uniongas
A Spectra Energy Company

July 9, 2015

BY COURIER & RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, Ontario
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RE: EB-2015-0029 – Union Gas Limited ("Union") – 2015-2020 DSM Plan Technical Conference Undertaking Responses

Dear Ms. Walli,

Please find attached Union's responses to the following technical conference undertakings received in the above case: JT2.1; JT2.3; JT2.5; JT2.7; JT2.8; and JT2.13.

If you have any questions with respect to this submission please contact me at 519-436-5334.

Yours truly,

[*Original Signed by*]

Vanessa Innis
Manager, Regulatory Initiatives

Encl.

cc: Lawrie Gluck, Board Staff
Alex Smith, Torys
All Intervenors (EB-2015-0029)

UNION GAS LIMITED

Undertaking of Ms. Lynch
To Mr. Elson ("ED")

To file a copy of the 2008 custom projects attribution study.

Please see Attachment 1.

Custom Projects Attribution Study

Final

Submitted To:

DSM Evaluation
Union Gas Limited – A Spectra Energy Co.
Enbridge Gas Distribution

October 31, 2008

Submitted to:

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E EXECUTIVE SUMMARY

Enbridge Gas Distribution (EGD and Union Gas deliver DSM programs to customer in their respective franchise areas.

In 2006, the Ontario Energy Board (OEB) convened a Generic Proceeding on the subject of natural gas DSM. Through the Proceeding, the OEB approved the utilities' DSM plans for the three-year period 2007 through 2009, including assumptions for measure savings and free ridership. Items identified as priorities for evaluation research included a free ridership study of the Custom Projects programs.

This report presents the results of market research conducted by Summit Blue Consulting, LLC/Summit Blue Canada, Inc. ("Summit Blue") during the winter of 2007-2008 to measure free ridership and spillover for the Custom Projects programs.

E.1 Definitions

To assist the reader in understanding the terms used throughout the document, Summit Blue has provided definitions for the following terms:

Free Ridership: Free riders are customers who received an incentive through an efficiency program, yet would have installed the same efficiency measure on their own had the program not been offered. This includes partial free riders, defined as customers who, at some point, would have installed the measure anyway, but the program persuaded them to install it sooner than otherwise.

Spillover represents energy savings that are due to the program but not counted in program records. Spillover can be broken out in three ways:

- **Participant inside spillover** represents energy savings from other measures taken by participants at participating sites not included in the program but directly attributable to the influence of the program.
- **Participant outside spillover** represents energy savings from measures taken by participants at non-participating sites not included in the program but directly attributable to the influence of the program.
- **Non-participant spillover** represents energy savings from measures that were taken by non-participating customers but are directly attributable to the influence of the program. Non-participant spillover is sometimes called the "Free-Driver effect."[1]

[1] See for example California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals. TecMarket Works. Prepared for the California Public Utilities Commission. April 2006. Page 226.

Net-to-Gross Ratio: Gross impacts are the program impacts prior to accounting for program attribution[2] effects. Net impacts are the program impacts once program attribution effects have been accounted for. The net-to-gross ratio is defined as 1 - free ridership ratio + spillover ratio.

E.2 Study Overview

The study included the following research tasks performed during the winter of 2007-2008:

- Development of a project analysis plan detailing the study's methodology
- A history and critique of the methods that have been used to estimate free ridership and spillover in nonresidential programs.
- On-site interviews (plus a few telephone interviews) with participants and participating trade allies.
- Telephone interviews with customers who had a program-supported energy audit but had not implemented any measures through the program.
- Telephone surveys with nonparticipants to look for and quantify nonparticipant spillover.
- An analysis and scoring of the data to produce the free ridership and spillover estimates.

E.3 Free Ridership Results

The total free ridership rate across both utilities and all sectors is 48% as shown in Table E-1. The free ridership rate for EGD is 41% and it is 54% for Union Gas. Summit Blue recommends that the utilities use the utility-specific total free ridership values of 41% and 54% as the best estimate of free ridership. Those results are based on larger sample sizes than the sector-specific results and proved more stable in the sensitivity analysis. The sector-specific results are based on smaller sample sizes and should only be used to support program management, for example to support targeting and marketing decisions.

[2] For purposes of this study, attribution is defined as the influence the program has had on customers installing the target measure when they otherwise would not have done so, including inside spillover influences to take additional energy efficiency measures.

Table E-1. Free Ridership Results

Sector	EGD	Union	Total
Agriculture	40%	0%	18%
Commercial Retrofit	12%	59%	27%
Industrial	50%	56%	53%
Multifamily	20%	42%	26%
New Construction	26%	33%	28%
Total	41%	54%	48%

Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

E.4 Spillover Results

Participant inside spillover, representing additional energy efficiency measures installed at the participant's same facility without going through the program, is 5% of gross reported savings for both EGD and Union.

Participant outside spillover, representing additional energy efficiency measures at *different* facilities without going through the program, is 5% combined across both utilities.

Customers who received an audit, implemented a recommended measure, but did not receive incentives through the program for that measure can be considered audit-only spillover. The audit-only spillover survey and analysis was completed for EGD only as Union Gas was unable to find any companies who had an audit in 2005 and had not implemented one of the recommended measures through the program. As a result, the savings inspired by the Union Gas audits will appear in the program tracking data rather than in spillover. For EGD, 35% of the gross recommended savings from energy audits were achieved, representing the audit-only spillover.

A screening survey of 1,228 non-participants found that 5.4% of non-participants were influenced by the program to implement measures (and did not receive a financial incentive). The study could not accurately calculate the m^3 savings from the respondents so the non-participant spillover was not factored into the net-to-gross ratio.

Summit Blue recommends the utilities use following spillover rates:

Table E-2. Spillover Results

Spillover Type	EGD	Union	Base
Participant Inside Spillover	5%	5%	Of gross reported savings
Participant Outside Spillover	5%	5%	Of gross reported savings
Audit-Only Spillover	35%	0%	Of gross audit-recommended savings
Nonparticipant Spillover	0%	0%	

E.5 Net-to-Gross Ratio

The net-to-gross ratio is defined as 1 - free ridership ratio + spillover ratio. As discussed above, spillover is in several parts: participant inside and outside spillover, audit-only spillover, and non-participant spillover. We know that 5.4% of the non-participants have spillover but cannot calculate its quantity so the calculation of net-to-gross in this report excludes it. Summit Blue recommends that the utilities use the utility-specific total net-to-gross ratios of 79% for EGD, 56% for Union, and 67% across both utilities as shown in the following table. As with the free ridership results, these recommended net-to-gross results are based on larger sample sizes than the sector-specific results.

Free ridership is calculated quite frequently in impact analysis studies. In the early days of attribution research, spillover was not often considered but over the past few years more and more jurisdictions are taking spillover into account along with free ridership. For example, California is now implementing studies to measure market transformation effects and spillover from its programs. NYSERDA takes both free ridership and spillover into account. Minnesota believes free ridership and spillover effectively cancel each other out. It is increasingly viewed that if programs are going to see their results discounted for free ridership that a more accurate view of net impacts can be had by adding in spillover. In 2006, Summit Blue researched the free ridership and spillover rates that have been found in studies in recent years. The 79% net-to-gross ratio for EGD is in the same range as several of the programs examined. The 56% ratio for Union Gas is lower than those found in this research.

Table E-3. Net-To-Gross Ratio

Utility	Sector	Free Ridership	Participant Inside + Outside Spillover	Audit-Only Spillover %	Net-to-Gross Ratio
EGD	Agriculture	40%			
EGD	Commercial Retrofit	12%			
EGD	Industrial	50%			
EGD	Multifamily	20%			
EGD	New Construction	26%			
EGD	Total	41%	10%	11%	79%
Union	Agriculture	0%			
Union	Commercial Retrofit	59%			
Union	Industrial	56%			
Union	Multifamily	42%			
Union	New Construction	33%			
Union	Total	54%	10%	0%	56%
Total	Agriculture	18%			
Total	Commercial Retrofit	27%			
Total	Industrial	53%			
Total	Multifamily	26%			
Total	New Construction	28%			
Total	Total	48%	10%	5%	67%

Free Ridership Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

E.6 Limitations

Three areas typically form the basis for research projects' constraints and limitations including: budgetary constraints, time constraints and reliability of data. This study, like most research, encountered constraints and limitations and they are documented below.

Budgetary Constraints

- Given sufficient time and budget, it is possible to survey every participant in a program and produce a precise calculation of a given characteristic across the entire population. However, it is typically not possible or desirable (except perhaps for very small programs) to have a budget large enough for that level of effort. As a result, free ridership studies are most often done with a sample of participants. The estimate based on that sample has an error bounds around it, and the error bounds is determined by the sample size and the variance in the result from the sample. As with most such studies, the current study used a sampling approach but with a sample designed to be sufficient to provide a result at the 90/10 confidence level, which means we are 90% confident that the mean free ridership from the sample is within 10% of the mean free ridership in the population.

Time Constraints

- The study was conducted on custom projects that were completed between the fourth quarter of 2006 and the third quarter of 2007. It is possible that the characteristics of participants and projects in a custom project program may change over time in response to changing conditions in the region. Ideally, changes in program implementation efforts also discourage free riders from participating and thus also bring about a change in the population of participants. To the extent that the characteristics of the population of participants changes over time, the results of a given study have less predictive power for the new population. When a relatively small number of participants has a particularly large impact on the free ridership value, as with the current study, changes in the population of participants could have a significant effect on future free ridership results.

- Self-report free ridership studies like the current study depend— by design— on respondents recalling events from the past. Ideally, the interviews on which to base these studies are done as soon as possible after pivotal decisions are made for each project. C&I custom projects often have a long lead time, sometimes measured in years. Thus some projects in the current study could have been incubating from as early as 2004. The time lag between when a project is conceived or key decisions are made and when the free ridership interview was completed may mean that crucial information is unavailable to the interviewer. Key decision-makers may have forgotten details or even moved from the participating company. The study included efforts to remind respondents of the history of their interaction with the program but this can never bring the entire history of a decision back to mind. While the risks here could skew results toward higher or lower free ridership values, it is more likely that these factors will produce higher free ridership values than the opposite.

Reliability of the Data

- The free ridership interviews were completed by four separate individuals. Most were done in-person and some Union Gas interviews were done by phone. The key questions that affect the free ridership results were precisely worded and all interviewers were carefully trained. However the interviews were designed to be more like free-flowing conversations than highly-scripted surveys. The interviewers were instructed to probe for details and follow lines of thought to their natural conclusions rather than stick strictly to a set script. As a result, some variations from one interviewer to the next are inevitable and they may affect the bottom line results. The results were examined to look for evidence of interviewer bias but no patterns were evident.

- As discussed above, the study is dependent on respondents' memory of past events. This is magnified in some circumstances when one respondent is responsible for providing answers on several different projects. The sample was picked at the project level, that is, projects were picked for the sample rather than participants. However, participants may have implemented more than one project in the study period. In those cases, we surveyed the respondent once but asked them separately about the individual projects. Given the reliance on Channel Partners, in the Union Gas sample 77 projects were covered by interviews with 52 respondents. The extent to which respondents were unable to distinguish in their head between one project and another will be reflected in the inaccuracy of their responses.

1 INTRODUCTION

This section gives a brief background on the purpose of the research, describes the utility programs, and introduces the organization of the report.

In 2006, the Ontario Energy Board (OEB) convened a Generic Proceeding on the subject of natural gas DSM. Through the Proceeding, the OEB approved the utilities' DSM plans for the three-year period 2007 through 2009, including assumptions for measure savings and free ridership. Items identified as priorities for evaluation research included a free ridership study of the Custom Projects programs.

Summit Blue Consulting, LLC/Summit Blue Canada, Inc. ("Summit Blue") were retained by Union Gas Ltd. (Union Gas) and Enbridge Gas Distribution (Enbridge) (jointly, the Utilities) to conduct a forward-looking evaluation of program influence attribution for free ridership and spillover associated with the Custom Projects programs offered by the Utilities.

The study included the following research tasks performed during the winter of 2007-2008:

- Development of a project analysis plan detailing the study's methodology
- A history and critique of the methods that have been used to estimate free ridership and spillover in nonresidential programs.
- On-site interviews (plus some telephone interviews) with participants and participating trade allies.
- Telephone interviews with customers who had a program-supported energy audit but had not implemented any measures through the program.
- Telephone surveys with non-participants to look for and quantify non-participant spillover.
- An analysis and scoring of the data to produce the free ridership and spillover estimates.

1.1 Utility Programs

Both Union and Enbridge operate DSM programs that include custom projects for the Commercial and Industrial sectors. Custom projects cover opportunities where savings are linked to unique building specifications, uses and technologies. Each project is assessed individually for participation in the program.

1.2 Report Organization

This chapter (Chapter 1) outlines the purpose of the study, background on utility programs and the report organization. Chapter 2 describes the methodology used to assess free ridership and spillover. Chapter 3 presents a history and critique of free ridership methodologies. Chapter 4 presents the sampling strategy and sample disposition. Chapter 5 presents the results of our research. Chapter 6 presents supplementary results. Finally, Chapter 7 presents our conclusions.

2 METHODOLOGY

This section presents a high-level overview of the methods and data sources used to conduct the study. Full details are included in Appendix A in the revised Analysis Plan.

2.1 Free Ridership

Free ridership and spillover were estimated using data from surveys with participants, non-participants, trade allies, and utility staff. This approach is based primarily on participant self-reported information along with other perspectives to triangulate the net-to-gross estimates.

Experienced utility industry consultants conducted the interviews and most were done on-site at the participant's premise. To address the possibility of respondent bias, the interviews approached each topic from a variety of directions. The interviewer had the discretion to probe for supporting information and the analysis process checks for consistency across answers. Interviewees were promised confidentiality and assured that their answers will not affect the incentives or support they have received from the program. To address the possibility of interviewer bias, each interviewer was trained in the purpose of the research and the importance of objectively probing and recording responses. Four different interviewers performed the interviews and the data from their interviews were compared to look for uneven application of the methodology.

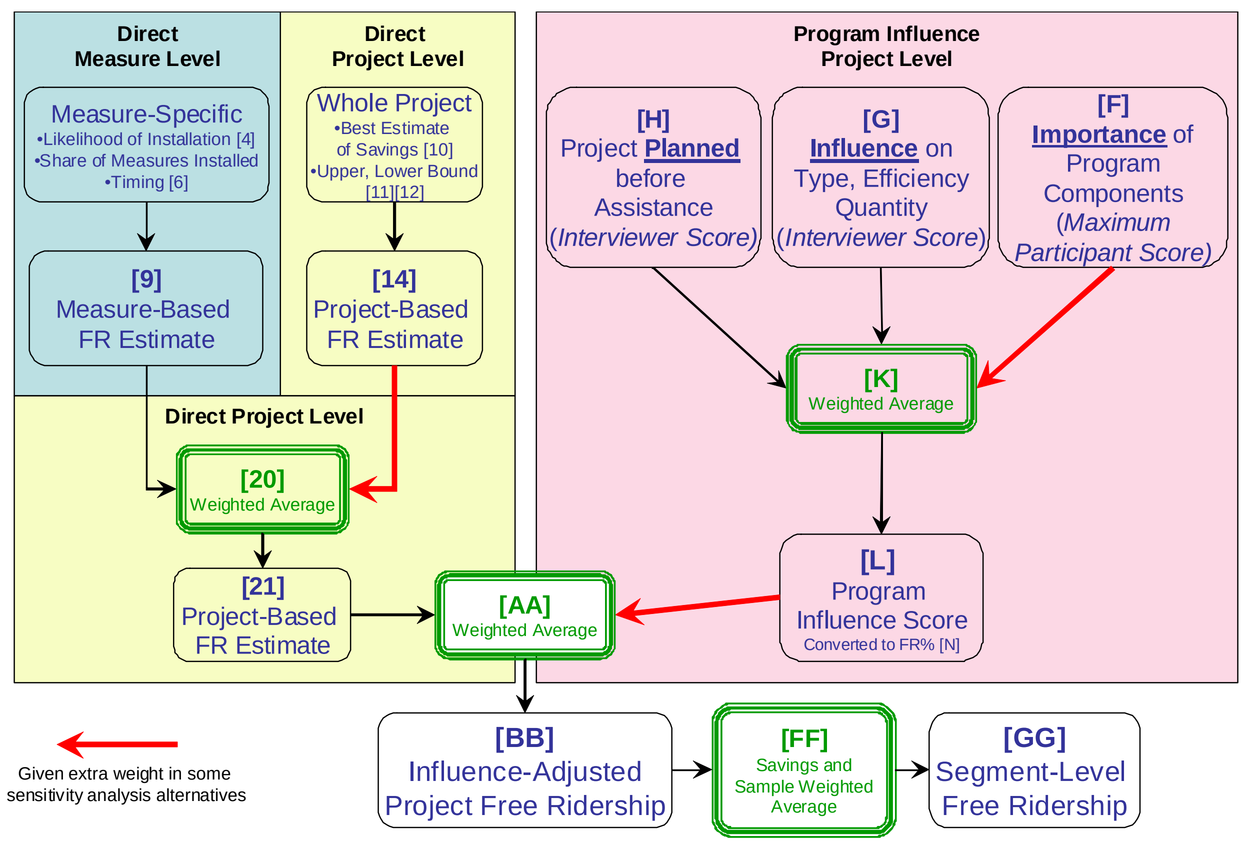
Figure 2-1 presents an overview of the survey and analysis approach. Key points in the diagram are labeled with numbers and letters in square brackets, which we will refer to below. Free ridership was discussed with each respondent in both **direct questions** aimed at obtaining respondent estimates of the appropriate (full or partial) free ridership rate to apply to them (represented by the large box on the left side of the diagram), and in **supporting or influencing questions** used to verify whether direct responses are consistent with participants' views of the program's influence on their equipment investment decisions (represented by the large box on the right side of the diagram). The direct questions were asked at the measure level [4] and [6] and at the whole project level [10]. They were then combined into a single, project-level direct free ridership score at [21]. Direct and program influence scores are combined into the final project-level free ridership score at [BB]. That project-level score is weighted by program-reported savings and sample weights [FF] to calculate the final savings-weighted free ridership percentage [GG].

Key calculations were examined in a sensitivity analysis to determine their effect on the final result. Three assumptions feeding into those calculations were found to have the most effect on the end result. Those assumptions relate to the weight given to various answers or answer categories in averages with other answers. The key calculations are shown at [20], [K], and [AA] in the calculation overview diagram. The sensitivity analysis tested the effect of increasing the weight given to [14] in the calculation at [20], the weight given to [F] in the calculation at [K], and the weight given to [L] in the calculation at [AA] (each represented by a thicker, red arrow).

Free ridership results were first calculated on the measure level. The measure-level gross and net savings are summed up across all customers and then net savings divided by gross savings produces the final savings-weighted, program-wide free ridership result. (Sample weights are applied during the summing step.)

Enbridge Gas Distribution designates some projects as "advancement" when they judge that the program moved a project forward in time. The designation of a project as an advancement project does not affect the annual savings but it does affect the TRC calculation. In their TRC calculations for advancement projects, EGD discounts the benefits and adjusts the incremental costs to account for the period which the program has moved projects forward in time. The current study addresses first-year annual savings only, it does not extend benefits and costs over time and does not include a cost/benefit analysis. On a measure-by-measure basis, respondents were asked if the program influenced them to install the equipment more than one year earlier than they otherwise would have otherwise [6]. If it did, the measure-level free ridership score is discounted in [9] in the diagram below. Several different scales were examined for discounting the free ridership score based on the number of months the project was brought forward in time. The final, utility-level free ridership score did not move significantly in that analysis. Because this study was focused on first-year savings only, it was agreed that the appropriate approach was to include this adjustment for all projects, including advancement projects. This is in keeping with standard practice in calculating free ridership. All respondents were asked the timing question [6] and their answers were accounted for in [9] whether they were being asked about an advancement project or not. Given the math of the calculation, the only possible effect of removing the timing question for advancement projects would be to **increase** the free ridership rate.

Figure 2-1. Free Ridership Analysis Overview



2.2 Spillover

Spillover represents energy savings that are due to the program but not counted in program records. Spillover can be broken out in three ways:

- **Participant inside spillover** represents energy savings from other measures taken by participants at participating sites not included in the program but directly attributable to the influence of the program.

- **Participant outside spillover** represents energy savings from measures taken by participants at non-participating sites not included in the program but directly attributable to the influence of the program.

- **Non-participant spillover** represents energy savings from measures that were taken by non-participating customers but are directly attributable to the influence of the program. Non-participant spillover is sometimes called the "Free-Driver effect."[3]

Summit Blue estimated **participant inside and outside spillover** through questions in the participant and trade ally surveys and through the Audit-Only Survey. Summit Blue estimated non-participant spillover through the non-participant survey.

The surveys did not address whether the respondent received funding from other sources to facilitate the energy efficiency measures. The survey questions were designed to designed to determine if the Custom Projects program was influential in the decision to install the spillover measure and if so the share of the savings from the extra equipment that can reasonably be attributed to the influence of the program. Given that approach, funding from other sources, if any, would not change the conclusions drawn from the survey. Even with other funding, if the utility program support was critical in convincing the respondent to implement the energy efficiency measure, then it should get credit for some of the savings.

2.2.1 Participant Inside and Outside Spillover

The spillover questions were incorporated in the participant and trade ally surveys and the spillover analysis was implemented in concert with the free ridership analysis.

For **inside spillover**, respondents are asked whether their experience with the programs caused them to install additional energy efficient equipment at the site that did not go through the program. This establishes whether inside spillover exists. For those respondents reporting that additional measures were installed, they are asked to identify in which year(s) the measures were installed, and to describe how the program influenced their decisions to install additional energy efficient equipment at their facility. An additional question is asked to determine the ratio of the savings from these additional measures compared to the savings from the measures installed under the program. That is, they are asked the percent of savings as a multiple of the savings achieved under the program (**savings multiplier**). Finally,

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[3] See for example California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals. TecMarket Works. Prepared for the California Public Utilities Commission. April 2006. Page 226.

respondents are asked to estimate the share of the savings from these additional measures that can “reasonably be attributed to the influence” of the program **(net-to-gross percentage)**.

Inside spillover is zero for those without additional measures (or those who failed to answer all of the questions), and it is the product of the savings multiplier and the net-to-gross percentage for those with inside spillover. Similar to the free ridership analysis, individual spillover estimates are weighted both by relative energy savings for each respondent, as well as by sample stratification to determine an inside spillover value for the group as a whole.

Similar to inside spillover, for **outside spillover**, respondents are asked first whether the influence of the program caused them to install any additional energy efficiency equipment, outside of the program, at other sites beyond what they would have done without their experience with the program. If they respond yes, they are asked several follow-up questions designed to provide an estimate of the level of savings from these actions that could be attributed to the program.

For outside spillover, the savings as a percent of the in-project measure is multiplied by the share of savings attributed to the program to calculate the outside spillover value.[4] Similar to the free ridership analysis, individual spillover estimates are weighted both by relative energy savings for each respondent, as well as by sample stratification to determine an outside spillover value for the group as a whole.

2.2.2 Audit-Only Spillover

Participants who received an audit, implemented a recommended measure, but did not receive incentives through the program for that measure can be considered spillover. These kinds of participants would not be included in either the participant or non-participant surveys. We implemented a survey specifically with this population and focusing solely on spillover measures to provide an additional estimate of program spillover.

The interviewer asks the respondent if they recall receiving the audit. If they do not, the interviewer attempts to speak to someone else who might recall the audit. The interviewer asks the participant about each measure recommended in the audit. (Although we will limit this to the measures with the largest savings if there are more than 5 measures recommended.) The interviewer examines whether the respondent remembers the recommendation and whether it has been installed and when. If the participant installed a measure, the interviewer asks the following:

1. On a scale of 1 to 5 where 1 is “no influence” and 5 is “a great deal of influence”, how much influence did the audit have in your decision to implement this measure?

2. What share of the savings from this measure can reasonably be attributed to the influence of the program?

The analysis of audit-related spillover savings is fairly straightforward. The program tracking data have measure-specific savings estimates from the audit. The two influence scores are converted to the same scale and averaged. That average is applied to the audit savings to calculate audit-related spillover savings.

[4] A cap of five outside spillover projects per respondent is used to prevent outliers from skewing the results.

2.2.3 Non-Participant Spillover

Summit Blue estimated non-participant spillover using a survey targeted at non-participants only. The approach to the data collection and analysis took the following steps:

1. Obtain sample of non-participants from the utilities

2. Execute telephone screening survey to identify customers who had implemented relevant measures and were influenced by the program.

3. Conduct engineering follow-up interview to estimate savings from those measures influenced by the program.

The screening survey went through the following steps:

1. Find someone knowledgeable about the replaced or modified equipment.

2. Are they aware of the program? If no, terminate.

3. Did the company participate in the program in the past 3 years? If yes, terminate.

4. Has the company modified or installed equipment that might fall under the program's incentives since the beginning of 2005? (List target equipment.) If no, terminate.

5. Determine what effect, if any, the program had on their decision. If none or little, terminate.

6. Obtain permission for the follow-up engineering call.

In the engineering follow-up call Summit Blue engineers asked enough questions about the equipment to make an engineering estimate of the energy savings it produces.

3 HISTORY AND CRITIQUE OF FREE RIDERSHIP METHODOLOGIES

This chapter was designed to analyze the methods used to assess both free riders and spillover for customized programs targeted to the commercial and industrial sector. Summit Blue conducted a literature review of methodology development and assessment and current practice, compared the various methods, and drew conclusions on the most appropriate method to use for C&I custom projects programs.

The recommended method to assess free riders and participant spillover is self-report in-person and telephone surveys with participants and market players. Issues such as self-selection bias would be controlled by using enhancements such as interviews with multiple decision makers at sampled sites, multiple question areas to address program influence on decision making, and well-thought out scoring algorithms. The market share method of estimating free ridership is not appropriate for custom projects with large customers mainly because the programs are focused on custom projects rather than promotion of specific equipment. Market sales methods rely on good equipment sales data and work best with programs targeted at measures that are uniform across applications and very specific definitions of technology. Econometric methods including billing analysis and discrete choice modeling are not applicable for C&I custom programs because large customers may skew the results, custom projects are less amenable to standardized approaches, difficulties with identifying comparable non-participant groups cast doubt on the validity of the model, the lack of good historical data (except for consumption) limits their scope, and the need to estimate a proportion rather than magnitude of net savings and the requirement to assess spillover limit their usefulness.

Self-report and econometric analyses have merit and often provide similar results. For example, a study by Torok in 1999 found consistent results from self-report, billing, and discrete choice analysis; net-to-gross (NTG) results for self-report and discrete choice methods differed by less than one percent. The study looked at the three methodologies used to estimate net impacts for Pacific Gas & Electric's Commercial Energy Efficiency Program, which provided prescriptive rebates for equipment as well as funding for custom projects (gas or electricity). The authors preferred the two stage discrete choice model, but recommended the continued use of multiple approaches. Most econometric methods for NTG require survey information; the more they rely upon self-report data, intentions, and psychographic data, the more they are likely to have some of the same measurement issues as the survey-based approach. Billing analysis can produce biased results because of participant self-selection into programs; this can be dealt with by various statistical methods which unfortunately require excluding large customers as they can skew the results.

3.1 Background & Development of Methodology

This section briefly outlines the history of evaluation of social actions and the development of evaluation methodology to assess free riders and spillover effects.

Evaluation is rooted in the empirical study of social problems in Britain in the 1660s with the first evaluative studies published in the 1800s, looking at the impact of education on crime or the usefulness of public works, for example. However, until quite recently, most policies and programs did not include provision for evaluation, assuming the remedies provided would solve the problems. "*People working in education and health fields were among the first to do systematic studies of the outcomes of their work*"[5] starting in the early 1900s. In the 1940s, private foundations began funding evaluations of innovative social programs they sponsored, such as a youth worker program to prevent delinquency in suburban neighborhoods near Boston. By the 1950s, the U.S. federal government was sponsoring new curriculum efforts with funding for evaluations of the success of the curriculums. In the mid-60s, the War on Poverty marked the beginning of large-scale government-funded evaluation—the Elementary and Secondary Education Act of 1965 included a requirement for evaluation. Robert Kennedy was the moving force behind this, seeing "*evaluation as a tool to provide parents with the necessary information.*"[6] The same period saw the rise of cost-benefit analysis in the RAND Corp, Department of Defense and elsewhere; evaluation branched out into other areas such as environmental protection, energy conservation, military recruitment, and control of immigration. In the 1970s, the inauguration of a series of social experiments to test policy and program ideas prior to enactment—using pilot programs—was a high point in evaluation history. *"By the end of the 1970s evaluation had become commonplace across federal agencies."*[7] Evaluation was a growth industry until 1981 when funding for new social initiatives was cut drastically and then made a comeback in the late 80s and early 90s.

The major shift toward more accurate measurement of program-related energy savings came about in the mid-to-late 1980s, a time of least-cost planning and large increases in utility spending on energy efficiency programs. Most analysts used definitions for cost-effectiveness tests based on the 1987 California Public Utilities Commission Standard Practice Manual of Economic Analysis of Demand-Side Management Programs; these only addressed free rider impacts; not spillover. The authors found that the most widespread approach to measuring free riders and spillover was through surveys where respondents self-report the impact of the program on their actions. Many of the early studies asked a single yes/no question to determine free ridership. By 2002, methods of inquiry were more sophisticated, with a string of questions and answers to understand partial free riders.

