers a few general observations on the decoupling issue to the involved parties. Decoupling mechanisms are relatively new and unproven among electric utilities (California is the exception). The rationale for decoupling in the electricity industry involved the extensive risk exposure to the utility when planned revenues did not materialize since the largest portion of the revenue requirements were fixed rather than variable costs. This is not the case however for gas utilities. There have been a few gas utilities who have proposed decoupling vis-a-vis weather-normalization clauses; and regulators have been reluctant to accept these clauses in these cases for several reasons. Traditional ratemaking and the rate of return allowed to stockholders has included the risks posed by weather and the level of economic activity. A decoupler removes that risk and places the burden directly on ratepayers.

ISSUE 7 DSM POTENTIAL & MONITORING & EVALUATION

CAESCO is a party to the consensus position on this issue and would only wish to express its willingness to lend expertise in identifying the technical and achievable potential among the commercial, institutional, and industrial sectors. Estimating the potential for load savings through energy efficiency among these sectors is, and should be, an entirely different approach than determining the potential for prescriptive measures among residential and small commercial customer sectors. ESCOs can provide their knowledge and expertise, to ensure that the introduction of new measures are well-planned and coordinated so that they do not create a malfunction of other systems.

ISSUE 8 RATE DESIGN, ISSUE 9 JURISDICTION AND ISSUE 10 IMPLEMENTATION OF IRP

CAESCO is a party to the consensus position on these issues.

ISSUE 11 GUIDELINE REQUIREMENTS

> "If the Board were to decide to call for the development and submission of DSM plans by utilities, what issues must be addressed by the Board in its EBO 169 report and what specific guidelines must be provided." (Tr. 3094)

CAESCO would like to see the Board address the issue of utility/energy service company co-operation. The Board should note that the utilities have each declared the ESCOs to be strategic allies or potential partners in the delivery of demand side measures and should encourage the utilities to meet with CAESCO to discuss collaboration between the two industries before developing specific demand side programs, and to develop programs that recognize the role of energy service companies in the sectors where they are active. The discussion should cover the issues referred to in this Executive Summary in particular section 12.

The Board should also provide Guidelines:

- for recovering program costs over a period of years to reduce or eliminate the chance of not recovering costs due to any jurisdictional constraints.

- for the methodology to calculate avoided costs which should be determined based on a consensus among the utilities, possibly with the Board Staff as facilitators. Allowances should be made for the absence of conditional demand forecasts which are required to calculate avoided costs with any level of confidence.

- to guarantee cost recovery of DSM investments once a program has been accepted by the Board. They should include;
    - capitalization rates
    - short term carrying costs (eg. AFUDC: Allowance for Fuels Used During Construction)
    - definition of the administrative and overhead costs that may be capitalized or expensed
    - explicit definition of the parameters and description of funds associated with a deferral account especially since it is being proposed that prudence reviews occur after the funds have been spent

- for cost allocation for program costs not recovered from participants.

- to define lost revenues.

- of its expectations on the use of customer contributions and for incentives for the utilities to implement DSM.

- for the required periods for monitoring and evaluating programs, load impacts and the process itself.

- for the protocols for modifying or eliminating a program.

- to provide an allocation process for budgeted DSM dollars to implement programs across all sectors.

ISSUE 12 ESCO/UTILITY COOPERATION

CAESCO is of the view that the gas utilities and the Energy Service Companies have many complimentary strengths in the marketplace for demand side measures. Energy Service Companies ("ESCOs") are private businesses which are expert in the art and science of creating sustainable energy savings in facilities. The following aspects of their business are particularly relevant to the utilities' objectives and planned activities to achieve effective demand side measures.

First, ESCOs guarantee that the energy savings generated by the retrofit projects which they implement will be sufficient to repay their investment in the project, including profits, over the term of the contract. The ESCO is paid by its client only to the extent the projected savings are actually realized. In that sense the ESCOs business is performance-based. Either the ESCO consistently realizes its savings targets or it cannot remain in business. It is therefore accountable for the savings in a direct, commercial sense. It follows that any funds the utility were to spend in assisting ESCOs to penetrate markets more quickly, would have a high probability of resulting in real savings. If, for example, the gas utilities were to implement a program akin to the Guaranteed Energy Performance Program ("GEPP") of Ontario Hydro, they would only be paying for savings actually realized. The utilities would not be spending money based only on <u>the expectation that savings might or should be forthcoming</u>. The certainty of achieving the savings reduces the utility risk in engaging in demand side measures.

Second, the ESCOs take a comprehensive approach to the retrofit of a facility. All potential energy savings measures are considered and a package of incentives with a commercially viable payback is agreed to between the ESCO and the customer. As a result of the comprehensive approach the proposed retrofit measures are technically coherent and mutually reinforcing. For example, lighting and HVAC measures are considered together so that, lighting retrofits which would, if done in isolation, increase the need for further cooling, are avoided. Cream skimming or the practice of selecting just the shortest payback measures, which make the longer payback retrofit measures unfinanceable, is also avoided. Measures with varying payback periods are blended together into a project with a commercially acceptable payback period. Generally speaking, it is in the ESCO's interest to enlarge the project as much as possible up to a maximum commercial payback. Finally, both gas and electricity savings measures are considered together in ESCO projects which leads to reduced auditing, marketing and monitoring expenses. The last point is particularly important as Ontario Hydro has substantial demand side programs available, and in order to minimize costs and maximize the effectiveness of demand side measures both electricity and gas savings measures should be considered and implemented in tandem. The ESCO can work with both the gas utility and the electric utility and integrate their efforts in respect of a particular facility.

Third, ESCOs create sustainable savings. If the savings do not persist over the contract term (5-9 years) the ESCO does not recover its investment and, if savings are consistently below projections, it may go out of business. To the extent utilities spend funds to support ESCO efforts, they can be assured the savings that result will be sustained over time.

Fourth, ESCOs pay for the retrofit measures and recover their investment including profits, from the stream of savings generated. Ultimately, the user pays in the sense that it must repay the ESCO from savings and this fact introduces a commercial perspective and discipline into the transaction. There is no giveaway with an ESCO project. The project size and payback is based on its value to the energy user. The energy user pays for all of the project costs from savings and must make a conscious decision about the period of time it is prepared to cede the dollar value of the energy savings to the ESCO. The ESCO essentially removes the transactional burden.

Fifth, the presence of ESCOs in the marketplace allows the utilities to leverage their own scarce resources. To the extent that ESCOs are financing retrofit measures, the utilities do not have to. Savings are being created with little or no monetary contribution from the utility. Consequently were the utility to invest a modest amount of funds in, for example, workshops or seminars with clients to assist ESCOs in their marketing efforts, and thereby enabled them to penetrate selected markets more quickly, the leverage the utility would obtain would likely be very large. Further, were the utility to invest in ESCO projects via a GEPP-like program, the leverage on the utility investment would still be substantial since the ESCO, and ultimately the end user, would be paying the largest part of the cost. The level of the utility incentive could be set so that total program costs are well below its avoided cost and yet allow the ESCO and the end user to increase the size of the retrofit. Further, it may be feasible for the utility to coinvest in projects with ESCOs under circumstances where the ESCO guaranteed the utility an appropriate return on its investment. These possibilities should be discussed at meetings between CAESCO and each utility. However CAESCO advises caution in the use of user financial incentives in that they may distort the market place. As a short term measure, they can be justified to "jump-start" the demand side industry.

Sixth, the ESCOs have the capability to implement projects immediately. They have both the analytical and implementation skills and represent a viable delivery vehicle for utility programs. They have penetrated various end use markets, are knowledgeable about customer needs and buying behaviour in those markets and have much information that would be useful to utilities in assessing energy savings potential and designing market strategies and programs. To the extent the utility works with and through ESCOs, it need not indulge in a time-consuming process to set up a parallel delivery mechanism and embark on a costly search for information.

Seventh, the ESCO is such an effective delivery mechanism for demand side measures because it offers a turnkey service to clients ranging from energy audit and analysis through detailed design to construction and financing. The ESCO addresses the overall transactional burden. It provides not only money, but the managerial and technical wherewithal for the client to complete the project. Clients often don't have the required technical knowledge, lack the managerial time to focus on the energy savings issue and lack the capital. The services offered by the ESCO address all of these needs. In addition ESCOs reduce client confusion by offering in-depth knowledge of all utility and government incentive programs, equipment options, and the like. Customers can be confused into inaction by too many competing messages from various purveyors of programs and services. ESCOs' delivery avoids this.

Eighth, utilities would also reduce their program marketing costs by working through ESCOs since the ESCOs have already identified targets and do this in the normal course of business. In effect, they can bring clients to the utility. Conversely, for a modest investment, utilities can assist the marketing efforts of ESCOs by acting as a bridge between the ESCOs and their clients. Union Gas recognized that it might assist ESCOs marketing their services to its clients. (Tr. 920)

Ninth, ESCOs must also closely monitor savings and do the necessary "fine-tuning" to ensure savings are sustained. Since these costs are spread over a large number of projects, ESCOs can perform the monitoring and measurement functions relatively 6 efficiently. They must also measure savings in order to determine the client's bill on a regular basis. Accordingly, to the degree a utility works with or through ESCOs it can hold program monitoring and measurement costs to a minimum.

The ESCO industry is regulated and endorsed by both the federal and the provincial governments. Ontario Hydro has qualified ESCOs for the GEPP program through a screening process, as have the federal government for its FBI initiative. The federal government is promoting energy performance contracting with ESCOs as a way to reduce energy costs in federal facilities at no cost to the government. CAESCO is in the process of launching a certification program for its membership which will require that the ESCOs not only maintain certain core capabilities but continue to remain abreast of recent technological developments.

The features of the ESCOs business described above, in particular the fact that the ESCO takes the risk of energy savings being generated, can reduce the program risk to the utilities. Sustainability of savings means the utility can rely on the ESCO generated savings in its resource planning.

The utilities also offer the ESCOs a number of advantages, including enhanced credibility in the market place. As Dr. Levy stated at p. 2962,

> "I think when we look at the strengths that the utilities bring to our marketplace, one of the strengths we feel the utilities have is the ability to, in the customer's mind, bring credibility to the activities that our members propose, in other words, in the sales cycle and in the marketing, having a utility support the efforts of what our companies are doing accelerates the decision making at the customer level."

Energy performance contracting is still a relatively new approach to achieving energy savings and the industry is only a few years old. Various end users sometimes think that the ESCO story is "too good to be true", and need to be persuaded that the concept works in practice. Utilities can also assist the ESCOs by helping the ESCOs market their services to utility clients, via information programs, workshops, seminars, and other methods of bringing their clients and ESCOs together.

With respect to financing demand side measures, ESCOs would appreciate utility assistance in working with financial institutions to design appropriate financial instruments to securitize the predictable cash flow from energy savings measures and, more generally, to help the financial community better understand the significant business opportunity the performance contracting industry represents.

ISSUE 13 REPLY ARGUMENT

CAESCO's Reply Argument focused on three issues raised by Board Staff in its Argument-in-Chief, competition between utility DSM programs and established suppliers of energy efficiency products and services, shared-savings incentives for utilities to implement DSM, and the benefits ESCOs can offer utilities.

First, Board Staff in its Argument concerning cost effectiveness has touched upon an issue that CAESCO agrees with completely and finds worthy of comment. On page 16, Board Staff states,

> "If the utilities are to offer DSM programs that will compete with other major commercial distributors, it will have to be done at a price that is less than that currently available in the market place, or the utility will have to differentiate its product or service. If not, the utility will have very few customers buying their products. In addition to the problem of undercutting the existing market, if the utilities are to sell their DSM programs at a lower price than commercial suppliers, many financially non-sustaining programs will result."

ESCOs are commercial suppliers of energy efficiency services to customers. Their projects are structured and costed so that the load savings that are generated within the contract period are sufficient to just cover the cost of the investment and a profit. CAESCO prefers to work with the utilities to design and implement their DSM programs so that they reduce the payback period for all stakeholders rather than find itself in a competitive relationship with utilities that results in programs that are either financially non-sustaining or result in duplicative efforts.

Second, the Board Staff's argument on financial incentives seems focused on shared savings, as were the oral discussions during the hearings. CAESCO firmly believes in the shared savings concept as a means of incentivizing the utilities. However, it may not be the most effective approach for some DSM measures.

Current ESCO programs are initiated through the ESCOs' financial investments. They rely on a sharing of the energy dollars generated by the load savings with the customer who shares in lower energy bills after the ESCO payback period. While this is not the forum to work through the particularities of a joint utility/ESCO program serving a <u>trio</u> of stakeholders, it should be noted that a shared savings approach may not meet the needs of all these stakeholders simultaneously, at least in the early years of the program. CAESCO is concerned that any financial incentives that are provided to the utilities for DSM investments create and maintain a level playing field between those programs a utility might implement directly with end users and programs a utility might implement with or through ESCOs. The incentives should be sufficiently broad in scope as to allow them to be tailored to different types of DSM programs.

Third, at page 66, Board Staff recognizes the value of ESCOs to the utilities but states that ESCO programs are substantially different from the programs that are most logical for the utilities to adopt. CAESCO urges the Board to encourage utilities not to think of ESCO programs as efforts apart from their own. It is CAESCO's position that <u>all</u> customer classes should be included in the utilities' portfolios of DSM resources not just in a nominal sense but in a material sense. ESCO-linked programs, which focus on institutional, industrial, and commercial customers, should be adopted by the utilities along with the prescriptive programs that have been successful in the residential and small commercial markets. CAESCO advocates ESCOs and utilities working together in the design and implementation of DSM rather than moving forward on parallel paths. There are opportunities to realize savings in every sector and DSM programs need support from all customer sectors if they are going to become a viable resource.

EXECUTIVE SUMMARY OF COALITION OF ENVIRONMENTAL GROUPS

1. INTRODUCTION -- THE ENVIRONMENTAL IMPERATIVE

Judicious regulation of the gas sector offers significant opportunity to reduce Ontario's contribution to the problem of global warming. Natural gas burning in Ontario is responsible for 25% of the CO_2 emissions in the Province. With fuel switching to gas from dirtier fuels, it may make up a higher proportion of the total in the future. Clearly, in order achieve significant reductions in CO_2 emissions, both fuel switching and highly efficient use of gas will be required.

Ontario Government policy

In June 1992 the Government published A Framework for Energy Efficiency and Conservation in Ontario. It contains a number of clear messages for the Board in developing an IRP framework.

- "Energy efficiency and conservation are the first priority for meeting Ontario's requirements for energy services.
- Where barriers to an efficiently functioning market exist, other tools, such as policy direction, incentives **or** regulation or supplier development initiatives will be used.
- Ontario Hydro and **the natural gas utilities,** in partnership with others such as the municipalities, municipal utilities and other energy suppliers, **will be key players in the planning and delivery of energy efficiency programs and policies."**

Making particular reference to the gas companies, the policy outlines the following directions:

"...greater efficiency measures are needed in the gas sector.

- Natural gas utilities, in conjunction with other energy supply and service companies, are expected to be central players in achieving the Province's energy efficiency objectives.
- Ontario's natural gas distributors should assume a leadership role by encouraging the purchase and rental of energy efficient equipment, **providing customer incentives** for the purchase of energy efficient products and materials, and advising customers on the use and installation of products designed to improve energy efficiency and conservation." (emphasis added throughout)

How should the Board honour this direction? For Ontario to be a leading jurisdiction, as suggested by government policy, three mechanisms are required: DSM program cost recovery; decoupling to deal with lost revenue effects; and positive financial incentives.

Business as usual is not an option.

No one has suggested that the market on its own will internalize the environmental costs of energy use. Traditional government environmental regulation has sought to control emissions from key sources. This method has its place, but given the variety of sources and situations, control orders and standards will be both inefficient and insufficient.

Two approaches have been suggested in this hearing to augment existing controls -- internalization via taxes, and internalization via IRP.

Some advocate changes to the pricing and taxation regime to include environmental costs in all fuel prices. While this approach has obvious attraction, the government has indicated that "these actions can have serious repercussions for Ontario's economy and could severely affect the competitiveness of Ontario industry." In an economist's perfect world, all jurisdictions would impose such universal taxes, and the government's reservation would disappear. We do not live in such a world.

The second approach is that encompassed by IRP. It can be characterized as a gradual internalization, where the full social costs are considered at the point of making investment decisions. IRP is really about ensuring that funds will be invested up front in efficiency, in order to gain long term benefits of reduced operating and environmental costs. In that respect, there sometimes will be rate impacts, offset in whole or part by reductions in bills. Rate impacts will occur where the savings accrue in the form of a cleaner environment. Further, those who choose not to participate, will quite appropriately, be asked to share in the cost burden of internalizing previously externalized environmental damage.

The CEG notes that the consensus statements developed by many of the parties to this hearing reflect widespread agreement as to what must be done, and provide significant guidance to the utilities in developing DSM plans. The Coalition strongly urges the Board to adopt these positions. Hereafter, we identify the CEG's preferred resolution in areas where there remains disagreement among the parties, and make suggestions on how the guidelines could be further elaborated upon.

ISSUE 1

A: Costing methodology -- Refer to consensus statement.