The methodology to assess free riders has been developing over many years, but the assessment of spillover is a more recent development. Vine in 1993 noted that free drivers (customers who install spillover measures) are more likely to be a significant problem for programs in existence for several years with high participation levels and that *"research on free drivers is limited."*[8] He suggested that there were three approaches available to enhance measurement of free drivers: (1) use a historical baseline from the early years of the program; (2) use survey methods – non-participants and trade ally interviewing; and (3) use community(ies) outside the area as a comparison group. A study done by Quantec in 2002[9] provides a snapshot of what was happening about a decade later, finding several studies on free riders but few on free drivers. The study also found there was no agreement on the best way to measure free riders and spillover and no regulatory agreement on which impacts required estimation.

[5] Weiss, Carol H. (1998). *Evaluation 2nd Edition: Methods for Studying Programs and Policy*. Upper Saddle River, New Jersey: Prentice Hall.

[6] Weiss, p. 12.

[7] Weiss, p. 14.

[8] Vine, Ed. *The Human Dimension of Program Evaluation.* Lawrence Berkley Lab, LBL-33601, 1993.

[9] Quantec, *Assessment of Energy and Capacity Savings Potential in Iowa Volume 2: Free Riders and Spillover – A Look Back, A Path Forward,* prepared for the Iowa Utility Association, 2002.

A notable feature of recent evaluation history is the growth of activity at state and local levels, the increasing use of qualitative methods for evaluation, and the development of professional associations in evaluation. According to Weiss in 1998, "*Not too long ago the only kind of evaluation with professional legitimacy…was quantitative evaluation, preferably using randomized experimental design.*"[10] However, some evaluators relied more on words than on numbers and did not collect data through stricter interview questions or quantitative records and their books and articles provided a "*spirited exchange with supporters of quantitative methods.*" Eventually, many key figures in evaluation concluded that there was room for both approaches and that they could complement each other. A common attribute of the quantitative approach is the collection of information through standardized instruments and usually include one or more comparison groups. The classical means to assess attribution is through a randomized experiment; without this ability, the evaluator uses a quasi-experimental design.[11] All of the methods discussed in this chapter, including self-report, are quantitative.

3.2 Methods to Assess Free Riders and Spillover

This section compares and critiques the key methods to assess net program impacts – self-report, econometric, and market share approaches.

Methods to estimate free ridership and spillover range from assuming a net-to-gross ratio (NTG) of 1.0 to triangulation of several methods (e.g., California's enhanced protocol). Iowa uses a NTG ratio of 1.0 based on a study done in 2002,[12] currently being updated by Summit Blue as part of a technical potential study. The new study is reviewing the literature on attribution and selected evaluation studies and found that several jurisdictions that look at both free riders and spillover are finding NTG ratios of about 1.0 (see Table 3-1)[13] and will likely recommend that "*this policy should not be changed.*"

In the early days of attribution research, spillover was not often considered but over the past few years more and more jurisdictions are taking spillover into account along with free ridership. It is increasingly viewed that if programs are going to see their results discounted for free ridership that a more accurate view of net impacts can be had by adding in spillover.

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[10] Weiss, p. 14.

[11] Vine, Ed. *The Human Dimension of Program Evaluation.* Lawrence Berkley Lab, LBL-33601, 1993.

[12] *Assessment of Energy and Capacity Savings Potential in Iowa Volume 2: Free Riders and Spillover – A Look Back, A Path Forward*, prepared for the Iowa Utility Association by Quantec, July 25, 2002.

[13] Personal correspondence with Gary Cullen, Summit Blue Consulting, October 2007.

Table 3-1. Selected Findings on NTG Ratios

		NTG Ratio
Residential	Efficiency Vermont[14] Energy Trust of Oregon[15]	1.19 1.00
Non-residential	NYSERDA (overall)[16] NYSERDA (CIPP)[17] Wisconsin Power & Light (Shared Savings)[18]	1.09 0.97 0.91

It is difficult to capture long-term market effects with an annual assessment of free ridership. A study done for Massachusetts regulators[19] noted that an annual snapshot of free-ridership and spillover measured without adequately considering the market effects associated with over a decade and a half of energy efficiency programs in Massachusetts will result in potentially biased estimates of net savings. Energy efficient technologies having high market share and few alternatives as a result of these market effects can mean energy efficiency programs now will have high free-ridership.

However, many other jurisdictions do conduct studies to assess the annual impact of free ridership and spillover using several methods. The most common methods used are described briefly below and in more detail in the rest of the section.

- **Self-Report** methods rely on responses to survey questions asking end users and/or vendors what they would have done in the absence of the program support. These methods are primarily used to determine if participating end users would have installed program measures without the program. However, these methods can also determine what additional efficiency improvements participating customers have made outside the program, how participating vendor sales practices would have been different without the program, and how nonparticipating vendor and customer practices have changed since the advent of the program.

- **Econometric Methods** consist of statistical models that compare participants' and non-participants' energy and demand patterns, their knowledge about efficiency options, and/or the trade-offs they are willing to make between efficiency options and the costs of purchasing and installing them. They

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

[15] *2003-2004 Home Energy Savings Program Residential Impact Evaluation,* prepared for the Energy Trust of Oregon, prepared by Itron, Inc., December 2006.

[16] *New York Energy $mart Program Evaluation and Status Report for the Year Ending December 31, 2006,* New York State Energy Research and Development Authority, March 2007.

[17] *Commercial/Industrial Performance Program (CIPP) Market Characterization, Market Assessment and Causality Evaluation*, prepared for New York State Energy Research and Development Authority by Summit Blue Consulting and Quantec, April 2006.

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

[19] *Standardized Methods for Free Ridership and Spillover Evaluation – Task 5 Final Report (Revised).* (PA Consulting Group Inc. 2003).

include billing analysis, econometric models, and discrete choice models and often include survey inputs as well as other non-program-related factors such as weather and rates.

- **Billing analysis** determines the effect of efficiency measures and/or a program by analysis of (usually monthly) consumption data from participating customers, often along with similar data for nonparticipating customers.
- **Other econometric models** expand on billing analysis methods to compare participants' and non-participants' energy and demand patterns, adjusting for external variables that could account for changes in use and patterns.
- **Discrete choice analysis** uses data on equipment or practice choices by participating and nonparticipating customers together with other information about customers to model choices participants would have made in the absence of the program.[20]

- **Market share methods** include the *market sales* approach which relies on aggregate data of total sales of a particular technology in a specific location, and compares this sales volume with a baseline estimate of the volume that would have been sold in the absence of the program. This method is generally used to assess transformations of markets and depends on completeness and accuracy of sales data and the validity of the baseline estimate. A similar method is *saturation data analysis* which uses observations at two points in time of the share of existing equipment stock that is high efficiency. Translating these successive observations into incremental attributable sales requires information (estimates or assumptions) about equipment turn-over rates, stocking practices, and changes that would have occurred over the time period without the program. Collecting reliable saturation data is typically expensive and not repeated frequently.

3.2.1 Econometric Methods

Billing analysis involves the use of multivariate regression models with historical utility billing data (kW and kWh) to calculate annual demand and energy savings. In general, billing analysis is used with complex equipment retrofits and controls projects and provides retrofit performance verification for projects where whole-facility baseline and post-installation data are available. Billing analysis usually involves collecting historical whole-facility baseline energy use data and a continuous measurement of the whole-facility energy use after measure installation. Energy consumption is calculated by developing statistically representative models of historical whole-facility energy consumption, and the model yields statistically adjusted engineering coefficients to modify gross engineering estimates and calculate net energy impacts.

The advantage of billing analysis is that it estimates the magnitude of net impacts rather than a fraction of total impacts attributable to the program; however, the method also has limitations. The net billing model specification incorporates both participants and nonparticipants into one model, and the resulting sample is not randomly determined. In particular, participants self-select into the program and therefore are unlikely to be randomly distributed; the unobserved characteristics that influence the decision to participate must be accounted for in the model to avoid producing biased coefficient estimates. The Inverse Mills method which includes a ratio in the model to account for self-selection was developed to

[20] Delphi methods which collect judgmental estimates from a panel of experts and develop a consensus or central range estimate are typically used only if more objective methods are not available.

correct for this bias but has several limitations: 1) large customers can exert such a significant influence that they overly bias results; 2) the usable sample is reduced by the need for good historical billing data for each customer; and 3) the method does not produce an estimate of spillover, rendering it an incomplete model of net impact[21]. Billing analysis also depends on finding a comparable non-participant population, which can be very difficult for custom projects. It also will have difficulty identifying energy savings if the expected savings are a small percentage of the total facility energy use or if other major events occur at facilities that significantly affect energy use (e.g., changes in plan schedules, adding new or closing old production lines).

Other econometric models expand on billing analysis methods to compare participants' and non-participants' energy and demand patterns, adjusting for external variables that could account for changes in use and patterns. Econometric models are used to analyze co-relational relationships, usually with the hope of determining causation. They are used to estimate macroeconomic trends and in microeconomics to estimate virtually any sort of social relationship (much as metric models, involving these same regression techniques, are used in other social sciences). The use of statistical/econometric models to estimate net impacts can avoid both the concern over the potential for bias and cognitive dissonance issues with survey research by analyzing participant and non-participant actions, characteristics and attitudes to predict free ridership and spillover. The disadvantage of this method is its inability to estimate spillover upstream in the distribution channel. A robust statistical analysis includes surveys designed to minimize self-reporting bias while collecting data on other program and participant characteristics. This level of sophistication requires a relatively large expenditure on evaluation, which can impact the cost-effectiveness of a marginal program. In California, econometric methods are preferred in situations with enough participants and comparable non-participants, and when the program is large enough to justify the expense. However, programs with either a very small number of participants or non-participants or where comparability is a severe problem are not amenable to these methods and need to rely on a survey-based method. Ed Vine of the Lawrence Berkeley Lab[22] identified the key analytical issue to assess the NTG ratio is determining an appropriate control group. Certain types of building, e.g., large industrial firms, may have unique facilities that have no comparative buildings, for example.

Another method of estimating the net-to-gross ratio is a two-stage **discrete choice model**. Discrete choice analysis uses data on equipment or practice choices by participating and nonparticipating customers together with other information about customers to model choices participants would have made in the absence of the program. This model is used to simulate the decision to purchase various types of commercial equipment. Once estimated, the model is used to determine the probability of purchasing high-efficiency equipment in the absence of the program. The probability of purchasing any given equipment option A can be expressed as the product of two probabilities—the probability that a purchase is made multiplied by the probability that equipment option A is chosen given that a purchase has been made. This method can work when the equipment examined is relatively simple in description and where choices exist in the market for different efficiency levels for that piece of equipment. Thus this can work well with prescriptive rebate programs where the types of equipment that meet and do not meet program requirements can be spelled out in detail ahead of time. Given that custom programs *by their very nature* do not follow this pattern, discrete choice models do not function well attempting to make sense of the choices involved in their necessarily more complex systems.

[21] Torok 1999.

[22] Vine, Ed. *The Human Dimension of Program Evaluation, Lawrence* Berkley Lab, LBL-33601, 1993

3.2.2 Self-Report Surveys

Generally, the simplest and lowest cost NTG method is using the survey-based stated intentions method with a telephone survey for data gathering. Although research has shown that this method can provide biased results, coming at the question of what the participant would have done in the absence of the program from a variety of different perspectives (directly asking, decision-making criteria, where they were in the process, etc.) and assessing these together is one way the survey methods have used to triangulate on the correct construct.[23].

The self-report approach used in the current study was based on Summit Blue's assessment of approaches taken in a variety of jurisdictions. Much of that research has been summarized in a paper by Schare and Ellefsen (2007)[24] that discusses the approach used to estimate free ridership for several New York State Energy Research and Development Authority (NYSERDA) programs The method used for NYSERDA evolved from previous NYSERDA evaluations and work done in California (described in more detail in the following section) and Massachusetts.

In 2002, Massachusetts regulators asked for a study to create a standardized free ridership survey method to be used by all Massachusetts utilities for program evaluations.[25] The objective was to develop standardized sampling techniques, data collection approaches, survey questions, survey instrument(s), and an analysis methodology that each of several sponsors[26] can use to determine free-ridership and spillover factors for C&I programs. This standardization project was designed to provide a methodology to meet the regulatory requirements to report annual program impacts (along with disaggregated free-ridership and spillover values)—an annual snapshot of the market as it currently operates.

The approach used in the current study was enhanced in subsequent studies of Wisconsin Power and Light's Shared Savings program and Arizona Public Service programs.

The method used in the current study overcomes a key limitation of self-report approaches—the difficulty of systematically converting opinions of participating customers into quantifiable free ridership values. It also provides a highly defensible approach to estimating net program impacts, which are critical inputs to benefit-cost analyses and policy decisions on the direction of energy efficiency programs.[27] The approach is based on participant self-reports and offers unique benefits of a clearly defined and repeatable method to quantify free ridership, while also incorporating qualitative information from program participants often used only as supporting illustration. The core principles of the approach include the following:

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[23] TecMarket Works, *California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals*, April 2006.

[24] Schare, S. & Ellefsen, J. *Advancing the "Science" of Free Ridership Estimation: An Evolution of the Self-Report Method for New York Energy $mart[SM] Programs, 2007.*

[25] *Standardized Methods for Free Ridership and Spillover Evaluation – Task 5 Final Report (Revised).* (PA Consulting Group Inc. 2003).

[26] National Grid (Massachusetts Electric, Nantucket Electric), NSTAR Electric, Northeast Utilities (Western Massachusetts Electric), Unitil (Fitchburg Gas & Electric Company), Cape Light Compact).

[27] Schare, S. & Ellefsen, J. Advancing the "Science" of Free Ridership Estimation: An Evolution of the Self-Report Method for New York Energy $mart[SM] Programs, 2007.

- Set the stage with the respondent by talking about the various ways the participant interacted with the program (including, for example, technical assistance, training, and financial incentives).

- Direct estimation of free ridership from the perspective that is most appropriate for the **project** and to which the respondent can best relate his program experience. This takes the form of either the likelihood that the high-efficiency measures would have been installed without the program, or the share of high-efficiency measures that would have been installed without the program.

- Separate estimation of free ridership addressing the complete project across all measure types and, alternatively, addressing decisions to install specific measures. The dual line of questioning allows respondents to provide a big-picture view of the program's influence on the project as well as to focus on specific measures, which may have been influenced by the program to varying degrees.

- Quantitative incorporation of qualitative responses based on interviewers' probing for details and causality. This aspect of the approach relies on experienced interviewers who are able to apply appropriate judgment to assign influence scores reflecting the degree to which the program affected equipment-purchasing decisions.

- Ask supporting or influencing questions that could be used to verify whether direct responses are consistent with participants' views of the program's influence."

The theory behind attribution analysis is that only impacts caused by the program should be included in net savings estimates; however, absolute proof of causality is unattainable since one can never observe what would have happened in the absence of the program. Consequently, causality "must be justified or rationalized on the basis of *a priori* argument, outside evidence, intuition, theory, or some other informal means."[28] The necessity of this approach to attribution analysis, relying in part on intuition and outside assumptions, is supported by Heckman in his argument that "there is no mechanical algorithm for producing a set of 'assumption free' facts or causal estimates based on those facts."[29]

3.2.3 Triangulation of Methods

California's new evaluation protocols for NTG impact evaluation rely heavily on self-report methods but require triangulation of methods for the enhanced level of rigor. In 2006-2007, California awarded contracts to over 70 consulting firms to perform impact evaluations of all IOU energy efficiency programs; as part of this process the CPUC supported the development of an Evaluation Framework[30] and a set of protocols[31] developed by a NTG Working Group composed of industry leaders in the evaluation field[32]. The Evaluation Framework notes that NTG can be expected to vary depending upon the maturity

[28] Moffitt, R., "*Causal Analysis in Population Research: An Economist's Perspective*," Johns Hopkins Univ., 2003.

[29] Heckman, J., "Causal Parameters and Policy Analysis in Economics: A Twentieth Century Retrospective," *The Quarterly Journal of Economics*, Volume 115, No. 2, 2000, pp. 45-97.

[30] TecMarket Works, *The California Evaluation Framework*, Southern California Edison, 2004.

[31] TecMarket Works, *California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals*, April 2006.

[32] Summary of Guidelines for Estimating Net-To-Gross Ratios Using the Self-Report Approach, Self-Report_NTG_Checklist_Ridge for CA_sept 07

of the equipment or service, type of delivery in the program, maturity of the program, and customer sector. The California documents classify NTG methods as econometric (comparing participant and non-participants and adjusting for selectivity biases through econometric models) and survey-based (asking participants what they would have done).

California has three levels of rigor that can be applied to NTG analysis—basic, standard, and enhanced. Participant self-report through surveys is the required method for the basic level of rigor; for the standard level of rigor, one of three methods can be used (billing analysis, self-report, econometric or discrete choice). The enhanced level requires triangulation using more than one of the methods in the standard rigor level. The enhanced level must include analysis and justification for the method for deriving the triangulation estimate from the various methodologies used.

Guidelines were developed for using the self-report method to estimate NTG ratios; these are consistent with Summit Blue's methodology:

1) identify the correct respondent
2) use multiple questions
3) assess validity and reliability of each question
4) include consistency checks
5) make the questions measure-specific
5) include and document partial free-ridership
6) assess deferred free-ridership [This is equivalent to EGD's "advancement" approach – see the discussion under section 2.1]
7) develop scoring algorithms
8) explain handling of non-responses and "don't knows"
9) weight the NTG for size of impacts
10) report precision of the estimated NTG
11) pre-test the questionnaire
12) use multiple respondents
13) consider third-party influence.

3.2.4 When to Use Market Share or Self-Report

Market sales methods can also be used to estimate free riders and spillover. A study done for Wisconsin Focus on Energy in 2006[33] developed an approach to assist in determining whether market sales or self-report methods are appropriate for net-to-gross assessment of results for various programs. The screening criteria outlined below provide a description of the screening process used to determine which method to use. For the first two criteria, the quality of available data depends in part on the details involved in data collection which in turn depends on resources available.

[33] *Net-to-Gross Method Selection Framework for Evaluating Focus on Energy Programs*, Goldberg M.L., Bloch, O., Prahl, R., Sumi, D., Ward, B., Winch, R. and Talerico, T., March 16, 2006.

Table 3-2. Screening Criteria for Self Report versus Market Share NTG Approaches

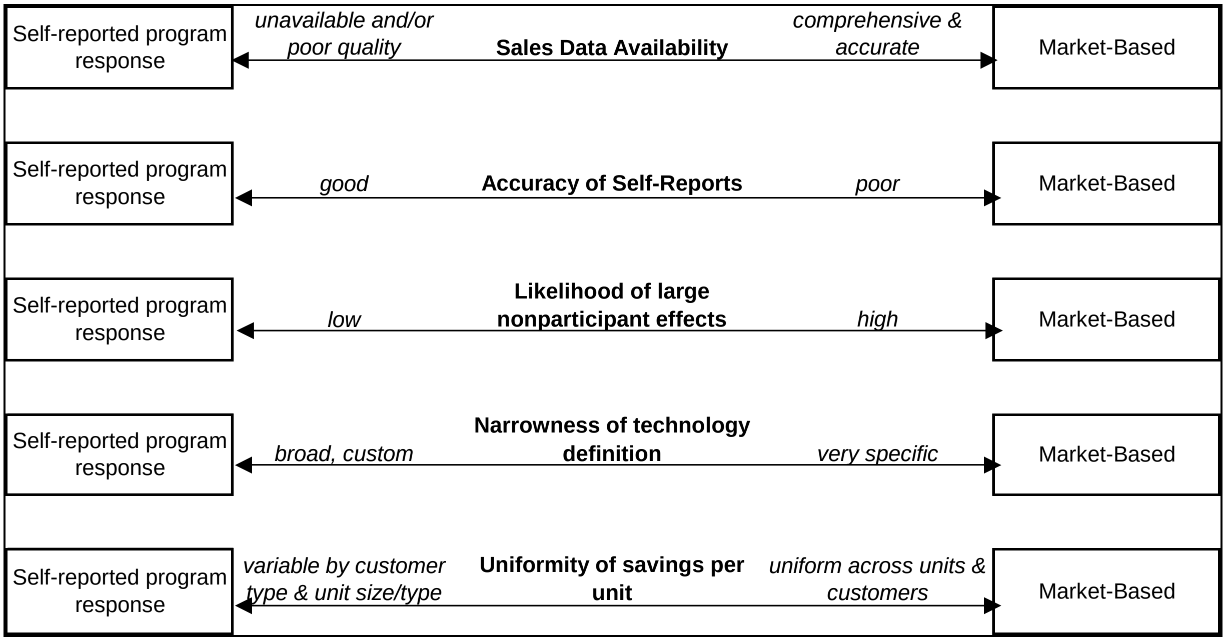
Screening Criteria	Example Screening Questions
Sales Data Availability: The availability of current and baseline market sales data enables estimating free ridership based on such data.	Are current and baseline data readily available? Are the data comprehensive and complete? Able to supplement/overcome shortcomings in data with other data collection techniques? Is the baseline estimate reliable?
Accuracy of Self-Reports: The ability of end users and vendors to report accurately what would have occurred in the absence of the program enables the use of program-response self-report methods.	Can end users/vendors accurately report what would have occurred without program? Supply-side actors can comment on programmatic versus non-programmatic influence on market? Has program altered the supply side in ways a participant would not be able to recognize?
Likelihood of Large Non-participant Market Effects: The likelihood of substantial non-participant market effects may indicate a need for applying methods for adequately capturing such effects.	Is the scale of program large relative to overall market? Are primary sales driving components (promotions, incentives) available at a consistent level throughout the year? Does the program have broad reach across market niches? Does program theory predict significant non-participant effects?
Narrowness of Technology Definition: A market data approach is suggested if the technology is a single type and well-defined, versus encompassing multiple categories, types, or wide variations.	Does program offer “custom” solutions (broad definition) or “prescriptive” measures (narrow definition)? Does program target specific technologies (narrow definition) or a broad range of technologies (broad definition)?
Uniformity of Unit Savings: The choice of method is guided by whether savings per unit is sufficiently consistent across types of units & customers to adequately quantify in terms of total units sold, or needs information on unit characteristics by customer type.	Do units promoted through the program come in widely varying size ranges/savings levels? Is an engineering estimate of necessary? Large variation in customer application of measures? Do savings per unit vary by customer application? Expect savings to vary widely by customer?

Source: Goldberg M.L. et al Net-to-Gross Method Selection Framework for Evaluating Focus on Energy Programs, March 2006.

Taken together, these factors can indicate an overall preference for one method or another. In some cases, the preference will be clear-cut. In others, the two methods may be nearly equally good—or nearly equally poor. The diagram in Figure 3-1 below indicates for each criterion what condition points toward use of market sales approaches and what condition points toward self-reported program responses.

By definition, measures implemented in custom programs do not fall into easily defined buckets for which market sales can be easily or accurately estimated. Even if discrete pieces of equipment can be identified, obtaining relevant and adequate market sales information can be very difficult.

Figure 3-1. NTG Method Selection Screening Criteria[34]



3.2.5 Overview of Pros and Cons

The survey approach is the most straightforward way to estimate free ridership and spillover and is usually the lowest cost approach. As noted by the NAP Guidelines…"survey methods can be used with any program regardless of the number of participants" whereas econometric methods "can only be used with programs with large numbers of participants because the models need large amounts of data to provide reliable results".[35] In California, econometric methods are preferred in situations with enough participants and comparable non-participants, and when the program is large enough to justify the expense. However, programs with either a very small number of participants or non-participants or where comparability is a severe problem (such as industrial plants with unique facilities) are not amenable to these methods and need to rely on a survey-based method[36]. Market share methods are generally used to assess market transformation programs or in situations where participation is not well defined.

Table 3-3 below shows an overview of the pros and cons of all of the methods discussed above.

[34] *Net-to-Gross Method Selection Framework*, ibid, Figure 1 p. 4.

[35] National Action Plan for Energy Efficiency. Model Energy Efficiency Program Impact Evaluation Guide 2007.

[36] Vine, Ed. *The Human Dimension of Program Evaluation*, *Lawrence* Berkley Lab, LBL-33601, 1993

Table 3-3. Comparison of Free Rider and Spillover Methodologies

Methodology	Pros	Cons
Billing Analysis	Quantitative estimates of magnitude of net impacts from statistically valid methods based on historical billing data.	Includes participants and non-participants in one model; sample not randomly determined due to self-selection. Could produce biased coefficient estimates if unobserved characteristics, which influence decision to participate, are not accounted for. Needs good historical data for each customer and this can reduce the number of data points. Large customers can overly bias results.[37]
Other Econometric or Discrete Choice Methods	Useful for programs that seek to transform the market. Modeling can provide more accuracy because tests for bias and precision can be included.	Econometric models need good historical data for each customer and this can reduce number of data points. Also needs data to account for variables that might be influencing the results. For discrete choice models it is difficult and costly to get accurate data on types and efficiency levels of existing equipment.[38] Neither method includes trade allies effects.
Self-Report	Simpler and less expensive than all other approaches. Can use all data points unlike billing or econometric analysis which requires historical data. Can be used in a variety of situations. Directly addresses the behaviours the program is seeking to affect. Flexible and so can take into account the complexities of program-participant interaction.	Potential for non-response bias, limited respondent recall of program influence on decision-making, and potential investigator bias in translating responses into free ridership values. Tends to underestimate spillover.
Market Share Approaches	Addresses trends in the entire market for equipment.	By definition, measures implemented in custom programs do not fall into easily defined buckets for which market sales can be easily or accurately estimated. Even if discrete pieces of equipment can be identified, obtaining relevant and adequate market sales information can be very difficult.

[37] Torok, C., Cavalli, J. and O’Drain, M. *Any Way You Slice It: Issues of Behavior and Influence in Net Impact Analysis*, 1999.

[38] Kandel, A. *Theory-Based Estimation of Energy Savings from DSM, Spillover, and Market Transformation Programs Using Survey and Billing Data*. Program Measurement and Evaluation, 2002.

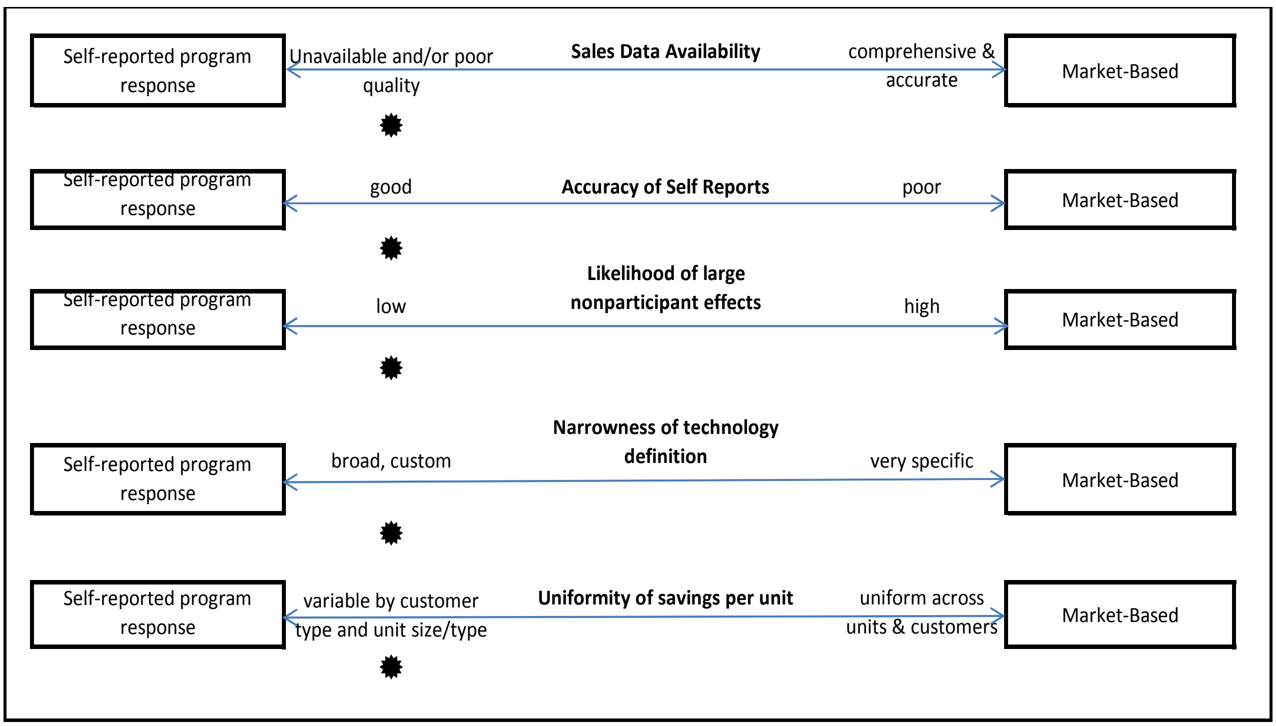
3.3 Best Method to Assess Union-Enbridge Custom Projects Free Riders and Spillover

This section applies the information discussed in the previous section about various methodologies to the Union-Enbridge research requirements to determine NTG for custom projects with large industrial and commercial customers.

It is clear that neither discrete choice models nor market share methods are appropriate methodologies for this research. Discrete choice models must focus on clear, standardized equipment choices. However, the Custom Projects measures are by definition custom and not easily placed into categories that are amenable to discrete choice analysis.

Applying the NTG method selection criteria to the custom projects program, as shown in Figure 3-2 below, clearly indicates that the self-report method is preferred over the market share approach.

Figure 3-2. Applying NTG Screening Criteria to Custom Projects



The self-report method using interviews with customers is more appropriate for this research than billing analysis or other econometric models. Table 3 compares self-report to the other two methods (combined as pros and cons are similar) based on relevant program characteristics. For example, the Custom Projects programs offered by Union Gas and Enbridge Gas Distribution are targeted specifically at large commercial and industrial customers and target complex and unique systems rather than offering prescriptive rebates. In addition, in some segments, e.g., agriculture, most eligible customers participate, making the selection of a non-participant group problematic. As shown in the table, there are problems in applying econometric methods which do not occur with self-report methods. The ideal methodology would be to apply California's Enhanced Level of Rigor which requires triangulation of estimates by at least two methods. This approach is very costly however, and still has the problems identified in Table 3-3 for econometric models.

Table 3-4. Compare Self-Report to Econometric Methods

Program Characteristic	Self-Report Methods	Econometric Methods
Targets large customers.	In-person or telephone surveys can be used with large customers.	Large customers can overly bias results
Non-participants difficult to identify.	Does not require non-participant data for free ridership or inside spillover.	Requires both participants and non-participants in analysis.
May not detect savings at whole building/facility level.	Targets measure level information.	Energy use data generally only available at building/facility level.
External factors likely to be significant.	Survey accounts for relevant external factors.	Need to collect appropriate data to adjust for external factors.
Focused on process changes rather than equipment.	Survey accounts for changes to processes as well as equipment.	Discrete choice and other models focus on equipment choices.

Based on this assessment, Summit Blue recommends using self-report methodology as described in the Analysis Plan, which modifies the methodology developed for other jurisdictions to the specific Union-Enbridge programs.

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4 SAMPLING AND DATA COLLECTION

This section reports on the sample design and data collection process for the study.

4.1 Participant and Trade Ally Survey

The sample was drawn from customers who participated in the Custom Projects Program between the fourth quarter of 2006 and the third quarter of 2007, inclusive. (As a result, the population of participants shown below will not match numbers reported by the utilities.)

There were 594 projects in the population for EGD and 345 for Union. We completed interviews covering 233 projects. For EGD 156 or 26% of the projects were completed and for Union 77 or 22% , which is an average of 25% across both utilities (see Table 4-1). Multifamily projects represented 35% of the population and 31% of the completed interviews. Industrial projects represented 24% of the projects and 18% of the completed interviews.

Table 4-1. Participant and Trade Ally Sample Disposition

	Population			Completes			Percent of Total		
Sector	**EGD**	**Union**	**Total**	**EGD**	**Union**	**Total**	**EGD**	**Union**	**Total**
Agriculture	39	20	59	9	8	17	23%	40%	29%
Building Retrofit	114	138	252	44	21	65	39	15	26
Industrial	111	114	225	23	19	42	21	17	19
New Construction	58	13	71	24	12	36	41	92	51
Multi-Family	272	60	332	56	17	73	21	28	22
Total	594	345	939	156	77	233	26	22	25
Percent of Total									
Agriculture	7%	6%	6%	6%	10%	7%			
Building Retrofit	19%	40%	27%	28%	27%	28%			
Industrial	19%	33%	24%	15%	25%	18%			
New Construction	10%	4%	8%	15%	16%	15%			
Multi-Family	46%	17%	35%	36%	22%	31%			
Total	100%	100%	100%	100%	100%	100%			

4.2 Audit-Only Survey

The sample was taken from customers who had audits in 2005 to provide the optimal balance between providing enough time for the customers to have acted on the recommendations in the audit and ensuring that the audit is not so far in the past that respondents have trouble recalling details of the recommendations. Because the sample will be based on a single year, the result of the analysis can be expressed in spillover per year.

The audit-only spillover survey and analysis was completed for EGD only as Union Gas was unable to find any companies who had an audit in 2005 and had not implemented one of the recommended measures through the program. As a result, the savings inspired by the Union Gas audits will appear in the program tracking data rather than in spillover. EGD provided a sample of 37 customers who had an audit but did not appear in the tracking data as having implemented a relevant measure. We attempted to complete a survey with each of those customers to estimate spillover and completed 24 surveys (including one who did not recall the audit).

4.3 Non-participant Survey

The utilities provided contact information for 1,228 non-participating customers and Global Target Marketing attempted to contact all customers for a screening interview (see Table 4-2). As expected, many respondents (32%) were screened out because they did not implement a measure since 2005. A further 10% were screened out because they were participants and 26% were screened out because they were not aware of the program. Just over one quarter (26%) had implemented a measure since 2005 and were aware of the program but the measure was not influenced by the program. Together, 94.6% of the respondents were screened out for the reasons stated above, leaving a total of 66 customers, or 5.4% of the total population, who were influenced by the program to implement measures (and did not receive a financial incentive).

These 66 customers were asked to participate in a follow up interview to help quantify savings and 38 agreed (3.1% of the total).

Table 4-2. Non-participant Spillover Screening and Engineering Survey Disposition

	Total		Union Gas				Enbridge Large Volume			
			Commercial		Industrial		Commercial		Industrial	
Screened (Total)	1,228	100.0%	1,078	100.0%	41	100.0%	72	100.0%	37	100.0%
Unaware of Energy Efficiency Program	321	26.1%	297	27.6%	3	7.3%	11	15.3%	10	27.0%
Received Financial Incentives	124	10.1%	88	8.2%	20	48.8%	14	19.4%	2	5.4%
Did Not Install/Modify Equipment Since 2005	398	32.4%	354	32.8%	8	19.5%	26	36.1%	10	27.0%
Installed Measure and Aware Of But Not Influenced By Program	319	26.0%	284	26.3%	6	14.6%	16	22.2%	13	35.1%
Installed Measure and Influenced by Program	66	5.4%	55	5.1%	4	9.8%	5	6.9%	2	5.4%
Agreed To Follow-Up	38	3.1%	33	3.1%	3	7.3%	1	1.4%	1	2.7%
Total Follow-up Interviews	27	2.2%	22	2.0%	3	7.3%	-	0.0%	1	2.7%
Total Providing Savings Estimates	5	0.4%	3	0.3%	2	4.9%	-	0.0%		0.0%

Note: The numbers in the middle rows (between the dark lines) sum to the total in the top row. The last three rows are components of the row titled "Installed Measure and Influenced by Program".

5 FINDINGS

The findings are presented in four parts, representing free ridership and three kinds of spillover, inside, outside, and audit-only. The final section combines the free ridership and spillover into one calculation to produce the final net-to-gross ratio.

5.1 Free Ridership Results

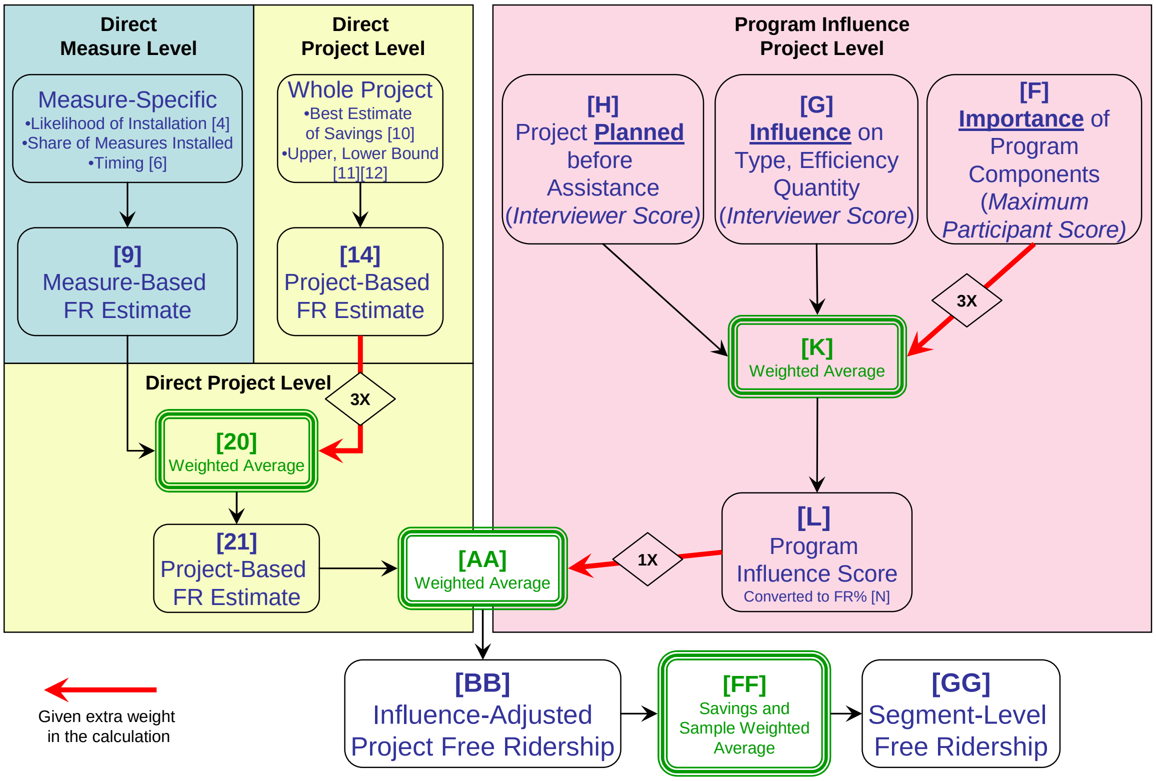
As discussed in the methodology chapter (and in the analysis plan), the calculation of free ridership requires combining answers from several different questions to come up with a single free ridership number for each measure. At several points in the calculation assumptions have to be made about how to combine answers. Should we take the maximum answer from a group of related questions? Should answers be averaged? Should some answers get more weight than others? Some calculation assumptions lend themselves to a clear decision. For example converting a 1-5 score into a free ridership percentage using a straight line conversion seems the obvious choice (where 1=0%, 3=50%, and 5=100%). Other calculation assumptions, do not present a clear answer. For example, when combining the project-based free ridership estimate with the program influence score, should they be averaged? If so, should one carry more weight than another? For those assumptions, we performed a sensitivity analysis, examined the open-ended responses and interview notes, and took into account the program approach to identify the most appropriate calculation approach. The next few paragraphs describe the recommended calculation approach. Following that are the results produced from that approach.

5.1.1 Recommended Calculation Approach

Three assumptions in the calculation had the most effect on the end result and were of the type that required a broad analysis of the program and survey data to suggest the appropriate calculation approach. Those three are shown at [20], [K], and [AA] in the calculation overview diagram in Figure 5-1. After examining all available evidence, we conclude that the most appropriate approach is to give the weights shown in the diamond shapes in those calculations. First, giving triple weight to [14] in the calculation at [20] is appropriate for the following reasons:

- The calculation at [20] averages direct measure level questions [9] and direct project level questions [14]. The direct measure level questions expect the respondent to think discretely about separate components of the project decision. The direct project level question [10] asks them to think about the project as a whole, and considering all program involvement. Given that the utility interacts with the customer over a long period of time, in a variety of ways, and that the measures are typically complex with many factors influencing the decision, it seems less likely that the respondent will be able to successfully think about a component of the decision than about the decision taken as a whole. As a result, the answer to the direct project level question [10] is probably more believable than the measure-based estimate [9]. Because of that conclusion, we weight the project-based estimate more heavily than the measure-based estimate in [20] by a factor of 3.

Figure 5-1. Final Calculation Overview



Second, giving triple weight to [F] in the calculation at [K] is appropriate for the following reasons:

- Point [H] in this calculation is an interviewer score of the amount of planning that went on for the measure before the program got involved. There are several potential weaknesses in the answers to this question that argue for reducing its weight in the calculation at [K]:
    - Program staff were frequently providing assistance to the participants over a long period of time. By the time the measure was installed (and we called on the participant for an interview), respondents may have forgotten the history of the project planning. Those involved in the initial planning may no longer be at the company or in a position to pass along the history of the planning to those ultimately interviewed.
    - Because the program projects are often complex and related to equipment central to a company's output, the fact that plans were in place prior to program involvement does not necessarily imply that the program had no influence. For example, the decision to modify a production line may be driven by changes in the market for their product. Thus plans might be in place to change equipment prior to program involvement but the program involvement could still affect the efficiency of the equipment chosen.
    - Because the program projects are often complex, planning takes place over a long period of time and proceeds through several steps. The program could get involved after initial planning took place – e.g., the decision was made to modify a production line – but before the specifications were written for the equipment affected by the program. Assessing the program's influence on planning in such a circumstance can be difficult to apply in a standard and uniform fashion across projects.

- Point [G] in the calculation at [K] is an interviewer score of the program's influence on the type, efficiency and quantity of the equipment installed. The driving question at [G] was as follows: "Did the assistance you received from [Enbridge/Union] in any way influence your capital funding acquisition process, the type or efficiency level of the equipment or the amount of high efficiency equipment you installed or process changes implemented?" Many of the projects implemented under this program were implemented primarily to address issues other than energy costs. In many cases, the program's hoped-for impact was to increase the energy efficiency of the project rather than inspire the change in the first place. As a result, factors other than energy are often driving decisions about capital funding and the type and quantity of equipment installed and it is unlikely that the program will have much if any affect on those factors. The question at hand was designed to measure the program's influence on those factors in addition to the efficiency of the equipment. This has the effect of diluting the impact of the efficiency issue in the final interviewer score. These weaknesses in this question argue for reducing its weight in the calculation at [K].

- Point [F] represents several questions on the importance of several program components or types of assistance in the participant's decision to install energy efficiency equipment. The questions in [H] and [G] ask the respondent to think about <u>all</u> program assistance as a bundle while focusing on a specific aspect of the decision process. The questions in [F], on the other hand, ask the respondent to think about individual components of program assistance while focusing on the whole decision process. As discussed above, given that the measures are typically complex with many factors influencing the decision, it seems less likely that the respondent will be able to successfully think about a component of the decision (as in [H] and [G]) than about the decision taken as a whole (as in [F]). The [F] series of questions brings in the specific components of the program assistance and, particularly given the drawbacks with [H] and [G], seems more likely to give a more accurate picture of the program's influence.

Finally, giving equal weight to [21] and [L] in the calculation at [AA] is appropriate for the following reasons:

- The conclusions drawn above on [20] and [K] give more weight to questions that address the whole project rather than specific components. They provide two different approaches for the respondent to address the program's influence: estimating savings that would have happened in the absence of the program in [14], and the how important program components were in the decision to install energy efficiency equipment in [F]. Addressing the same general issue from two different perspectives ought to provide a more robust estimate of the true impact.

- Given that the questions at [14] and [F] have already had their weight in the calculation increased, giving more weight to one or the other of these components in the calculation at [AA] would have the effect of ensuring that the final result is largely driven by the answer to one question (or one type of question in the case of [F]). This places too much importance on a single question and is contrary to the philosophy of the general approach which is of triangulating at the answer from a variety of perspectives.

5.1.2 Results

Using the calculation approach defined above produces a total free ridership rate across both utilities and all sectors of 48% as shown in Table 5-1. The free ridership rate for EGD is 41% and it is 54% for Union Gas. Free ridership rates of near 50% are not uncommon in custom programs throughout North America. In a 2006 study Summit Blue performed for Alliant Energy, we found five programs out of 21 with free ridership rates above 40%.[39] Summit Blue recommends that the utilities use the utility-specific total free ridership values of 41% and 54% as the best estimate of free ridership. Those results are based on larger sample sizes than the sector-specific results and proved more stable in the sensitivity analysis. The sector-specific results are based on smaller sample sizes and should only be used to support program management, for example to support targeting and marketing decisions.

Table 5-1. Free Ridership Results

Sector	EGD	Union	Total
Agriculture	40%	0%	18%
Commercial Retrofit	12%	59%	27%
Industrial	50%	56%	53%
Multifamily	20%	42%	26%
New Construction	26%	33%	28%
Total	41%	54%	48%

Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

5.1.3 Bin Analysis

As discussed above, there are several potential weaknesses in the answers to some of the questions asked of participants. Given that the utility is often involved well in advance of project implementation, it is possible that in the intervening time the institutional memory of the history of the utility's program involvement has been lost. It is also possible that the participant has taken ownership of the information or approach that originally came with support from the utility and now views it as their own, not something brought to them by the utility. Now of course without defining away the possibility of free ridership even existing, we cannot say that prior utility program involvement prior to project implementation is evidence that free ridership does not exist. However, there is one area that is more concrete than simple "prior program involvement" that is worth examining. In some cases, the utilities supported energy audits that looked for and provided support to decisions to implement specific energy efficiency measures. It seems reasonable to conclude that at least in some cases those audits inspired the subsequent installation or modification. It also seems possible that if the audit were some time before implementation, the respondents we talked to may not have been aware of the influence of the audit.

[39] Shared Savings Decision-Making Process Evaluation Research Results. Jeff Erickson, Summit Blue Consulting for Wisconsin Power & Light (Alliant). August 11, 2006.

To examine the possible implications of this issue, we performed a bin analysis. We received from the utilities dates of energy audits or studies done in advance of specific measures that were addressed in our participant interviews. The free ridership savings were placed in two bins based on historical data provided by the utilities. Projects that met any of the following criteria were placed in a "Preceding Audit" bin:

- A utility-sponsored audit or feasibility study preceded the measure implementation and was directly related to the measure installed.
- The same measure had been installed through the program in a previous program year.
- EGD paid part or all of the salary for an on-site energy manager at the facility prior to the measure implementation.

All other projects were placed in a "No Preceding Audit" bin. In this way, on a measure-by-measure basis, we put the m^3 savings that had been defined as free ridership into one of two bins. The results are shown in the following table. As in the previous table, the total free ridership across both utilities is 48% (the bottom right cell in the table). Splitting this into two pieces shows that the total free ridership is made of 25% from projects that had preceding audits and 23% that did not. (Note that 25%+23%=48%, the total free ridership percentage.) The "Preceding Audit" values represent just over half of the total free ridership for the two utilities combined and represent well over half of Union's free ridership.

Table 5-2. Free Ridership Split Based on Preceding Audit

	Preceding Audit			No Preceding Audit			Total		
Sector	**EGD**	**Union**	**Total**	**EGD**	**Union**	**Total**	**EGD**	**Union**	**Total**
Agriculture	6%	0%	3%	34%	0%	15%	40%	0%	18%
Commercial Retrofit	0%	7%	2%	12%	52%	25%	12%	59%	27%
Industrial	12%	44%	31%	38%	12%	22%	50%	56%	53%
Multifamily	0%	0%	0%	20%	42%	26%	20%	42%	26%
New Construction	0%	6%	2%	26%	27%	26%	26%	33%	28%
Total	8%	38%	25%	33%	16%	23%	41%	54%	48%

One possible interpretation of the "Preceding Audit" free ridership values is that they are spillover caused by the audit and the "No Preceding Audit" values are pure free ridership. If the audit altered the participant behavior and/or plans, but the respondent either was not aware of that change or had forgotten about the program's earlier influence, then the "Preceding Audit" values would accurately be described as spillover. If, on the other hand, the earlier measure implementations were also free riders and the audit truly did not significantly affect the decision-making process, then the "Preceding Audit" values would not be spillover.

The preparation for the surveys, the surveys themselves, and the survey process were designed to get to respondents with knowledge of the history of the project and remind participants of their company's past involvement in the program. Given the high free ridership rates, it seemed appropriate to do some additional research in this area. We called back three of the largest participants who had prior audits to verify whether they were aware of the audits and to gauge the impact of the audits on their planning and decision process. In two of the three cases, we judged that our original free ridership estimate was accurate and that the prior audits were not driving factors in the decision. In the third case we adjusted responses from the earlier interview to reflect the new information we received in the follow-up call.

5.1.4 What is Driving the Results?

This section examines various factors that may help explain where the most significant issues with free ridership are.

Sector

Industrial gross m^3 savings represent 84% of the total program savings (Table 5-3) and therefore drive the final results. The Industrial sector accounts for 77% of EGD's gross savings and 89% of Union's.

Table 5-3. Gross m^3 Savings as Percent of Total by Sector

Sector	EGD	Union	Total
Agriculture	3%	3%	3%
Industrial	77%	89%	84%
Multifamily	8%	1%	4%
New Construction	2%	1%	1%
Commercial Retrofit	10%	6%	7%
Total	100%	100%	100%

The EGD Industrial free ridership rate is 50% and Union's is 56% (see Table 5-4, which is identical to Table 5-1). The other EGD sectors have relatively low free ridership rates, with the exception of Agriculture, which is only 3% of the total savings. The other Union sectors (with the exception of agriculture) have fairly high free ridership rates, which explains why the total Union free ridership rate is higher than EGD's, given that their Industrial rates are close.

Table 5-4. Free Ridership Results

Sector	EGD	Union	Total
Agriculture	40%	0%	18%
Commercial Retrofit	12%	59%	27%
Industrial	50%	56%	53%
Multifamily	20%	42%	26%
New Construction	26%	33%	28%
Total	41%	54%	48%

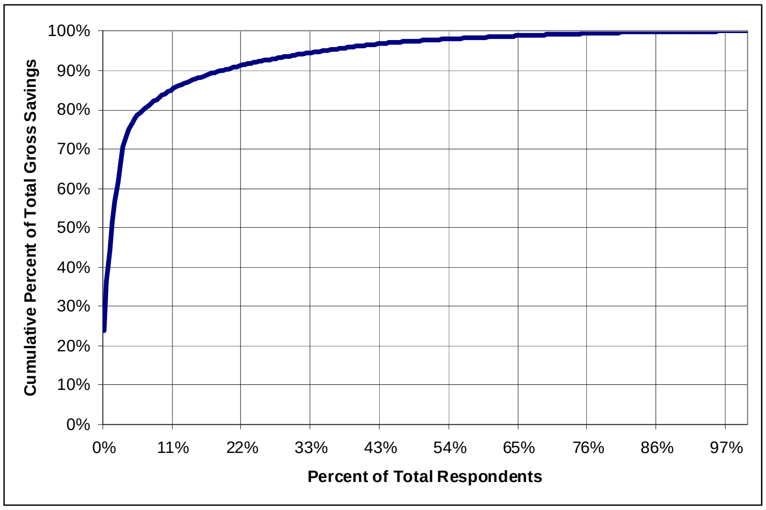
Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

Company Size

Program gross m^3 savings are concentrated in a relatively small number of participants. The top 10% of respondents based on gross m^3 savings consume 84% of total program savings (among those interviewed) (Figure 5-2). The 15 companies with the most m^3 savings together save 80% of total gross m^3 savings. The free ridership rate for those 15 companies is 56% across both utilities. If we eliminate those 15 companies, the free ridership rate drops to 34%.

Figure 5-2. Cumulative Percent of Gross Savings



Measure Type

Machine/Process measures account for 44% of the gross savings and HVAC measures account for 39%; together they drive the final results. The Machine/Process free ridership rate is 56% and HVAC is 46%. Lighting and "Other" measures have fairly high free ridership rates and Hot Water, Envelope, and Controls have fairly low rates.

Table 5-5. Free Ridership By Measure Type

Measure Type	Free Ridership Rate
Machine/Process	56%
HVAC	46%
Lighting	43%
Other	37%
Agriculture	29%
Envelope	22%
Hot Water	15%
Controls	13%

Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

Other Observations

There are several factors that influence the free ridership results, which can be loosely categorized into factors that increase free ridership, those that decrease free ridership, and those that reflect well on the program but that do not improve the free ridership value.

<u>Factors that increase free ridership</u>

- In many energy efficiency programs for large, complex projects the utility incentive will typically not be particularly large compared to the overall project cost. As a result, the respondents may feel that it has relatively little impact on the direction of their project. (On the other hand, the existence of an incentive can raise the level of interest and still have an effect even if the incentive is not large.)

- Regardless of the size of the incentive, it can only have an impact on decision making if the potential recipient feels the chances of receiving the incentive are reasonably high. Because custom projects can involve multiple vendors any confusion about who will receive the incentive will reduce its overall impact on the decision process.

- Design Engineers and Energy Performance Contractors see themselves as sophisticated energy users, and pride themselves on being knowledgeable and competent on energy efficiency issues and in providing the most energy efficient solutions to their clients. This may imply that approaches that aim to influence these channels are not as effective in changing existing energy efficiency choices.

- Again because custom projects can involve multiple vendors, some vendors may be insulated from the key decision makers by other vendors. As a result, any program activities targeting these vendors may fail to influence the final decisions.

- Large industrial end-users often have the accounting mechanisms in place to understand the effects of energy use on their bottom line, they require highly specialized technologies for their application, and they have the in-house expertise to identify and evaluate efficient options for those specialized technologies. In addition, there may be a number of very competent consultants and suppliers who assist the industry with energy efficiency and in a number of other technical support areas. For this kind of company, assistance provided by utility programs must stand out in some particular way to be noticed. The subtleties of that assistance may be lost as time goes on and as staff change, making it harder to identify the effects of that assistance when looking back over time.

Factors that decrease free ridership

- The Utility provides an independent third party verification of the predicted savings and this is very valuable in the decision making process in many organizations.

Positive stories, but ones that do not improve the free ridership

- The participants are quite pleased with their involvement with the program, glad to get the Utility's assistance, and satisfied with the program.

- The Program assistance and incentives help grease the skids, but they do not change the direction or destination of the sled.

- One trade ally reported "The program gives a comfort factor on value of energy efficiency measures. It improves the interaction between the utility and the customer."

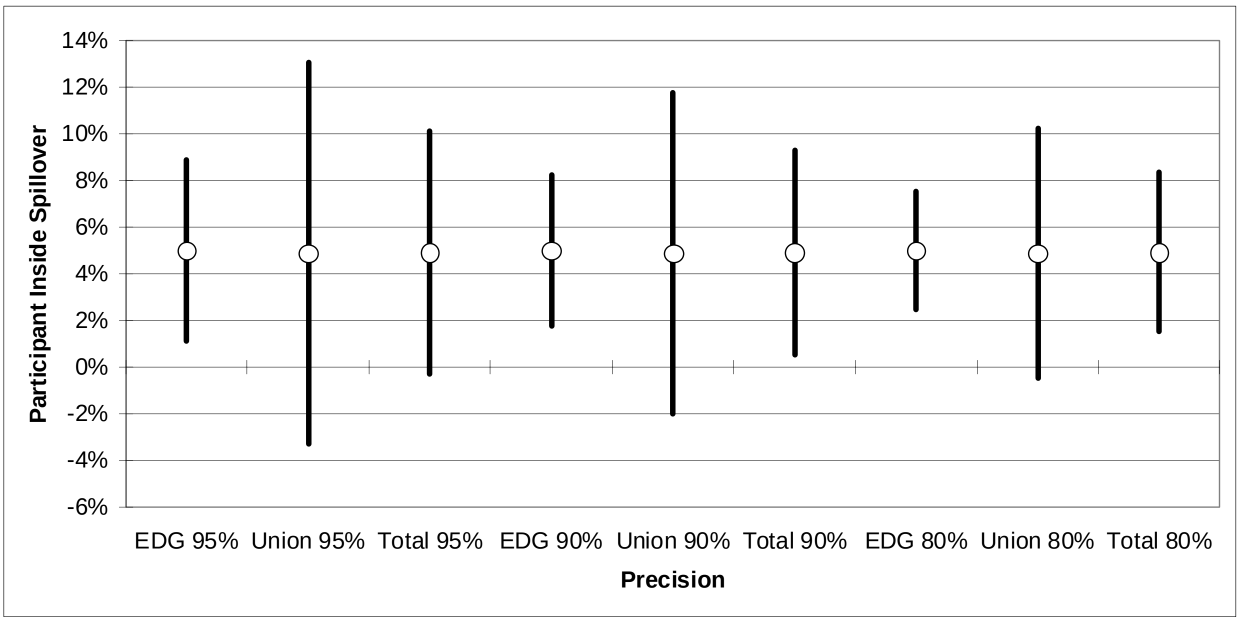
5.2 Spillover Results

Spillover represents energy savings that are due to the program but not counted in program records. Summit Blue estimated **participant inside and outside spillover** through questions in the participant and trade ally surveys and through the Audit-Only Survey. Summit Blue estimated non-participant spillover through the non-participant survey.

5.2.1 Participant Inside Spillover Results

Nine respondents for EGD and five for Union indicated that they had installed additional energy efficiency measures at the same facility without going through the program, those measures count as inside spillover. By extrapolating the m^3 savings from those measures to the population, we calculate that **inside spillover was 5% of gross reported savings for both EGD and Union**. The results for EDG are statistically significant at the 95% level. However, the results for Union are not statistically significant, even at the 80% level. The following figure shows the error bounds around the mean estimate. When the error bounds crosses zero, we cannot say with statistical precision that the results are not zero. The EDG-Union combined total is statistically significant at 90%. Given that the spillover numbers are based on a rather small number of respondents, it is appropriate to calculate spillover across the entire pool of respondents, for Union and EGD combined.