B: Extent of reliance on DSM

Within the consensus positions, parties to the hearing have agreed that a societal cost test and inclusion of externalities are among the key tools for carrying out this task. The CEG takes from this that a paraphrased and clarified definition of IRP in this hearing would be "...to meet society's energy service needs at the lowest total social cost".

Given this background, the definition requires that all DSM which is less expensive than supply should be pursued, where "less expensive" includes both the financial and the external costs of both options. Only a strategy that pursues all such DSM will succeed in achieving the result of minimizing the total cost of meeting society's energy service needs.

Practically, this means that all DSM measures and programs that pass the Societal Cost Test as defined and applied under Issue 2 should be pursued vigourously. This test indicates whether or not the DSM option (and its second order effects) is cheaper than avoided costs, including externalities. Some exceptions, properly documented and justified can be made, but these exceptions should not become the rule.

An approach that achieves only a portion of the cost-effective DSM potential will, by definition, result in higher cost (energy bills and environmental costs) than necessary.

Reject arbitrary DSM limits

The Board should reject a priori limitations on this proposal, such as "no rate increase from the portfolio". Such a policy could serve to unduly restrict DSM activity and arbitrarily limit the benefits of IRP.

A "zero rate impact portfolio" is inappropriate, because this approach would likely result in missing DSM opportunities which will become "lost opportunities". Without a willingness or ability to invest up to the full social value of the measures, utilities' DSM programs will not go as far as is socially cost-effective. The effect of separating DSM measures into "cheap ones now, more expensive ones later" is to increase the overhead cost such that the cost of obtaining the second round of measures is no longer cost-effective -- it is a recipe for "cream skimming" that must be rejected.

ISSUE 2 -- See consensus statements.

ISSUE 3 -- Should societal and/or environmental externalities be included in the cost analysis of demand side management programs? If so, how should these costs and benefits be included?

Externality valuation is consistent with user pay

It has been implied that externality valuation involves raising customer's rates to confer benefits upon others. In fact, the purpose is to have the customers who are currently enjoying the energy service benefits gradually take responsibility for the costs of reducing the externalities they impose on others:

> MR. CHERNICK: A. The primary purpose of monetizing externalities...is to internalize the costs which are currently being imposed by the users of the energy on the rest of society, internalize that in the decisions about the energy source without necessarily imposing the full costs on those users. It's consistent with the principle of polluter pay, but without some of the burdens of the direct taxation. [V.10, pg 1453]

Partial monetization is better than none - precision is not necessary

Where environmental impacts are certain to be created, but the amount is uncertain, then zero is clearly the wrong answer to valuing those impacts.

> "Externality estimates need not be perfect or completely accurate to be useful in energy planning. Energy planners routinely use estimates and approximations where necessary. There is probably no one in this room who can precisely estimate the cost of gas in the year 2000, if they are I think they will probably be very wealthy.
>
> Energy planners routinely use estimates and approximations when they have to. The appropriate standard to be applied is whether the values incorporated are so imprecise and inaccurate that we will make poor decisions when externalities are considered than if they were ignored.
>
> As has often been stated in the current system, the value of social and environmental externalities has generally been set at zero, which would appear to clearly understate the value of these existing externalities.
>
> Furthermore, the recently stringent environmental regulations and restrictions on energy supply and consumption that have been applied over the last several decades, reflect the fact that society believes that the existing residual damages are significant and should be reduced.
>
> To the extent that this trend of more stringent regulation is likely to continue, the application of externality values can be viewed as a forward looking exercise that will help to reduce the cost of complying with those future regulations." [Mr. Goodman V.14, pg. 2412]

The Board's original discussion paper (Exh. 1.11, pg 131) observed "Planning in general is fraught with uncertainties, so their presence should not necessarily prevent considering externalities."

No need to assess environmental problems

Adopting an approach of including externality costs in the gas system planning process does not require the OEB to become expert on all the environmental issues and their severity in order to value them appropriately. Adoption of the Cost-of-Control approach leaves these decisions to the environmental regulators, and simply values reductions in these pollutants from DSM activity at the value of avoiding the cost of controlling them by the alternative method.[1]

Can externality policy work without other fuels being covered?

Pending application of this approach to other fuels the Board should not delay its application to gas. The OEB should take a leadership role. Just as the absence of child labour laws in competing economies was no excuse for delaying reform at home, the absence of adequate environmental impact internalization in other fuel sectors should be no excuse here. Monetization of externalities in the gas sector will surely speed the application of that approach to other fuels, whether in OEB jurisdiction, or elsewhere.

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1 Using the cost of control approach has been supported by Union Gas (Ex.4.1, pg 4-46), Centra Gas (Ex.1.9, V.3, pg 687), the CEG (V.10, pg 1458), the Consumers Association (Ex.6.2, pg 2) and Pollution Probe (V.18, pg 3401). At V.5 pg 591 and V.6 pg 823, Mr Taylor from Consumers Gas endorsed this approach as well.

ISSUE 4 -- See consensus statements.

ISSUE 5 -- Who should pay for DSM programs? Should the principle of user pay apply to DSM programs?

It is the CEG's position that the existence of market barriers and imperfections, including the externalization of environmental costs, necessitates various actions, including the incenting of conservation measures by public utilities. Some object to this approach as being in conflict with user pay. However, the CEG submits that this approach is in accord with the polluter pay principle and is therefor entirely consistent with user pay broadly defined. Mr. Chernick discussed the point in the context of externalities:

> Given the role of externality valuation it's particularly appropriate to apply externalities in the valuation of demand management where all customers are paying for measures and those customers who choose not to participate in the programs and remain non-participants, have the largest environmental effect, impose the greatest costs on other parties and, therefore, should be paying the largest part of the costs of the programs intended to mitigate or offset some of the effects of their actions. V.10, pgs 1453/54

ISSUE 6 -- Decoupling and Incentives

Rationale for Decoupling and Shareholder Incentives

The rationale for incentives and decoupling is the need to obtain all appropriate DSM, not just the most lucrative, easiest, most obvious, or least threatening to the utility or its affiliates.

Even if the regulatory regime were neutral as between conservation and supply (as we argue it must become) there are at least four reasons for creating a positive tilt in favour of conservation through use of "carrots and sticks".

First, the reality of institutional inertia must be overcome.

Second, all three LDCs are controlled by shareholders with major upstream gas interests. Even in the absence of affiliate gas transactions, there is a conflict of interest with respect to conservation aspects of DSM. Conservation will affect the market for, and price of gas. Especially in the early days of gas IRP, upstream interests will have an interest in supporting a less aggressive approach among the precedent setting utilities. Accordingly, this conflicting interest must be overcome by regulatory incentives favouring conservation.

Third, in the absence of full cost internalization and marginal cost pricing, customers do not see a correct price signal that reflects true costs. For this and related reasons utility action is required to overcome market barriers and imperfections at the customer level.

Finally, in recognition of the societal and environmental benefits of conservation, government policy strongly favours conservation. This Board should enthusiastically pursue that policy direction both in deference to the democratic institution and because the policy has obvious wisdom. The specifics of government policy are discussed above in the Introduction section of this argument.

The existing regulatory regime creates an incentive for the utilities to build load, regardless of its social utility. While in the long run there is an incentive to add rate base either by conservation or supply additions, in the rate year conservation efforts are positively discouraged while supply additions are positively rewarded. The existence of this "tilted field" is not in dispute. However, the utilities argue that decoupling of revenues from throughput is a response that is greater than needed to overcome the current disincentive to conservation -- that it has undesirable side-effects in terms of the impact on load building efforts and rate stability.

As we discuss at length in the body of our argument, all of the utility objections are either inapplicable, exaggerated, or the potential for negative impact is easily mitigated. Indeed, at least one concern, that weather and economic cycle variances are far greater than any anticipated conservation variance, suggests a further benefit of decoupling, that the avoidance of these risks can improve utility management and lower customer costs.

Particularly important, in our submission, is the fact that those who object to decoupling have offered no workable, fair and efficient alternative to overcome the problem.

Conclusions on Decoupling

Despite a very creative effort on the part of the utilities opposed to decoupling, the evidence in this proceeding rebuts each and every concern raised against decoupling and offers several undisputed benefits, not the least of which is a level field for conservation.

The existing regulatory regime tilts against conservation. Decoupling will level the field. It will reduce regulatory complexity. It will reduce utility business risk and therefore save customers money. It will eliminate the perverse impacts of weather and economic cycles on utility management. It will not have any significant unmanageable negative side-effects. If conservation is to be of equal profitability to utilities (let alone the most profitable course) full decoupling for all 3 utilities is a must.

ISSUE 7 -- See consensus and comments on Issue 11.

ISSUE 8 -- See consensus.

ISSUE 9 -- If the Board decides that DSM implementation is appropriate, are there any current jurisdictional constraints which need to be addressed in order to fully implement a DSM effort?

The Board has jurisdiction to implement a DSM effort including decoupling. Clarification of its jurisdiction to offer utility incentives and adjust rate of return to foster DSM would be desirable to avoid any possible challenges from reluctant utilities or other parties. Further, jurisdiction should be sought to provide advance funding to interested parties for collaborative efforts (though the utilities may fund these efforts voluntarily if given reasonable assurances of cost recovery). The ability to convene joint electricity and gas hearings should be made explicit, especially if it is anticipated that the Board may obtain regulatory powers in regard to Ontario Hydro as we suggest it should.

ISSUE 10 -- Should the Board proceed with the implementation of IRP and, if so, how should it proceed?

The Need for full IRP:

A logical approach to DSM requires evaluation of avoided costs, the cornerstone of IRP. Utilities will be called upon to defend their assumptions about avoided costs to demonstrate that they are pursuing an appropriate level of DSM. Accordingly, the work associated with IRP cannot be avoided by restricting the intended regulatory review to a focus on DSM aspects in rate cases. Supply side aspects will emerge as issues in any event. This proceeding has not adequately considered the supply side and avoided costs side of IRP. By formalizing the full IRP process the Board can ensure timely public involvement and encourage pre-submission collaboration to narrow issues in dispute. IRP will result in a reduction of regulatory risks and will ensure that social and customer costs are minimized.

ISSUE 11 -- If the Board were to decide to call for development and submission of DSM plans by the utilities, what issues must be addressed by the Board in its E.B.O. 169 Report, and what specific guidelines must be provided?

We refer the Board to Exhibit 5.1.1 at pages 3-7 - 3-11 where we provide a listing of information requirements that should be met in utility filings. In addition utilities should demonstrate how they intend to capture all lost opportunity resources.

Utilities should not simply provide a single preferred plan. Alternatives should be presented in detail.

In particular utilities should include:

- program alternatives;
- measure bundle alternatives for each program;
- alternative program costs;
- alternative measure costs;
- customer incentives by measure;
- assumed penetration of each program and measure in each customer niche;
- for each measure provide an evaluation of the impact of increased or decreased incentives on penetration;
- UCT, RIM, PCT, TCCT, SCT results for each measure and program and for the portfolio and for each alternative at each level.

Please note that we have made a number of specific suggestions throughout the argument on issues 1-10 which we do not repeat here.

EXECUTIVE SUMMARY OF THE CONSUMERS' ASSOCIATION OF CANADA (ONTARIO)

I. INTRODUCTION

1. Consumers' Association of Canada (Ontario) (CACO) is the Ontario Branch of a national organization, the Consumers' Association of Canada, formed to protect and promote the interests of residential consumers. The objective of CACO in its participation in EBO 169 has been to protect and promote the interests of residential consumers in integrated resource planning (IRP) for the supply of natural gas by the Consumers' Gas Company, Union Gas Limited and Centra Gas Ontario Inc (hereinafter referred to collectively as the LDCs)

2. CACO believes that the OEB's inquiry in EBO 169 has three principal goals, as follows:

   - To determine whether IRP should be adopted for the natural gas industry in Ontario;
   - To determine what IRP consists of;
   - To determine how IRP should be implemented.

3. CACO believes that IRP is in the best interests of residential consumers and other stakeholders, and would contribute substantially to the achievement of the Ontario government's stated policy of achieving optimum energy efficiency.

4. CACO accepts that one of the goals of EBO 169, namely the exploration of what IRP consists of, necessitates an examination of demand side management (DSM) measures. CACO believes, however, that the OEB must distinguish between the specifics of DSM measures and the broader context of IRP. CACO does not believe that a selection of DSM measures alone constitutes IRP. CACO believes taht the OEB should, in its report, provide a comprehensive definition of IRP and relate DSM measures to that definition.

5. CACO believes that the United States experience with IRP demonstrates the central importance of an effective institutional framework for IRP in order to ensure the existence of the following matters, which are themselves critical to achieving the goals of IRP:

   1. The development of effective and cost effective DSM programs that minimize the cost requirements to the utilties, both in the short and long run, as well as produce other societal benefits;

   2. An orderly and systematic way to determine what actions or resource options are most cost effective for the utility to pursue;

   3. A means to ensure public input into the process at meaningful and critical points;

   4. A body with the ability to determine and promote the public interest in IRP;

   5. A means for formal consideration of the LDCs' entire integrated resource plan.

6. CACO believes that substantial progress has been made, through the EBO 169 process, in determining whether IRP should be adopted for the natural gas industry in Ontario, in determining what IRP consists of and in determining how IRP should be implemented. That progress is embodied in the consensus positions on the individual issues identified by the OEB. However, those consensus positions are static, and do not in and of themselves suggest a method of implementation which would give maximum effect to them. The key for the OEB is to find a method of implementation which gives maximum effect to the consensus positions.

II THE ISSUES

7. CACO accepts the consensus position on Issue 1.

8. CACO accepts the consensus position on Issue 2.

9. CACO accepts the consensus position on Issue 3. The consensus position contemplates the creation of a working group to report on the recommended methodology for the treatment of externalities to be included in LDCs' societal cost tests. CACO believes that the OEB should issue separate guidelines to the working group directing it as follows:

   1. To provide the best current control costs for emissions, other than carbon dioxide, arising from the use of natural gas;

   2. To provide for carbon dioxide emissions, for which no control technology exists, a survey of the monetary values which have been proposed for the environmental effects of carbon dioxide emissions and the levels of carbon tax which have been proposed to attain certain policy goals;

3. To provide an analysis of the reasons for the wide range which exists in those numbers.

10. CACO accepts the consensus position on Issue 4.

11. CACO accepts the consensus position on Issue 5.

12. CACO accepts the consensus position on Issue 6, part 2(a) dealing with the decoupling of profits and throughput volumes. CACO is concerned, however, that a focus on decoupling may distract the OEB from the larger issues in its inquiry in EBO 169. CACO suggests that decoupling is a useful tool which can be employed in certain circumstances to promote the attainment of the goals of IRP. CACO suggests that it is essential that the OEB, in establishing an institutional framework for the achievement of the goals of IRP, provide a flexible mechanism for the optimum use of decoupling.

13. CACO accepts the consensus position on Issue 7.

14. CACO accepts the consensus position on Issue 8.

15. CACO believes that the treatment of Issues 9 and 10 is critical to EBO 169 and to the recommendations which are to be included in the OEB's report. CACO's position on issues number 9 and 10 is broken down as follows:

a) <u>**The OEB's Present Jurisdiction**</u>

16. CACO, together with all of the other parties to EBO 169, accepts the position that the EBO, under its present legislation, does not have the jurisdiction to do any of the following:

    1. Order the LDCs to develop integrated resource plans using criteria established by the OEB and then approve the plan and the implementation of the plan;

    2. Order the LDCs to develop integrated resource plans using a collaborative process whereby input into the development of the plan is acquired by various interested parties through working groups;

    3. Order the LDCs to develop and pursue DSM or conservation or load management programs.

17. CACO, together with all of the other parties to EBO 169, agree that the OEB has the jurisdiction to do the following:

    1. Take IRP principles into account in establishing rate base, setting the rate of return and fixing just and reasonable rates. The OEB cannot, however, fetter its discretion and must consider each case on the evidence before it and on its merits;

2. Issue recommendations on IRP and the appropriate principles and inform the utilities that these principles will be taken into account in the utility rate cases. Again, the OEB cannot fetter its discretion.

18. CACO also believes that the OEB does not have the jurisdiction to approve the cost consequences of some DSM measures, for example those which involve the payment of incentives and reflect a value-of-service approach rather than a cost of service approach.

19. CACO believes that the OEB does not have the jurisdiction to require the LDCs to consult with interested parties in the development of DSM measures and does not have the jurisdiction to impose a sanction on the LDCs should they fail to consult either at all or in a meaningful way.

20. In light of the accepted limitations on the OEB's jurisdiction, two alternative approaches are possible. One is to pursue IRP goals through DSM measures within the existing legislation. The other is to have a legislated IRP.

b) <u>The Pursuit of IRP Goals Within the Existing Jurisdiction</u>

21. Several parties to EBO 169 have recommended a model for the pursuit of DSM measures within the existing OEB jurisdiction. Under that model, the OEB would issue guidelines embodying the consensus positions reached in EBO 169 and would require the LDCs to present a portfolio of DSM measures based on those guidelines in their rate approval applications. In addition, under the proposed model, the LDCs would voluntarily consult with stakeholders on DSM programs. The nature and extent of that consultation would be left substantially in the discretion of the LDCs. The guidelines would give a substantial measure of assurance to the LDCs that investments in DSM measures would be accepted, now and in the future, for rate-making purposes.