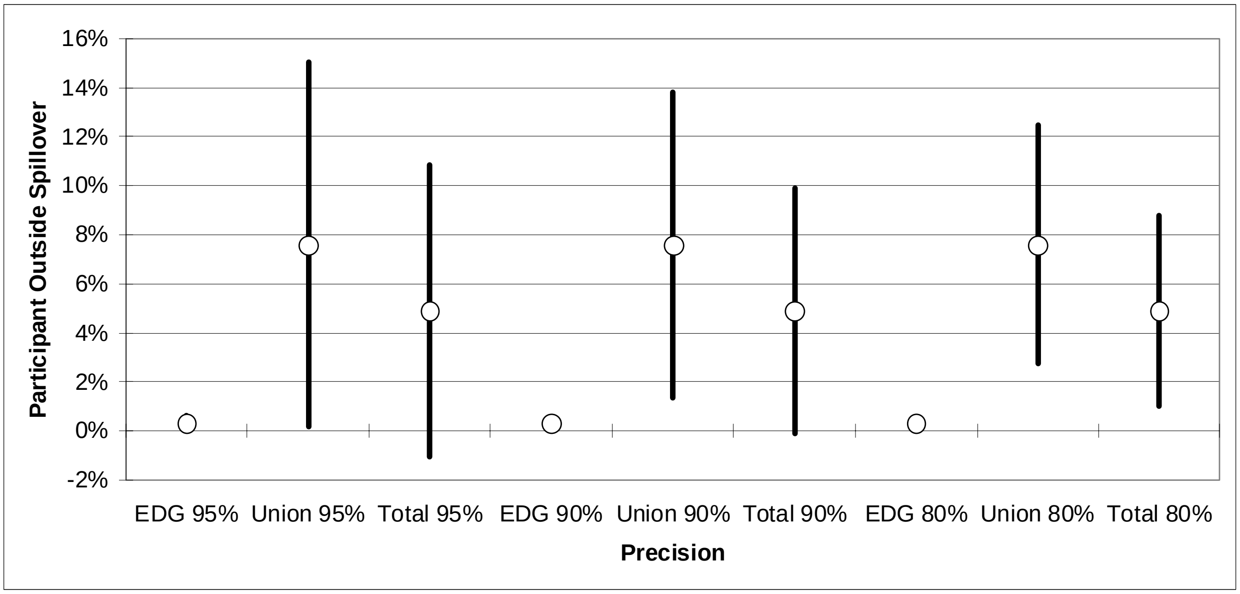
Figure 5-3. Participant Inside Spillover



5.2.2 Participant Outside Spillover Results

Four respondents for EGD and three for Union indicated that they had installed additional energy efficiency measures at *different* facilities without going through the program. Those measures count as outside spillover. By extrapolating the m^3 savings from those measures to the population, we calculate that **outside spillover for Union was 7.6% of gross reported savings, less than 1/2 percent for EGD, and 5% combined across both utilities.** The following figure shows the error bounds around the mean estimate. Given that the spillover numbers are based on a rather small number of respondents, it is appropriate to calculate spillover across the entire pool of respondents, for Union and EGD combined, which is statistically significant at the 80% confidence level.

Figure 5-4. Participant Outside Spillover



5.2.3 Participant Audit-Only Spillover Results

Customers who received an audit, implemented a recommended measure, but did not receive incentives through the program for that measure can be considered audit-only spillover. The audit-only spillover survey and analysis was completed for EGD only as Union Gas was unable to find any companies who had an audit in 2005 and had not implemented one of the recommended measures through the program. As a result, the savings inspired by the Union Gas audits will appear in the program tracking data rather than in spillover. EGD provided a sample of 37 customers who had an audit but did not appear in the tracking data as having implemented a relevant measure. We attempted to complete a survey with each of those customers to estimate spillover and completed 24 surveys (including one who did not recall the audit).

For each respondent, we calculated the share of the recommended measure savings that could be attributed to the influence of the program. 43% of the m^3 savings estimated in the audit were achieved by those who completed a survey. We then applied the 43% savings to parts of the population that can be assumed to follow the same pattern as the respondents (non-respondents and refusals) and assumed zero savings for those who did not recall the audit or whose business was sold or closed (one company was sold, 3 were closed). Summing spillover savings over the whole group then dividing by the sum of the recommended savings gives the final realization rate for spillover savings for the population, which was 35%. **Thus 35% of the gross recommended savings from energy audits are achieved, representing the audit-only spillover.** The total audit-only spillover savings (1,969,700 m^3) will be brought into the final calculation of the program's net-to-gross ratio.

Since the sample was a census of the eligible population there is no need to extrapolate beyond the calculation explained above.

5.2.4 Non-participant Spillover Results

Screening Survey Results. The utilities provided contact information for 1,228 non-participating customers and Global Target Marketing attempted to contact all customers for a screening interview (see Table 5-6). As expected, many respondents (32%) were screened out because they did not implement a measure since 2005. A further 10% were screened out because they were participants and 26% were screened out because they were not aware of the program. Just over one quarter (26%) had implemented a measure since 2005 and were aware of the program but the measure was not influenced by the program. Together, 94.6% of the respondents were screened out for the reasons stated above, leaving a total of 66 customers, or **5.4% of the total population, who were influenced by the program to implement measures** (and did not receive a financial incentive).

These 66 customers were asked to participate in a follow up interview to help quantify savings and 38 agreed (3.1% of the total). Three engineers attempted to contact all 38 customers and conducted interviews with 27 customers (2.2% of the total population and a 71% response rate). Of these, only 5 Union Gas customers (3 commercial and 2 industrial, representing 0.4% of the population) were able to provide enough information to the engineers to enable them to quantify savings. The engineers rated their confidence in the accuracy of their spillover estimates for each project, given the information the respondent was able to provide and the assumptions that they had to make given shortfalls in the data. None of the engineers felt more than modestly confident that the estimates were accurate and several estimates were rated "weak".

Conclusion. Because of the large size of the sample submitted to the screening effort, the fact that **5.4% of the population had spillover measures** is a meaningful and important result. However, given that we were able to estimate m^3 savings for only 5 respondents, which was less than 10% of those with spillover, and that our engineers were not very confident in the accuracy of the savings calculations, we cannot extrapolate m^3 spillover savings to the population.

Our engineers reported that most respondents could not provide useful information about the equipment installed. As a result, any effort to improve on this effort should include on-site visits by evaluation engineers so that they can directly observe the equipment and collect the data they need to make the savings estimates. This will increase the accuracy of the site-specific savings estimates and will likely increase the number of sites for which estimates can be calculated.

Table 5-6. Non-participant Spillover Screening and Engineering Survey Disposition

	Total		Union Gas				Enbridge Large Volume			
			Commercial		Industrial		Commercial		Industrial	
Screened (Total)	1,228	100.0%	1,078	100.0%	41	100.0%	72	100.0%	37	100.0%
Unaware of Energy Efficiency Program	321	26.1%	297	27.6%	3	7.3%	11	15.3%	10	27.0%
Received Financial Incentives	124	10.1%	88	8.2%	20	48.8%	14	19.4%	2	5.4%
Did Not Install/Modify Equipment Since 2005	398	32.4%	354	32.8%	8	19.5%	26	36.1%	10	27.0%
Installed Measure and Aware Of But Not Influenced By Program	319	26.0%	284	26.3%	6	14.6%	16	22.2%	13	35.1%
Installed Measure and Influenced by Program	66	5.4%	55	5.1%	4	9.8%	5	6.9%	2	5.4%
Agreed To Follow-Up	38	3.1%	33	3.1%	3	7.3%	1	1.4%	1	2.7%
Total Follow-up Interviews	27	2.2%	22	2.0%	3	7.3%	-	0.0%	1	2.7%
Total Providing Savings Estimates	5	0.4%	3	0.3%	2	4.9%	-	0.0%		0.0%

5.2.5 Recommended Spillover Rates

Summit Blue recommends the utilities use following spillover rates:

Table 5-7. Spillover Results

Spillover Type	EGD	Union	Base
Participant Inside Spillover	5%	5%	Of gross reported savings
Participant Outside Spillover	5%	5%	Of gross reported savings
Audit-Only Spillover	35%	0%	Of gross audit-recommended savings
Nonparticipant Spillover	0%	0%	

5.3 Net-to-Gross Ratio

The net-to-gross ratio is defined as 1 - free ridership ratio + spillover ratio. As discussed above, spillover is in several parts: participant inside and outside spillover, audit-only spillover, and non-participant spillover. We know that 5.4% of the non-participants have spillover but cannot calculate its quantity so the calculation of net-to-gross presented below excludes it. Together participant inside and outside spillover amount to 10%. The audit-only savings were 1,969,700 m^3 for EGD, which represents 11% of EGD total gross savings (see Table 5-8). With zero Union audit-only savings, the total audit-only savings equals the EGD savings and the combined audit-only spillover rate is 5%. Subtracting free ridership and adding spillover produces a final **net-to-gross ratio of 79% for EGD, 56% for Union, and 67% across both utilities.** Summit Blue recommends that the utilities use the utility-specific total net-to-gross ratios, as they are based on larger sample sizes than the sector-specific results.

Table 5-8. Net-To-Gross Ratio

Utility	Sector	Gross m^3 Savings	Free Ridership	Participant Inside + Outside Spillover	Audit-Only m^3 Savings	Audit-Only Spillover %	Net-to-Gross Ratio
EGD	Agriculture	1,111,398	40%				
EGD	Commercial Retrofit	3,052,840	12%				
EGD	Industrial	10,028,771	50%				
EGD	Multifamily	1,575,482	20%				
EGD	New Construction	798,310	26%				
EGD	Total	18,588,008	41%	10%	1,969,700	11%	79%
Union	Agriculture	1,387,850	0%				
Union	Commercial Retrofit	1,406,897	59%				
Union	Industrial	14,874,847	56%				
Union	Multifamily	520,974	42%				
Union	New Construction	304,991	33%				
Union	Total	23,209,837	54%	10%	0	0%	56%
Total	Agriculture	2,499,248	18%				
Total	Commercial Retrofit	4,459,738	27%				
Total	Industrial	24,903,618	53%				
Total	Multifamily	2,096,456	26%				
Total	New Construction	1,103,302	28%				
Total	Total	41,797,844	48%	10%	1,969,700	5%	67%

Free Ridership Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

6 SUPPLEMENTARY RESULTS

The participant surveys included several questions that illuminate the customer's decision-making process, but do not necessarily feed directly into the free ridership calculation. This section will present some of those results, first for end users, next for trade allies, and then at the sector level. Following that will be a brief summary of free ridership, spillover, and net-to-gross results from other jurisdictions.

6.1 End Users

Most (35 out of 40 or 88%) EGD end user respondents have a policy that specifies energy efficiency requirements. 18 target specific energy efficiency levels.

For Union 12 out of 24 (50%) have a policy that specifies energy efficiency requirements (4 target energy efficiency levels).

Table 6-1. Company Has an Energy efficiency Policy

	Missing	Yes	No	Total
EGD	1	35	3	39
Union	0	12	12	24
Total	1	47	15	63

Those who had a policy were asked about the efficiency level stated in the policy. The results are shown in the following table.

Table 6-2. Efficiency Level Stated in the Policy

Efficiency Level Stated in the Policy	EGD	Union	Total
Missing	22	8	30
1	0	1	1
20	1	0	1
35	0	1	1
5 % reduction in energy cost per vehicle	2	0	2
8	1	0	1
80+	0	1	1
84 % efficiency on boilers	4	0	4
86 % for boilers	1	0	1
86 % for boilers; new school perspective specifies nature of any equipment	1	0	1
Better than code but no specific amount set.	2	0	2
Exceed National Building code by 25 % on new buildings	1	0	1
reduce fossil fuels by 15% per year, starting in 2002	0	1	1
Total	35	12	47

Virtually all respondents had criteria for energy efficient equipment.

Table 6-3. Do You Have Criteria For Energy Efficient Equipment?

	Yes	No	Total
EGD	39	0	39
Union	23	1	24
Total	62	1	63

The criteria for approving energy efficiency equipment is predominantly simple payback period (multiple respondents mentioned this). 95% of EGD respondents mentioned payback, 17% life cycle cost analysis, 14% internal rate of return (IRR).

78% of Union respondents mentioned payback, 22% mentioned IRR, 9% mentioned life cycle cost analysis.

Only 7 respondents (3 EGD, 4 Union) changed their energy efficiency policy since the project. The table below shows the changes they made.

Table 6-4. How has your energy efficiency policy changed since the project?

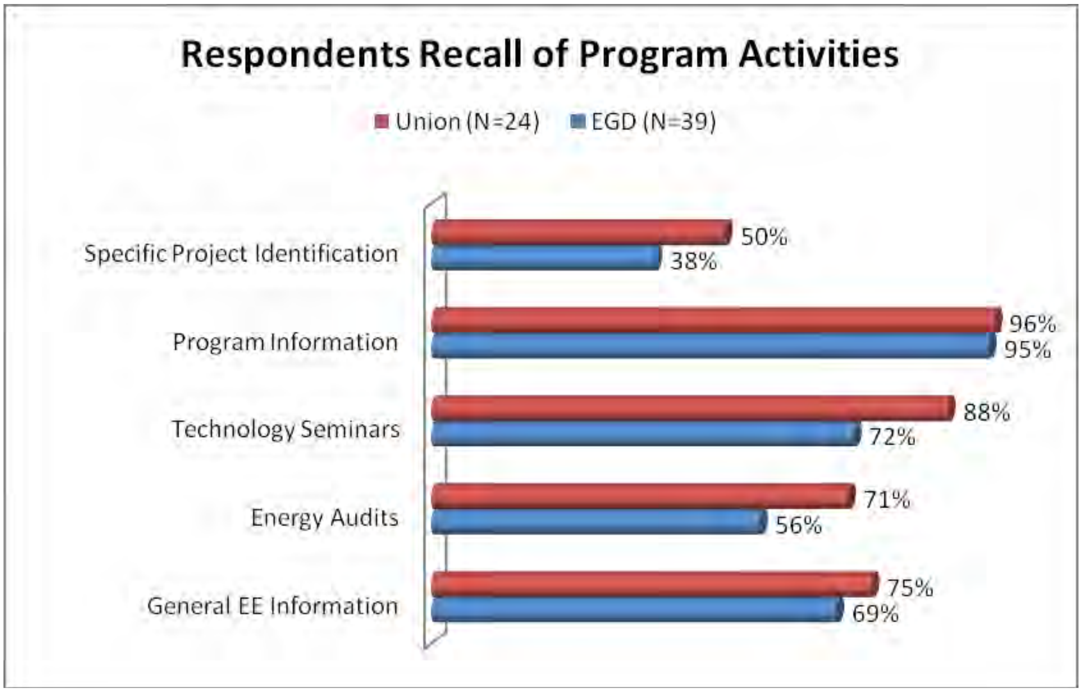
	EGD	Union	Total
EE is now part of their business plan, with a target reduction of 5% annually	0	1	1
Energy wise program has raised awareness of energy efficiency	0	1	1
Greater awareness of need to maintain energy efficiency	0	1	1
Payback has been extended to 5 years	1	0	1
Since the project, the end user has developed a corporate energy policy with a target of a 20% reduction by 2020	0	1	1
Total energy reduction of 6 %	2	0	2
Total	3	4	7

Table 6-5. Percent of respondents recalling program initiative by utility

	General energy efficiency Information	Energy Audits	Technology Seminars	Program Information	Specific Project Identification
EGD (N=39)	69%	56%	72%	95%	38%
Union (N=24)	75%	71%	88%	96%	50%
Total (N=63)	71%	62%	78%	95%	43%

Respondents were asked whether they recalled participating in various program activities. Almost all recalled getting program information (Figure 6-1). Approximately three-fourths remembered going to technology seminars and getting general energy efficiency information.

Figure 6-1. Respondents' Recall of Program Activities



Respondents were asked what the payback was for their project after figuring in the utility incentive. For EGD, 18 of 39 did not respond and 6 had paybacks under a year after incentive (Table 6-6 and Figure 6-2). For Union Gas, 19 of 24 did not respond. Of the 5 who responded, 1 had a payback period under a year.

Table 6-6. What was the project's payback after figuring in the utility incentive?

	EGD	Union	Total
Missing	18	19	37
LT 1 YR	6	1	1
1 to 3 Years	6	3	1
4 to 11 years	9	1	1
Total	39	24	63

6.2 Trade Allies

Consulting Engineers were the most common type of trade ally among the respondents followed by installation contractors (Table 6-7, Figure 6-2, and Figure 6-3). Among our respondents, Enbridge had no manufacturer or distributor/sales as business partners and Union had no property managers as allies.

Table 6-7. Primary Line of Business

	EGD	Union	Total
Consulting Engineer	17	21	38
Installation Contractor	8	6	14
ESCO	5	7	12
Manufacturer	0	8	8
Distributor or Equipment Sales	0	5	5
Property Manager	3	0	3
Other	2	0	2
Total	35	47	82

Figure 6-2. Types of Trade Allies

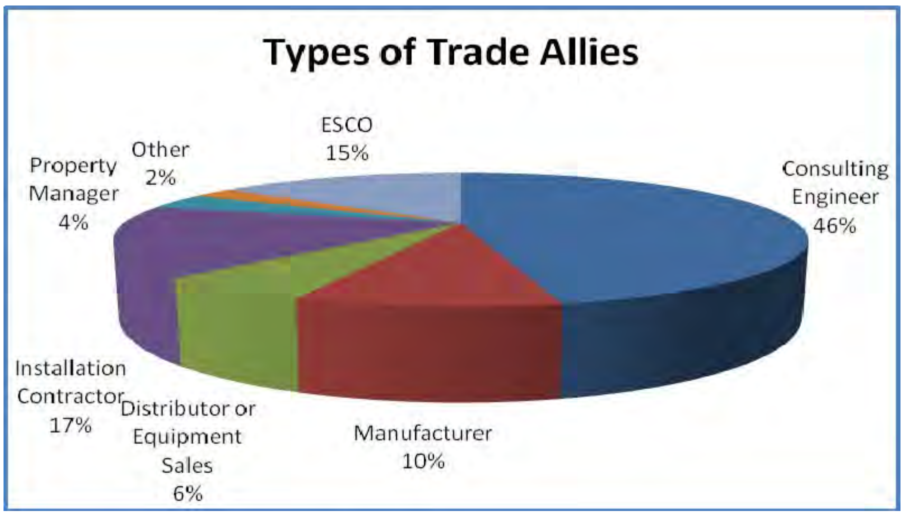
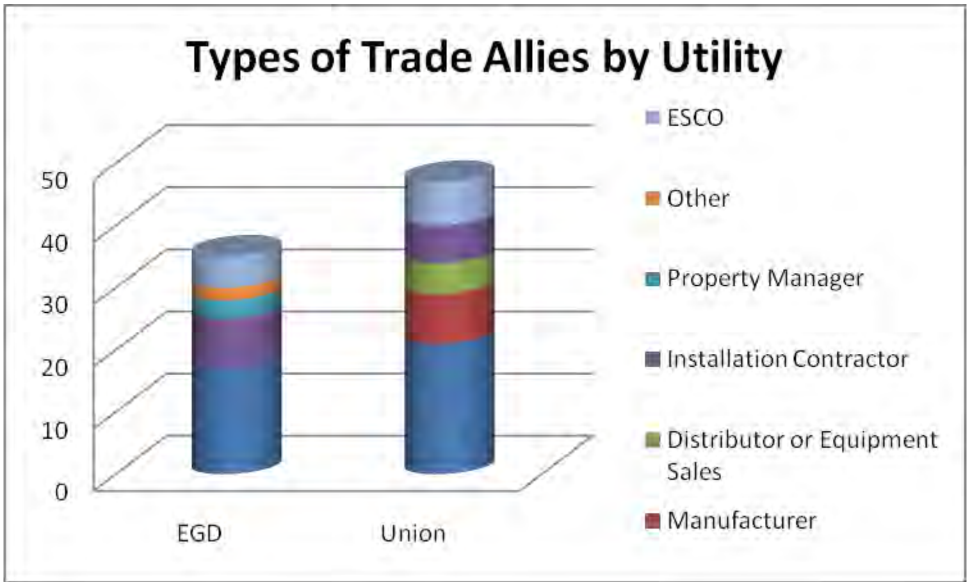
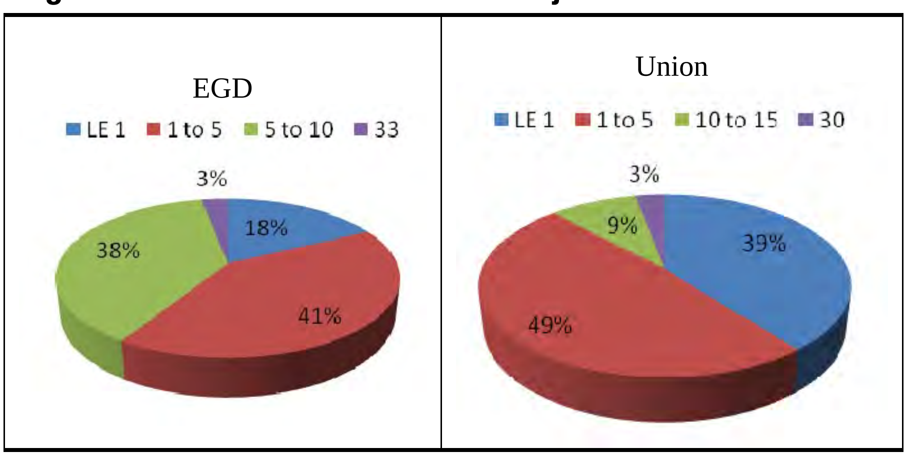


Figure 6-3. Types of Trade Allies by Utility



Respondents were asked to quantify the program incentives as a percent of total project costs. The most common answer was 1-5%, named by just under half of the respondents (Figure 6-4). Over one third of trade allies associated with Union Gas projects thought the incentives were less than or equal to 1%, compared to 18% of the EGD respondents.

Figure 6-4. Incentives as a % of Project Costs



According to the trade allies, all of Enbridge customers were aware of the utility role in the project but only 2/3 of the Union customers were aware.

Table 6-8. Customer Aware Of Utility Role

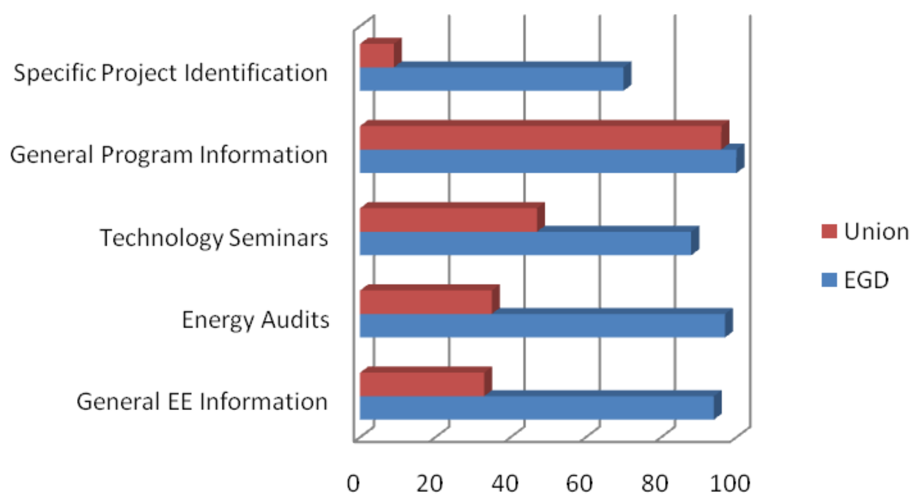
	Yes	Total	%
EGD	34	34	100
Union	27	40	68

Trade allies were asked "Do you recall receiving energy efficiency information and/or training in any of the following areas that was sponsored or delivered by Union Gas/Enbridge Gas Distribution?" Almost all remembered getting general program information (Table 6-9 and Figure 6-5). Among the EGD trade allies, almost all remembered getting information or training in energy audits and general energy efficiency information, compared to around one third for Union trade allies. Over two thirds of EGD respondents recalled getting "specific project identification" compared to nine percent for Union.

Table 6-9 % of Mentions by Utility

	EGD	Union
General Program Information	100	96
Energy Audits	97	35
General EE Information	94	33
Technology Seminars	88	47
Specific Project Identification	70	9
Software	0.38	0.20
Lunch N Learns	0.26	0.22

Figure 6-5. Percent Recall Information Etc. by Utility



6.3 Sector-Specific Answers to Key Questions

This section will present answers to the questions that carry the most weight in the free ridership calculations broken out by utility and sector. The results are presented as percentages after sector weights have been applied. This corresponds to the weighting used when the sector-specific free ridership results were calculated. The key questions that will be presented in this section are shown in the following table.

Table 6-10. Key Questions Influencing Free Ridership Calculation

Label in Text	Marker in Figure 5-1	Description and Survey Question
Direct Measure Level		
Likelihood and/or Share	[4] and [7]	Free Rider percentage based on likelihood (question E2a) and/or share (question E2b)
Months of Early Replacement	[6]	Number of months program caused the project to be moved forward, used to calculate the early replacement adjustment multiplier (question E1a)
Direct Project Level		
Best Estimate of Savings	[14]	Interviewee best estimate of the extra savings that would have been achieved without the program (question E3).
Program Influence Project Level		
Planning	[H]	Project planning interviewer score (question D3b)
Influence	[G]	Interviewer-assigned influence score (question D2b)
Importance	[F]	Program importance participant score (question D1)

The sector level free ridership results are shown in Tables E-1 and 5-1, which can be summarized as follows:

EGD: Industrial and Agriculture are relatively higher than Commercial Retrofit, Multifamily, and New Construction with Commercial Retrofit being particularly low.

Union: Commercial Retrofit and Industrial are relatively higher than Multifamily and New Construction with Agriculture being particularly low (zero).

The discussion of the question-specific results will address those sector differences. Those sectors that saw relatively high free ridership rates are shaded in the tables that follow.

6.3.1 Direct Measure Level

Likelihood and/or Share. Respondents were asked to estimate the *likelihood* that they would have incorporated measures "of the same high level of efficiency" if not for the financial and technical assistance of the program (Figure 5-1 [4]). In cases where respondents indicate that they may have incorporated some, but not all, of the measures, they are asked to estimate the *share of measures* that would have been incorporated anyway at the same level of high-efficiency. The answers they gave were converted into a free ridership percentage, which is shown in the following table.

EGD Notes: In the industrial sector, 67% of the respondents had free ridership scores of 70% or more based on this measure, which was significantly higher than the other sectors, and 89% of the agriculture respondents had free ridership scores at 50% or higher.

Union Gas Notes: Fully 84% of the commercial retrofit respondents had free ridership scores of 100% based on this measure. The industrial scores were somewhat better than multifamily and new construction on this measure. Most of the very largest industrial companies had very high free ridership rates in this area, which is the primary driver of the final free ridership score.

Table 6-11. Likelihood and / or Share – EGD

Free Ridership Percent	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
0	0%	29%	42%	25%	39%
10	0%	0%	0%	0%	0%
20	11%	0%	2%	0%	0%
25	0%	0%	5%	0%	3%
30	0%	0%	0%	8%	0%
40	0%	0%	0%	0%	0%
45	0%	0%	0%	0%	6%
50	44%	5%	14%	25%	0%
60	11%	0%	0%	0%	0%
65	0%	0%	0%	0%	3%
70	0%	10%	7%	0%	0%
75	11%	19%	2%	0%	0%
80	0%	14%	9%	0%	3%
85	11%	0%	0%	21%	0%
90	0%	0%	5%	4%	0%
100	11%	24%	14%	17%	47%
Total	100%	100%	100%	100%	100%
N	9	22	56	24	44

Table 6-12. Likelihood and / or Share – Union Gas

Free Ridership Percent	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
0	67%	6%	0%	0%	5%
30	0%	17%	0%	0%	0%
40	0%	0%	6%	0%	0%
50	0%	17%	13%	8%	0%
60	11%	0%	0%	0%	0%
70	0%	6%	0%	0%	0%
75	0%	0%	6%	0%	0%
80	22%	6%	6%	25%	5%
85	0%	6%	0%	0%	0%
90	0%	6%	13%	8%	5%
100	0%	39%	56%	58%	84%
Total	100%	100%	100%	100%	100%
N	8	19	17	12	20

Early Replacement Adjustment Multiplier. On a measure-by-measure basis, respondents were asked if the program influenced them to install the equipment more than one year earlier than they otherwise would have otherwise. If it had, they were asked when they would have installed the equipment without the program (Figure 5-1 [6]). That answer was converted to months and then converted to a percentage multiplier to discount the measure-specific free ridership rate. The answers given are shown below.

EGD Notes: Few projects were moved forward in time in most sectors except for the multifamily sector.

Union Gas Notes: Very few projects in any sector were moved forward by more than 12 months, with the exception of commercial retrofit.

Table 6-13. Months the Program Moved the Project Forward in Time – EGD

Months	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
0	67%	86%	14%	100%	82%
2	0%	7%	7%	0%	0%
6	0%	7%	7%	0%	0%
9	0%	0%	11%	0%	0%
12	17%	0%	29%	0%	0%
18	0%	0%	14%	0%	0%
24	17%	0%	4%	0%	6%
36	0%	0%	11%	0%	0%
240	0%	0%	4%	0%	12%
Total	100%	100%	100%	100%	100%
N	6	15	32	9	20

Table 6-14. Months the Program Moved the Project Forward in Time – Union Gas

Months	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
0	0%	92%	0%		50%
6	0%	8%	0%		0%
9	0%	0%	100%		0%
12	100%	0%	0%		0%
24	0%	0%	0%		50%
Total	100%	100%	100%		100%
N	1	13	6	0	3

6.3.2 Direct Project Level

Best Estimate of Savings. Respondents are asked to give an upper, lower and their best estimate [10] of the overall energy savings attributable to the program across all measure categories. If a “best estimate” is not provided, the midpoint between the lower and upper bound is used (Figure 5-1 [14]). Their answers are presented in the following two tables.

EGD Notes: Only two agriculture respondents answered this question, which minimized its effect on this sector, although both said 100% of the savings were attributable to the program. Industrial respondents attributed relatively more of the savings to the program, which would tend to *reduce* their free ridership score.

Union Gas Notes: Industrial and commercial retrofit respondents attributed relatively more of the savings to the program, which would tend to *reduce* their free ridership score.

Table 6-15. Respondent Estimate of Savings Attributable to the Program – EGD

Savings Attributable to the Program (%)	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
0	0%	6%	19%	8%	0%
10	0%	0%	0%	0%	0%
20	0%	0%	12%	17%	36%
25	0%	6%	0%	0%	0%
35	0%	0%	7%	0%	0%
50	0%	0%	17%	0%	8%
65	0%	0%	5%	0%	0%
70	0%	6%	10%	0%	0%
75	0%	11%	0%	0%	8%
80	0%	17%	14%	25%	6%
85	0%	11%	5%	21%	0%
90	0%	0%	2%	0%	0%
100	100%	44%	10%	29%	42%
Total	100%	100%	100%	100%	100%
N	2	20	56	24	44

Table 6-16. Respondent Estimate of Savings Attributable to the Program – Union Gas

Savings Attributable to the Program (%)	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
0	75%	6%	0%	0%	5%
20	0%	0%	0%	0%	0%
40	0%	0%	0%	8%	0%
50	0%	19%	14%	0%	0%
70	0%	0%	14%	0%	0%
80	0%	6%	7%	25%	0%
90	0%	0%	0%	17%	0%
100	25%	69%	64%	50%	95%
Total	100%	100%	100%	100%	100%
N	7	15	16	12	20

6.3.3 Program Influence Project Level

Planning. Point [H] in Figure 5-1 is an interviewer score of the amount of planning that went on for the measure before the program got involved, based on open-ended questions to the respondent and probing questions as appropriate. The planning score shown in the following tables is on a scale where 5 indicates that respondent had no plans at all and 1 indicates that respondent had documented plans and had budgeted for all of the efficient equipment.

EGD Notes: Compared to the other sectors, only commercial retrofit stands out as having respondents who had relatively far advanced plans prior to program involvement so this question does not contribute meaningfully to explaining the high free ridership scores for agriculture and industrial.

Union Gas Notes: Three quarters of the commercial retrofit respondents had planning scores of 2 or 1, significantly more than the other sectors. The 42% of industrial respondents having a planning score of 1 is significantly higher than agriculture and multifamily, but less than new construction. Most of the very largest industrial companies had planning scores of 1 or 2.

Table 6-17. Project Planning Score – EGD

Planning Score	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
1	11%	13%	18%	17%	22%
2	11%	9%	7%	0%	14%
3	0%	0%	4%	0%	8%
4	11%	48%	31%	25%	44%
5	67%	30%	40%	58%	11%
Total	100%	100%	100%	100%	100%
N	9	23	56	24	41

Table 6-18. Project Planning Score – Union

Planning Score	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
1	22%	42%	7%	50%	58%
2	0%	0%	27%	0%	16%
3	0%	16%	53%	0%	16%
4	0%	26%	0%	25%	0%
5	78%	16%	13%	25%	11%
Total	100%	100%	100%	100%	100%
N	8	19	16	12	19

Influence. Point [G] Figure 5-1 is an interviewer score of the program's influence on the type, efficiency and quantity of the equipment installed. The driving question at [G] was as follows: "Did the assistance you received from [Enbridge/Union] in any way influence your capital funding acquisition process, the type or efficiency level of the equipment or the amount of high efficiency equipment you installed or process changes implemented?" After asking probing questions to understand the answer, the interviewer assigns a 1-5 score where "1" indicates that the program had no influence and "5" indicates that the program was the primary reason that energy efficient equipment was installed. The results are in the following tables.

EGD Notes: Agriculture and industrial respondents are somewhat more likely to score low on this question than multifamily and commercial retrofit (33% agriculture and 29% industrial at 3 or lower compared to 16% multifamily and 25% commercial retrofit) with a low score being correlated with a higher free ridership score.

Union Gas Notes: All commercial retrofit respondents got a program influence score of 3 or lower, which was significantly lower than the other sectors. The industrial respondents had lower program influence scores than the agriculture respondents but higher than the other sectors.

Table 6-19. Program Influence – EGD

Program Influence	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
1	0%	0%	0%	0%	4%
2	0%	6%	0%	25%	7%
3	33%	24%	16%	42%	14%
4	67%	35%	35%	0%	4%
5	0%	35%	48%	33%	71%
Total	100%	100%	100%	100%	100%
N	3	17	35	24	35

Table 6-20. Program Influence – Union Gas

Program Influence	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
1	0%	0%	0%	0%	50%
2	0%	10%	0%	20%	25%
3	0%	30%	67%	60%	25%
4	0%	50%	0%	20%	0%
5	100%	10%	33%	0%	0%
Total	100%	100%	100%	100%	100%
N	6	11	3	5	5

Importance. Point [F] in Figure 5-1 represents several questions on the importance of several program components or types of assistance in the participant's decision to install energy efficiency equipment. The maximum score among those questions is carried forward in the calculation where 1 is "not at all important" and 5 is "very important". The maximum score by sector is shown in the following tables.

EGD Notes: Over half of the Agriculture respondents had an importance score of 3 or less, with lower numbers correlated with higher free ridership. This was significantly lower than the other sectors. The industrial scores were lower than multifamily and new construction.

Union Gas Notes: Commercial retrofit importance scores were significantly lower than the other sectors. Industrial importance scores were higher than the other sectors.

Table 6-21. Program Importance – EGD

Importance	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
1	11%	0%	0%	0%	3%
2	11%	0%	0%	0%	3%
3	33%	22%	0%	4%	16%
4	22%	26%	14%	38%	3%
5	22%	52%	86%	58%	76%
Total	100%	100%	100%	100%	100%
N	9	23	56	24	44

Table 6-22. Program Importance – Union Gas

Importance	Agriculture	Industrial	Multifamily	New Construction	Commercial Retrofit
1	0%	0%	7%	0%	37%
2	22%	0%	7%	8%	21%
3	0%	6%	13%	17%	5%
4	0%	50%	13%	75%	16%
5	78%	44%	60%	0%	21%
Total	100%	100%	100%	100%	100%
N	8	19	17	12	20

6.3.4 Summary

The following table summarizes the top-level information from the previous tables. It indicates which questions are driving the results for each of the sectors with relatively high free ridership rates.

Table 6-23. Summary of Sector-Specific Questions on High Free Ridership Sectors

Label in Text	EGD Industrial	EGD Agriculture	Union Gas Industrial	Union Gas Commercial Retrofit
Direct Measure Level				
Likelihood and/or Share	High	High	High*	High
Months of Early Replacement				
Direct Project Level				
Best Estimate of Savings	Low	Low	Low	Low
Program Influence Project Level				
Planning			Medium High*	High
Influence	Medium	Medium	Low	High
Importance	Medium	High	Low	High

High = Answers strongly supported the relatively high free ridership scores for these sectors.
High = High for the very largest industrial participants.*
Medium = Answers somewhat supported the relatively high free ridership scores for these sectors.
Low = Answers tended to bring down the free ridership scores for these sectors compared to other sectors.
Blank = Answers neither support nor contradict the free ridership scores.

EGD Summary. The high EGD industrial free ridership results are driven by high scores in the Likelihood and/or Share questions with support from the Influence and Importance questions. The high EGD agriculture free ridership results are driven by high scores in the Likelihood and/or Share and Importance questions with support from the Influence questions.

The EGD commercial retrofit has a relatively low free ridership rate at 12%. This sector had scores corresponding to low free ridership rates on four of the six main questions examined:

- Likelihood and/or Share: One of the lowest free ridership scores.
- Best estimate of savings: One of the highest estimates with 42% saying 100%
- Influence: The highest score (corresponding to a low free ridership rate), with 71% with a score of 5
- Importance: The second to the highest score (corresponding to a low free ridership rate), with 76% with a score of 5.

Union Gas Summary. The Union Gas commercial retrofit respondents show answers correlated with high free ridership results across most questions examined, except the Best Estimate of Savings.

The Union Gas industrial free ridership results are driven by the responses of a small number of very large industrial participants, who are significantly larger than the other Union Gas industrial participants (based on gross m^3 savings). The scores of these large participants on the Likelihood and/or Share and Project Planning questions were the primary drivers in their high free ridership scores.

6.4 Free Ridership, Spillover, and Net-to-Gross from Other Jurisdictions

Free ridership, spillover, and net-to-gross ratios from other jurisdictions can put the Union and EGD results in context.

The Database for Energy Efficiency Resources (DEER) is one commonly-cited source for free ridership numbers. DEER developed by the California Public Utilities Commission and the California Energy Commission, with support and input from the Investor-Owned Utilities and other interested stakeholders. The net-to-gross ratios in DEER take only free ridership into account and not spillover. As of late 2006 the DEER net-to-gross rates were as follows:[40]

0.83	Commercial and agricultural information, tools, or design assistance services
0.80	Default
0.96	Express Efficiency (rebates)
0.83	Energy Management Services, including audits (for small and medium customers)
0.74	Industrial Information and Services
0.70	Large Standard Performance Contract
0.80	All other nonresidential programs

[40] DEER is currently being updated and is off-line as of this writing. The original source of these numbers was : http://eega.cpuc.ca.gov/deer/Ntg.asp.

In 2006, Summit Blue researched the free ridership and spillover rates that have been found in studies in recent years. The results of that benchmarking exercise are presented in the following pages (with some slight updates from studies we are aware of that occurred since 2006). The 79% net-to-gross ratio for EGD is in the same range as several of the programs examined. The 56% ratio for Union Gas is lower than those found in this research.

Table 6-24. Results from Other Jurisdictions

State/Region	Utility	Program Name	Report Title	Year of Research	Program Description	Market Sector	Measures Covered	Free ridership values	Total Spillover Value	NTG Ratio
California	PG&E	Advanced Performance Options (All Measures)	Evaluation of Pacific Gas and Electric Company's 1997 Commercial Energy Efficiency Incentives Program: HVAC Technologies PG&E Study ID number: 333B	1999		Commercial	Adjustable Speed Drives, Water Chillers, Customized EMS, Convert to VAV, Other Custom Equipment, Other HVAC Technologies	0.46	0.21	0.75
California	PG&E	Commercial Energy Efficiency Incentives Program: Lighting Technologies	Evaluation of Pacific Gas and Electric Company's 1997 Commercial Energy Efficiency Incentives Program: Lighting Technologies PG&E Study ID number: 333A	1999	This evaluation covers indoor lighting technology retrofits that were rebated during 1997. These retrofits were performed under three different PG&E programs: the Retrofit Express (RE), Customized Efficiency Options (CEO) and Advanced Performance Options (APO) Programs.	Commercial	Lighting	0.24	0.05	0.82
California	Southern California Edison	Non-Residential Financial Incentives Program	Evaluation of the Southern California Gas Company 2004-05 Non-Residential Financial Incentives Program June 7, 2006	2006	The program focuses on small to medium nonresidential gas customers served under core rate schedules. The program incorporates technical support, education, training, outreach, contractor referral, prescriptive rebates and equitable financial incentives through three program elements.	Small and Medium Commercial, Agricultural, and Industrial		0.3	10% (not evaluated, just an estimate)	0.8
California	PG&E	Retrofit Efficiency Options Program	Evaluation of Pacific Gas and Electric Company's 1997 Commercial Energy Efficiency Incentives Program: HVAC Technologies PG&E Study ID number: 333B	1999	The REO program targeted commercial, industrial, agricultural, and multi-family market segments. Customers were required to submit calculations for the projected first-year energy savings along with their application prior to installation of the high efficiency equipment. PG&E	Commercial, Industrial, Agricultural, and Multifamily	Adjustable Speed Drives, Water Chillers, Cooling Towers	0.46	0.21	0.75

State/Region	Utility	Program Name	Report Title	Year of Research	Program Description	Market Sector	Measures Covered	Free ridership values	Total Spillover Value	NTG Ratio
					representatives worked with customers to identify cost-effective improvements, with special emphasis on operational and maintenance measures at the customers' facilities. Marketing efforts were coordinated amongst PG&E's divisions, emphasizing local planning areas with high marginal electric costs to maximum the program's benefits.					
California	PG&E	Retrofit Express Program	Evaluation of Pacific Gas and Electric Company's 1997 Commercial Energy Efficiency Incentives Program: HVAC Technologies PG&E Study ID number: 333B	1999	The RE program offered fixed rebates to customers who installed specific electric energy efficient equipment. It covered covers lighting, air conditioning, refrigeration, motors, and food service. Customers were required to submit proof of purchase with their applications in order to receive rebates. The program was marketed to small- and medium-sized commercial, industrial, and agricultural (CIA) customers.	Small and Medium Commercial, Industrial, and Agricultural Customers	Central A/C, Adjustable Speed Drives, Package Terminal A/C, Set-Back Thermostat, Reflective Window Film, Water Chillers, Other HVAC Technologies	0.39	0.21	0.82
California		SPC	2003 Statewide Nonresidential Standard Performance Contract (SPC) Program Measurement And Evaluation Study	2005	The program offered fixed-price incentives to project sponsors for kWh energy savings achieved by the installation of energy-efficiency measures. The fixed price per kWh, performance measurement protocols, payment terms, and other operating rules of the program were specified in a standard contract. PG&E and SDG&E also offer incentives for energy efficient gas measures.	Nonresidential	Lighting, lighting controls, VSDs, HVAC	49% / 59% / 35% / 55% / 41% (1999-2003)	5% (not evaluated, just an estimate)	63% (for 2002-2003)
Colorado	Xcel	Bid 2001 Program	Impact and Process Evaluation of the Bid 2001 Program	2003	Demand-side bidding program that acquires demand reductions by	Commercial and Industrial		0.36	0.06	0.7

State/Region	Utility	Program Name	Report Title	Year of Research	Program Description	Market Sector	Measures Covered	Free ridership values	Total Spillover Value	NTG Ratio
					soliciting proposals for demand reduction projects from customers, and third-party bidders contractors. This program has subsequently been succeeded by the Custom Efficiency program.					
Colorado	Xcel	Custom Efficiency	Colorado Demand-Side Management Programs Impact, Cost-Effectiveness, Process, and Customer satisfaction Evaluations	2005	Launched on December 1, 2001, this program is a C&I DSM bidding program and successor to Bid 2001. The program's goal is to obtain reliable and verifiable electric demand reduction in Company's Front Range service territory. To participate, eligible customers and qualified providers of energy related services respond to RFPs seeking electric demand reduction projects within eligible facilities.	Commercial and Industrial		0.398	0.139	0.741
Massachusetts/ New Hampshire	National Grid	Accelerated Application Process	National Grid 2001 Commercial and Industrial Free-ridership and Spillover Study	2002				0.121	0.146	1.025
Massachusetts/ New Hampshire	National Grid	Comprehensive Project	National Grid 2001 Commercial and Industrial Free-ridership and Spillover Study	2002				0.154	0.109	0.955
Massachusetts/ New Hampshire	National Grid	Design 2000plus	National Grid 2001 Commercial and Industrial Free-ridership and Spillover Study	2002	The program offers technical assistance and financial incentives to large commercial and industrial customers who are building new facilities, adding capacity for manufacturing, replacing failed equipment or undergoing major renovations.	Large Commercial and Industrial	Motors, VFD, HVAC, Lighting, Custom	0.307	0.188	0.881
Massachusetts/ New Hampshire	National Grid	Energy Initiative Program	National Grid 2001 Commercial and Industrial Free-	2002	The program offers technical assistance and incentives to help large C&I customers	Large Commercial and Industrial	Motors, VFD, HVAC, Lighting,	0.096	0.111	1.015

State/Region	Utility	Program Name	Report Title	Year of Research	Program Description	Market Sector	Measures Covered	Free ridership values	Total Spillover Value	NTG Ratio
			ridership and Spillover Study		purchase energy-efficient measures for their existing facilities.		Custom			
Massachusetts	NSTAR	Business Solutions	PY2002 Business Solutions Impact Evaluation for NSTAR Electric	2004	The program provides technical and financial assistance to NSTAR Electric's commercial, industrial, and institutional customers (except in Cape Light Compact territory) to facilitate the installation of energy saving equipment in existing buildings.	Commercial, Industrial, Institutional	Lighting, lighting controls, VSDs, HVAC, EMS, Refrigeration, Compressed Air, Motors	0.277	0.103	0.854
Massachusetts	NSTAR	Construction Solutions	Construction Solutions Program Year 2002 Impact Evaluation Final Report	2004	The program (previously the C&I New Construction Program) offers technical and financial assistance to design professionals and developers to promote the use of efficient design measures and electrical equipment in the construction, remodeling, or renovation of commercial and industrial buildings. The program also offers incentives to encourage the installation of energy efficient replacement equipment when existing systems fail during operation or at the time of purchasing new equipment.	Commercial and Industrial	Chillers, VSDs, Refrigeration, Lighting, Lighting Controls, Controls, Compressed Air	0.173	0.003	0.848
New York	NYSERDA	CIPP	Commercial/Industrial Performance Program (CIPP) Market Characterization, Market Assessment and Causality Evaluation	2006	CIPP began in June 1998. It provides financial incentives to energy service companies (ESCos) and other contractors to promote energy efficiency capital improvement projects. Program objectives are to: 1) foster the growth of the ESCO industry in New York State and 2) encourage end-use customers to invest in energy-efficient equipment based on the potential	Commercial and Industrial	Lighting, EMS, motors and VSDs, unitary HVAC and chiller replacements, heat pump water heaters, Energy Star vending machines, custom measures with paybacks of greater than one year, including	0.35	0.58	1.04

State/Region	Utility	Program Name	Report Title	Year of Research	Program Description	Market Sector	Measures Covered	Free ridership values	Total Spillover Value	NTG Ratio
					energy cost savings. Eligible energy efficiency measures must reduce electric energy consumption at the project site and this reduction must be measurable and verifiable. In addition, cost effective renewable energy measures and measures that reduce summer peak demand are eligible for funding consideration as custom measures whether or not electric energy consumption is reduced.		renewable measures and measures that reduce peak summer demand.			
New York	NYSERDA	New Construction Program (NCP)	New Construction Program (NCP) Market Characterization, Market Assessment, and Causality (MCAC)	2006	This comprehensive evaluation covered the period from program inception through year-end 2005. In late 2006, the MCAC Team was tasked with updating certain aspects of the earlier comprehensive evaluation effort. This report discusses the results of the update work.	Commercial and Industrial		0.40	0.85	1.22
New York	NYSERDA	Technical Assistance Program	Technical Assistance Program Market Characterization, Market Assessment And Causality Evaluation	2007	The Program provides customers with objective, customized information by funding detailed energy studies capable of facilitating better energy efficiency, energy procurement, and financing decisions.	Commercial and Industrial		0.27	0.44	1.17

7 CONCLUSIONS

The total free ridership rate across both utilities and all sectors is 48% as shown in Table 7-1. The free ridership rate for EGD is 41% and it is 54% for Union Gas. Summit Blue recommends that the utilities use the utility-specific total free ridership values of 41% and 54% as the best estimate of free ridership. Those results are based on larger sample sizes than the sector-specific results and proved more stable in the sensitivity analysis. The sector-specific results are based on smaller sample sizes and should only be used to support program management, for example to support targeting and marketing decisions.

Table 7-1. Free Ridership Results

Sector	EGD	Union	Total
Agriculture	40%	0%	18%
Commercial Retrofit	12%	59%	27%
Industrial	50%	56%	53%
Multifamily	20%	42%	26%
New Construction	26%	33%	28%
Total	41%	54%	48%

Assumptions (See Figure 2.1 for the interpretation of these assumptions):

Weight of Participant Reported Importance [F] in [K] compared to the planning [H] and influence [G] scores	Triple weight
Weight of Project-based estimate [14] in [20] compared to the measure-specific scores [9]	Triple Weight
Weight of Program Influence Score [L] compared to the Project-Based score [21]	Equal Weight

Summit Blue recommends the utilities use following spillover rates:

Table 7-2. Spillover Results

Spillover Type	EGD	Union	Base
Participant Inside Spillover	5%	5%	Of gross reported savings
Participant Outside Spillover	5%	5%	Of gross reported savings
Audit-Only Spillover	35%	0%	Of gross audit-recommended savings
Nonparticipant Spillover	0%	0%	

Summit Blue recommends the utilities use the following net-to-gross ratios, reflecting both free ridership and spillover:

Table 7-3. Net-to-gross Results

	EGD	Union
Net-to-gross ratio	79%	56%

Appendix A. Revised Analysis Plan

Appendix B: Survey Instruments

APPENDIX A

CUSTOM PROJECT FREE RIDERSHIP AND SPILLOVER STUDY ANALYSIS PLAN

FINAL

Submitted To:

Union Gas Ltd.

Enbridge Gas Distribution Inc.

January 15, 2008
Annotated July 28, 2008 to reflect decisions made for the final calculations.

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Note: The analysis plan presented here has changed from the original approved plan in two ways:
1. Assumptions left undefined in the original plan were finalized.
2. Some details of the free ridership calculation had to be changed to appropriately adjust to realities in the actual data.

INTRODUCTION

This document presents the detailed analysis plan that will govern the free ridership and spillover study for the Custom Projects programs implemented by Enbridge Gas Distribution and Union Gas. This document will present the planned survey and analysis approach and sample design for three surveys:

1. Participant and Trade Ally survey covering free ridership and spillover

2. Participant Audit-Only survey covering spillover

3. Nonparticipant Survey covering spillover.

Finally, this document will outline the final report.

Approach Overview

Free ridership and spillover will be estimated using data from surveys with participants, nonparticipants, trade allies, and utility staff. This approach is based primarily on participant self-reported information along with other perspectives to triangulate the net-to-gross estimates. It is the most common and generally accepted approach to measuring free ridership and spillover in a commercial and industrial energy efficiency program.

Experienced utility industry consultants will personally conduct the interviews and most will be done on-site. This is standard practice for our firm where estimating attribution[1] is a primary objective of the research. Typically the internal champion in an industrial firm will have the most complete information on influences, and this information can best be extracted in an in-person interview which encourages the free flow of significant information.

To address the possibility of respondent bias, the interviews will approach each topic from a variety of directions. The interviewer has the discretion to probe for supporting information and the analysis process checks for consistency across answers. Interviewees will be promised confidentiality and assured that their answers will not affect the incentives or support they have received from the program. To address the possibility of interviewer bias, each interviewer will be trained in the purpose of the research and the importance of objectively probing and recording responses. Three different interviewers will perform the interviews and the data from their interviews will be compared to look for uneven application of the methodology. The interviewers chosen for this effort each have a long history of tackling evaluation projects from an objective point of view.

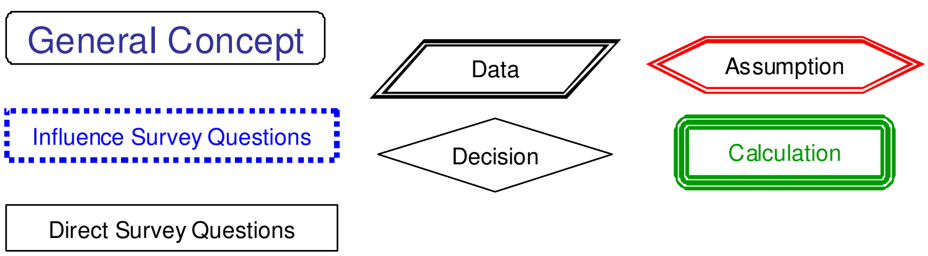
[1] In this study and Analysis Plan, "attribution" is defined as the combined program market influence of free ridership and spillover.

Introduction to the Flow Diagrams

The description below contains references to diagrams of the flow of survey questions and analysis logic shown after page 7. The first diagram (Figure 3) shows a high-level overview of the analysis and survey logic. The revised version of Figure 3 shows revisions to the general approach and the weights given to various parts of the analysis in the calculations used to produce the final, recommended results. Figures 4 through 6 show the direct question sequence with Figure 4 showing the measure-level approach, Figure 5 the project-level approach, and Figure 6 the combined approach. Figure 7 shows the program influence sequence, and Figure 8 shows the combination of the direct and program influence sequences to produce the final results.

Key points in the diagrams are labeled with bold, large numbers and letters. Those labels are referred to in the text in brackets, e.g., [1] [2] [A] [B]. Key assumptions in the logic are noted in the text with bold, italics set off by < > symbols (e.g., ***<Average>***). Key assumptions in the diagrams are noted with the figure labeled "Assumption" shown in the key in Figure 1.

Figure 1. Key to Symbols in the Analysis Diagrams



PARTICIPANT SURVEY – FREE RIDERSHIP

This section will first outline the survey and analysis approach for the participant and trade ally survey, covering the free ridership aspect, and then discuss the sample design.

Participant and Trade Ally Survey and Free Ridership Analysis Approach

We will design and implement surveys with participating end users and trade allies (Channel Partners for Union Gas and Business Partners for Enbridge) to measure free ridership and spillover. The discussion that follows is largely written with the participants in mind. The survey for the trade allies follows the same general logic and they will be asked for their opinion on the impact of the program on specific participants. (The spillover approach will be discussed in the following section.)

Figure 3 presents an overview of the survey and analysis approach. Free ridership will be discussed with each respondent in both **direct questions** aimed at obtaining respondent estimates of the appropriate (full or partial) free ridership rate to apply to them, and in **supporting or influencing questions** used to verify whether direct responses are consistent with participants' views of the program's influence on their equipment investment decisions. The direct questions will be asked at the measure level and at the whole project level. They will then be combined into a single, project-level direct free ridership score. Direct and program influence scores are combined into the final project-level free ridership score. That project-level score is weighted by program-reported savings to calculate the final savings-weighted free ridership percentage. Each of these steps is explained in more detail below, corresponding to the diagrams following Figure 3.

Direct Free Ridership Questions

The direct free ridership questions are posed first for each major category of measures that were reported to the program (*e.g.,* HVAC, building controls, process technologies) (Figure 4), and then for the project as a whole (Figure 5). The measure-level and project-level results are combined in the analysis (Figure 6). For the measure-specific questions, respondents are first asked when, if at all in the foreseeable future, they would have replaced existing equipment or installed new equipment if not for the technical and financial assistance of the program (Figure 4 [1]).

Respondents are then asked to estimate the *likelihood* that they would have incorporated measures "of the same high level of efficiency" if not for the financial and technical assistance of the program (Figure 4 [4]). In cases where respondents indicate that they may have incorporated some, but not all, of the measures, they are asked to estimate the *share of measures* that would have been incorporated anyway at the same level of high-efficiency. This flexibility in how respondents could conceptualize and convey their views on free ridership allows respondents to give their most informed answer, thus improving the accuracy of the free ridership estimates.

Additional direct project-level free ridership questions are then asked to obtain a lower bound, an upper bound, and a best estimate of overall energy savings attributable to the program across all measure categories (Figure 5 [10, 11, 12]). These questions focus on incremental savings from incorporating high-efficiency equipment or controls instead of standard-efficiency equipment and controls. The questions are asked after measure-specific questions so respondents have the decisions they made on individual measures fresh in their minds. Asking respondents about a lower and an upper bound has been successfully used by Summit Blue in several past net-to-gross studies to help respondents narrow down the possible range of free ridership values before making a best estimate.

Program Influence Questions

The **"program influence"** questions (Figure 7) are designed to clarify the role that program interventions (*e.g.*, technical assistance and financing) played in decision-making, and to provide supporting information on free ridership. Questions address the following topics:

- Figure 7 [A] – The importance of features of the program in the decision to incorporate high-efficiency measures in the project. The dimensions include the following:
  - program technical assistance
  - program financial assistance
  - ongoing relationship with the utility (providing impartial advice and facilitating unbiased contacts, e.g., business partners)
  - utility education activities
    - providing best practice information through case studies, as well as specific industry adoption, proven track records, operating experience to help instill confidence etc.
    - training, workshops, and seminars to improve the general or specific knowledge and competencies of customers
    - on-going advertisements re: energy efficiency to heighten customer awareness and concerns

- promotion of energy efficiency at conferences, trade shows and other industry events

- Figure 7 [B] – The influence of the program on the type or efficiency level of the measures, or the amount of high-efficiency measures, incorporated into the project.
  - Figure 7 [B1] – Each respondent indicating some degree of program influence was asked to describe how the program influenced the decision to install high-efficiency equipment in the project.

- Figure 7 [C] – The customer's plans (or lack thereof) to incorporate the energy efficiency measures included in the project prior to participating in the program.
  - Figure 7 [C1] – Each respondent indicating any degree of planning for high efficiency prior to participating in the programs is asked to describe these plans in detail and is asked for the equipment type, timing, quantity, and efficiency, as well as for any prior budgeting for the high efficiency equipment.