22. CACO submits that the model outlined in the preceding paragraph would be inadequate to achieve the goals of IRP, for several reasons. Chief among those reasons are the following:

    1. Under the existing OEB jurisdiction, guidelines are not binding. Any attempt to enforce those guidelines brings with it the risk of a court challenge to the correctness of the OEB's actions;

    2. All DSM measures must be evaluated solely on the criteria of their relationship to rates. The OEB may not be able to accept all DSM measures within the existing legislation, for example, those predicated on incentives or a value-of-service approach;

    3. The OEB, and through it both the government and stakeholders, can never be certain that the goals of IRP are being pursued in a way which achieves the maximum benefit for society.

23. CACO does not believe that a legislated IRP would impose a burdensome and complex additional process. On the contrary, CACO believes that a legislated IRP would simplify rate hearings and would allow the OEB to focus on the key issue of achieving the goals of IRP. CACO accpts that

a legislated IRP would add additional costs for the OEB, the LDCs and the stakeholders. CACO believes, however, that those added costs would be present even when DSM measures are pursued within the existing legislation and that the additional costs are justified by the benefits to be achieved through a legislated IRP.

c) **A Legislated IRP**

24. CACO believes that there are five principal benefits to be obtained through a legislated IRP, as follows:

1. A legislated IRP would ensure that the integrated resource plans of the individual LDCs are constructed and implemented with the overriding objective of minimum resource cost. It would also ensure that such plans are implemented in a timely fashion. It would also ensure that there was a means of resolving conflicts between various stakeholders in order to ensure that individual IRPs are planned and implemented.

2. A legislated IRP ensures that a regulatory body like the OEB has the authority to resolve disagreements and to require individual LDCs to take appropriate steps when required. That regulatory body must have the legislative authority to ensure that individual integrated resource plans are in the public interest and that they are being pursued effectively;

3. A legislated IRP is the only way to ensure that there is an opportunity for public input in a meaningful context. Different stakeholders have different interests in the nature and extent of public participation. The nature and extent of that public participation should not be left to the discretion of the LDCs. Inadequate public participation cannot properly be dealt with in after-the-fact compliance reviews;

4. A legislated IRP ensures that pursuit of IRP goals is not sidetracked by arguments about jurisdiction;

5. A legislated IRP reduces the regulatory and therefore, the business and finance uncertainties and risks for the LDCs. In addition, a legislated IRP simplifies and shortens rate approval proceedings.

III THE RECOMMENDATIONS OF THE CACO

25. CACO submits that the OEB should make the following recommendations in its report:

1. That the legislative framework for a formal IRP be established;

2. That that legislation require, at a minimum, the following:

   (i) that IRP is a defined term;

(ii) that each LDC file an IRP for a ten year period;

(iii) that each IRP is to include an assessment of all DSM and supply side measures, with a proposal as to which ones are to be followed and which are not, with reasons therefore;

(iv) that prior to and as a condition to the filing of each IRP, each LDC is to consult formally with at least the participants in EBO 169;

(v) that, as a part of that formal consultation, the LDCs are to provide the participants with sufficient data to permit the participants to evaluate independently the accuracy and completeness of each component of the IRP;

(vi) that each IRP be reviewed on a regular basis to assess whether it is meeting its goals, whether changes are required and, if so, what those changes are;

(vii) that interested parties be entitled to participate in the regular, periodic reviews of the IRPs;

(viii) that the OEB be entitled to issue guidelines on aspects of IRP including the design and evaluation of DSM measures and the treatment of their costs. Those guidelines should, to the extent practicable, embody the recommendations in the consensus statements and should be sensitive to the need for incentives for the LDCs to pursue certain DSM measures;

(ix) that the OEB has the authority to approve, disapprove or modify each IRP, including the financial incentives to the LDCs;

(x) that the LDCs may require some financial incentives to achieve the goals of IRP and that, accordingly, the legislation permit the OEB to adopt different approaches to the setting of rates to permit the use of such incentives.

26. Pending the legislative changes, the OEB should issue guidelines on DSM measures. Those guidelines should, at a minimum, do the following:

(i) require the LDCs to prepare a portfolio of DSM measures to be considered at their next rate application;

(ii) require each LDC to include in the portfolio of DSM measures an evaluation of those DSM measures with a proposal as to which ones are to be followed and which are not, with reasons therefore;

(iii) require each LDC to consult with all participants in EBO 169, prior to the filing of the rate application, on the elements of their DSM portfolio;

(iv) require that, as part of that consultation, the LDCs provide participants with sufficient data to enable them to independently evaluate the accuracy and completeness of the DSM portfolio;

(v) that included in the guidelines be guidelines on the design and evaluation of DSM measures and the treatment of the costs of those DSM measures. Those guidelines should reflect, to the extent possible, the recommendations embodied in the consensus statements;

(vi) that intervenor funding be made available for all participants to cover the costs of an independent review of DSM portfolios.

27. CACO, in numbered paragraph 8 hereof has recommended that the OEB issue guidelines to the working group on externalities contemplated by the consensus position on Issue number 3.

28. CACO believes that the consultative process is critical to the success of IRP. CACO believes that, for that process to be successful, funding must be provided to stakeholders. CACO suggests that that funding should be provided under the Intervenor Funding Project Act and should be recoverable by the LDCs in their rates.

EXECUTIVE SUMMARY
OF
THE CONSUMERS' GAS COMPANY LTD.

ISSUE 1 DEMAND-SIDE OPTIONS - COSTING & FORECASTING

The Consumers' Gas Company Ltd. ("Consumers Gas" or the "Company") supports the use of avoided supply-side costs as the basis for costing Demand Side Management ("DSM") programs. Avoided costs should quantitatively include monetized external costs, where available. Relevant, non-monetized external costs should be considered qualitatively.

Demand-side options should be given equal consideration with supply-side options in meeting forecast demand, allowing for appropriate flexibility in both demand- and supply-side plans. The expected results for accepted demand-side programs should be included in the regulatory demand forecast, and thus be reflected in supply-side plans.

ISSUE 2 COST-EFFECTIVENESS TESTS FOR DSM PROGRAMS

Consumers Gas supports the use of several tests to assess the cost-effectiveness of proposed DSM programs. These are:

a) the Societal Cost Test ("SCT"), which includes all quantified costs and benefits of a given program without regard to which parties bear the costs or receive the benefits, and which therefore excludes simple transfers between parties (e.g., customer incentives);

b) the Total Resource Cost Test ("TRCT"), which is equivalent to the SCT without externalities;

c) the Rate Impact Measure Test ("RIM"), or Non-Participant Test, which measures the change in a utility's revenue requirement and the resulting revenue changes due to programs; and

d) the Participant Test, which measures costs and benefits from the perspective of program participants.

The EBO 134 feasibility analysis should be modified to be consistent with the DSM analysis. Thus, for both supply- and demand-side analyses, the SCT would serve as the primary screening, or Stage 1 test. Stage 2 would then consist of the RIM and Participant Tests, designed to address issues of "who pays", cross-subsidization, and program design features such as customer contributions and/or incentives. Qualitative factors would be considered at Stage 3.

Consumers Gas is of the view that EBO 169 is properly constituted to address, and, if appropriate, implement modifications to the EBO 134 analysis.

ISSUE 3 EXTERNALITIES

Consumers Gas supports the inclusion of monetized externalities in the Societal Cost Test. To the extent that relevant externalities remain non-monetized, they should be considered qualitatively when evaluating program cost-effectiveness.

Consumers Gas supports the working group proposal, and is of the view that results will be produced quickly and cost-effectively by pursuing the informal, consultative approach contemplated in that proposal. Consumers Gas is prepared to provide funding for the working group, subject to a budget for its operation being accepted by the Board as eligible for inclusion in its cost of service.

ISSUE 4 INVESTMENTS IN DEMAND-SIDE OPTIONS

The appropriate cost recovery mechanism for the direct costs of DSM programs is one which recognizes the expense and investment nature of the costs.

Specifically, direct DSM program costs should be recovered by: 1) dividing the costs into capital investments and operating expenses, where capital investments are those expenditures with longer-term benefits and operating expenses are those expenditures with shorter-term benefits; 2) recovering the operating expenses through the cost of service, in the year in which they are incurred; 3) treating the capital investment portion of the DSM program costs in a similar manner to traditional rate base components, with the amortization period being the lifetime of the technologies or the period over which the benefits are to be realized; and 4) establishing deferral accounts for DSM operating and capital expenditures, with carrying charges and with disposition of the balances in the next rate period.
This cost recovery mechanism places all resource options, demand-side and supply-side, on an equal footing. It also facilitates the implementation of large scale, cost-effective DSM programs and provides the utility with greater flexibility to respond to a program's success or failure.

ISSUE 5 WHO PAYS?

Customers who are the direct beneficiaries of a program should bear, to the extent possible, the direct financial cost of the program in order to minimize the rate impacts of the program. However, this consideration should be balanced against the objectives of achieving reasonable customer participation rates and other factors such as avoiding lost opportunities. While the overall portfolio of DSM programs should not impose an undue rate impact, a strict 'user-pay' approach would unduly limit the scope and benefits of DSM programs.

Allocation of DSM program costs not recovered from participants should recognize and be proportional to the distribution of program benefits. To the extent that the benefits fall outside of the target group, customers receiving those benefits should bear a commensurate portion of the costs.

ISSUE 6 PART 1: INCENTIVES

In order that the private value to the utilities of pursuing DSM programs be aligned with social objectives, shareholder incentive mechanisms that reward successful implementation of cost-effective DSM should be made available to the utilities. The incentive mechanism must be meaningful to utility shareholders and managers, and to the financial markets, while being fair from a customer perspective.

The incentive mechanism should be tailored to the individual circumstances a utility operates within, and should be flexible enough to accommodate an appropriate range of different DSM program designs and objectives. It should also be performance-based. One appropriate incentive mechanism is the "Shared Savings" approach, whereby a utility would retain a reasonable, yet significant proportion of the net savings arising from a DSM program, subject to the achievement of a threshold level of performance.

The incentive percentages and the associated performance thresholds applicable to differing programs should depend, in part, on the circumstances of the individual utility and the market it serves, the type of DSM program involved, and the difficulty or risk of instituting the program. The performance measures used to determine the amount of the incentive payment for a particular program would be presented to the Board at the same time that the program itself was proposed for approval. These measures would be based on the same estimates of unit program performance that were used to evaluate the cost-effectiveness of the proposed program, and to determine the amount of the distribution margin adjustment, if necessary.

In the case where a program was instituted but did not meet the threshold level of performance, the utility would not be eligible for shareholder incentives, despite the effort and resources devoted to the program, and the net positive savings resulting therefrom. In this circumstance, the failure to earn the incentive payment, in and of itself, constitutes a significant penalty to the utility which utility managers would naturally seek to avoid. Therefore, additional penalties are unnecessary and inappropriate.

ISSUE 6 PART 2: DECOUPLING

Consumers Gas supports partial decoupling as a reasonable and balanced response to the concerns of those who believe that a utility will not aggressively undertake conservation DSM if the existing link between profits and throughput volumes is maintained.

Partial decoupling is a mechanism which specifically and exclusively captures variations in distribution margin, resulting from variations in DSM program performance relative to budget. This is in contrast to full decoupling, which does not distinguish among the factors that operate to cause variances from budget in throughput volumes.

In comparison to full decoupling, partial decoupling would also accomplish the following:

a) it would remove the disincentive created by full decoupling to pursue socially desirable additional sales to existing customers;

b) the potential size of the deferral account balance arising from partial decoupling would likely be less than that under full decoupling, since the focus would be restricted to variances in distribution margin due to variances in the performance of conservation DSM programs and not due to other factors such as weather or the economy;

c) as a result of (b), legitimate concerns with respect to rate variability, particularly for industrial customers, would be addressed;

d) also as a result of (b), risks to both the utilities and the Board would be lessened; and

e) the concerns of parties on both sides of the issue as to how full decoupling would affect utility risk and return on equity would be eliminated.

Partial decoupling and a shareholder incentive mechanism require much the same information, so that partial decoupling does not introduce additional regulatory complexities.

Partial decoupling could and should be symmetrical, so that it applies to situations where the conservation DSM efforts are more successful than forecast and those where the efforts are less successful than forecast. This symmetry would ensure that both customers and the utility are protected.

The disposition of the partial decoupling deferral account balance should be addressed during a rate proceeding. Its disposition must occur independently of the utility's earnings position due to non-DSM related factors, if demand-and supply-side options are to be equally aligned. Also, linking the disposition of the balance to non-DSM factors for which the utility is at risk, would act to maintain the financial disincentive to conservation.

Since partial decoupling seems to offer the optimal resolution to the disincentive issue, its adoption would result in a regulatory principle which could be widely embraced and consistently applied across the utilities by the Board.

ISSUE 7 MEASURING AND MONITORING DSM PROGRAMS

For programs which are determined to be cost-effective, utilities should develop estimates of achievable potential using the best available information from sources such as test marketing, focus groups, and similar programs conducted by the utility or other utilities. Utilities should attempt to maximize achievable potential of cost-effective programs through careful program design and implementation.

The best available point estimates of the volumetric impacts of DSM programs should be incorporated into the demand forecast in order to arrive at a "net" volumetric forecast.

Appropriate measuring and monitoring of DSM programs is necessary to determine their effectiveness and to obtain information used in refining program design. Incremental costs of measuring and monitoring programs must be weighed against the incremental benefits obtained in terms of increased accuracy. While a reasonable degree of accuracy is required, devotion of excessive resources to the monitoring function will impair program cost-effectiveness and inhibit the achievement of real results. As experience is gained, design, implementation, monitoring, and evaluation activities can be refined.

ISSUE 8 MANAGING DEMAND VIA RATE DESIGN ALTERNATIVES

Existing rate design alternatives adequately provide for an enhanced and expanded DSM effort on the part of utilities, and therefore there is no current need to alter existing rate structures. Initial utility DSM efforts should be aimed at implementing effective programs, which might be enhanced at a later stage with potential rate design initiatives. Furthermore, it would be imprudent to institute novel rate design alternatives before gaining substantially more experience, both directly and through monitoring developments in other jurisdictions. Therefore, the management of demand through rate design alternatives should be approached, cautiously and gradually.

Potential rate design initiatives to manage demand must be carefully analyzed to ensure that they will promote desirable objectives and at the same time, satisfy fundamental rate design principles and constraints such as market acceptance. The analysis of any rate design proposal must encompass an examination of competing objectives and the potential impact on the level of a utility's business risk.

ISSUE 9 JURISDICTIONAL CONSTRAINTS TO DSM

The Board has the jurisdiction to approve the test year ratemaking implications of investments and expenditures made by a utility to pursue DSM programs. Further, the Board has the jurisdiction to issue guidelines as to how it intends to evaluate DSM programs for ratemaking purposes within the context of a utility rate case. However, these guidelines cannot fetter the Board's jurisdiction to consider any matter before it, including a departure from the guidelines.

In the opinion of Consumers Gas, there are, however, two areas which will ultimately require legislative attention. They are:

a) whether or not DSM assets are used or useful in the same way as traditional assets; and

b) the longer-term stability of DSM plans, given the nonbinding nature on future Board panels of previous Board panels' decisions.

Without an eventual resolution of these two areas of concern, there is the potential for the appropriateness of previously approved DSM investments to be challenged and for the long-term stability of a DSM plan to be undermined.

It is essential that the utilities and the financial community have complete assurance that DSM assets are on an equal footing with traditional assets in terms of the used or useful standard. Given that the utilities may be required to raise large amounts of capital to fund substantial DSM projects and given that this may be difficult generally, the difficulty could be exacerbated if DSM investments are seen to be open to jurisdictional challenge.

Consumers Gas recognizes that putting amending legislation in place will be a time-consuming process. Therefore in the short term, the Board, the utilities, and all other interested parties can and should proceed with DSM planning and implementation without amending legislation. The Board is urged to use strong language in its EBO 169-III report to indicate its support for these early DSM efforts. However, in the long term, the regulatory concerns enunciated above can only be fully addressed by means of legislation which supports what the Board is adopting as practice. In fact, identifying the exact nature of the required legislation may be well served by a period of actual experience with DSM.

ISSUE 10 IMPLEMENTATION OF IRP

It is the view of Consumers Gas that the Board should proceed with the implementation of expanded DSM as follows.

a) The Board should issue a report with DSM recommendations and guidelines.

b) One of the guidelines would be the expectation that each utility would come forward at its next rate case with DSM programs or plans, the scope of which will be dependent upon the time available to each utility to review the Board's report, consider the guidelines and determine the best approach to implementing them.

c) Further, each utility would undertake meaningful discussion or consultations with representatives of known interested and significantly affected parties, in advance of filing a DSM plan. The purpose of the consultation would be to obtain input from parties so that the DSM programs brought forward by the utility are well targeted, well designed, cost-effective and generally, beneficial from a societal perspective. Effective consultation should tend to ensure a more efficient regulatory process with respect to DSM and a higher prospect of success before the regulator.

d) At a utility specific rate case, the Board would approve the test year impacts of those aspects of the DSM plan which it considered to be just and reasonable, with consideration given to the guidelines issued in EBO 169-III. Ongoing cost recovery would be the subject of future rate cases.

e) Changes in risk (e.g., forecasting, business, regulatory, jurisdictional) arising from the implementation of DSM should be evaluated at the time DSM proposals are made by a utility.

With respect to Integrated Resource Planning ("IRP"), the Board should use its current legislative mandate to the fullest extent possible to pursue the goals of IRP.

Attaining the benefits of IRP, which are predominantly related to DSM, can be fully accommodated within the context of a rate proceeding, both in the short term and in the long term. A full range IRP process, with hearings separate from a rate proceeding, is not necessary. The test year ratemaking implications of a utility's investments and expenditures on DSM can only be approved in a rate proceeding. Therefore, a separate IRP hearing would only add to the complexity and the cost, since to some extent, the examination of certain DSM and IRP issues would have to be repeated in a rate hearing in any case. Separate IRP hearings would also not be conducive to getting on with DSM initiatives in the nearer term.

It cannot be determined now whether further generic hearings on other aspects of IRP will be necessary in order to pursue the goals of IRP. After the first round of DSM plans is considered, it may become apparent whether further generic investigations into supply-side or integration issues are required. The Board should make this determination in consultation with the interested parties.

ISSUE 11 EBO 169 REPORT

In its report, the Board should find that moving forward with DSM programs is in the public interest.

The major elements or issues which must then be addressed by the Board, in order that parties may proceed with DSM, are covered by the ten issues which have been discussed in the EBO 169-II and EBO 169-III proceedings.

If the Board adopts the Consensus Position Statements contained in Exhibit 1.10 and to which Consumers Gas and others are parties, then the guidelines required to move forward with DSM programs will be in place. To a large extent, the Consensus Position Statements are reflected above, in the summary of the Company's position on the ten DSM issues.

There are, however, three particular areas which, in the Company's view, require additional findings by the Board. First, for the reasons summarized above under Issue #6 - Part 2: Decoupling, the Board should find that partial decoupling is a reasonable and balanced resolution to the disincentive issue regarding conservation DSM. Second, the Board should find that in principle, capital investments contemplated in the DSM process are used or useful in serving the public interest. Third, as summarized above under Issue #3, the Board should find that it supports the overall purpose of the working group on externalities and should issue clear guidelines on the timing of the group's reports and on an acceptable approach for financing the operation of the group.

By adopting the principles and guidelines proposed by the Company, the Board will have provided sufficient guidance and direction for parties to continue to work together to advance DSM, and to learn and consequently enhance the DSM process.

OTHER ISSUES AFFILIATE GAS SUPPLY TRANSACTIONS

Neither of Pollution Probe's recommendations on affiliate gas supply transactions are warranted because: 1) affiliate gas supply transactions do not currently represent a substantial proportion of the Company's total requirements; 2) all new supplies are acquired through a public tendering process; 3) the limitations as proposed by Pollution Probe would constrain the Company's future contract negotiations for gas supply; and 4) through the public hearing process, the Board and other interested parties have ample opportunity to review affiliate transactions to ensure that such transactions are not impairing the aggressive pursuit of energy conservation.

EXECUTIVE SUMMARY OF ENERGY PROBE

I. INTRODUCTION

Should Ontario's natural gas customers be allowed to make consumption decisions for themselves, or should they be required to turn decision-making authority over their gas usage to a bureaucratic elite of paternalistic "experts" who claim to know what is best for them?

This is the most important issue facing the Board, and the Board must choose between two vastly different roles for itself: on the one hand, it can decide that Ontarians are incapable of determining how best to meet their energy needs, and disempower the consumer by validating central-planners. If so, it must then permit, or encourage, or even compel the LDCs to subsidize the provision of certain demand-reducing goods and services to some customers with funds collected from other customers. After having made that decision, the Board and the LDCs must commit themselves to a never-ending and, we submit, ultimately fruitless process of conflicting "expert" evidence, argument, regulatory oversight, and monitoring, to determine whether the benefits that were theoretically promised from the subsidies actually materialized, or whether the programs have actually done more harm than good.

On the other hand, the Board can decide to empower the individual gas customer, as it did in its far-sighted 1985 decision to allow residential customers to contract directly for their own gas purchases. If the Board opts to empower the customer, it will work to enhance the free flow of information to customers by encouraging the pursuit of these customers by marketers of both demand-reducing and demand-increasing goods and services that may improve their lives; it will work to further refine the financial accuracy of the price signals these customers receive, so that they will know and consider and incur the true financial costs and benefits of their decisions; it will prod the governments of Ontario and Canada to impose a regime of "green" emissions taxes or of tradable emission rights to incorporate environmental costs into the prices of fuels and all the goods and services made from them; and it will ensure that the LDCs give all due attention to their main mandate -- to provide natural gas and directly related customer-driven services, at least profitable cost, to their customers.

Centrally-planned subsidized DSM programs are characterized by complexity and arbitrariness, by untenable *ceteris paribus* assumptions, by a tendency to equate low gas use with social good, and, ironically, by a tendency to redistribute wealth from poor to rich. Centrally-planned DSM programs are justified by the same philosophies as the well-meaning but largely failed policies of centrally planned economies, and share the untestability of most of their claims, both in advance and after the fact.

ISSUE 1, PART 1 **Costing Methodology**

There is only one way, in our submission, to reliably calculate the total net value of goods and services to those who receive the goods and services, and that is to measure their willingness to pay a price approaching that total net value. Any alternative, theoretical valuation methods based on untestable or provably false assumptions about "equivalent energy services" or "all other things being equal" or "market barriers" or the like -- especially when confronted with clear evidence of well-informed customers' unwillingness to pay a price approaching the theoretically proposed "total net value" -- must be rejected as unreliable and inaccurate measures of value. Attempts to force customers to support subsidized programs should, in our submission, be categorically rejected by the Board;. as the focus group findings in Ex. 14.10 (c) suggest, "universal sharing of costs for conservation programs", as opposed to user pay, was opposed by all members of the group, who "felt quite strongly about their point of view." In any case, inserting these unreliable expert measures of other people's personal value into still more complicated and theoretical formulae to calculate total societal value will merely compound the initial unreliable and inaccurate measurement of value.

Recommendation:

Energy Probe urges the Board to rely on the willingness of well-informed customers to pay for a program as the only reliable measure of the total net value of goods and services to the people who receive those goods and services, and specifically to reject any specious arguments or theories that purport to prove that people receive far higher value from something than they are willing to pay for it.

In our submission, bringing the marginal price of natural gas closer to its marginal financial cost of supply will further inform and empower customers of all kind, and will unavoidably make their own individual "resource plans" result in lower total costs to the system and to society than at present. We submit further that the benefits of improved pricing are generally independent of, and do not conflict with, either the presence or the absence of subsidized DSM programs, or any other matters now being decided by this Board.

Therefore:

Recommendation:

Energy Probe recommends that, whatever the Board should decide on DSM subsidies and other EBO-169 issues, the Board, in conjunction with the LDCs, should take every opportunity to improve the pricing of natural gas in Ontario by making its price as financial-cost-based as practical, whether by time differentiation, or by a further "unbundling" of total gas-system cost components.

Without an accurate assessment of the marginal cost of supplying gas to each group of customers in each time period, none of these calculations can be done accurately, nor can the Board accurately determine the actual rate impact -- and therefore the appropriateness -- of any expense incurred to increase or decrease the demand for natural gas, nor can the avoided cost methodology of the Consensus Statement to Issue #1 be applied, nor can the Total Societal Cost Test recommended in the Consensus Statement to Issue #2 be applied. There is clear evidence that such an accurate assessment of the marginal cost of supplying gas does not now exist, at least in public.

Recommendations:

Energy Probe therefore recommends that the OEB, as a matter of high public-interest priority, require the LDCs to present and defend numerical estimates of the actual ("financial") marginal cost of supplying gas to each group of customers at each time.

Energy Probe further recommends that the results of these calculations be used first and primarily to refine the pricing of natural gas so that its price more accurately reflects its total financial costs to the gas system, and secondly and secondarily as a guide to the cost-effectiveness of the LDCs' demand-altering programs, and third or (better) not at all as a guide to subsidized DSM activities.

The utilities should generally pursue their least-cost option -- as measured by rate impacts for their customers -- when planning to meet their forecast demand. Their forecasters should use any and all techniques and inputs that will improve the accuracy of their results. That would normally include forecasting the demand-reducing ("DSM") activities of their customers, in conjunction with all suppliers of demand-reducing goods and services, including the utilities themselves. The utilities should give similar attention to forecasting the fuel-substituting and demand-increasing activities of their customers, which may well have even larger impacts on load.

ISSUE 2 COST-EFFECTIVENESS TESTS

Due to our concerns about the negative social, equity, and environmental impacts of increasing natural gas prices; and our concerns about the regulatory complexity and arbitrariness of judgments about the actual cost-effectiveness of cross-subsidized measures; and our concerns about the impacts of monopoly-subsidized DSM activities on the non-monopoly suppliers of DSM goods and services), we urge the Board not to encourage or permit DSM activities that are subsidized by revenues from LDC monopoly activities.

It is therefore our submission that the most appropriate cost-effectiveness test is the Rate Impact Measure or "No-Losers" Test which ensures that no customer's conservation benefits are subsidized from another customer's rate increase.

We further submit that the choice of an appropriate cost-effectiveness test, and the corresponding decision under Issue #5 about who should pay, loom especially large in this Hearing precisely because virtually all the evidence indicates little potential for "win-win" gas saving in Ontario -- gas conservation where everybody comes out paying less than under the alternative supply-side alternative.

The market for natural gas in Ontario (while admittedly imperfect, like every other real-world market) is functioning reasonably well. Specifically, this market is apparently not rife with widespread "market failures" that can be overcome with the expertise, credibility, financing, or good program design that is available to LDC experts; the gas market's main "flaw" is to be rife with customers unreceptive to DSM products and services, who can only be induced to buy at below-market prices.

Participants who only participate because of the subsidies -- i.e., who could not be induced to participate by any available (profitable) combination of marketing/information, packaging, financing, or warranties -- are participants whose total expected net increase in value from the measure is lower than the full financial cost of the measure. From a financial perspective (i.e., net of externalized costs), delivering the measure to any and all of these "subsidy-conditional participants" constitutes a net societal cost, not a benefit.

This net societal cost from an individual measure or program cannot logically or conceivably be transformed into a net benefit by expanding it into a "broad menu of demand management programs" designed to appeal to everybody, since the sum of a series of negative numbers will always be a negative number.

Ironically, the only reliable net financial benefit to society from a subsidized DSM measure will be the sum of the net financial benefits of the so-called "free riders" -- the individuals who found enough value in the measure that they were willing (or would have been with better information) to pay its full costs! And, since this benefit could have been achieved without the subsidy -- i.e., at lower or zero cost -- overpaying for it clearly is unlikely to increase societal benefit.

The Board should not adopt the Consensus Statement on this Issue as Board policy because, in our submission, it would provide a flawed and impractical screen for subsidized DSM programs:

n The Societal Cost Test, on which it primarily depends, cannot be reliably applied or tested for accuracy in the presence of subsidized prices. Indeed, applying it requires the correct valuation and summing of all components of a measure's costs and benefits, including the measure's total net value to the people who actually receive the goods and services, which in turn include many cost terms that are typically ignored or "externalized" in the cost-effectiveness calculations done by subsidized DSM planners.

n The four conditions set out in the Consensus Statement under paragraph c) for approving non-sustaining programs which fail the RIM test are variously too vague or weak to have any real value in the selection of programs. It is extremely difficult to forecast -- or even to calculate afterwards -- the "second order costs" of a DSM initiative which raises rates. In fact, they are conceded to be more difficult to forecast than the first round effects.

ISSUE 3 SOCIETAL AND/OR ENVIRONMENTAL EXTERNALITIES

Despite the assurance given by the Consensus Statement that the measure of externalities will be "based on scientifically defensible data", the accuracy of monetized externality values cannot be tested in the absence of a market; hence, the values are essentially arbitrary in their reflection of the economic costs of externalities, and cannot be considered reliable.

A second problem with the consensus approach to externalities arises from trying to internalize the cost of externalities for natural gas in isolation of competing fuel sources. The environmental advantage of natural gas over competing fuel forms is unchallenged at these proceedings. It would not be in the best interest of the environment to burden natural gas with adders that threaten its competitive position, with subsidized DSM programs that will increase natural gas rates. Dr. Ruff refers to this conflict as the problem of "second-best" and explains how,

...even if the price of gas is too low because it does not include all the environmental impacts of gas production and use, it might be that the gas price should be decreased even more ... if other, dirtier energy forms cannot be priced to reflect their external environmental costs.

Recommendations:

4.5 The Board should not try to internalize externalities for natural gas at all unless equal regulatory treatment of more hazardous fuel forms is already enacted.

Given that the Board does not regulate pricing for all competing fuel forms, and is therefore not in a position to internalize externalities across the board, it would be advisable for the Board to work with other regulatory agencies to help establish economically efficient, polluter-pay environmental regulations which can be applied to all sectors, not just the gas sector.

Regardless of which policy instrument is employed to internalize costs, is most important that it is applied broadly across the economy and reflects those costs in the price of all fuel forms.

Recommendations:

The Board should recommend that the Government of Ontario urge the federal government to internalize environmental externalities for energy/fuel use in Canada in the near future, through the introduction of emissions charges and/or tradable emissions permits. Should the federal government fail to act quickly, the Ontario government should take all steps possible to internalize environmental externalities for energy/fuel use in Ontario in the near future, through the introduction of emissions charges and/or tradable emissions permits.

ISSUE 4 INVESTMENTS IN DEMAND SIDE OPTIONS

DSM investments should be recovered in a business-like way from the proceeds of those investments, preferably by fence-ringed, non-regulated, DSM businesses. As Dr. Ruff noted, separating DSM activities from a utility's gas supply business will protect customers from possible rate impacts due to the implementation of financially unsustainable programs.

Recommendation

Investments in demand side options should be recovered from the proceeds of those investments.

The public is well served by regulation only in those areas, such as natural monopolies, where it cannot protect itself. Any area which can be efficiently removed from the regulatory system should be set free, to enable willing consumers to control those aspects of the gas system which can be unbundled and made competitive.

The business of supplying DSM products is not a natural monopoly, rather it is an inherently decentralized activity.

Recommendation

Demand side management should be a deregulated activity.

The Board should ensure that the demand side and supply side activities are accounted for on an equal basis in the sense that no activities should be permitted for rate making purposes which generate less revenues than costs. Neither the LDCs nor the Board should consider giveaways or subsidies to be assets.

Recommendation

The Board should not permit rate basing of non-utility-owned facilities.

Mr. Gibbons, on behalf of Pollution Probe, suggested that the Board might disallow imprudently allowed costs. The threat of cost disallowance will provide the LDCs with an incentive to design successful programs and will act as a brake on what might otherwise be recklessly wasteful programs.

Recommendation

The Board should maintain the option of disallowance of LDC DSM costs in the future if the expected benefits do not materialize.

The Board should ensure that consumers are informed about their contributions to conservation program subsidies. Dr. Ruff notes that, "The quasi-market type of program suggested here would at least give consumers the information, incentive and opportunity they need to complain if they feel they are not getting their money's worth -- which may be why DSM advocates almost universally oppose telling consumers how much they are paying for DSM."

Recommendation

Should the Board permit subsidized DSM, gas utilities should be required to indicate individual customer contributions to the subsidy on each customer's bill.

ISSUE 5 SHOULD "USER PAY" PRINCIPLES APPLY TO DSM PROGRAMS?

The Board should endorse the principle of individual user pay and ensure that profits from DSM businesses do not subsidize gas rates (and therefore gas consumption) by directing DSM profits to DSM businesses.

Recommendation:

The principle of individual user pay should apply to DSM programs within the practical limits of cost allocation.

ISSUE 6 SHOULD UTILITIES RECEIVE DSM INCENTIVES?

DSM program costs should not be regulated or rate based and therefore should not receive a higher regulated rate of return than returns on investments in monopoly supply services.

The Board should reject the suggestion that increased conservation of natural gas requires removing from rate design the profit incentive to increase throughput volumes.

Recommendation:

The benefits of decoupling should be achieved by way of a further unbundling of gas services and rates so that customer costs, capacity costs, and commodity costs are priced separately on a user pay basis.

ISSUE 8 MANAGING DEMAND THROUGH RATE DESIGN

Customers should be charged separately for capacity charges (disaggregated by season and time as much as practical), customer charges, commodity charges, and DSM charges within the practical limits of the cost allocation process. The benefits of this approach include economic efficiency, total resource (not just gas) conservation and efficiency, and maximization of customer information, range of choice, and both the right to profit from, and the responsibility to pay for, the full financial consequences of his or her activities.

Rate design should pass useful information to the consumer about the costs created by the consumer's actions, not make moral judgments about appliance choices. Instituting gas-service surcharges to fund so-called "socially beneficial" subsidized DSM programs is a move away from the proper role of rate design.

Recommendations:

The Board should manage demand by promoting, wherever feasible, the unbundling of all gas products and services.

The Board should eschew rate design alternatives unrelated to the market cost of service.

ISSUE 9 JURISDICTIONAL CONSTRAINTS

To protect the fairness of the IRP deliberations, demand side and supply side initiatives must receive equal treatment.