Program influence questions are both closed-ended and open-ended and may require probing by experienced interviewers to elicit complete responses that accurately reflect the level of program influence. If the responses are inconsistent across the three types of questions, the interviewer will probe to attempt to resolve the inconsistency (Figure 7 [J]). Some responses to open-ended questions are quantitatively scored by interviewers using a pre-prepared scoring guide (Figure 7 [G][H]), while other questions ask respondents directly to quantify program influence (Figure 7 [F]).

Using the Participant and Trade Ally Survey Responses to Estimate Free Ridership

Direct Free Ridership Estimate

The direct free ridership estimate is based on both the measure-specific questions and the "whole project" questions. For each measure category for which the respondent had installed equipment through the program, the survey collects information on when, if ever, the equipment would likely have been installed (Figure 4 [2]) and the *likelihood* that the same high efficiency equipment would have been used, or the *share of high-efficiency measures* that would have been installed (Figure 4 [4]). The response to the likelihood/share-of-measures questions are used as the initial free ridership value for the measure category (Figure 4 [7]). This value is then discounted if the respondent indicated that the program influenced them to install the equipment more than one year earlier than they otherwise would have (Figure 4 [6]). The specific discount values (*i.e.,* adjustment multipliers), when defined, will likely follow the outline presented in Table 1.

Options for the specific discount values (*i.e.,* adjustment multipliers) have not yet been determined. The history and critique task will look for precedents in the field in this area and specific values will then be developed.

Enbridge Gas Distribution designates some projects as "advancement". For "advancement" projects, the TRC calculation already discounts the TRC benefits to account for the period which the program has moved projects forward in time. However, there is no need to modify the survey and analysis to take this into account and Enbridge and Union customers will be asked the same questions, including the timing questions.

Table 1. Early Replacement Adjustment Multipliers

Early Replacement ***Within ____ years of program participation***	Adjustment Multiplier <Assumption>	Early Replacement ***Within __ months of program participation***	Adjustment Multiplier <Final>
Within ___ Months	100%	Within 12 Months	100%
__ Months to __ years	__%	13 to 24 months	75%
__ to __ years	__%	25 to 36 Months	50%
__ to __ years	__%	37 to 48 Months	25%
More than __ years	0%	More than 48 Months	0%

Each measure category is also assigned an energy savings value (in cubic metres (m^3)) from the gas savings recorded for that respondent in the program database (Figure 6 [16]). The direct free ridership estimate for each measure category (after any adjustment for early replacement) is weighted according to the relative savings from the category to determine a weighted average free ridership estimate across all measures (Figure 6 [17]). As it turned out, measure-specific gas savings values were not available for the sample period under examination so this adjustment could not be made and the measure adjusted free ridership value [9] fed straight through to the weighting calculation in [18].

A second direct free ridership estimate is determined based on answers to the direct free ridership questions regarding the lower bound (Figure 5 [12]), upper bound [11], and best estimate [10] of the overall energy savings attributable to the program across all measure categories. If a "best estimate" is provided, this value is used as a second direct free ridership estimate (Figure 5 [14]) in addition to the measure-based estimate discussed above. If a "best estimate" is not provided, the midpoint between the lower and upper bound is used (Figure 5 [13]).[2] The final direct free ridership estimate (Figure 6 [21]) is the ***<weighted average>*** (Figure 6 [20]) of the measure-based estimate [17] and the "best estimate" [14]. If sufficient information is available for only one of these values, then this value is used as the final direct free ridership estimate. ***<Equal weight>*** will be given to the measure-specific and best estimate values to calculate the final direct free ridership estimate (Figure 6 [18][19]). In the final approach, the best estimate values were given three times the weight of the measure-specific estimates.

Program Influence Free Ridership Estimate

As previously discussed, additional questions are included in the surveys to support an analysis of the consistency of responses. Responses to these "program influence" questions are used to adjust the direct free ridership estimates using objective criteria described below. Adjustments are made to individual respondents' free ridership estimates—not to the aggregate free ridership value across respondents. **Adjustments are only made if the respondent's direct free ridership score is beyond the bounds that could reasonably be expected based on responses to the influence questions.** Specifically, the process for whether and by how much to adjust a respondent's direct free ridership estimate is as follows:

Step 1. **Calculate an** ***<average>*** **program influence score (Figure 7 [L])** (on a 5-point scale) from the scores assigned to the three sets of program influence questions regarding program's importance (Figure 7 [A]), influence of the program [B], and project planning [C]. In the final approach, the importance score [F] was given three times the weight of the Influence [G] and Planning [H] scores (as shown in the revised Figure 3). The ***<maximum score>*** [E] for the program influence dimensions is carried forward in the calculation [F]. A higher score for program influence and importance suggests greater program

[2] Previous research showed that the average "best estimate" was within 3 percentage points of the midpoint.

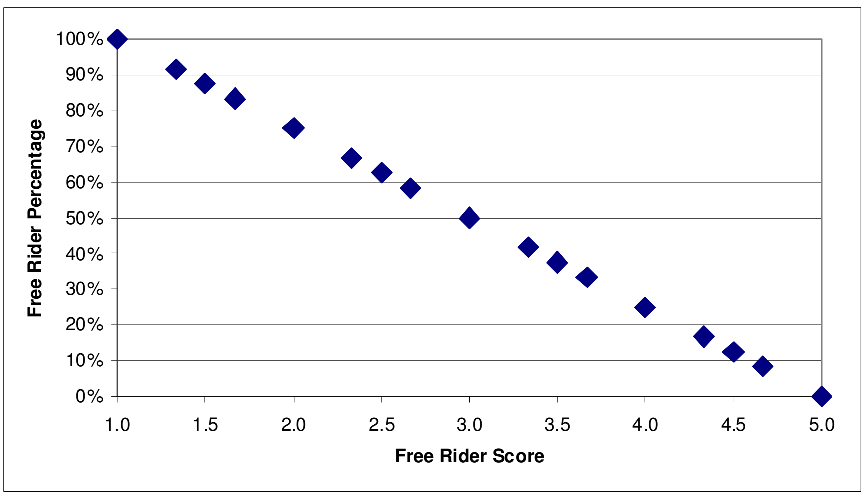
impact, but a higher score for planning indicates lower impact. Therefore, prior to calculating an average score across the three sets of questions, the planning score is inverted so that 1=5, 2=4, etc. In this way, a higher average score across these questions unequivocally represents greater program impact. If the participant's contractor was the most significant influence [D], ***<the results of the trade ally survey will determine the free ridership score>*** [I].

Step 2. Translate the program influence score into a free ridership rate. The influence score has to be converted into a free ridership rate (Figure 7 [M] to [N]) to be used in subsequent calculations. The assumption governing the conversion is that ***<the relationship should be linear>*** with an influence score of 5 converting to 0% free ridership and an influence score of 1 converting to 100% free ridership (see Table 2 and Figure 2).

Table 2. Translate Influence Score to Free Ridership Percentage *<Assumptions>*

Average Influence Score	1.00	1.33	1.50	1.67	2.00	2.33	2.50	2.67	3.00	3.33	3.50	3.67	4.00	4.33	4.50	4.67	5.00
Free ridership	100%	92%	88%	83%	75%	67%	63%	58%	50%	42%	38%	33%	25%	17%	13%	8%	0%

Figure 2. Translate Influence Score to Free Ridership Percentage



<u>Step 3.</u> **Define reasonable bounds for the program influence score** (Figure 7 [P][Q]). These bounds are intended to reflect the range of free ridership values that could reasonably characterize a project based on a respondent's answers to the program influence questions. For example, if a respondent's program influence score is the maximum possible value of 5.0 (implying that the program was very influential), then a reasonable free ridership value would be as low as 0% and ought to be no higher than 50% to be logically consistent. The width of the range that defines the reasonable bounds (50% in this example) will be identified in the data analysis phase. A reasonable bounds width ought to cause a reasonable number of scores to be adjusted by this step, which probably means less than a third of the scores but more than 5%. Exactly what that "reasonable number" should be can only be determined by examining the results.

Adjusting Direct Estimate with the Influence Estimate

The upper and lower bound estimates derived from the program influence questions are used to adjust the direct free ridership estimate. ***<If the direct free ridership value falls outside of the bounds, then it is***

adjusted to a final free ridership estimate equal to the closest lower or upper bound value> (Figure 8 [AA]). Thus, if the direct free ridership value is higher than the program influence upper bound, then the upper bound is used as the final free ridership value. Conversely, if the direct free ridership value is lower than the program influence lower bound, then the lower bound is used as the final free ridership value.[3] This creates the influence-adjusted, customer-specific final free ridership estimate (Figure 8 [BB]). In the final analysis, because the final direct project level free ridership rate [21] was almost always significantly different from the program influence score [N], the influence upper [Q] and lower bounds [P] had to be very wide or the vast majority of scores were adjusted to the influence bounds. As this gave too much weight to [N], it was decided that a more appropriate approach was to average [21] and [N]. In the final results, [N] and [21] were given equal weights (also shown in Figure 3).

Scaling Customer-Specific Results to the Population

The customer-specific free ridership results are scaled up to the population using project-level energy savings to create a savings-weighted free ridership result (Figure 8). The customer-level free ridership score is multiplied by the customer-level gross energy savings [CC] to calculate customer-level net free rider savings [EE]. The gross and net savings are summed up across all customers and then net savings divided by gross savings produces the final savings-weighted, program-wide free ridership result (Figure 8 [GG]). (Segment-level strata weights, if any, are applied during this step [FF] to calculate the final results.)

[3] The actual calculation shown in the diagram is: Maximum(Lower bound, Minimum(Upper bound, direct free ridership result)).

Figure 3. Free Ridership Analysis – Overview – Original

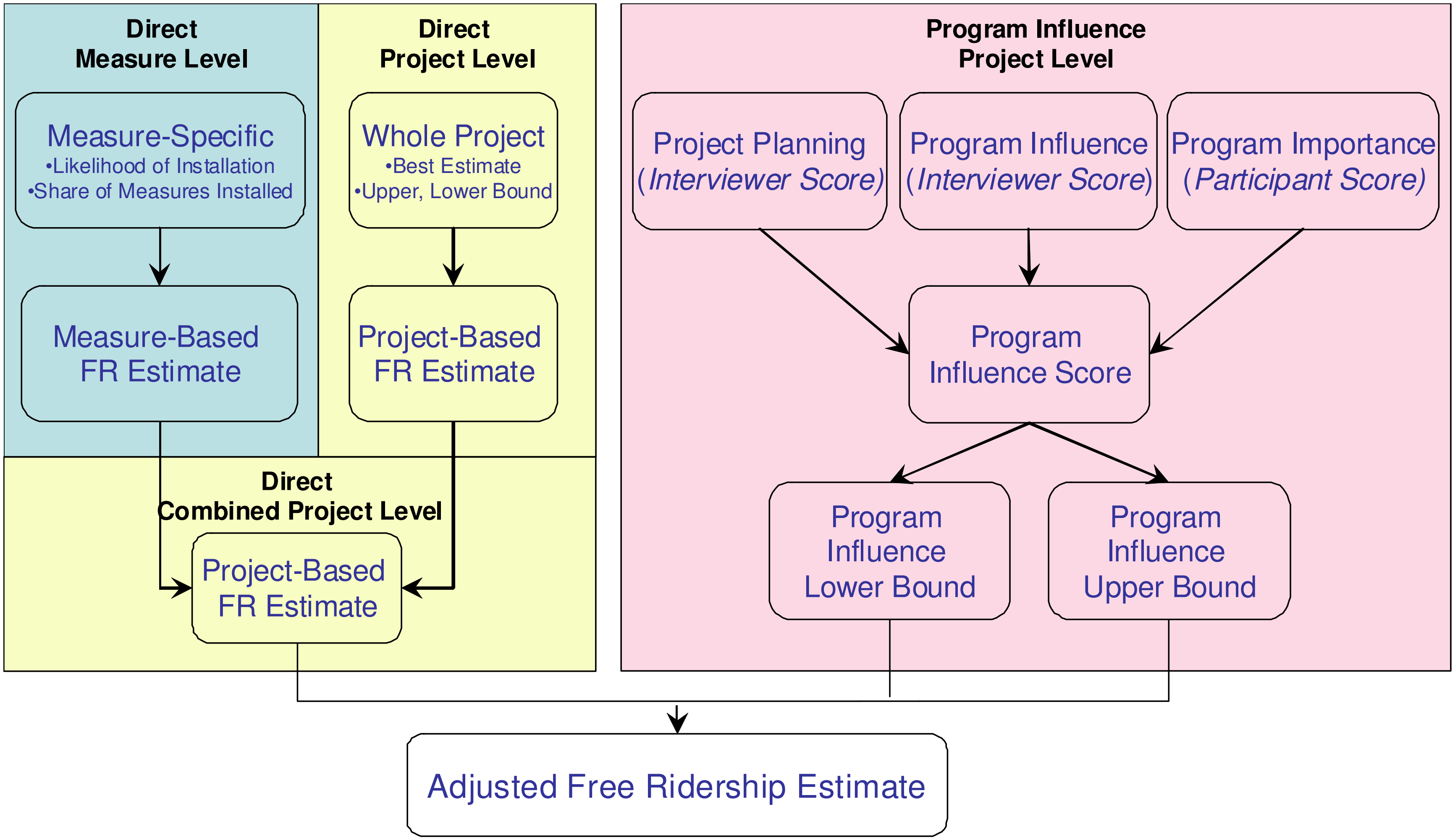


Figure 3. Free Ridership Analysis – Overview – Final Approach

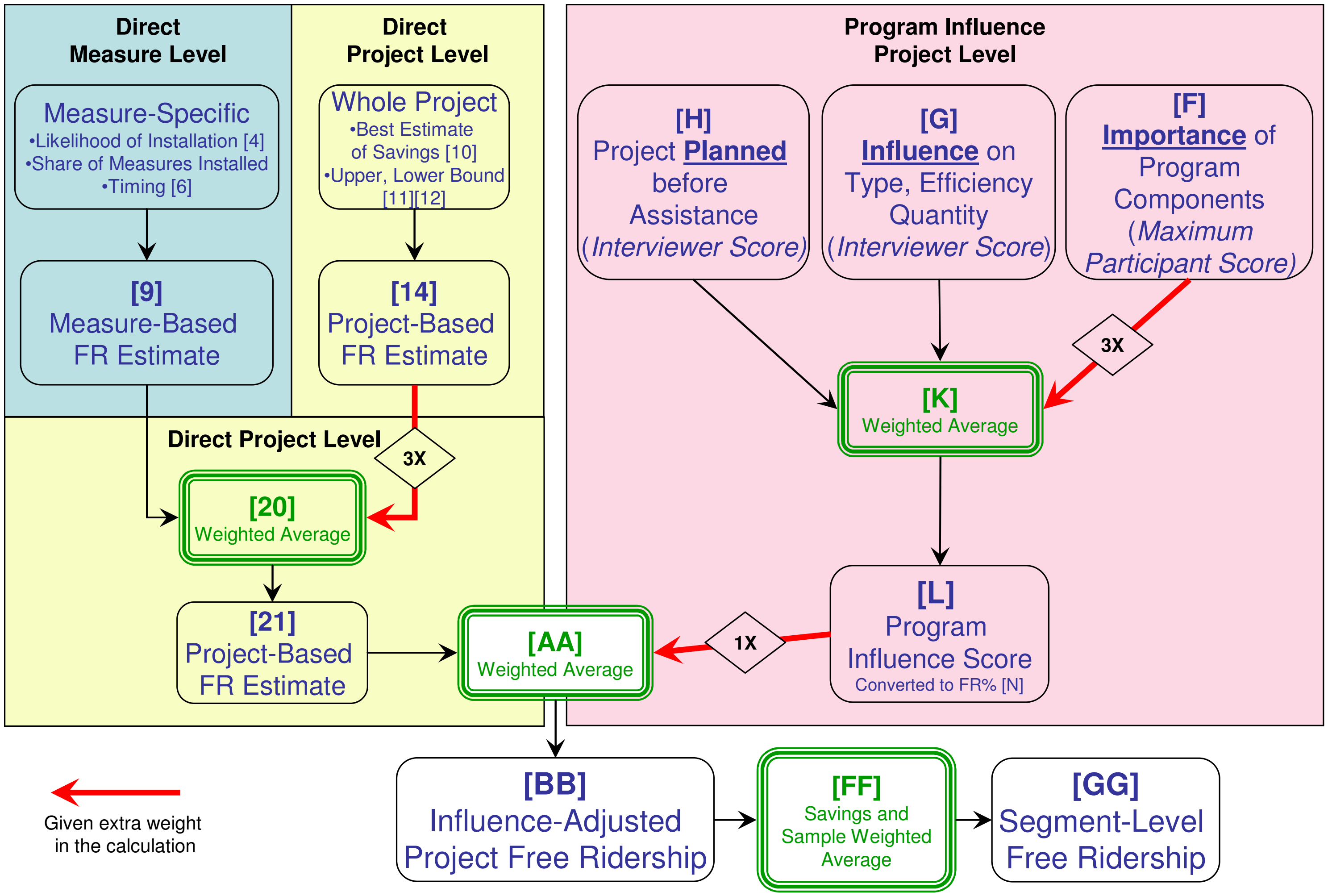


Figure 4. Free Ridership Analysis – Direct, Measure Level

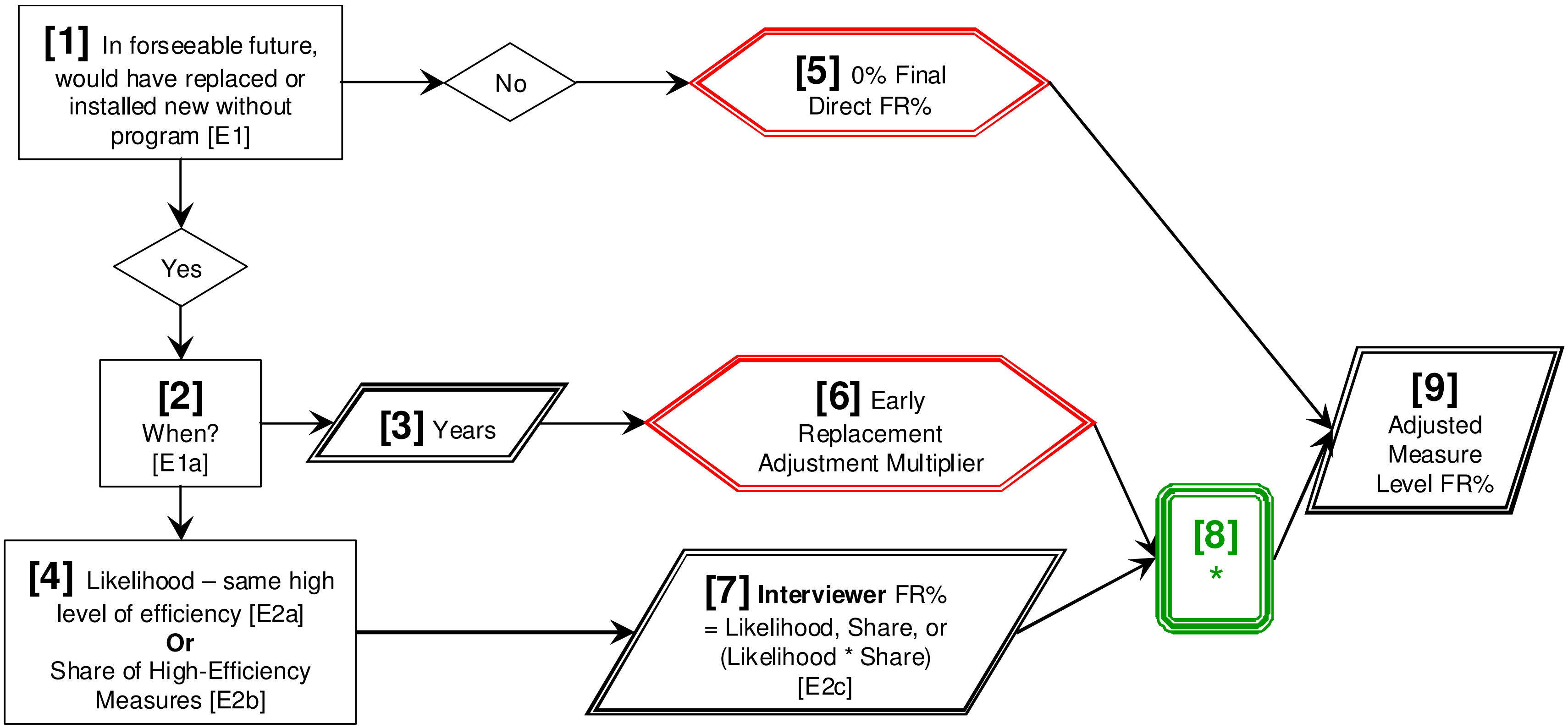


Figure 5. Free Ridership Analysis – Direct, Project Level

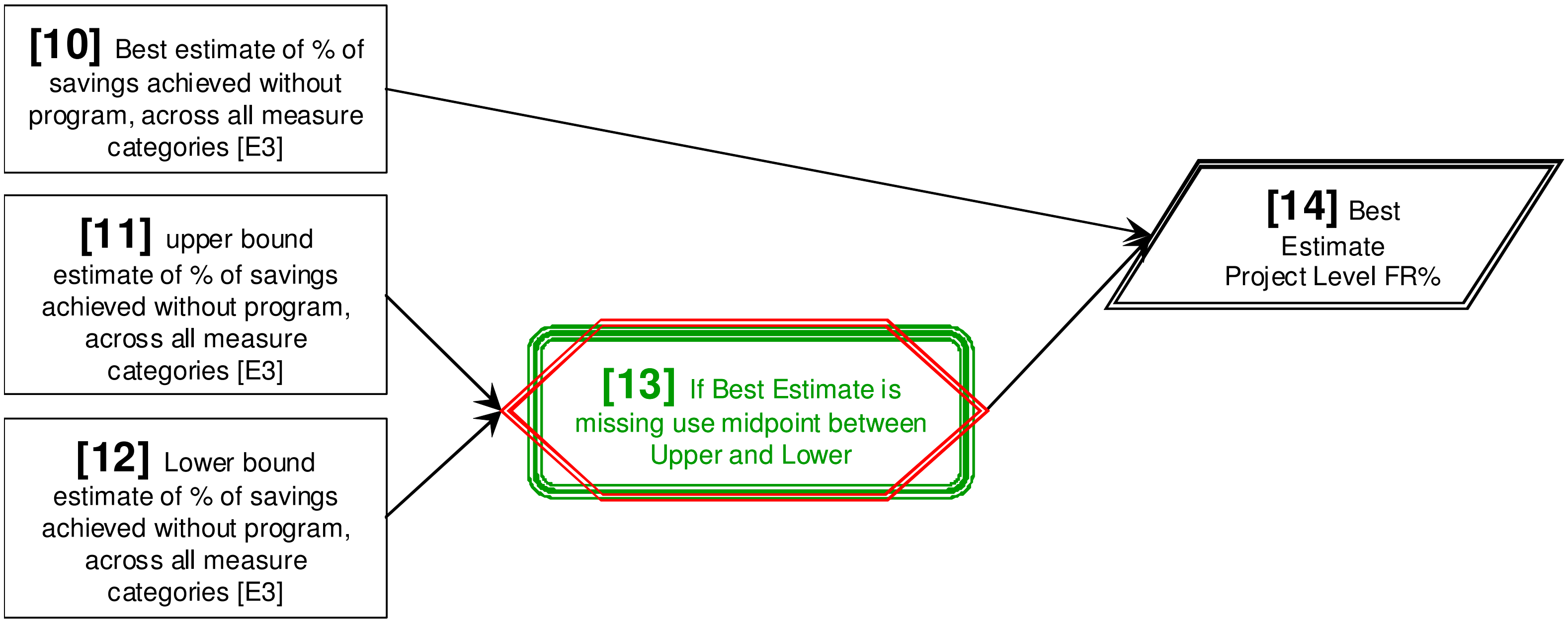


Figure 6. Free Ridership Analysis – Direct, Combined Project Level - Original

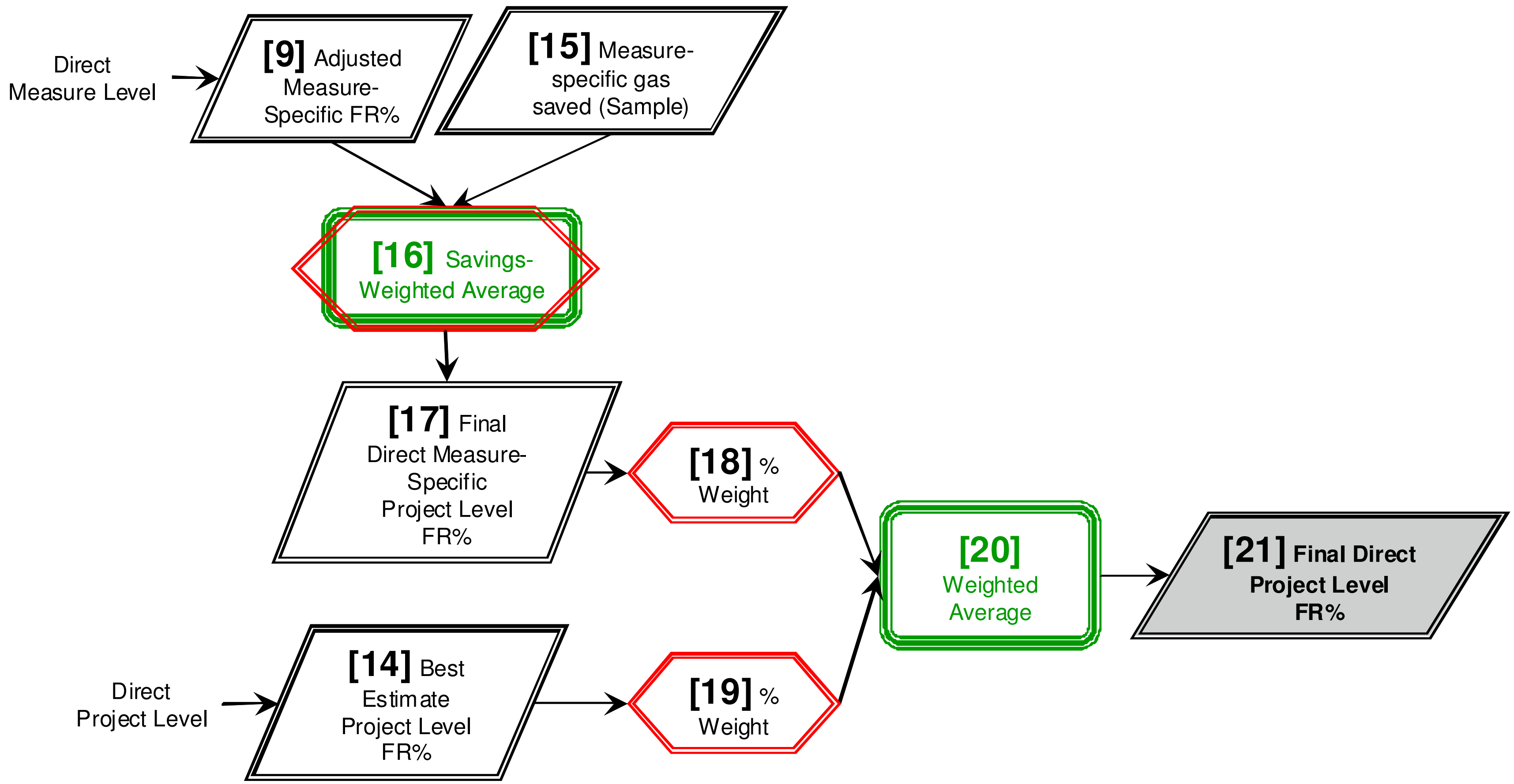
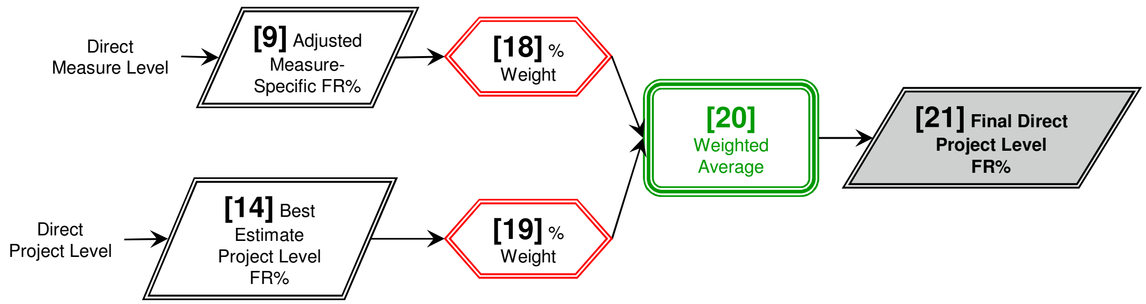
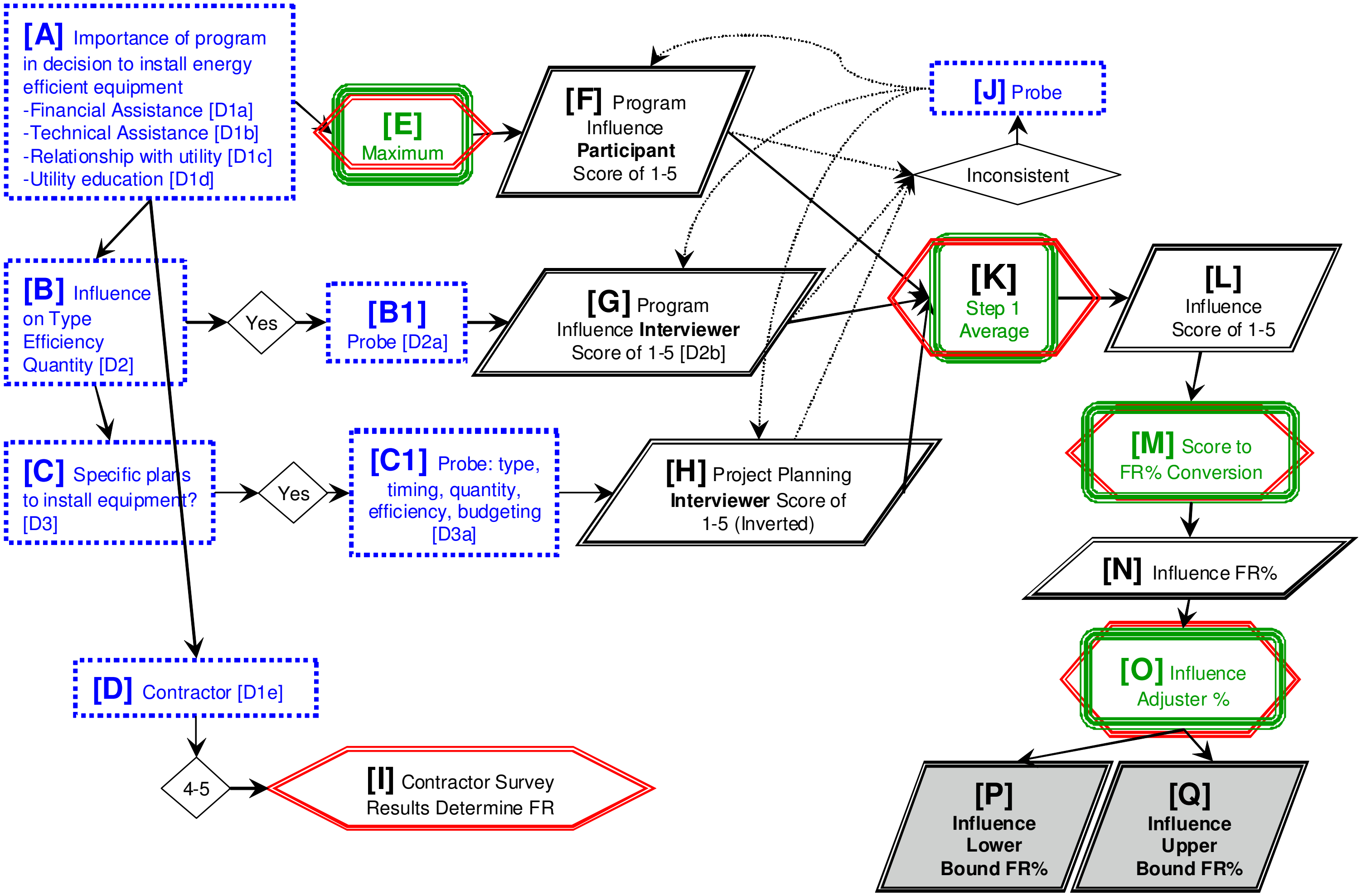


Figure 6. Free Ridership Analysis – Direct, Combined Project Level – Revised



Changes: Measure-specific gas savings values were not available so [9] fed straight through to [18].