Recommendations:

If the Board wishes to adopt Energy Probe's preferred recommendation, that utility DSM activities be removed from the utility's regulated monopoly operations and be undertaken by unregulated, for-profit, spinoff DSM businesses, it should feel free to proceed. The Board's current jurisdiction is sufficient.

If the Board wishes to adopt Energy Probe's second-best recommendation, that Ontario's LDC's be guided by the principles of user-pay and rate minimization when designing and implementing DSM programs within their regulated operations (in a manner similar to the treatment of their appliance sales and rental businesses), it should feel free to proceed. The Board's current jurisdiction is sufficient.

If the Board wishes to adopt the October 9, 1992 Consensus Statements on the demand side Issues List, the Board must ensure that supply and demand side options are subject to equal, symmetrical treatment in the regulatory process; hence, the Board should hesitate until getting a clear legislated mandate to do so.

With respect to the issue of DSM subsidies, it is important to consider not only the Board's jurisdictional constraints in allowing them, but more importantly, whether or not in allowing them, the Board is attempting to fulfill a societal function outside its mandate.

Recommendation:

Energy Probe recommends that the Board leave the function of optimizing social welfare to the government who has a prescribed mandate to carry out this function and concentrate its own efforts on consumer protection.

ISSUE 10 IRP: IS THERE A NEXT STEP?

Energy Probe submits that centrally planned IRP which contemplates the implementation of subsidized DSM programs is unlikely to serve the public interest. However, we do not want the Board to reject the concept of integrated resource planning or to forsake regulatory actions which can enhance beneficial forms of planning.

Recommendations:

Energy Probe recommends that the Board proceed with IRP by encouraging the LDCs to implement non-regulated, for-profit, spinoff DSM businesses.

If the Board chooses not to adopt Energy Probe's recommendation for spinoff DSM businesses, Energy Probe recommends that the LDCs be guided by the principle of user-pay when developing DSM programs within their regulated operations.

ISSUE 11 DEVELOPMENT AND SUBMISSION OF DSM PLANS

ISSUE 12 OTHER ISSUES

Recommendation:

Energy Probe recommends that the Board amend its E.B.O. 134 Cost-Effectiveness Test for supply-side investments to make it more difficult to justify rate-increasing, financially non-sustaining (i.e., subsidized) investments, at least to the extent of correcting criticisms noted by Pollution Probe in points 1-3 in Exhibit 8.1, pp. 14-15, "Flaws of the E.B.O. 134 Cost-Effectiveness Test", and as elaborated in Mr. Gibbons's testimony at TR pp. 3161-4.

EXECUTIVE SUMMARY OF THE KITCHENER GAS DISTRIBUTION UTILITY

Kitchener recommends Board guidelines to emphasize demand side measures in the operations of the Ontario gas utilities, along the following lines.

ISSUE 1

Costing Methodology

1. Kitchener does not fully accept the consensus statement on this issue because it ignores the direct financial costs associated with any proposed demand side/supply side project and it requires consideration of all avoided costs and benefits. Kitchener submits that there are some social benefits which incidentally result from a demand side investment, which, as argued under Issue 2, should not be used to justify investment.

The Role of DSM in Utility Operations and the Forecasting of Demand

2. Kitchener submits that the effects of the utilities' DSM portfolios should be fully factored into the utilities' forecast of demand and the approach contemplated by the four paragraphs of the second part of Issue 1 should be endorsed by the Board. In the result, it can be expected that the utilities will demonstrate, at the next rate hearing, that they have placed greater emphasis on the DSM side of their operation. On the other hand the Board should recognize the limits, in practical terms, to the potential scope of DSM activities. However, if a DSM option is costed equally or less than the supply side option, then of course, the Board should expect that the DSM will prevail.

ISSUE 2

Screening and Approval Stages

1. The Board should approve the staged screening and approval process outlined in the consensus statement.

Undue Rate Impact

2. The Board should recognize in its decision that the question of undue rate impacts cannot be determined in a generic hearing and that acceptability of rate impacts will depend on the circumstances which exist at the time of the rate case. Accordingly, no definition as to what constitutes "undue rate impacts" should be issued by the Board.

Inclusion/Exclusion of Externalities

3. Kitchener disagrees with the consensus statement under Issues 1, 2 and 3 which assume that all environmental and social externalities of an investment should be considered in the cost/benefit analysis. In its guideline as to the selection of externalities which can be used by the utilities to justify an uneconomic investment, the Board should instruct them to disregard those externalities which do not fall within the ambit of the utilities mandate or responsibilities. It is recognized that the utility is responsible for all of the social and environmental consequences of its projects. However it should also be recognized that it is not responsible for all the benefits which flow incidentally from its investments. In particular it is not responsible for the creation of tax revenues to government or employment wages in the community. These may result from investment, but the utilities should not be able to obtain revenues from rate payers for investments which require these factors to be taken into account in order to obtain the Board's approval. In other words, regulation is a surrogate for competition, not government; and therefore it should not require rate payers to finance uneconomic projects because they meet governmental objectives. Similarly, the utilities should not be allowed to justify their investment in uneconomic projects because they will reduce the energy costs of prospective customers. Unregulated companies do not make investments for this purpose and therefore regulation should not force the rate payers to bear this burden.

4. Accordingly, Kitchener submits that the principles of E.B.O. 134 should not be endorsed for application to demand side investments insofar as they permit utilities to justify investment on the basis of incidental benefits such as taxes to government, increased employment wages to the community and energy savings to prospective customers. The investment policies of E.B.O. 134 have the effect of approving investment for reasons which fall outside of the requirement to provide utility services on an economic basis. Also they result in unnecessary investment, in terms of utility services, and hence encourage an inefficient use of resources in fundamental contradiction of I.R.P. principles.

ISSUE 3

Working Group

1. The Board should recognize that the working group has a continuing and useful role to play for the purposes of compiling and organizing the literature on monetization and determining the range of monetized values as evidenced by the literature. The Board cannot reasonably expect the working group to reach a consensus on the monetized value and therefore this task should be excluded from the working group's mandate.

2. The working group membership should be scaled down so as to permit representation, without duplication, of the environmental groups, customers and native peoples.

ISSUE 5

The Degree of Subsidization

1. The Board should be willing to entertain DSM programs that result in subsidization within classes and between classes of customers. Accordingly, the Board should be willing to accept proposals for portfolios which are not self-sufficient. The problem with portfolio self-sufficiency is that it confines the burden of subsidization to those who engage in DSM activities. In practical terms this will mean that the purchasers and renters of high efficiency equipment, a program which yields a return above the awarded return, will support all of the other programs. This in turn will tend to discourage participation in the self-supporting program by making it more expensive than otherwise.

Incentives to Participants

2. It is recognized that incentives may be very difficult to justify and that indeed incentives in the form of "giveaways" and "life-line" rates may be counter-productive in IRP terms. The fact remains, however, that situations can exist where incentives are useful. Accordingly, Kitchener submits that the appropriateness of any incentive must fall to be determined on a program-by-program basis in the rate hearings.

Cost Allocation

3. The cost of DSM programs should be allocated on the basis of their causal relationship, where possible, by following the basic cost allocation principles which determine the allocation of supply side cost. In addition, the Board should not allow utilities to pass the costs of their DSM programs on to other utilities, which have DSM responsibilities of their own.

ISSUE 6 - PART I

Incentives to the Utilities

1. Kitchener submits that the Board should not be willing to entertain proposals for "shared savings" or other mechanisms by which revenues depend on a systems of penalties and rewards geared to the success of the DSM activity. The reasons for this position can be summarized as follows. Shared savings do not fall within the formula for revenue recovery in s.19 of the **Act**; the relative success of a program may not be known for a number of years and a system of rewards and penalties would discourage the introduction of worthwhile investments or the premature discontinuation of a program before its potential was fairly determined; also, the relative performance of a program may not necessarily indicate the competence level of management; finally, it is submitted that the nature of regulation itself works against the use of a shared savings mechanism for ensuring efficiency. Regulation can pass judgment on a company proposal but it cannot, apart from flagrant dereliction, second guess (and in that sense assume) the management of company operations.

2. It is also noted that compensation by way of incentive is unnecessary because of the existence, under regulation, of the very strong incentive to expansion of investment. Accordingly, the most effective way to induce utilities to allocate a fair share of their investment capital to demand side measures is to curtail current supply side spending by restricting it to projects which can be justified by reference to the utilities service, social and environmental responsibilities and reject projects which can only obtain approval if the Board permits consideration of benefits which fall outside of the utilities' responsibility.

3. On the other hand some incentive type features, not involving revenue compensation, should be allowed. In particular, the Board should favourably entertain proposals designed to reduce the risk of not earning the allowed return including proposals for a deferral account and a multi-year expenditure commitment.

Decoupling

4. Decoupling represents a significant and fundamental change in the way utilities are regulated. Accordingly, it should not be forced on the utilities unless the evidence in favour of such a step is sufficiently strong to warrant such a fundamental change. In the circumstances here it is submitted that the evidence is not sufficient weighted in favour of a forced decoupling.

5. In addition, in Ontario, one utility intends to introduce a decoupling measure and the other two do not. This will permit the Board to observe the effects of decoupling in an almost laboratory type setting. By comparing the two approaches, the Board will be in a far better position to access them than if decoupling was forced on all three utilities at the same time.

6. Accordingly, Kitchener submits that the Board should express its willingness to entertain a decoupling proposal but should not mandate it.

ISSUE 7

1. Kitchener supports the expectations expressed in the consensus statement under this issue and would only add that the Board should require the utilities to formalize a process for the sharing of research and development activities required to obtain the identification of the best possible portfolio. In this respect Kitchener asks that the collaborating group of utilities be required to report to the Board at rate hearings on the results of their work so that the parties and the Board can make an assessment, of their own, as to the extent of DSM programming worthy of consideration.

ISSUE 9

The Board's Jurisdiction

1. The Board should not recommend an alteration of its jurisdiction at this stage, but rather should adopt the assumptions in the consensus statement under this issue as the basis on which to proceed with the introduction of IRP.

2. In addition it is submitted that the Board should recognize that in rate cases it may be necessary to give multi-year commitments to some DSM expenditures. In this it is not suggested that future panels be bound by such commitments; however it is suggested that the Board should be willing to approve a program for a number of years unless, at an intervening rate hearing, circumstances arise which warrant a reconsideration of the original long term approval.

ISSUE 10

Level of Investment

1. While the Board can expect the level of DSM investment to be increased in the future, it should be recognized that there are a number of limiting factors. First there was no suggestion at the hearing that there were types of DSM programs which a utility had ignored. Accordingly, the parties should not be surprised if the portfolios presented at the next rate cases contain programs similar to those which currently exist. Secondly, the initiative in the gas industry will be limited by the degree of IRP exhibited in other fuels. If all fuel prices do not reflect the cost of externalities to some degree, then the more harmful environmental fuels will prevail.

Consultation to Improve Program Design

2. Subject to the role to be given to the working group under Issue 3, it is submitted that the development of DSM programs should remain the responsibility of the utilities. Accordingly, the requirement of consultation referred to in paragraph 3 of the consensus statement should not become a formal component of rate case preparation. The initiative and responsibility for developing programs of any kind, including DSM proposals, must necessarily reside with management. Consultation should be seen as part of the ongoing responsibilities of the market research departments in each utility, it should not be regarded as a condition precedent to the formulation of plans.

EXECUTIVE SUMMARY OF ONTARIO METIS AND ABORIGINAL ASSOCIATION

The Ontario Metis and Aboriginal Association (OMAA) fully supports the adoption of Gas Integrated Resource Planning (IRP) in Ontario. Such a process can provide benefits to the members of OMAA and society as a whole. However, the implementation of an IRP process presents difficult challenges. OMAA believes that the benefits of integrated resource planning can best be achieved through a comprehensive planning process which takes into account the concerns of various affected parties, and guarantees their full participation.

OMAA has a number of specific concerns regarding the integrated resource planning process. These relate to the valuation and incorporation of externalities into the planning process, the regulatory authority of the Board to implement an IRP process, the format in which IRP will be considered, equity concerns relating to the implementation of demand-side management (DSM) programs and low-income ratepayers, the level of consultation with affected parties, and the availability of funding.

OMAA members may be greatly affected by externalities related to the production, transmission, and consumption of natural gas. OMAA is therefore concerned that the identification and valuation of such externalities is performed adequately. Of particular concern is the issue of externalities which are difficult to quantify and monetize. In such instances, the qualitative treatment in the planning process must be meaningful. OMAA's members should be consulted on this matter, since they offer a unique expertise which can assist in this process.

OMAA is concerned that the Board's current regulatory authority is insufficient for the development of a comprehensive IRP process. Under the Board's present mandate, the IRP process as implemented may fall short of securing all of the benefits that may be attainable through a more comprehensive process.

Nonetheless, in the absence of broader authority, the IRP process should be developed to the extent possible. While not as complete or beneficial as it might be, this process would still provide substantial benefits to society. In proceeding, it is important that the Board establish a regulatory environment which provides very clear signals to the participants, and which provides an adequate level of incentives to promote the utilities' participation.

Rate case hearings have been suggested as the appropriate adjudicatory forum for the IRP process. Such a forum would be limiting for two reasons. First, OMAA would be practically and financially unable to participate in each individual rate hearing. Second, OMAA is concerned that insufficient attention will be paid to the IRP process in the midst of the numerous competing priorities normally inherent in rate case hearings.

In addition, the issue of equity must be carefully considered in the planning and implementation of DSM programs. While the majority of OMAA's members are not gas users, some of its members who do use gas are low- or fixed-income ratepayers. The IRP process must make a concerted effort to ensure that such individuals can participate in DSM programs.

OMAA is also concerned about its ability to meaningfully participate in the development of the integrated resource planning process. OMAA's members are likely to be significantly affected by the outcome of this process, and can contribute a unique expertise and perspective to assist in its development. However, OMAA does not itself have the resources to ensure that its concerns will be considered in the IRP process. At present it is uncertain whether meaningful consultation will actually take place in the development of the IRP process. OMAA's concerns in this regard are illustrated by the experience to date with the Externality Working Group. While OMAA was invited to participate in this Group, such participation has been effectively foreclosed by lack of financial support.

The IRP process should involve meaningful consultation with all affected parties. OMAA suggests that consultation should occur on three levels. First, the Board and gas utilities should make a special effort to understand OMAA's concerns and orientation. This outcome would be greatly facilitated by consultation at the community level. Second, OMAA members who are gas users should be consulted in the development and implementation of DSM programs, just as other groups of consumers are consulted. Third, the Board should establish a meaningful process for consultation with OMAA members regarding the identification and valuation of social and environmental externalities. This should occur with the input of affected communities.

Finally, for the IRP process to be effective, sufficient funding must be provided for consultation, as well as legal and expert support of affected parties. Such consultation and support is necessary to ensure that the integrated resource planning process is comprehensive, effective, and equitable, thereby maximizing the potential benefits to Ontario society.

EXECUTIVE SUMMARY OF POLLUTION PROBE

ISSUE 1 GENERAL ROLE OF DSM

Pollution Probe supports the consensus position statement on Issue #1.

ISSUE 2 COST-EFFECTIVENESS TEST

Pollution Probe supports the consensus position statement on Issue #2.

ISSUE 3 EXTERNALITIES

Pollution Probe supports the consensus position statement on Issue #3.

ISSUE 4 DSM INVESTMENTS

Pollution Probe supports the consensus position statement on Issue #4.

ISSUE 5 WHO SHOULD PAY?

Pollution Probe supports the consensus position statement on Issue #5.

ISSUE 6 Part 1 INCENTIVES AND PENALTIES

Pollution Probe supports the consensus position statement on Issue #6 Part 1.

Issue 6 Part 2(a) DECOUPLING

<u>COUPLING AND THE PENALTY FOR CONSERVATION</u>

For many years the O.E.B. has held that the primary function of Ontario's gas utilities should be to sell and/or distribute natural gas. Therefore it is not surprising that the Board adopted rate making principles that link or couple the gas utilities' profits to their natural gas throughput volumes. That is, under the O.E.B.'s status quo rules, the higher are the utilities' throughput volumes, the higher are their profits and conversely, the lower the volumes, the lower the profits. This is true whether or not throughput volumes are above or below forecast levels.

However, one effect of coupling the utilities' profits to their throughput volumes is that a utility is financially penalized if it promotes conservation, since a conservation measure by definition reduces throughput volumes, and therefore profits, from what they otherwise would have been.

DECOUPLING--ELIMINATING THE PENALTY FOR CONSERVATION

In his classic text, Principles of Public Utility Rates, James Bonbright stated that regulation should not penalize utilities for acting in accordance with the public interest:

> "...rate regulation...should at least take pains to avoid rules or rate making that positively penalize stockholders for efficient or otherwise desirable action by management."

There are two main reasons why Bonbright's admonition against penalties is applicable to coupling throughput volumes and profits. These reasons suggest that the rate making principle of coupling should be replaced by a decoupled regime.

1. Penalizing Conservation Conflicts With Government Policy

   Penalizing a utility for promoting conservation is inconsistent with Government of Ontario policy. As the Deputy Minister of Energy stated in his February 28, 1992 letter to the O.E.B.:

   > "The Government of Ontario strongly supports demand side planning by all energy utilities. Conservation is the priority in meeting energy needs in Ontario"

2. Penalizing Conservation Conflicts With IRP

   The purpose of IRP is to meet customers' energy service needs by the least cost mix of supply side and demand side (energy conservation and energy efficiency) options. As the consensus statement on Issue #1 has noted:

   > "In terms of meeting future demand, DSM options should be given equal consideration as supply-side actions"

   If DSM options should be given equal consideration with supply side options, it is irrational to penalize a utility when it promotes conservation. As the National Association of Regulatory Utility Commissioners has stated:

   > "Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society."