Figure 7. Free Ridership Analysis – Program Influence, Project Level



Changes: Boxes [O], [P], and [Q] were deleted. See discussion on the following pages.

Figure 8. Free Ridership Analysis – Combined Direct and Program Influence Results - Original

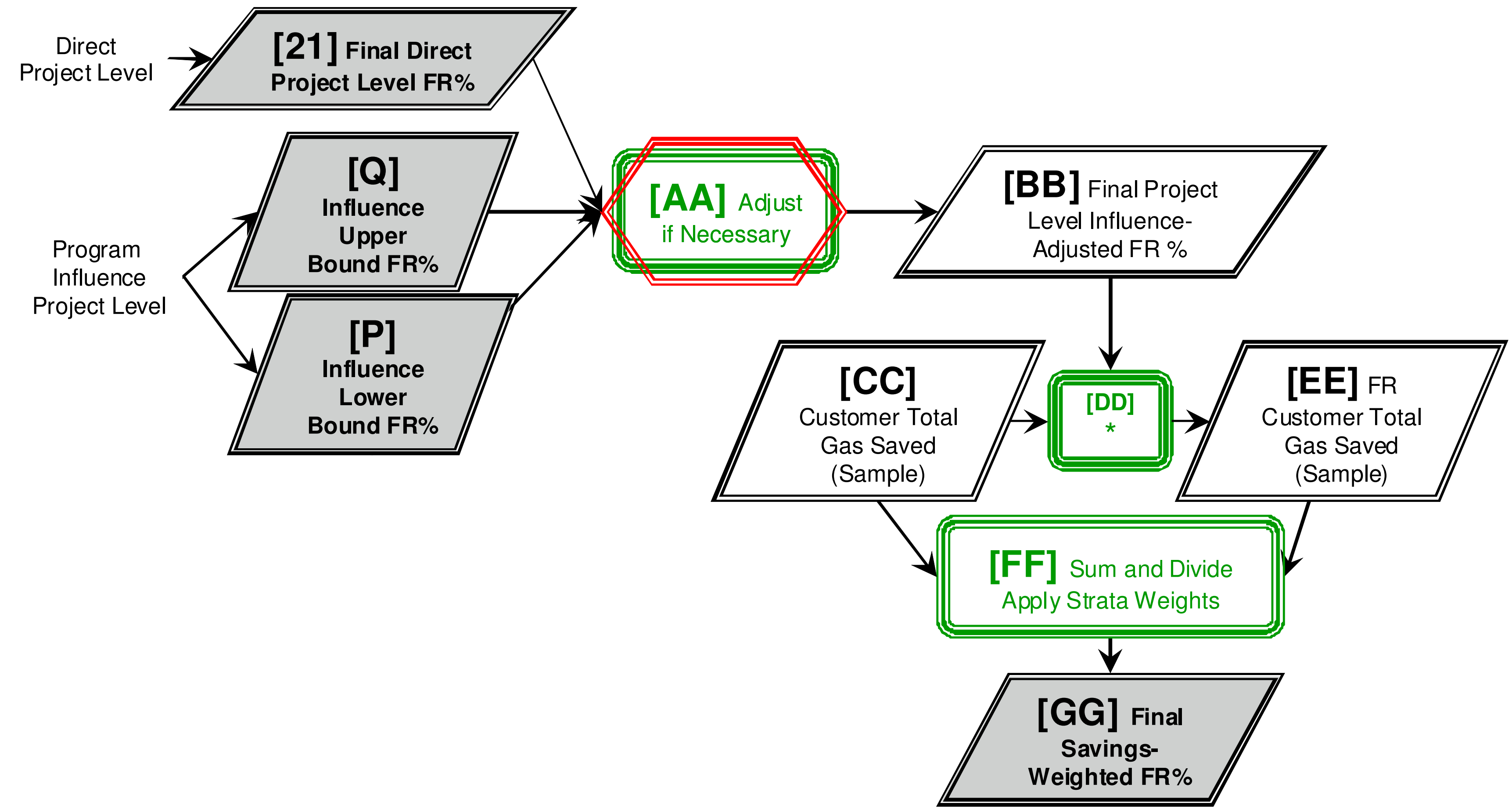
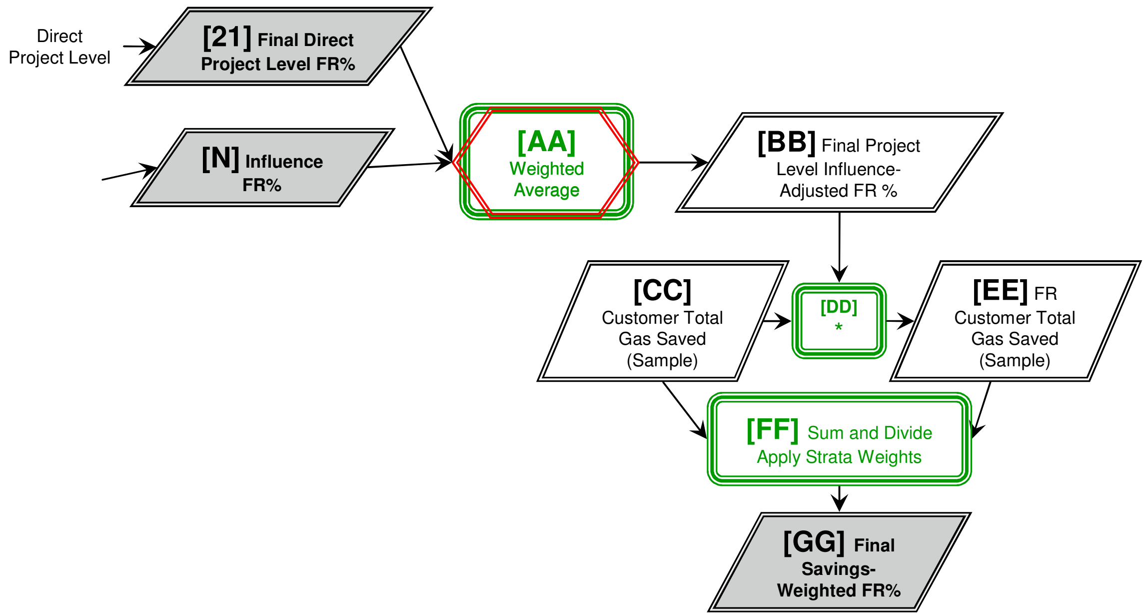


Figure 8. Free Ridership Analysis – Combined Direct and Program Influence Results - Revised



Changes: Because [21] was almost always significantly different from [N], the influence upper [Q] and lower bounds [P] had to be very wide to incorporate [21], which gave too much weight to [N]. It was decided that a more appropriate approach was to average [21] and [N].

Participant and Trade Ally Survey Sample Design

The budget for this study is designed to produce results at 90% confidence level at +/- 20% precision at the segment level with five segments per utility and 90% confidence level at +/- 10% precision at the utility level. The budget is based on the assumption that we will complete 17 surveys per segment per utility, covering a total of 170 projects. Since the total number of surveys that would be completed at 90/20 precision with 5 segments is more than that needed to produce 90/10 precision at the utility level, the budget should be sufficient to produce both 90/20 precision at the segment level and 90/10 precision at the utility level. Some extra surveys may be needed in certain segments to improve the fit of the sample to the utility-level population to produce 90/10 results.

We will on occasion complete more than one survey per project if we need to talk to both the end user and the contractor. The survey costs assume we will complete an average of 1.3 surveys per project.

Segments

Enbridge and Union agreed to the following definitions of the segments that should be included in the sample:

- Industrial
- Agriculture
- New Construction
- Commercial
- Multifamily (Multifamily is also referred to as "multi-residential".)

Enbridge provides design assistance and a holistic approach to all new construction projects in commercial and multifamily buildings. As a result, it includes new construction projects in those sectors in a "New Construction" category. For all other sectors, energy savings claimed typically refer only to mechanical upgrades related to the new facility and so are grouped with retrofit projects in their sector.[4]

Sample Size within Segments

It may be that the optimal sample distribution is not simply to do a random distribution from among the participants in each segment. There are two issues to consider. First the available population, second the size of individual projects relative to the population.

Sample compared to population size. It appears that there are enough participants in each segment to complete 17 surveys per segment with the exception of the Agriculture and New Construction segments for Union (Table 3). There are 18 individual agriculture customers and only five new construction customers. We will attempt to interview all Union participants in those segments (and will stop if we get 17 in agriculture). We can distribute the 12 completes that cannot be obtained in the Union new construction segment to other segments.

[4] Source: Judith Ramsay email 10/23/2007.

Table 3. Sample Size as Percent of Population

	Individual customers/ decision makers		17 Completes as % of Population	
	Union	Enbridge	Union	Enbridge
Industrial	67	76	25%	22%
Agriculture	18	32	**94%**	53%
Multi-family	29	187	59%	9%
New Construction	5	52	**340%**	33%
Building Retrofit	94	105	18%	16%

Source: Derived from spreadsheet sent by Christine Zivanov October 10, 2007.

If the population is not large, a small population correction factor is typically used to reduce the needed sample size,[5] e.g., if the population in a targeted group is 100, the sample size to achieve 90/10 precision is reduced to 40. For 90/20 precision, the small population correction factor comes into effect for populations of 170 or smaller, which covers all but one segment, Enbridge multifamily projects. The required sample size to reach 90/20 by segment, after applying the small population correction factor is shown in Table 4, which shows a total of 124 surveys. Given a budget based on 170 completes we could potentially distribute 46 surveys (170-124=46) to address other issues (we will return to this below).

Table 4. Sample Sizes Adjusted for Small Population

Segment	Utility	Population Size	Adjusted Sample Size
New Building	Union	5	4
Agriculture	Union	18	9
Multi-family	Union	29	11
Agriculture	Enbridge	32	12
New Building	Enbridge	52	13
Large Industrial	Union	67	14
Large Industrial	Enbridge	76	14
Building Retrofit	Union	94	15
Building Retrofit	Enbridge	105	15
Multi-family	Enbridge	187	17
Total			*124*

Source: Population size from spreadsheet sent by Christine Zivanov October 10, 2007.

Size of individual projects relative to the population. One common approach to sampling for DSM program evaluations is to stratify the sample to ensure that many of the participants with the highest energy savings are included. This reduces the variance among respondents within each stratum and results in a greater overall precision in estimating the share of energy savings that could be considered free

[5] When the sample size exceeds 1/10th of the population size, then the sample size is calculated as (Sample Size)/((Sample Size)/(Population Size)+1).

riders. This is the approach that will be taken for this analysis, basing the segmentation only on gas savings, without regard to water or electricity savings or the TRC.

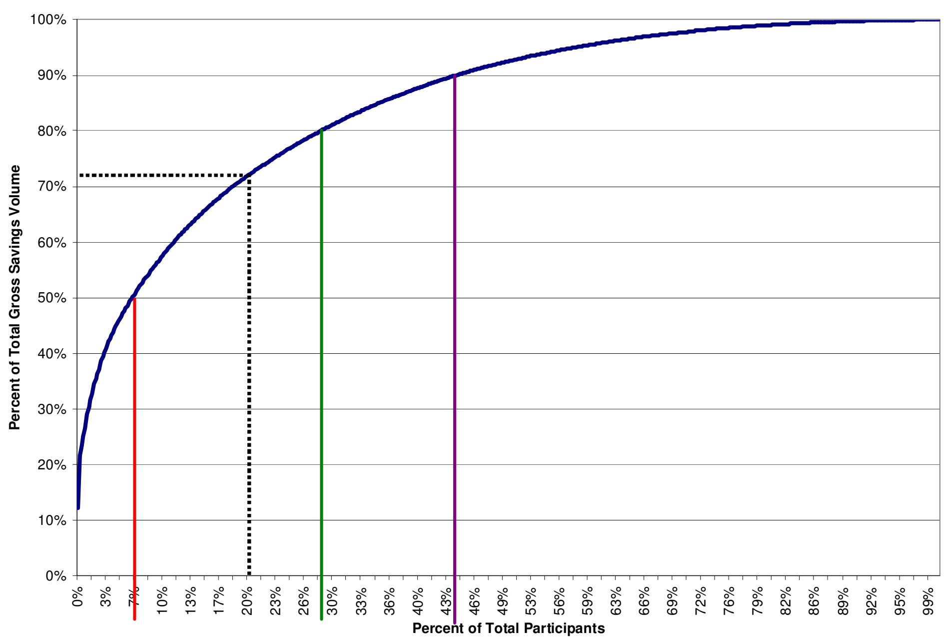
One half of the savings reported by Enbridge from the last quarter of 2006 and the first three quarters of 2007 was achieved by 6.4% of the participants, the largest 20% of projects represent 72% of the program savings, and the top 44% of participants represent 90% of the savings (Table 5 and Figure 9). Given this distribution, it seems appropriate to segment the sample by savings.

Table 5. Participants' Share of Savings – Enbridge

Percent of Participants	Percent of Gross m^3
6.4%	50%
20.0%	72%
22.8%	75%
28.2%	80%
44.0%	90%

Interpretation: 6.4 Percent of the participants account for 50% of the gross savings volume.
Source: Derived from spreadsheet sent by Judith Ramsay October 09, 2007.

Figure 9. Participants' Share of Savings – Enbridge



Source: Derived from spreadsheet sent by Judith Ramsay October 09, 2007.

One approach to segmenting the sample by savings would be to sample with certainty the customers responsible for the most savings within each segment. Table 6 shows the percent of segment savings for Enbridge projects of the five projects with the largest savings within each segment. In three of the segments, the top five projects represent over 40% of the savings. Since this represents a fairly large percent of the savings, this supports the decision to sample the top five projects in each segment for each utility with certainty and the remaining sample should be picked at random from the remainder.

Table 6. Percent of Savings from Top 5 Projects

	Total Gross m^3			Percent of Segment Total		
Segment	Top 5 Projects	Remainder	Total	Top 5 Projects	Remainder	Total
Industrial	24,066,050	26,646,410	50,712,460	47%	53%	100%
Agriculture	1,900,331	2,588,866	4,489,197	42%	58%	100%
Multifamily	1,917,380	21,570,252	23,487,632	8%	92%	100%
New Construction	1,023,733	3,061,981	4,085,714	25%	75%	100%
Commercial	5,771,444	8,124,495	13,895,939	42%	58%	100%
Total	34,678,938	61,992,004	96,670,942	36%	64%	100%

Source: Derived from spreadsheet sent by Judith Ramsay October 09, 2007.

Participant and Trade Ally Survey – Spillover

This section will outline the survey and analysis approach for the participant survey, covering the spillover aspect. The spillover questions will be incorporated in the participants and trade ally surveys described above and the spillover analysis will be implemented in concert with the free ridership analysis.

Survey Overview

Spillover represents energy savings that are due to the program but not counted in program records. Spillover can be broken out in three ways:

- **Participant inside spillover** represents energy savings from other measures taken by participants at participating sites not included in the program but directly attributable to the influence of the program.
- **Participant outside spillover** represents energy savings from measures taken by participants at non-participating sites not included in the program but directly attributable to the influence of the program.
- **Non-participant spillover** represents energy savings from measures that were taken by non-participating customers but are directly attributable to the influence of the program. Non-participant spillover is sometimes called the "Free-Driver effect."[6]

Summit Blue will estimate **participant inside and outside spillover** through questions in the participant and trade ally surveys and through the Audit-Only Survey. Summit Blue will estimate nonparticipant spillover through the nonparticipant survey.

[6] See for example California Energy Efficiency Evaluation Protocols: Technical, Methodological and Reporting Requirements for Evaluation Professionals. TecMarket Works. Prepared for the California Public Utilities Commission. April 2006. Page 226.

Participant Inside Spillover

Respondents are asked whether their experience with the programs caused them to install additional energy efficient equipment at the site that did not go through the program. This establishes whether inside spillover exists. For those respondents reporting that additional measures were installed, they are asked to identify in which year(s) the measures were installed, and to describe how the program influenced their decisions to install additional energy efficient equipment at their facility. An additional question is asked to determine the ratio of the savings from these additional measures compared to the savings from the measures installed under the program. That is, they are asked the percent of savings as a multiple of the savings achieved under the program (**savings multiplier**). Finally, respondents are asked to estimate the share of the savings from these additional measures that can "reasonably be attributed to the influence" of the program (**net-to-gross percentage**). The process of breaking the questions into incremental steps helps the respondent think through each part, and it allows the respondent to provide his or her expert judgment as a participant in the target market.

Participant Outside Spillover

Similar to inside spillover, respondents are asked first whether the influence of the program caused them to install any additional energy efficiency equipment, outside of the program, at other sites beyond what they would have done without their experience with the program. If they respond yes, they are asked several follow-up questions designed to provide an estimate of the level of savings from these actions that could be attributed to the program. These questions address the following:

- The number of non-program-funded facilities at which these extra installations occurred.
- How the program has influenced their decisions to install the high efficiency equipment at other facilities.
- The savings—per site—from the additional measures relative to the savings from the participating project being discussed in the interview.
- The share of the savings that can reasonably be attributed to the program's influence.

Using the Participant and Trade Ally Survey Responses to Estimate Spillover

Participant Inside Spillover

Inside spillover is zero for those without additional measures (or those who failed to answer all of the questions), and it is the product of the savings multiplier and the net-to-gross percentage for those with inside spillover. Similar to the free ridership analysis, individual spillover estimates are weighted both by relative energy savings for each respondent, as well as by sample stratification to determine an inside spillover value for the group as a whole.

Participant Outside Spillover

The savings as a percent of the in-project measure is multiplied by the share of savings attributed to the program to calculate the outside spillover value.[7] Similar to the free ridership analysis, individual spillover estimates are weighted both by relative energy savings for each respondent, as well as by sample stratification to determine an outside spillover value for the group as a whole.

AUDIT-ONLY SURVEY

This section will outline the survey, analysis approach, and sample design for the Audit-Only Participant survey.

Survey Overview

Participants who received an audit, implemented a recommended measure, but did not receive incentives through the program for that measure can be considered spillover. These kinds of participants would not be included in either the participant or nonparticipant surveys discussed above and below. We will implement a survey specifically with this population and focusing solely on spillover measures to provide an important additional estimate of program spillover.

The interviewer will begin by asking the respondent if they recall receiving the audit. If they do not, the interviewer will attempt to speak to someone else who might recall the audit.

The interviewer will ask the participant about each measure recommended in the audit. (Although we will limit this to the measures with the largest savings if there are more than 5 measures recommended.) The interviewer will examine whether the respondent remembers the recommendation and whether it has been installed and when. If the participant installed a measure, the interviewer will ask the following:

1. On a scale of 1 to 5 where 1 is “no influence” and 5 is “a great deal of influence”, how much influence did the audit have in your decision to implement this measure?

2. What share of the savings from this measure can reasonably be attributed to the influence of the program?

During the survey, the interviewer will fill in a matrix approximately like the following.

[7] A cap of five outside spillover projects per respondent is used to prevent outliers from skewing the results.

Table 7. Audit Survey Question Matrix

Recommended Measure Description	Recall recom-mended?	Measure installed?	% of Measures	% of Savings	When was it installed?	Influence of Program	Share of Savings
1. [Data]	Y/N	Y/N/DK	%	%	Month, Year	1 2 3 4 5	%
2. [Data]	Y/N	Y/N/DK	%	%	Month, Year	1 2 3 4 5	%
3. [Date]	Y/N	Y/N/DK	%	%	Month, Year	1 2 3 4 5	%
4. [Date]	Y/N	Y/N/DK	%	%	Month, Year	1 2 3 4 5	%
5. [Date]	Y/N	Y/N/DK	%	%	Month, Year	1 2 3 4 5	%

Using the Audit-Only Survey Responses to Estimate Spillover

The analysis of audit-related spillover savings will be fairly straightforward. The program tracking data will have measure-specific savings estimates from the audit. In general form, the participant-level spillover calculation will be:

Spillover Multiplier = (Influence of Program {converted to percentage} + Share of Savings)/2

Participant-level spillover = (Savings Estimate *{from sample}*) * (Spillover Multiplier) * (Percent of Items that were recommended that were installed)

This amounts to ***<averaging>*** the converted influence score with the answers to the share of savings question. Converting the influence of the program score to a percentage will be done using the scale shown in Table 8 below.

Table 8. Translate Influence Score to Free Ridership Percentage *<Assumptions>*

Average Influence Score	1.00	2.00	3.00	4.00	5.00
Influence Percentage	0%	25%	50%	75%	100%

Calculating program level savings will require weighting respondents and scaling up to the population.

Audit-Only Survey Sample Design

The sample will be taken from customers who had audits in 2005. This provides the optimal balance between providing enough time for the customers to have acted on the recommendations in the audit and ensuring that the audit is not so far in the past that respondents have trouble recalling details of the recommendations. Because the sample will be based on a single year, the result of the analysis can be expressed in spillover per year. Given that there have not been any significant changes in the program strategy, spillover calculated from a prior year ought to reasonably represent the probable spillover from the current year.

The costs of implementing the Audit-Only survey are based on these assumptions:

1. The survey would be done over the phone
2. Enbridge and Union provide the sample

3. Program tracking records provide estimates of savings for measures that get counted as spillover.
4. Completing 67 surveys for each utility to provide 90/10 precision at the utility level

Enbridge and Union will provide customer-level data from their program tracking systems that describes customers who have had audits in 2005 but have not implemented measures that appear in their program tracking systems. However, Union Gas was unable to find any companies who had an audit in 2005 and had not implemented one of the recommended measures through the program. As a result, no audit-only surveys were attempted with Union Gas customers. Based on the relatively limited sample available, Summit Blue will survey all available sample.

NONPARTICIPANT SPILLOVER SURVEY

This section will outline the survey, analysis approach, and sample design for the nonparticipant spillover survey.

Survey Overview

Summit Blue will estimate nonparticipant spillover using a survey targeted at nonparticipants only. The approach will be similar to participant spillover as follows:

- Whether spillover may exist. Using yes/no questions ask whether the respondent installed energy efficiency equipment.
- The amount of savings per spillover project. Asking respondents to estimate the energy savings associated with the implemented measures.
- The share of those savings that could be attributed to the influence of the program.

The approach to determine program influence will parallel that taken to determine free ridership – determining how much influence the program had on the decision to implement the measure.

The largest challenge in a nonparticipant spillover survey is identifying an appropriate sample and reaching a person within each company who can and will address the relevant issues. Using Enbridge and Union customer data we will identify a sample that would be reasonably close to the participant population then implement a phone survey in the following sequence:

1. Find someone knowledgeable about the replaced or modified equipment.
2. Aware of the program? If no, terminate.
3. Did the company participate in the program in the past 3 years? If yes, terminate.
4. Has the company modified or installed equipment that might fall under the program's incentives? (List target equipment.) If no, terminate. If yes, when?
5. Determine what effect, if any, the program had on their decision. (Same questions as in the Audit-Only survey.)

5A. On a scale of 1 to 5 where 1 is “no influence” and 5 is “a great deal of influence”, how much influence did the program have in your decision to install or modify your equipment?

5B. What share of the savings from this change can reasonably be attributed to the influence of the program?

5C. On a scale of 1 to 5 where 1 is “no influence” and 5 is “a great deal of influence”, how much influence did **your suppliers or contractors** have in your decision to install or modify your equipment?

5D. If ***<5A > 2 or 5B > 30%>*** then: “We want to have one of our engineers follow up with you to ask some technical questions. Will that be OK?

6. If 5D=Yes. Quantify the magnitude of savings. Summit Blue engineer calls to ask enough questions about the equipment to make an engineering estimate of the energy savings it produces.

Because a large number of companies may be screened out in the first four steps, it is most cost-effective to implement this kind of survey over the phone. The costs are driven more by locating a company and person able to get to step 5 than by the asking the questions that come in step 5. However, costs can also be significant in step 6, if detailed questions and engineering calculations are needed to calculate savings for each measure that was influenced by the program.

Using the Nonparticipant Survey Responses to Estimate Spillover

As described above, if the company indicates that it implemented measures that were influenced by the program, then a Summit Blue engineer will call to ask enough questions to estimate the measure’s energy savings. With that done, the calculation of spillover parallels that for the Audit-Only survey, as follows.

Nonparticipant spillover = (Engineering-based Savings Estimate) * (Spillover Multiplier *{calculated from survey}*)

The Multiplier is calculated in the same way as the Audit-Only multiplier.

Nonparticipant Sample Design

The project budget assumes that we will implement a minimum of 670 screening surveys across both utilities but cannot guarantee a specific number of respondents getting through to step 6. In theory, completing 67 screening surveys with companies who have made appropriate equipment purchases or changes that could have been influenced by the program would provide 90/10 precision for an estimate of whether spillover happened (again across both utilities). If the incidence of spillover is small, it would not provide a very robust estimate of the therm value of that spillover. We based the budget on an assumption that 10 screening calls are needed to complete 1 call through step 5, thus requiring 670 screening calls. If the 1/10 ratio is low, then we will spend relatively more money on engineering calls and reviews. If it is high, then we will complete relatively more screening surveys. We will complete as many screening calls and engineering reviews as the budget will allow.

The sample will be done at random after eliminating customers in the small commercial rate class. This will target the sample at the segment most likely to have been influenced by the program and allow a simple extrapolation to the population. Summit Blue staff will advise utility staff on the best approaches to drawing a random sample from their data.

OUTLINE OF FINAL REPORT

The following is a preliminary outline of the final report presented to start a dialog about how the report should be structured.