3. The Importance of Removing The Penalty

As noted by NARUC, above, the penalty for conservation is "a serious impediment" to important public interest objectives. According to a joint statement of the Natural Resources Defense Council and the Pacific Gas and Electric Company (the largest investor-owned utility in the U.S.), the California Public Utility Commission's decision to decouple profits and throughput volumes was an essential prerequisite for PG&E's renewed commitment to energy efficiency programmes.

> "The first step in improving the regulatory system, therefore, is to decouple net revenues and profits from total sales. This step was taken in California beginning in the late 1970s, and it has been essential to PG&E's renewed commitment to efficiency programs."

The general importance of using financial self-interest to encourage conservation is recognized by, for example, Union Gas. Mr. van der Woerd has stressed the importance of relying on market mechanisms to achieve energy efficiency goals:

> "And our position would be that if it [conserving energy] is done using the market mechanism, we will get a lot farther in achieving that goal than if we do it in a manner which will require more regulation, more scrutiny, more non-productive activities in the marketplace, other than simply conserving energy and using it more efficiently.
>
> And what we're suggesting is that if we use market mechanisms wherever possible, as this government also endorses in the same policy statement, then we will be able to get on with this subject quickly."

Finally, it is worth noting that Ms. Peverett of Centra Gas conceded that the O.E.B.'s status quo rules which couple utility profits and throughput volumes motivates a utility to sell gas:

> "Q. All right. Ms. Peverett, does Centra believe that there is an inherent bias in the rate making process which encourages utilities to sell more gas rather than less gas?
>
> A. I think it's fair to say that utilities in the short-term are motivated to sell more gas."

OBJECTIONS TO DECOUPLING

1. Decoupling Will Lead to Undue Rate Variability

According to Centra Gas, decoupling is not in the public interest because it will lead to undue variability in the rates of its large volume industrial customers.

It is Pollution Probe's submission that the evidence does not support Centra's assertion.

If decoupling had been in existence in 1991, the 1991 debit balance in Centra's decoupling deferral account would have been $11,088,100. Furthermore, according to Exhibit 14.6(a), if the debit balance was allocated amongst Centra's rate classes in proportion to their share of Centra's rate base, the temporary decoupling-related rate increases would have been:

Residential Rate 1 customers	4.2%
Commercial Rate 1 customers	4.8%
Commercial Rate 10 customers	2.4%
Industrial Rate 20 and 25 customers	0.47% to .87%

Moreover, the evidence before the Board indicates that the magnitude of an annual Centra decoupling deferral balance would typically be much lower than $11 million. According to Mr. Oosterbaan of Centra Gas, if decoupling had been in place in the past, the deferral account debit for 1990 would be only $4.1 million. Furthermore, in 1988 and 1989 the deferral account would have had credits of $3.6 million and $5.3 million respectively.

Thus if decoupling had been introduced in the past and if Centra amortized the deferral account balances over a three year period, the temporary rate impact would be 70% less than the impact shown in Exhibit 14.6(a). That is, the rate impacts would be:

Residential Rate 1 customers	1.26%
Commercial Rate 1 customers	1.44%
Commercial Rate 10 customers	0.72%
Industrial Rate 20 and 25 customers	0.14% to 0.26%

It is Pollution Probe's submission that temporary rate impacts of the above noted magnitude will not impose an undue burden on Centra's customers. Furthermore, to put these temporary rate variations into context, it is important to note that:

1. if Centra's throughput volume forecasting methodology is unbiased, Centra's customers will experience temporary rate reductions as often as they will experience temporary rate increases;

2. by reducing Centra's cost of equity, decoupling will ensure that, on average, Centra's rates will be lower than they would be in the absence of decoupling; and

3. any decoupling-related rate variations will be small in relation to the rate variations that have been historically experienced by Centra's customers (e.g., in 1987 a typical 100% load factor Rate 20 customer experienced a 31% rate increase).

Furthermore, with respect to fuel switching, it is Pollution Probe's submission that a firm large volume industrial customer will not leave Centra's system because of a temporary rate increase of 0.14% to 0.26%.

It is also Pollution Probe's submission that it is very unlikely that a large volume interruptible industrial customer will go off gas because of a temporary rate increase of 0.14% to 0.26%. Moreover, if a large volume interruptible customer is about to leave the system because of a temporary rate increase of the above noted magnitude, Centra could retain the customer by renegotiating the customer's range rate.

Finally, it is important to note that if a decoupling-related temporary rate increase of 0.14% to 0.26% would cause an industrial customer to go off gas; parity of reasoning implies that a similar decoupling-related decrease in gas rates would cause an equal increase in gas consumption.

Thus, on balance, there is no reason to believe that decoupling-related rate variations would lead to a net long term reduction in natural gas consumption.

2. If Decoupling Is Adopted Gas Utilities Will Not Have Sufficient Incentive To Promote Fuel Switching

According to Dr. Bower, a witness called on behalf of Centra Gas and Union Gas, if decoupling is adopted, gas utilities will not have sufficient incentive to promote fuel switching.

It is Pollution Probe's submission that Dr. Bower's assertion is not persuasive for the following reasons.

First, under Pollution Probe's Formula B decoupling proposal, a utility's revenues would be linked to its number of customers. That is, under Pollution Probe's proposal, a utility can increase its revenues by increasing its number of customers.

Second, under a decoupling regime, it will still be in a utility's long run financial self-interest to increase its number of customers and the number of gas end-uses per customer because these activities will lead to increased utility rate base. As the Board is aware, everything else being equal, the greater is a utility's rate base, the greater are its profits.

Third, under a decoupling regime, it will still be in a utility's long run financial self-interest to increase its number of customers and the number of gas end-uses per customer because these activities will lead to increased natural gas throughput volumes. Everything else being equal, higher throughput volumes imply lower rates. Moreover, lower rates are in the self-interest of utility shareholders for at least two reasons:

1. by making natural gas more competitive, lower rates will increase the probability that the utility will be able to earn a fair rate of return on its investment; and
2. lower rates will lead to increased natural gas sales and hence increased utility rate base and profits.

In light of the above and other evidence, it is Pollution Probe's submission that Ontario's gas utilities will continue to aggressively promote fuel switching to natural gas if the O.E.B. decouples the link between profits and throughput volumes.

However, if the O.E.B. believes that there would be insufficient incentive for gas utilities to promote fuel switching if their profits are linked to their number of customers, as opposed to their throughput volumes, there are a number of remedies available to the Board. First, it could approve a decoupling mechanism that links a utility's revenues to its number of customers and the number of gas end-uses per customer.

Second, it could establish a deferral account with respect to a utility's operating and capital costs of promoting and implementing fuel switching (i.e., a fuel switching expenditures deferral account similar to the DSM expenditures deferral account proposed in the consensus position statement on Issue #4).

Third, the Board could establish financial bonuses for utilities that aggressively and cost-effectively increase the number of socially cost-effective gas end-uses per customer.

3. A DSM Lost Revenue Adjustment Mechanism (LRAM) Is Superior To Decoupling

According to the three gas utilities a DSM lost revenue adjustment mechanism (LRAM) is a superior mechanism to eliminate the penalty for promoting conservation. An LRAM is an accounting mechanism which, in theory, would sever the link between a utility's profits and changes in its throughput volumes due to its DSM programmes. Moreover, if an LRAM is implemented a utility's profits would still be a function of throughput volume fluctuations that are due to unforecast changes in the business cycle, unforecast changes in alternative fuel prices and the weather.

It is Pollution Probe's submission that an LRAM is <u>not</u> superior to decoupling for the following reasons:

1. In practice, an LRAM cannot completely remove the financial penalty for promoting conservation;

2. An LRAM will unnecessarily increase the cost of making conservation a utility's most profitable course of action. That is, an LRAM will needlessly enrich utility shareholders at the expense of utility customers; and

3. An LRAM will increase regulatory costs.

<u>An LRAM Cannot Remove The Penalty For Promoting Conservation</u>

In practice an LRAM cannot completely remove the financial penalty for promoting conservation for at least two reasons.

First, for some conservation options (e.g., public information programmes, rate reform) it is impossible to measure their impact on utility throughput volumes and revenues. Thus an LRAM would not be able to remove the financial penalty for the successful implementation of these options.

Second, for the remaining DSM options it is impossible to measure with a satisfactory degree of precision their impact on a utility's throughput volumes and revenues. As a consequence, assuming an LRAM, a utility's O.E.B.-approved lost revenues will be either greater or less than its actual DSM-related lost revenues; whereas under decoupling the utility's actual DSM-related (and other) lost revenues will be returned to the utility.

Thus, assuming an LRAM, the probability of full recovery of DSM-related lost revenues will be less than the probability of full recovery of throughput volume related revenues. In short, under an LRAM, a utility's risk minimizing strategy will be to aggressively promote sales, not conservation.

An LRAM Will Unnecessarily Increase The Cost of Making Conservation A Utility's Most Profitable Course Of Action

Pollution Probe, Centra Gas, Consumers' Gas, Union Gas and others have endorsed the consensus position statement with respect to Issue #6 - Part 1. That is, Pollution Probe and the gas utilities are in favour of shared savings incentives for utilities that successfully implement cost-effective DSM programmes.

However, if the O.E.B. approves shared savings incentives and an LRAM it will have established a contradictory set of utility incentives. A shared savings incentive and an LRAM would be mutually inconsistent because:

1. a shared savings incentive rewards a utility for conserving energy; and
2. an LRAM maintains the status quo financial bonus for exceeding the O.E.B.-approved throughput volume forecast.

The creation of contradictory incentives will increase the cost of making conservation a utility's most profitable course of action. As Exhibit 13.4 demonstrates, if an LRAM maintains a 50 basis point reward for a 1% increase in throughput volumes, the shared savings and LRAM incentives for reducing throughput volumes by 1% must be at least 51 basis points if conservation is to be the utility's most profitable course of action. On the other hand, if the link between a utility's profits and its throughput volumes is decoupled, conservation will be a utility's most profitable course of action if the shared savings incentive is only 1 basis point. Thus, using the numbers chosen as examples in Exhibit 13.4, an LRAM increases the cost of making conservation a utility's most profitable course of action by 50 basis points.

In short, an LRAM will enrich utility shareholders at the expense of utility ratepayers.

An LRAM Will Increase Regulatory Costs

As noted above, it is impossible to precisely measure the impact of DSM measures on a utility's throughput volumes. As a consequence it is reasonable to assume that if an LRAM is established, many hearing days will be devoted to adversarial cross-examination of utility, Board Staff and intervenor expert witnesses with respect to exactly how much energy was saved by utility DSM programmes.

Lengthy and acrimonious debates on the appropriate magnitude of a utility's LRAM account balance are not in the public interest, assuming the existence of a simpler and less contentious solution (decoupling), for at least two reasons.

First, it would needlessly increase the direct financial cost of regulation to the ratepayers.

Second, it will tend to embitter the relationship between the utilities, Board Staff and other intervenors. As a consequence, it will reduce the ability/willingness of these parties to resolve other DSM matters in a constructive and cooperative manner.

CONCLUSION

In order to make the O.E.B.'s rate making principles consistent with Government of Ontario policy and the principles of IRP, the O.E.B. should decouple the link between a utility's profits and its throughput volumes.

Thus it is Pollution Probe's respectful submission that the O.E.B. should adopt the majority consensus position statement on decoupling. That is:

"1) Decoupling of profits and throughput volumes should be introduced to remove the existing disincentive to aggressive pursuit and implementation of cost-effective conservation DSM programs.

2) Decoupling mechanisms should recognize, and be tailored to, individual utility operating conditions, markets, and other circumstances. Individual utilities should propose specifics of a decoupling mechanism best suited to their respective circumstances. The proposal should be brought forward in the context of a rate case."

As the Board is aware, the above quoted consensus position statement is supported by Board Staff, the City of Toronto, the Coalition of Environmental Groups, the Consumers' Association of Canada (Ontario), the Ontario Metis and Aboriginal Association and Pollution Probe.

ISSUE 7 MEASURING DSM

Pollution Probe supports the consensus position statement on Issue #7.

ISSUE 8 RATE DESIGN

Pollution Probe supports the consensus position statement on Issue #8.

ISSUE 9 JURISDICTION

Pollution Probe supports the consensus position statement on Issue #9.

ISSUE 10 IMPLEMENTATION

Pollution Probe supports the following consensus position statements on Issue #10: Part 1, Part 2(b) and Part 2(c).

ISSUE 11 THE BOARD'S REPORT

The Board has invited comments addressing 1) issues which should be addressed in its report, and 2) specific guidelines which should be provided in its report.

It is Pollution Probe's respectful submission that it is not necessary for the Board to provide in its report a lengthy and detailed review of the issues, or specific guidelines, in the event that the Board chooses to rely on the consensus statements, since the statements are relatively well understood.

While the Board's report need not be lengthy or detailed, Pollution Probe submits that it is crucial that the report clearly state the direction the Board favours. An ambiguous or ambivalent position is not likely to provide adequate guidance to the parties.

AFFILIATE GAS SUPPLY TRANSACTIONS

If a utility purchases gas from an affiliate then, everything else being equal, the aggressive promotion of energy efficiency by the utility will lead to a reduction in its affiliate gas purchases. Furthermore, everything else being equal, a fall in affiliate gas purchases will entail lower profits for its affiliate and controlling shareholder.

Thus it is Pollution Probe's submission that new affiliate gas supply transactions should be banned in order to ensure that the aggressive pursuit of energy conservation will not be contrary to the financial self-interest of the controlling shareholders of Centra Gas, Consumers' Gas and Union Gas.

If the Board does not wish to ban all new affiliate gas supply transactions, it is Pollution Probe's recommendation that the Board state that all new affiliate gas supply transactions should have a "no displacement" clause. That is, the utility must not be able to reduce its gas purchases from its affiliate suppliers if the utility's requirements decline. A "no displacement" clause would be in the public interest because it would ensure that the aggressive promotion of energy conservation by a utility would not reduce the short run profits of its affiliate gas supplier(s) and its parent corporation.

In this context it is worth noting that Consumers' Gas does not have the right to reduce its gas purchases from its affiliate supplier, Telesis Oil and Gas, if its gas requirements decline.

Furthermore, it is Pollution Probe's submission that a ban on new affiliate gas supply transactions is unlikely to lead to a rise in a utility's gas costs for two reasons:

1) the gas reserves of the affiliates of Ontario's gas utilities are a very small percentage of Canada's total gas reserves; and

2) Ontario's gas utilities have a tendency to structure affiliate transactions so as to benefit the affiliate at the expense of the ratepayer.

In other words, it is Pollution Probe's submission that a ban on new affiliate gas supply transactions is more likely to lower utility gas costs than to raise them.

EXECUTIVE SUMMARY OF THE CITY OF TORONTO

In accordance with the Board's Procedural Order No. 4 herein dated December 7, 1992, the City of Toronto hereby submits its Executive Summary of its argument in this matter. This Executive Summary firstly sets out the City's submissions in respect of Issues 1 through 11; secondly summarizes the City's position; and thirdly reiterates the City's requests of this Board.

CITY OF TORONTO COUNCIL'S POSITION ON ISSUES DESCRIBED IN THE OEB'S DEMAND-SIDE ISSUES LIST AND ISSUE 11

City of Toronto Council presented no evidence in support of matters related to Issues 1 to 10 at the hearing, but solely takes the following positions as set out in Exhibit 10.4, pp.50-57. It also takes the following position related to Issue 11:

Issue	Position
1.	As per paragraphs 1, 3 and 6 in the Consensus Statement. No position taken on the other paragraphs.
2.	No position
3.	As per the Consensus Statement.
4.	No position.
5.	No position.
6. Part 1	As per the Consensus Statement.
6. Part 2a	As per the Consensus Statement of Board Staff, et al. Not in agreement with Centra's/Union's Consensus Statement.
7.	As per paragraphs 2, 3, 6 and 8 in the Consensus Statement. No position taken on the other paragraphs.
8.	No position.
9.	No position.

10. Part 1 As per paragraphs 1, 2, 3 and 4 in the Consensus Statement of Board Staff et al. No position taken in respect of paragraph 5.

10. Part 2(a) No position.

10.Part 2(b) No position.

10.Part 2(c) No position.

11.

It is respectfully submitted that the Board should address the issue of **need.** In other words, the Board should make findings on why these DSM plans are necessary. In support thereof, the City refers to the uncontradicted written evidence of Dr. Danny Harvey, as supported by his vice voce testimony on November 27, 1992, which is summarized as follows:

As a result of human activities the concentrations of greenhouse gases have increased, leading to a strengthening of the greenhouse effect. There is no scientific doubt that such strengthening will lead to a warmer climate, although there is uncertainty concerning the amount and rates of warming, the regional distribution of precipitation and soil moisture changes, and the full impact of these changes.

Scientific concern over human emissions of greenhouse gases is based on the following:

- human activities have already caused greenhouse gas concentration increases;
- much larger greenhouse gas concentration increases will occur if present trends continue;
- significant and potentially catastrophic climatic changes will likely result in many regions from the greenhouse gas concentration increases projected for business-as-usual scenarios;
- rates of climatic change will likely be such as to pose severe stresses on natural ecosystems, even for changes which,, were they to occur slowly, would be beneficial;
- time lags of up to several decades will occur between greenhouse gas increases and the climatic and ecosystem response, so that adoption of a wait-and-see approach will mean that human societies will be committed to significantly greater changes by the time that unambiguous impacts begin to be felt; and
- such changes as do occur will be irreversible for all practical purposes.

Under business-as-usual scenarios, greenhouse gas concentrations will continue to increase beyond the end of the next century, leading to global warming and ecosystem responses for hundreds of years. Initial impacts could therefore be quite different from later impacts but, overall, the risk of negative impact will increase the longer that greenhouse gas concentrations are allowed to increase. Impacts expected in Canada will relate to agriculture, forestry, water resources, natural habitats, fisheries and sea level increases.

The extraction, processing, transportation and end use of natural gas result in emissions of both carbon dioxide and methane. Per unit of energy, natural gas releases the smallest amount of carbon dioxide of any fossil fuel, and shifting from oil and coal use to natural gas could be an important and effective method of reducing carbon dioxide and in some cases methane emissions. It is therefore important that every effort be made to use natural gas as efficiently as possible if greenhouse gas emissions are to be reduced by the magnitude required, on a global basis, for atmospheric stabilization. DSM plans should therefore be developed and submitted by the utilities to the Board.

Furthermore, Canada is a signatory to the United Nations Framework Convention on Global Climate Change, which Convention has not yet been ratified by Parliament or Cabinet. By requiring the development and submission of DSM plans by the utilities, the Board would be in part implementing the intent of Articles 3.1 and 3.3 of this Convention.

II. CITY'S POSITIONS

1. The City of Toronto submits that there is scientific evidence which supports this Board deciding that DSM plans should be developed and submitted by the utilities; so as to assist in the protection and maintenance of the human and natural environments and to reduce greenhouse gas emissions.

   1.0.1 The City further submits, based at least on the City's evidence, that there is a need for such plans, given that:

      (a) global warming in all likelihood will create significant detrimental economic and environmental effects in Canada during at least the next century;

      (b) global warming is largely caused by a build-up of greenhouse gases, including Co_2 and CH_4;

      (c) an appreciable volume of greenhouse gas emissions are from the LDC's systems; and

      (d) this Board and the LDC's are in a position to reduce these emissions through IRP, without negatively impacting fuel switching initiatives or the LDC's shareholders.

4. The City further submits that the City's specific requests, as hereafter described in Section III of this Executive Summary can be fulfilled by the adoption of a number of the Technical Conference Consensus Statements.

III. CITY'S REQUESTS

The City of Toronto respectfully requests that this Board:

(a) call for the development and submission of IRP plans by the utilities;

(b) find that there is a need for such plans given the need to reduce greenhouse gas emissions as soon as possible;

(c) adopt ratemaking mechanisms which will allow and encourage Consumers' Gas to reduce carbon emissions associated with natural gas consumption in the City of Toronto and elsewhere by 20%, relative to the 1988 level by the-year 2005, through improved end use efficiency;

(d) find that the mandate of Consumers' Gas' should include the aggressive promotion of energy efficiency and conservation in addition to its service role as a natural gas distributor;

(e) establish ratemaking mechanisms which will ensure that the aggressive promotion of energy efficiency and conservation by Consumers' Gas is in the interest of Consumers' shareholders; and

(f) find that Consumers' Gas be allowed and encouraged to finance research, development and commercialization of technologies with higher efficiencies in the use of natural gas than are available at present.

EXECUTIVE SUMMARY OF UNION GAS LIMITED

I. INTRODUCTION

Union emphasized its strong support for the goals of IRP and the pursuit of new DSM measures to promote conservation and efficiency, as Union regards DSM as an essential part of its overall mission and its commitment to its customers to provide cost-effective, energy efficient and environmentally sound energy products and services.

Union pointed out that ultimately, the measure of success in the pursuit of conservation and efficiency would be customer attitudes and decisions. It therefore emphasized the need for consultation with its customers in planning DSM initiatives, and for pursuing the most cost-effective opportunities to promote the wise use of natural gas.

Union cautioned against transplanting the DSM experience of the electrical utility industry into the context of Ontario gas utilities. It drew attention to the significant differences in typical avoided costs in the two industries, as well as other points of distinction, and accordingly submitted that the U.S. Electric industry approach based on "give-aways" or financial incentives to encourage participation which might be cost-effective in the electric utility context would be far less likely to be appropriate and cost-effective if implemented by Ontario gas utilities.

Union referred to its own previous experience and success in the area of DSM. It emphasized the need to look to that and other relevant experience, as well as employing common sense, in order to avoid actions which, though seemingly attractive in theory, may have unforeseen and undesirable consequences. Union stated that its previous experience and analysis of potential programs underscored the importance of focussing on customers and on overcoming market barriers to wise energy use through customer value and choice.

Union pointed out that, consistent with the declared policy of the Ontario Government, the promotion of energy efficiency and conservation involved not only reducing gas use per application, but also providing for the wider availability of gas and its greater use in new efficient applications and in substitution for other more environmentally harmful fuels. Union noted that there was far greater potential for achieving environmental benefits through encouraging the substitution of gas for other fuels than through reducing gas use per application.

ISSUE 1 (COSTING METHODOLOGY)

Union endorsed the consensus statement on this issue, but observed, that its own avoided costs for typical DSM conservation measures are relatively low for reasons specific to it. Union therefor submitted that proposed DSM measures should be examined in light of each utility's particular circumstances, rather than in the context of a "one size fits all" approach.

Union recognized the importance of identifying avoided costs in evaluating DSM options and ensuring that they receive the same consideration in meeting demand as distribution supply side options. Union also pointed out, however, that demand side options differ fundamentally from supply side options in that the former are targeted to provide special benefits for distinct customer groups, rather than to ensure a consistent level of service for all distribution customers. As a result, Union cautioned that equal consideration of demand and supply side options does not mean giving identical weight to identical sets of public interest considerations.

Union expressed its intention to consider as many DSM opportunities as possible and to develop the most comprehensive portfolio of DSM measures as would be practical, consistent with its portfolio approach to demand side management.

ISSUE 2 (COST-EFFECTIVENESS TESTS)

Union endorsed the consensus statement on this issue and submitted that the most important principle underlying the tests to be applied to determine the desirability of DSM programs, was the need to ensure that all considerations concerning societal, customer and participant impacts are included, and that the same methodology is used to assess both different types of DSM options and supply side options.

Union strongly disagreed with suggestions made by others that rate impacts due to DSM (which would occur when the rate impacts of DSM exceed the rate impacts of the avoided supply options) are of little or no consequence. Union noted that these suggestions were contradicted by actual experience and other data concerning customer behaviour, and that they ignored the environmental benefits to be achieved by enhancing the competitive position of gas and promoting its use in additional wise applications. It also observed that since new DSM programs would benefit targeted customer segments, rate impacts could influence customer perceptions of the overall fairness of the programs, thereby affecting customer response. Union explained in Reply that its desire to develop a portfolio of DSM programs with no overall rate impact over the life of the project was based on sound principles.

ISSUE 3 (EXTERNALITIES)

Union endorsed the consensus in principle but submitted that in order to take proper account of social and environmental externalities, both the costs and benefits of supply side and demand side options must be considered and given the appropriate weight. Union cautioned that it was seemingly impossible, and certainly undesirable, to attempt to reduce that exercise to the application of mathematical formulae. Union noted the difficulties involved in trying to monetize externalities, and urged that judgment had to be exercised in attempting to compare the value of monetized externalities to economic costs determined by market transactions.

Union shared the concern raised by Energy Probe and others that in attempting to monetize environmental externalities, care must be taken to avoid gas-only monetization in a way that makes gas appear less attractive than more environmentally detrimental fuels, simply because gas is regulated. Union pointed out that the environmental and other benefits resulting from the wise use of gas are enormous in comparison to the benefits associated with attempting to reduce the use of gas.

Union recommended that the working group contemplated in the consensus statements be limited to participants in EBO 169, with the addition of a government representative if desired, and that it be given a specific mandate to prepare a timely report indicating the extent to which the parties can agree upon the externalities to be considered, their measurable impacts, monetized values and the methodologies to be employed. Union also recommended, in order to maximize the efficiency of the process, that any required consulting experts be retained by the group as a whole, to be paid for by the three LDCs.

ISSUE 4 (DSM INVESTMENTS)

Union endorsed the consensus statement on this issue, Union supported the establishment of deferral accounts for DSM capital and operating expenditures in order to provide equal treatment to demand and supply side expenditures. Union submitted that demand side "investments" must be amortized and included in rate base, and made subject to an investor return, in the same way as costs associated with the construction of new facilities. It also noted that DSM initiatives presented significant forecasting risks substantially beyond Union's control, and submitted that the deferral accounts were appropriate, in part to help remove potential disincentives relating to forecasting risks, as well as regulatory risks.

ISSUE 5 (WHO SHOULD PAY FOR DSM PROGRAMS)

Consistent with the consensus statement which Union endorsed, the cost of DSM programs should be borne, to the extent possible, by the direct beneficiaries of those programs. Union submitted that the use of a DSM portfolio approach would be appropriate so that financially self-sustaining programs could support DSM programs which were not self-sustaining.

Union strongly disagreed with basing DSM programs on "give-aways" or excessively large financial incentives, on the grounds that for a gas utility in Union's circumstances, those would lead to adverse rate impacts, undesirable cross-subsidization and unfair competition with other suppliers of goods and services. Union also rejected as illusory, and financially foolish, suggestions that such problems could be overcome by providing "something for everyone", and argued that this approach would only exacerbate the problems, particularly in Union's circumstances given its existing base of DSM activities participation and relatively low avoided costs.

ISSUE 6 (Part 1) (INCENTIVES)

Union endorsed the consensus statement on this part of the issue.

Union submitted that in order to eliminate any potential disincentives to demand side programs and ensure equal treatment for demand side and supply side options, several matters needed to be addressed. The first was the need to provide a mechanism to trace DSM investment costs between rate cases in a deferral account to be amortized and included in cost of service for the purpose of recovery through future rates. Union recommended that there be a carrying cost associated with the deferral account comparable to the utilities' overall rate of return. The second matter was the need for the utilities to have the necessary confidence that, as a matter of principle, prudently incurred DSM costs recorded in deferral accounts, together with adequate financing costs, would be recoverable in rates. Union indicated that it would be satisfactory if the Board's Report in this case included an appropriate declaration of principle and recognition of the need for adherence to such principle by future panels of the Board.

Union submitted that as long as a DSM portfolio is cost-effective, and the utility has the opportunity to earn its allowed rate of return through both demand and supply side investments, no further bonuses would be necessary at this time. Union noted that the design and implementation of bonus mechanisms would be fraught with difficulties and would likely result in significant burdens, including administrative and regulatory burdens.

ISSUE 6 (Part 2) (DECOUPLING)

Union endorsed the consensus statement of Union and Centra regarding decoupling.

Union submitted that decoupling was far too blunt an instrument to deal with the matter of potential unforecasted lost revenues between rate cases, and that the implications and likely adverse impacts of decoupling were out of all proportion to the magnitude of the potential lost revenue problem intended to be addressed.

Union noted that inasmuch as the promotion of energy conservation included efforts to increase the efficient use of gas, and given the opportunity to have regular rate cases and to set rates based on forecasted DSM efforts, the overall concern regarding lost revenues between rate cases was likely to be modest. Union emphasised that it does not consider that without decoupling, it has been financially penalized or discouraged to date from promoting conservation and efficiency which it explained is fundamental to the pursuit of its customer and corporate goals in the 1990's.

Union acknowledged that there might be specific circumstances in which unplanned or unforecasted DSM opportunities between rate cases would raise a lost revenue concern, but submitted that other more appropriate mechanisms should be made available to resolve any such potential barrier to DSM. Union referred in that regard to alternatives such as a formal lost revenue adjustment mechanism, or a more program specific accounting order mechanism which most other regulators have adopted to deal with DSM related lost revenue concerns.

Union submitted that by contrast to these alternatives, decoupling would present a number of significant problems. Union argued that a major problem with decoupling was that it would eliminate an incentive to promote the socially beneficial use of gas, and thus undermine a major element of Ontario's energy policy objectives. Union also commented on other likely adverse impacts of decoupling, including the potential for distortion of utility decision making and perverse price signals, added regulatory complexity, negative effects on competitive gas markets and unacceptably large price swings for significant industrial customers.

Union strongly objected to suggestions that support for decoupling could be viewed as a reflection of a utility's, or a regulator's, commitment to conservation. Union pointed out that the majority of Electric utilities and virtually all gas utilities that have aggressively pursued DSM are doing so without decoupling.

Union asked the Board to confirm in its Report that it would, if necessary to allow the pursuit of new DSM opportunities, accommodate utility specific regimes which would involve specific accounting orders and the subsequent disposition of the lost revenue related accounting balances subject to the standard tests of prudency.

ISSUE 7 (DSM POTENTIAL)

Union submitted that since DSM depended upon consumer acceptance, it was far more important to focus on examining "achievable potential" (through consultation, reviewing information regarding other utilities and market research), rather than conducting theoretical and costly studies of "technical potential". Subject to this concern, and comments about the problems of end use forecasting, Union endorsed the consensus statement.

ISSUE 8 (RATE DESIGN)

Union endorsed the consensus statement on this issue. Union submitted that rate design is a relatively weak tool to promote conservation, and that it is far more important to address the market barriers to wise energy use where there is substantially greater opportunities to promote conservation and sufficiency. Union indicated that it considered the existing M2 rate structure for residential consumers to represent an appropriate balance between competing rate design objectives. Union agreed that it was important to provide customers with information concerning their consumption patterns and resulting cost.

ISSUE 9 (JURISDICTION)

Union endorsed the consensus statement on this issue. Union referred to a portion of the consensus statement addressing the need for consistency on the part of the Board and for an expression by the Board of its support for longer term DSM programs proposed by utilities in rate cases. Recognizing the potentially large new DSM investments and related risks, Union asked the Board for a firm endorsement of that aspect of the consensus statement.

ISSUE 10 (Part 1) (IMPLEMENTATION)

Union endorsed the consensus statement regarding this aspect of Issue No. 10.

Union observed that the scope and detail of formal DSM plans is likely to evolve over future rate cases as more information regarding avoided costs, market barriers and customer research becomes available. While recognizing the value of meaningful discussions with known interested parties, Union noted that the most important assessments to be made with respect to successful DSM relate to Union's customers.

Union proposed, consistent with its approach to supply side programs, that it would provide funding where appropriate to facilitate participation by interested parties in the consultative process relating to DSM, and seek the recovery of forecasted costs in future rate cases. Union asked for the Board's endorsement of this approach.

ISSUE 10 (Part 2(a) (IMPLEMENTATION)

Union endorsed the consensus statement for this aspect of Issue No. 10 notwithstanding it's belief that future generic hearings on supply side integration matters will not be required. Union expressed the view that current regulatory processes, utility planning capabilities and appropriate consultation create ample opportunities to evaluate supply side alternatives. It noted further that the major elements of IRP with respect to integration of plans will also be in place through the process of estimating avoided costs and employing those estimates in DSM program evaluation. Union indicated, however, that subsequent workshops might be beneficial.

ISSUE 10 (Part 2(b)) (IMPLEMENTATION)

Union rejected the consensus statement on this aspect of Issue No. 10.

Union did not support the further formalization of IRP through legislative measures as a necessary precondition to the pursuit of DSM or the goals of IRP. Union submitted that no need or justification had been shown for such additional regulatory complexity or the substantial cost that would result, particularly in view of the LDCs' support for virtually all of the important provisions of the consensus statement and for the goals of IRP.

ISSUE 11 (GUIDELINES)

Union submitted that the Board should address all of the issues set forth in the consensus statement. Union commended to the Board the guidelines discussed in the consensus statement under the issues endorsed in Union's argument, together with certain clarifications identified in Union's argument. Union submitted that the guidelines should be sufficiently flexible to allow each utility to pursue DSM in light of its own particular circumstances, and to recognize that DSM is evolving and should be permitted to develop based on experience.

GLOSSARY OF TERMS

Achievable Potential - An estimate of the amount of energy savings that reasonably can be expected to result from the implementation of a DSM program or plan, taking account of such factors as market acceptance and economics. (see also **Technical Potential)**

Administrative Costs - Expenses incurred by a utility for program planning, design, management and administration. These costs include general overhead costs required to implement a program, but do not include direct program costs such as marketing, purchasing, incentives, monitoring and evaluation costs.

Average Costs - A natural gas utility's total costs divided by its total throughput, expressed as the cost per unit of volume, or as the cost per unit of energy.

Avoided Cost - The total supply-side costs that are not incurred, or deferred into the future, as a result of the implementation of a DSM program. Avoided costs are usually taken to be the full marginal or incremental costs of supply that will be avoided.

Balancing Account - An account established by a utility, with regulatory approval, to record differences between estimated and actual charges (or credits) relating to a current accounting period; for disposition in a future accounting period or periods. Also referred to as a **Deferral Account**.

Base Case Forecast - The anticipated natural gas demand in the absence of additional DSM programs. In this Report, the base case forecast includes all of the utility's DSM programs to date and its NGV efforts.

Base Load - The minimum continuous load over a given period of time. Excludes peak demand.

Break-Even Analysis - Analysis of the costs and benefits of a DSM program to define the level at which the benefits from a program will just cover the costs.

BTU Tax - A tax on energy sources, including non-fossil fuels, based on their heating values.

Carbon Dioxide - The gaseous product of the complete combustion of carbon. The chemical formula for carbon dioxide is CO_2.

Carbon Tax - A tax on fossil fuels usually in proportion to the carbon dioxide they emit when fully combusted. Sometimes used as synonym for **BTU tax.**

Collaborative - A balanced, manageable and diverse group of parties formed to assist in utility planning processes. In this Report, the Collaborative assists the Ontario natural gas utilities with the selection, qualitative assessment, measurement and, if possible, monetization of externalities.

Conservation Programs - Programs aimed at increasing the efficiency of energy use, thereby reducing consumption.

Cost Award - An amount of money payable by one party to another as directed by the Board in relation to a proceeding before the Board.

Cost-Based Rates - Rates which recover the costs of providing a particular service. These rates may differ from Cost-Related Rates, which are less strictly based on cost causality.

Cost-Effectiveness Tests - Tests which compare the costs and the benefits of a program. Such tests include the Societal Cost Test, the Total Resource Cost Test, the Rate Impact Measure Test, the Utility Test, and the Participant Test.

Cost-of-Control Method - An evaluation method, used to assign values to externalities, which utilizes the cost of controlling the generation of the externality as a proxy for the cost of the damage which results from the externality. (Also see **Damage Costing)**

Cost-Related Rates - Rates that reflect cost causality but may recognize risk and other factors, such as rate stability and value of service.

Cream-skimming - (pejorative) A DSM strategy which involves the implementation of only the least costly, most profitable or most readily implementable programs.

Cross-subsidization - Financial subsidies obtained from one customer or customer group to pay all or a portion of the costs for a program, service or facility used by a different customer or customer group.

Customer Class - A group of customers with similar characteristics, such as economic activity or demand level, typically served under the same rate schedule.

Customer Incentive - Cash or non-cash payment offered to customers to encourage participation in a DSM program.

Damage Costing - An evaluation method used to estimate the value of an externality based on an estimate of the damage caused by the externality. (Also see **Cost-of-Control Method)**

Declining Block Rates - A rate structure that has two or more successive rate steps where the unit price of each level declines as energy consumption increases.

Decoupling - A ratemaking mechanism or incentive which eliminates the link between profits and sales volume, so that a utility will not suffer a profit reduction if it implements a DSM program which results in an unforecast reduction in sales revenue.

Deferral Account - An account established by a utility, with regulatory approval, to record differences between estimated and actual charges (or credits) relating to a current accounting period; for disposition in a future accounting period or periods. Also referred to as a **Balancing Account.**

Demand-Side Management (DSM) - Actions taken by a utility or other agency which are expected to influence the amount or timing of a customer's energy consumption.

Demand-Side Options - Load management techniques a utility can use to reduce or alter its load profile, such as energy efficiency improvements and load shifting.

Discounted Cash Flow (DCF) Analysis - A financial evaluation methodology that accounts for the time value of money through the application of an appropriate discount rate to a project's forecast costs and benefits/revenues. Typically used for long-term projects.

DSM Activity/Measure - An action taken by customers to alter the amount or timing of their energy consumption.

DSM Plan - A strategic plan which sets objectives for, and directs and controls the implementation, monitoring and improvement of a utility's preferred DSM portfolio.

DSM Portfolio - A group of DSM programs which have been selected and combined in order to achieve the objectives of a utility's DSM plan.

DSM Program - An organized collection of related DSM activities or measures which a utility may use to affect the amount and timing of a customer's energy consumption.

DSM Strategy - The combination of a portfolio of DSM programs and its implementation plan which a utility intends to employ in order to achieve its DSM objectives.

E.B.O. 134 - A generic hearing by the Ontario Energy Board in 1987 to review the issue of natural gas system expansions in Ontario, during which tests for determining the economic feasibility of such expansions were recommended.

Embedded Costs - The sum of a utility's costs related to its fixed assets and/or long-term debt of different vintages. Assets are valued at their installed cost less depreciation without adjustment for inflation or changes in market values.

Emissions Trading - A pollution control mechanism by which a regulator or government attempts to restrict undesirable emissions in a certain area by setting an upper limit or cap on the total discharge of a pollutant for a region. Clearance to emit a limited quantity of the offending substance is then granted to existing and potential polluters, who are permitted to sell these rights in an open market.

End-Use Forecasting - Load forecasting relying primarily on end-use models to extrapolate historical use per customer patterns under different economic and market assumptions.

End-Use Model - A "grass-roots" approach to estimating a customer's energy consumption, which focusses mainly on the type and efficiency of an end-user's equipment. These models require relatively large amounts of detailed data.

Energy Service Company (ESCO) - An organization that contracts with energy users, landlords and/or utilities to evaluate, design, install and monitor capital and operating improvements in an existing building facility or industrial process, to reduce energy and operating costs over a contract period. ESCOs typically finance the costs of these improvements and receive payment by sharing in the resultant energy and operating savings.

Energy Services

1. (End-User) The comfort, lifestyle or industrial production capability an end-user obtains through the use of an energy form.

2. (Utility) The storage, transmission and distribution of natural gas and any other services provided by the utility as part of the delivery of natural gas to its customers.

Environmental Externalities - Costs and benefits which result from changes to the environment as a direct or indirect result of a company's or individual's actions, but which are not accounted for as business costs or benefits.

Environmental Impact - The effect of any change imposed on the ecology of an area due to some action.

Expensed - The accounting process by which a utility's costs are charged in the current period against current revenues and proposed for recovery as a cost of service to the ratepayers.

Externalities - A general term encompassing **Social Externalities** and **Environmental Externalities.**

Filing Requirement - Information that a utility or other applicant is required by the Board to present as part of its evidence in a rates hearing or other proceeding.

First Round Costs and Benefits - The direct effects of a DSM program, portfolio or plan.

Fixed Costs - Costs that remain relatively constant and do not tend to vary with throughput. For example, interest expense, depreciation charges and property taxes. (Also see **Variable Costs**)

Free Riders - Customers who would have adopted program-recommended action even without program incentives, but who participate directly in the program when it is offered and claim the benefits of any incentive or subsidy.

Fuel-Switching Programs - Measures or activities which encourage customers to change from one fuel or energy form to an alternate fuel or energy form.

Global warming - The possible warming of the earth due in part to human activities.

Grandfathering - Exempting an existing activity or condition from compliance with a new policy or regulation.

Greenhouse Effect - The theory that the earth's atmosphere is changing as a result of the buildup of gaseous emissions, such as carbon dioxide and methane, due to natural causes and human activity, and thereby inhibiting the earth's ability to dissipate its heat.

Incentive - See **Customer Incentive** or **Utility Incentive.**

Incremental Cost - The cost of supplying one additional unit of energy. Also called **Marginal Cost.**

Incremental Participation - The number of additional participants in a DSM program compared to a previous time frame or an alternative circumstance.

Industrial Sector - The group of non-residential, non-commercial customers that provide products, including agriculture, construction, mining, and manufactured goods and services.

Integrated Resource Planning (IRP) - A planning method for use by natural gas and electric utilities whereby expected demand for energy services is met by the least costly mix of demand-side and supply-side programs and strategies. Sometimes referred to as **Least-Cost Planning.**

Integration Phase - A future phase of the E.B.O. 169 IRP proceedings which will consider how to combine the demand-side and supply-side aspects of planning in order to ensure the consistent treatment of both aspects in the development of a utility's integrated resource plan.

Inter-class subsidization - Financial subsidies obtained from one customer class to pay for a program, service or facility used by a different customer class whose own contributions are insufficient to completely finance the program, service or facility.

Interruptible Rates - Rates, typically involving discounts, offered to customers in return for the utility's right to curtail deliveries of an energy form for a specified duration, subject to mutually agreed-upon conditions.

Intervenor Funding Project Act (IFP Act) - Ontario legislation which provides for the awarding of funding, in advance of the commencement of a hearing, for interventions before selected tribunals, including the Ontario Energy Board.

Internalization - Accounting for the costs and/or benefits that are related to, or result from, the activities of an individual or enterprise, but which previously have not been accounted for in the cost of doing business.

Intra-class subsidization - Financial subsidies obtained from a customer or customers in a particular customer class to pay for a program, service or facility used by a different customer or customers in the same customer class whose own contributions are insufficient to finance the program, service or facility.

Inverted Rates - A rate structure with two or more successive steps where the unit price of each level increases as consumption increases.

Iterative Process - A process in which some or all steps in a normal progression may be repeated as more knowledge or information is gained.

Least Cost Planning - A synonym for Integrated Resource Planning.

Load - The amount of natural gas consumed by a particular customer, group of customers, or all the utility's customers.

Load Factor - The average consumption of natural gas over a designated period expressed as a percentage of the peak or maximum consumption during that same period.

Load Profile - The demand for a utility's energy supply or the amount of consumption by a particular customer or group of customers displayed over time to illustrate consumption patterns during a specified period.

Local Distribution Company (LDC) - A natural gas utility which sells and/or delivers gas to end users in a specific franchise area or areas.

Lost Opportunity - An occasion to improve the efficient use of energy which is foregone when a decision is based only on short-term or immediate benefits and does not consider long-term cost impacts, e.g. not adding insulation during a renovation.

Lost Revenue Adjustment Mechanism (LRAM) - A technique which allows the utility to recover, in its rates, the revenue loss associated with a specific DSM program or set of programs. (See also **Revenue Adjustment Mechanism**)

Marginal Cost - The incremental cost of supplying one additional unit of energy.

Market Barrier/Imperfection - A factor which prevents a market from arriving at an efficient equilibrium price which would result from matching supply with demand.

Methane - a colourless hydrocarbon gas which is the chief component of natural gas. Its chemical formula is CH_4.

Monetization - Assigning a dollar value to the effect of an externality for use in planning processes.

Net Rate Impact - The overall change in the customer's per unit cost of an energy form due to the introduction of a proposed DSM program, portfolio or plan.

Net Societal Benefit - The aggregate impact on society of an activity, taking into account all effects on the economy, environment and society (both quantitative and qualitative).

NGV Programs - Gas utility programs aimed at promoting the use of natural gas as a vehicle fuel.

"No Regrets" Approach - A policy which includes actions to be undertaken that may mitigate the potential adverse effects of a future event (e.g. global warming) for which the severity and timing of occurrence are uncertain.

Partial Decoupling - A technique which weakens the linkage between profits and unforecast reductions in revenue due to a DSM program. For example, a Lost Revenue Adjustment Mechanism.

Participant Test - An evaluation of the costs and benefits of a DSM program to determine the total financial effect that the program will have on the end users that partake in the program.

Participation Rate - The ratio of the number of actual program participants to the total number of participants eligible to partake in the program.

Payback Period - The time required for a program to generate sufficient revenue or cost savings to recover the costs of developing and implementing the program.

Peak Demand - The maximum amount of natural gas required by a customer or LDC over a given, usually short, period of time.

Penalty - A regulatory mechanism that disciplines a utility for not achieving a specified target.

Penetration - A measure of the level of customer acceptance or market share for a particular service, product or program.

Penetration Rate - A measure of the level of customer acceptance or market share for a particular service, product or program, expressed relative to the total potential market.

Pilot Programs - A trial or experimental program to test customer acceptance and program potential, before deciding whether to commit to the full implementation of a DSM program.

Planning Horizon

1. The time required for the full achievement and/or cost of recovery of a demand-side or supply-side plan.
2. The forecast useful life of a DSM program.
3. A pre-determined outpost year for the forecasting, monitoring or duration of a program, portfolio or plan.

Polluter-Pay - The principle which requires that those who are the source or cause of pollutants pay their proportionate share of the societal cost of the damage caused by the pollution.

Program Effect - The net change in energy demand of a participating customer or group of customers that can be attributed to a DSM program.

Qualitative Assessment - An evaluation of the costs and/or benefits of an event or activity in non-numeric or non-monetized terms.

Quantification - The process by which numeric values are assigned to the costs and/or benefits of an event or activity.

Rate Impact Measure (RIM) Test - A screening test which measures the impact of a DSM program on the customer's unit cost of energy.

Retrofit - The modification of existing equipment or of a current facility, typically to improve energy efficiency.

Revenue Adjustment Mechanism - A usually symmetric technique which allows the utility to include, in its rates, the revenue loss or gain associated with a specific DSM program or set of programs. (See also **Lost Revenue Adjustment Mechanism**)

Screening Process - The application of cost-effectiveness tests to select the most appropriate DSM programs and portfolio.

Seasonal Rates - Service rates offered by a utility to recognize changing operating conditions and costs during different times of the year.

Second Round Costs and Benefits - The indirect effects of a DSM activity or measure.

Sensitivity Analysis - The variation of an input or assumption to determine how the expected output of an analysis will respond, and to identify which of the variables and assumptions are most determinant of the expected output. For example, testing the response of DSM program savings to pessimistic, optimistic and most likely natural gas price forecasts.

Shared Savings Mechanism

1. A regulatory incentive to the utility's shareholders whereby they are allowed to retain a portion of the net dollar benefit from a DSM program or set of programs.

2. An arrangement whereby an Energy Service Company (ESCO) finances a DSM activity in return for a portion of the savings that are generated.

Significance - That quality of a factor or effect which is considered important or of consequence and therefore, worthy of further consideration.

Social Externalities - Costs and/or benefits, which affect the well-being or lifestyle of segments of the public as a direct result of a company's or individual's activities, but which are not accounted for as a cost of doing business.

Social Impact - The effect of any change imposed on the well-being or lifestyle of an individual, family, community or institution due to some action.

Societal Cost Test - An evaluation of the costs and/or benefits accruing to society as a whole, due to an activity.

Societal Impact - The total impact of an activity on the economy, the environment, and society as a whole.

Supply-Side Options - Expansion or replacement projects, such as pipeline or storage construction, upstream of the customer's meter.

Synergy - A productivity or efficiency improvement resulting from the combination of two or more compatible actions or operations to yield a benefit which is greater, or a cost which is lower, than would be the case were the actions to have been pursued independently.

Technical Potential - The total amount of energy that could be saved if all energy uses were served by the most efficient technology or design currently available, without consideration of cost effectiveness, market and institutional barriers or limitations on manufacturing capability. (See also **Achievable Potential**)

Throughput - The total volume of natural gas consumption or utility gas sales which occurs in a specified time frame, usually measured annually.

Total (Financial) Costs - The sum of a utility's fixed and variable costs, including capital, operating and interest costs.

Total Market - All the customers in a given market sector, or sub-sector targeted for a DSM program.

Total Resource Cost Test - An evaluation which incorporates all of the costs and benefits included in the Societal Cost Test with the exception of externalities.

Trade Allies - Organizations that cooperate in the provision of goods and/or services and, in doing so, affect the energy-related decisions of customers who might participate in DSM programs.

User-Pay - The principle which requires beneficiaries of a program, service or facility to pay their proportionate share of the total cost of the program, service or facility.

Utility Costs - Costs incurred by a utility in a given year for the operation of a DSM program or portfolio. Includes administration costs.

Utility Incentive - A regulatory measure which rewards a utility when it achieves a specified target. Also referred to as a shareholder incentive.

Utility Test - An evaluation of the impact of a DSM program on a utility's revenue requirement as a result of changes in costs. Excludes any lost revenues due to the DSM program.

Value of Service Rates - Rates which are not strictly based on cost causality, but also considers other factors such as the customer's ability to use an alternative to natural gas.

Variable Costs - Costs that vary proportionally with throughput. (Also see **Fixed Costs**)

APPENDIX C

THE BOARD'S E.B.O. 134 FINDINGS ON ECONOMIC FEASIBILITY TESTS

The Board finds that of the tests currently in use by the utilities, the DCF analysis provides a superior measure of the subsidy required from existing customers for a particular project.

The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion.

The Board encourages the use of more formal risk measurement in the feasibility test and it would not discourage the use of sensitivity analyses of variables being regularly employed in the test.

The Board finds that incremental costs should be used in evaluating the feasibility of system expansion.

The Board will continue to assess the adequacy of the DCF analysis and any other tests used for project evaluation at the time of a utility's rate case hearing.

The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest.

The first stage is a test based on a DCF analysis.

The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage.

The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.

A project could, therefore, be accepted if it passed the DCF analysis of stage one and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated.

The Board is aware that each utility will continue to approve internally projects that lie within areas for which a franchise and a certificate of public convenience and necessity have been issued. At subsequent rate hearings the Board may assess the analyses employed before approving the inclusion in rate base of any specific project.

Any project brought before the Board for approval should be supported by all data used by the Applicant in reaching its conclusion that the project is viable. The utilities and other interested parties may use alternative analyses, but these and the results must be presented at the relevant hearing. The Board will continue to weigh the various benefits against the various disadvantages as it always has in reaching its decision in the public interest.

The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rats, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.