1. Executive Summary
    a) Top-Level Results
    b) Program-Wide Free Ridership
    c) Segment-Level Free Ridership
    d) Role of Prior Program Experience
    e) Spillover
    f) Net-to-Gross Ratio
2. Introduction
    a) Definitions
    b) Report Contents
3. History and Critique of Free Ridership Methodologies
4. Summary of Analysis Methodology
    a) Estimating Free Ridership
    b) Estimating Spillover
5. Sampling and Data Collection
6. Findings
    a) Free Ridership Results
        i) Direct Free Ridership Estimates
        ii) Program Influence Questions
        iii) Adjusted Free Ridership Estimates
        iv) Role of Prior Program Experience
    b) Spillover Results
    c) Net-to-Gross Ratio
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Appendix A: Methodology Detail—Estimating Free Ridership and Spillover
Appendix B: Survey Instruments

Appendix B. Surveys

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1. CUSTOM PROJECTS PARTICIPANT SURVEY

1.1 CONVENTIONS

- **Bold text is spoken.**
- *Italics text is instructions for the interviewer.*
- *{VIP}* indicates questions that are particularly important and represent specific boxes in the analysis flow chart.

1.2 SAMPLE DATA

(NOTE: Projects are the survey unit, so each project to be interviewed separately. Thus, use separate form for each Project, even if the same interviewee is associated with multiple projects)

Name________________________________ Interviewer Initials ______________________

Firm Name ___________________________ Survey Date __________________________

Address ______________________________ Sample ID # __________________________

Phone Number ________________________ Project ID #___________________________

Project Completion Date__________________

Equipment installed: ____
Channel Partner involved: ____
Program activity: ____

2.2. Project Briefing Information – Union Gas sales/marketing staff input:

2.2.1. Month/year of initial Union Gas involvement with the project or its precursors
2.2.1a Month_______
2.2.1b Year_______

2.2.2. General context of Union Gas relationship with customer:
a. Historical education effort with customer on efficiency opportunities & Union Gas programs (high, medium, low level of effort):

____

____

b. Facility energy audits performed (steam traps, boilers, etc)

____

____

c. Distribution and merchant services support provided (general credibility & relationship building)

____

____

d. Other (describe) ____

____

____

2.2.3. Services provided to customer in project-related contacts:

a. Gas bill histories (usage, cost) ______________________________

b. Approximate number of project-related contacts with customer ______________

c. General information on program ______________________________

____

____

d. Project-specific technical information or analysis: technical/engineering, financial, vendor/technology alternatives, etc.

____

____

e. Project/technology recommendations______________________________

____

____

f. Other (describe)______________________________________

____

____

ga. Low/medium/high intensity of support to customer generally

____

____

gb. Low/medium/high intensity of support to project specifically

____

____

h. Low/medium/high effect of on project's efficiency level

____

____

1.3 IDENTIFY CORRECT RESPONDENT

[Note: These questions may be covered on the phone while setting up an appointment.]

A1. Are you the most appropriate person to talk to about the decision to install that equipment and about the selection of the specific energy efficiency equipment?

1. YES Continue to Question A3

2. NO ➔ "May I ask who would be the best person to talk to?"
   [obtain names and phone numbers] ______________________________

   [Ask to speak with this person. Start again at the beginning.]
3. DO NOT REMEMBER PROJECT ➔ Ask Question A2

A2. Do you recall participating in <u>any</u> programs through Union Gas/Enbridge Gas Distribution in the past few years regarding this location?

1. YES

   A2A. Did the program involve assistance from Union Gas/Enbridge Gas Distribution in identifying energy efficient equipment or process changes and financing toward the initial capital costs?

   1. YES *Continue to Question A3*
   2. NO➔ "Can you provide me…" *[See text for "NO" above]*
2. NO ➔ "Can you provide me with a contact name and phone number for a person who might be familiar with the work that was done?" *[Get contact information and call this person; Start again at the beginning.]*

[If they express hesitation, use an appropriate combination of the following.]
Confidentiality. We are an independent research firm and will not report your individual responses in any way that would reveal your identity, as your response only will be presented in aggregate along with responses from other survey participants.
Security. Your responses will not affect your ability to participate in the program in the future.
Sales concern. I am not selling anything. I simply want to understand what factors were important to your company when deciding to install energy efficient equipment with assistance from this program.
Contact. If you would like to talk with someone about this effort from
–Union Gas, you can call your account manager.
–Enbridge Gas Distribution, the Enbridge Industrial contact is Peter Goldman at 416-495-6348, the Enbridge Commercial contact is Stefan Surdu at 416-495-5917, or you may contact your Energy Solutions Consultant.

1.4 Confirmation Of Equipment Installed

B1. Prior to calling, review program records for the project. In Table 1 below under "Program Records," check off each measure category for which energy efficient equipment was installed.

B2. Just to make sure that we're talking about the same project, I show that you installed *[list major equipment or equipment categories]***. To your recollection, was all this equipment installed?**
[Check off each category for which respondent recalls installing equipment. If information is not available from program records, ask the respondent to recall what measures were undertaken.]

B3. Did Union Gas/Enbridge Gas Distribution provide financial assistance for installing this equipment?
[Ask of only those checked in B2. Check off each category for which respondent recalls that Union Gas/Enbridge Gas Distribution provided financial assistance.]

B3b. Approximately how much was the incentive as a percent of the total project cost?
[Ask of only those checked in B3.]

B4. Did you receive any technical assistance from Union Gas/Enbridge Gas Distribution staff with any of this equipment?
[Ask of only those checked in B2. Check off each category for which respondent recalls that Union Gas/Enbridge Gas Distribution provided technical assistance for the measure.]

Table 1. Equipment in program records and recalled by respondent

[Check if Yes]

Measure Category	**B1.** Program Records	**B2.** Respondent Recollection	**B3.** Union Gas/Enbridge Gas Financial Assistance	**B3b.** Incentive as % of Project Cost	**B4.** Union Gas/Enbridge Gas Distribution Technical Assistance	**Notes/Caveats**
a. Machine/Process	❒	❒	❒	%	❒	
b. HVAC (incl. furnaces, all boilers, A/Cs, chillers, EMS, etc.)	❒	❒	❒	%	❒	
c. Lighting	❒	❒	❒	%	❒	
d Controls (boiler controls, variable frequency drive controls	❒	❒	❒	%	❒	
e. Building envelope (incl. insulation, windows)	❒	❒	❒	%	❒	
f. Domestic hot water	❒	❒	❒	%	❒	
g. Refrigeration	❒	❒	❒	%	❒	
h. Agriculture	❒	❒	❒	%	❒	
i. Converted equipment from electricity to gas (fuel substitution)	❒	❒	❒	%	❒	
j. Other: _______________	❒	❒	❒	%	❒	

1.5 Set the Context

C1. **Prior to the project being discussed, did your organization have a general policy regarding the energy efficiency specification of projects involving new construction and equipment retrofits, replacements or building remodeling generally?**
1. Yes   2. No   -8. Do not know   -9. Refused

C2. **[If yes] Did your policy target a specific standard of efficiency levels?**
1. Yes   2. No   -8. Do not know   -9. Refused

C2a. **[If yes] Can you specify what those efficiency levels are?**
-8. Do not know   -9. Refused

C3. **Since the project, has your energy efficiency policy changed**
1. Yes   2. No   -8. Do not know   -9. Refused

C4. **[If Yes] How?**

____

C5. **Does your organization have specific criteria for selecting energy efficient equipment based on payback periods, life cycle costs, or internal rate of return?**
1. Yes   2. No   -8. Do not know   -9. Refused

C6. **[If C5=1 (yes)] Which?**
1. Simple payback period
2. Life-cycle cost analysis
3. Internal rate of return
4. Other [Record verbatim] C6B. ______________________________

-8. Don't know
-9. Refused

C7. **[If C6=1 (simple payback period)] How many years or less must the project payback be?**
-8. Do not know   -9. Refused

C8. **[If C6=2 (internal rate of return)] What is the minimum percent rate of return required for energy-efficiency related projects? [Record 10% as "10" not "0.10"]**
-8. Do not know   -9. Refused

C9. **What was simple payback period for this project <u>prior</u> to any financial assistance from Enbridge/Union?**
-8. Do not know   -9. Refused

C10. **What was simple payback period for this project <u>after</u> financial assistance from Enbridge/Union?** ***{VIP}***
-8. Do not know   -9. Refused

C11. **[Note other relevant comments about how payback period figured in the decision process.]**

____

C12. **Do you recall receiving energy efficiency information and training in any of the following areas that was sponsored or delivered by Union Gas/Enbridge Gas Distribution?**
1. Yes   2. No   -8. Do not know   -9. Refused

C12a. General energy efficiency information
C12b. Energy audits
C12c. Technology seminars (including those co-sponsored with trades)
C12d. Program information
C12e. Specific project identification

1.6 Free Ridership Battery

1.1.1 Program Influences

[Ask Questions in this section for all the equipment installed in aggregate.]

I'm going to ask a few more questions about the influence of Enbridge Gas Distribution/Union Gas on your decisions to install high efficiency equipment.

D1. On a scale of 1 to 5, where 1 = "not at all important" and 5 = "very important"… Please indicate how important each of the following aspects of your experience with [Enbridge/Union] were in your decision to install energy efficient equipment at your facility? {*VIP*}

D1a. Financial assistance	**1 2 3 4 5**	**DK**	**Refused**
D1b. Project technical assistance	**1 2 3 4 5**	**DK**	**Refused**
D1c. Your ongoing relationship with the utility *(Providing impartial advice and facilitating unbiased contacts, e.g., business partners)*	**1 2 3 4 5**	**DK**	**Refused**
D1d. Utility education activities *(e.g., case studies, best practice information, training, seminars, conferences, trade shows)*	**1 2 3 4 5**	**DK**	**Refused**
D1e. Advice and assistance from a contractor	**1 2 3 4 5**	**DK**	**Refused**

D1e1. [If D1e>3] Who was that contractor?

D1e2. [If D1e>3] May I have the name and phone number of your main contact there?

D2. Did the assistance you received from [Enbridge/Union] in any way influence the <u>type</u> or <u>efficiency level</u> of the equipment or the <u>amount</u> of high efficiency equipment you installed or process changes implemented?

1 Yes ➔ *Continue to Question D2a*
2 No (all the same equipment would have been installed at the same high efficiencies) ➔ *Skip to Question D3*
-8 Don't know ➔ *Skip to Question D3*
-9 Refused➔ *Skip to Question D3*

D2a. In what ways did the assistance you received from [Enbridge/Union] change your plans or in any other way influence your decision to install energy efficient equipment. Be sure to identify specific equipment.

____

D2b. [Based on response to D2a, fill in a "1 to 5"score indicating the extent to which the program influenced the decision to install energy efficient equipment. DO NOT ASK RESPONDENT DIRECTLY. "1" indicates that the program had no influence; "5" indicates that the program was the primary reason that energy efficient equipment was installed.]
{VIP}

(No program influence) 1 2 3 4 5 (Program was primary influence)

D3. Did your company have specific plans to install any of the *[list all relevant measure categories]* **equipment prior to your first contact with [Enbridge/Union] staff regarding this project?**

1 Yes ➔ *Continue to Question D3a*
2 No ➔ *Skip to Next Section*
-8 Don't know ➔ *Skip to Next Section*
-9 Refused➔ *Skip to Next Section*

D3a. Please describe any plans that you had to install the equipment prior to receiving assistance you received from [Enbridge/Union].
[Interviewer note: the goal here is to understand the plans that were in place before being influenced by program. Probe for equipment type, timing, quantity, and efficiency, as well as prior budgeting. Attempt to elicit responses that will provide answers for the "likelihood" or "share of savings" questions (E2a and E2b).]

D3b. *[Based on responses to D3a, fill in a "1 to 5"score indicating the extent to which respondent was already planning to install the energy efficient equipment. DO NOT ASK RESPONDENT DIRECTLY. "1" indicates that respondent had no plans at all; "5" indicates that respondent had documented plans and had budgeted for all of the efficient equipment.] {VIP}*

(No plans) 1 2 3 4 5 (Documented plans/budget)

1.1.2 Direct Decision Making Questions

[Ask the following questions for each measure category checked under Question B2 in Table 1 above. If previous open-ended questions have provided the necessary information, interviewer may skip the question/measure category. By the end of the interview, interviewer should be able to populate Table 2 below with EITHER a "likelihood" OR a "share of equipment" OR both, for each relevant measure category.]

Now I'd like to try to quantify the impact of the [Enbridge/Union] assistance. I'd like you to think about the energy savings you achieved with the equipment you replaced. Some of the savings may have come from just replacing old equipment with any new equipment *[as appropriate: or replacing your existing process with a new process]***. And some of the savings may have come from the fact that the equipment you installed was more efficient than standard new equipment. I'd like you to think about the utility's influence on this last type of savings.**

First, let me ask about the ____________*[MEASURE CATEGORY]***.**

E1. If you had not received assistance you received from [Enbridge/Union] , would you have replaced your existing ___________*[MEASURE CATEGORY]* or installed new equipment in the foreseeable future? *{VIP}*

[Note that these do not have to be "energy efficient" equipment.]

1 Yes ➔ *Continue to Question E1a*

2 No ➔ *ENTER 0% for the category in the Free Ridership Value column in Table 2 below (E2c) and move on to the next measure category.*

-8 Don't know ➔ Probe, perhaps using *Question E1a*

-9 Refused➔ *Skip to next measure category*

E1a. When would you likely have made these investments if you had not received assistance from [Enbridge/Union]? *[If clarification needed:]* (Within how many months or years of when you participated in the program?) *{VIP}*

E1aM. _____ Months

E1aY. _____ Years

-8 Don't know ➔ Probe, perhaps using *Question E1a*

-9 Refused➔ *Skip to next measure category*

- *Fill in only for categories for which equipment has been installed.*
- *Enter "0" years if equipment would have been installed in the same timeframe regardless of program participation.*
- *If respondent says, "…in a year or two," enter "1.5" years.*
- *Based on earlier responses, ask either the "likelihood" question below or the "share of equipment" question, whichever is more appropriate.*
- *For example, if respondent installed a single chiller, then the "likelihood" question may be most appropriate; if they installed multiple measures of various types/sizes, then the "share of equipment" may be more appropriate. Some respondents may be able to offer valid responses to both questions.*
- *If you are uncertain, ask both questions. If respondent can provide a response to each, then record both responses.*

E2a. *[Likelihood]* What is the likelihood that you would have installed the same or similar ___________ *[MEASURE CATEGORY]* of the same level of energy efficiency if it had not been for the assistance you received from [Enbridge/Union]? *{VIP}*

1 Definitely would NOT have installed equipment of the same level of energy efficiency

2 Definitely WOULD have installed equipment of the same level of energy efficiency anyway

3 MAY HAVE installed equipment of the same level of energy efficiency, even without the program

E2a2.About what percent likelihood? _____%

-8 Don't know

-9 Refused

E2b. *[Share of equipment]* (Or, if you might have installed some but not all of the ___________ *[MEASURE CATEGORY]* even without the assistance you received from [Enbridge/Union] , then…) what share of the ___________ *[MEASURE CATEGORY]* would you have installed anyway at the same level of energy efficiency? *{VIP}*

[If necessary, or if the flow of the interview dictates, you may derive this value by asking 1) the share of equipment that would have been installed (at any efficiency) and 2) the share of installed equipment that would have been high efficiency. The value in the table below for Question E2b would be the product of these two values.]

Table 2. Equipment

[Fill in EITHER the "likelihood" value OR the "share of equipment" value OR both values for each relevant measure category. If respondents ask for the timeframe, use the timeframe specified above in Question E1a.

Then enter the appropriate free ridership value (E2c), which will be one of the following, depending on the nature of the project and the responses:

1) *The single value for "likelihood" or "share of equipment" if only one is entered;*
2) *If value provided for both, enter either Likelihood or Share value, whichever best represents the appropriate value*
3) *The product of the two, if appropriate (e.g., if there is a 50% likelihood that 75% of the equipment would have been installed, and respondent definitely wouldn't have done the final 25%)*

Measure Category	**E1. Would have installed in foreseeable future** *[Check no or yes]* 2=No *FR=0%*	1=Yes (cont.)	**E1a. Within ____ Years of participation** *[Enter # of years]*	**E2a. Likelihood that energy efficient equipment…**		**E2b. Share of energy efficient equipment that…** …would have been installed without the program	**E2c.** *[Entered by interviewer]* **Free Ridership Value**
a.Machine/Process	❐	❐	Months Yrs	%	and/or	%	%
b. HVAC	❐	❐	Months Yrs	%	and/or	%	%
c. Controls							
d. Lighting	❐	❐	Months Yrs	%	and/or	%	%
e. Building envelope	❐	❐	Months Yrs	%	and/or	%	%
f. Domestic hot water	❐	❐	Months Yrs	%	and/or	%	%
g. Refrigeration	❐	❐	Months Yrs	%	and/or	%	%
h. Agriculture	❐	❐	Months Yrs	%	and/or	%	%
i. Fuel substitution	❐	❐	Months Yrs	%	and/or	%	%
j. Other:	❐	❐	Months Yrs	%	and/or	%	%

E2d. *[Additional notes/caveats (e.g., explaining how/why free ridership value was chosen, if necessary)]*

____

E3. **Overall, across all equipment, that is the entire project, how much of these extra energy savings would have been achieved anyway, even if you had not received assistance from [Enbridge/Union]. Please provide a lower and upper bound, and then your best estimate. {VIP}**

***[If needed for clarification:]* For example, 50% means that half of the extra savings from the energy efficient equipment would have been achieved anyway. Remember, I'm asking only about the extra savings from installing energy efficient equipment instead of standard equipment.**

E3A.Lower bound ➔ _____ %   E3B. Upper bound ➔ _____ %   E3C. Best estimate ➔ _____ %

1.7 Participant Inside Spillover

Now I want to ask about whether the assistance you received from [Enbridge/Union] has influenced you to install any other energy efficient equipment that did not receive financial support from [Enbridge/Union].
[For these questions, I'm talking about all your company's participation in the program, not just since October 2006.]

G1. **Did the assistance you got from [Enbridge/Union] in any way influence you to install additional energy efficient equipment** *at this site* **that did not get reported to the program** (i.e., *equipment that would not have been installed without the influence of the program)***?**

1 Yes➔ Continue to Question G2
2 No ➔ Skip to next section
-8 Don't know ➔ Skip to next section
-9 Refused➔ Skip to next section

G2. [*If G1 = "yes"]* **What year did you install this equipment?**

G3. *[If G1 = "yes"]* **Please briefly describe how the assistance you received from [Enbridge/Union] has influenced your decisions to install additional energy efficient equipment at your facility.**
[Identify the types of equipment affected.]

G4. **Would you estimate the energy savings from this extra equipment to be less than, similar to, or more than the savings from the energy efficient equipment from the original project?**

1 Less than the original project ➔
G4a. About what percentage of the savings from the original project?
____% *[Enter a number less than 100%]*
2 About the same savings
3 More than the original project ➔
G4b. About what percentage of the savings from the original project?
____% *[Enter a number greater than 100%]*
-8 Don't know
-9 Refused

G5. **What share of the savings from this extra equipment can reasonably be attributed to the influence of the assistance you received from [Enbridge/Union]?**
______% *[100% or less]*
-8 Don't know
-9 Refused
[Interviewer may be able to complete this based on response to G3, or at least use G3 to check for consistency. Probe if inconsistent to ensure that respondent is correctly interpreting the question.]

1.8 Participant Outside Spillover

H1. **Did the assistance you received from [Enbridge/Union] in any way influence you to install any additional energy efficient equipment** ***at other jobs or facilities in Union Gas/Enbridge Gas Distribution's Service Territory*** **beyond what you would have done otherwise?**
[Don't include projects that participated in another Union/Enbridge program.]

1 Yes ➔

H1a. How many other facilities were influenced (that did not participate in Union Gas/Enbridge Gas Distribution programs)? _________ (-8 Don't know, -9 Refused)

2 No ➔ Skip to next section
-8 Don't know ➔ Skip to next section
-9 Refused ➔ Skip to next section

H2. *[If H1 = "yes"]* **Please briefly describe how the assistance you received has influenced your decisions to install this equipment. (Probe to identify the types of equipment affected.)**

H3. On average, would you estimate the energy savings from these other non-program projects to be less than, similar to, or more than the savings from the energy efficient equipment from the program-supported that we've been discussing?
[E.g., if the same equipment was implemented in a facility twice as big, then savings would be 200%. Be sure to emphasize that this is savings "on average" not in aggregate across the many buildings that might be affected.]

1. Less than the Custom Projects project
   H3A. About what percentage of the savings from the Custom Projects project? ____% ***[Enter a number less than 100%]***
2. About the same savings
3. More than the Custom Projects project
   H3B. About what percentage of the savings from the Custom Projects project? ____% ***[Enter a number greater than 100%]***

-8 Don't know
-9 Refused

H4. What share of the savings from energy efficient equipment at these facilities can reasonably be attributed to the influence of the assistance you received from [Enbridge/Union]?
[Interviewer may be able to complete this based on response to H2, or at least use H2 to check for consistency. Probe if inconsistent to ensure that respondent is correctly interpreting the question.]
______% [100% or less]
-8 Don't know
-9 Refused

1.9 FIRMOGRAPHICS

Z1. Does your company own or lease this building? :

1. Owner
2. Lease

-8. Don't know
-9. Refused

Z2. Approximately how large is the facility that received the efficiency improvements we have been talking about? (square meters)

1. Up to 5,000
2. 5,001 to 10,000
3. 10,001 to 15,000
4. 15,001 to 25,000
5. 25,001 to 50,000
6. 50,001 to 100,000
7. 100,001 to 200,000
8. 200,001 to 500,000
9. Over 500,000

-8 Do not know
-9 Refused

Z3. Is your company independent, or part of a larger organization?

1. Independent
2. Part of a larger company
3. Other Z3a. (specify) ______________________________

-8. Don't know
-9. Refused

Z4. How old is your facility?

-8 Don't know
-9 Refused

Z5. Does your building contain any manufacturing processes?

1. Yes   2. No   -8. Do not know   -9. Refused

Z6a. [If yes] What type of energy do they use?

1. Natural Gas
2. Electricity
3. Other

-8 Don't know
-9 Refused

Z6b. [If yes to Z5] Have you reviewed their energy usage?

1. Yes   2. No   -8. Do not know   -9. Refused

Z7. How many locations does your organization have in Ontario?

1. One	5. More than 20
2. 2 to 5	6. Currently Unoccupied
3. 6 to 10	-8. Don't know
4. 11 to 20	-9. Refused

Z8. Approximately how many full time employees or full time equivalents does your organization have at your locations in Ontario?

1. Fewer than 5	5. 50 to 99
2. 5 to 9	6. 100 to 249
3. 10 to 19	7. 250 or More
4. 20 to 49	-8 Do not know
	-9 Refused

Those are all the questions I had.

Z9. Do you have any final comments you would like to make?

____

____

Thank you very much for your time!

Z10. Record all additional or supporting comments here.

____

____

2. CUSTOM PROJECTS TRADE ALLY SURVEY

Business Partner (EGD) or Channel Partner (UG)

2.1 CONVENTIONS

- Bold text is spoken.
- Italics text is instructions for the interviewer.
- *{VIP}* indicates questions that are particularly important and represent specific boxes in the analysis flow chart.

2.2 SAMPLE DATA

(NOTE: Projects are the survey unit, so each project to be interviewed separately. Thus, use separate form for each Project, even if the same interviewee is associated with multiple projects)

Contact Name ____________________________ Interviewer Initials ________________________

Firm Name ______________________________ Survey Date _____________________________

Address _________________________________ Sample ID # _____________________________

Phone Number ___________________________ Project ID #______________________________

Project Completion Date____________________

Equipment installed: ____

Customer involved: ____

2.3 INFORMATION FROM UTILITY STAFF AND RECORDS

3.1. Project Briefing Information – Union/EGD sales/marketing staff input:

3.1.1. Month/year of initial EGD/Union Gas involvement with the project or its precursors

3.1.1a Month_______

3.1.1b Year_______

3.1.2. General context of EGD/Union Gas relationship with Channel/Business Partner:

a. Historical education effort with customer on efficiency opportunities & Enbridge/Union Gas programs (high, medium, low level of effort):

____

____

b. Facility energy audits performed (steam traps, boilers, etc)

____

____

c. Distribution and merchant services support provided (general credibility & relationship building)

____

____

d. Other (describe)____

____

3.1.3. Services provided to Channel/Business Partner in project-related contacts:

a. Gas bill histories (usage, cost) ____

b. Approximate number of project-related contacts with customer ________________

c. General information on program ______________________________________

____

d. Project-specific technical information or analysis: technical/engineering, financial , vendor/technology alternatives, etc.
____

____

e. Project/technology recommendations ___________________________________

____

f. Other (describe) ____

____

3.1.4. Channel/Business Partner involvement with customer project:

a. General context of Channel/Business Partner involvement with project or its precursors

____

____

b. Extent of Channel/Business Partner use of Union Gas program & other needed information, Union Gas technical services or other support

____

____

c. Type of service & information support given customer generally and project specifically by Channel/Business Partner (engineering/financial analysis of alternatives, project engineering, project construction, ongoing Maintenance/Repair/Operations support, other/describe)

____

d. **Low/medium/high intensity of support by Channel/Business Partner to customer generally and project specifically**

____

e. **Low/medium/high effect of on project's efficiency level**

____

2.4 Preliminary Concerns

[If they express hesitation, use an appropriate combination of the following.]
Confidentiality. We are an independent research firm and will not report your individual responses in any way that would reveal your identity. Your response will only be presented in aggregate along with responses from other survey participants.
Security. Your responses will not affect your ability to participate in the program in the future. All responses are your opinion and there are no wrong answers.
Sales concern. I am not selling anything. I simply want to understand what factors were important to your company when deciding to install energy efficient equipment with assistance from this program.
Contact. For Union, the Channel Partners would have been notified by phone call or email from their Account Manager. If they have any questions, it is their Union Gas Account Manager they can call.
The Enbridge Industrial contact is Peter Goldman at 416-495-6348 or Stefan Surdu at 416-495-5917 or your Enbridge Energy Solutions Consultant/Union representative.

2.5 Introduction

A1. **What is your primary line of business?**
1. Consulting engineer
2. Manufacturer
3. Distributor or equipment sales
4. Installation contractor
5. Property manager
6. Other. A1b. Please specify. ____

2.6 Confirmation Of Equipment Installed

B1. Prior to the interview, review program records for the project or projects. In Table 1 below under "Program Records," check off each measure category for which energy efficient equipment was installed.

B2. **Just to make sure that we're talking about the same project, I show that your company designed and specified/supplied/installed** *[list major equipment or equipment categories]* at *[end use customer}***. To your recollection, was all this work completed?**
[Check off each category for which respondent recalls installing equipment. If information is not available from program records, ask the respondent to recall what measures were undertaken.]

B3. **Do you recall if Union Gas/Enbridge provided financial assistance for installing this equipment?**
1. Yes 2. No -8. Do not know -9. Refused

[Ask of only those checked in B2. Check off each category for which respondent recalls that Union Gas/Enbridge provided financial assistance.]

B3a. *[If yes, for Union Only]* **Who received the incentive, your company or the customer?**
1. Your Company
2. The Customer
-8. Do not know
-9. Refused

B3b. **Approximately how much was the incentive as a percent of the total project cost?**
*[Ask of only those checked in B3.]*______________________________*%*
-8. Do not know
-9. Refused

[Ask of only those checked in B2. Check off each category for which respondent recalls that Union Gas/Enbridge provided technical assistance for the measure.]

B4. **Did your company receive any technical or marketing assistance from Union Gas/Enbridge staff?**
1. Yes 2. No -8. Do not know -9. Refused

B4a. ***[If Yes]*** **Please describe.**

____

____

B5. **Was the customer aware that Union/Enbridge was involved with the project?**
1. Yes 2. No -8. Do not know -9. Refused

Table 1. Equipment in program records and recalled by respondent

[Check if Yes]

Measure Category	B1. Program Records	B2. Respondent Recollection	B3. Union /Enbridge Financial Assistance	B3a. Trade ally received incentive	B3b. Incentive as % of Project Cost	B4. Union /Enbridge Technical or Marketing Assistance	Notes/Caveats
a. Machine/Process	❒	❒	❒	❒	%	❒	
b. HVAC (incl. furnaces, all boilers, A/Cs, chillers, EMS, etc.)	❒	❒	❒	❒	%	❒	
c. Lighting	❒	❒	❒	❒	%	❒	
d Controls (boiler controls, variable frequency drive controls	❒	❒	❒	❒	%	❒	
e. Building envelope (incl. insulation, windows)	❒	❒	❒	❒	%	❒	
f. Domestic hot water	❒	❒	❒	❒	%	❒	
g. Refrigeration	❒	❒	❒	❒	%	❒	
h. Agriculture	❒	❒	❒	❒	%	❒	
i. Converted equipment from electricity to gas (fuel substitution)	❒	❒	❒	❒	%	❒	
j. Other: _______________	❒	❒	❒	❒	%	❒	

2.7 Set the Context

C1. Do you recall receiving energy efficiency information and/or training in any of the following areas that was sponsored or delivered by Union Gas/Enbridge?

1. Yes 2. No -8. Do not know -9. Refused

		Yes	No	Do not know	Refused
C1a.	General energy efficiency information	❐	❐	❐	❐
C1b.	Energy audits	❐	❐	❐	❐
C1c.	Technology seminars	❐	❐	❐	❐
C1d.	Program information	❐	❐	❐	❐
C1e.	Specific project identification	❐	❐	❐	❐
C1f.	Training or workshops	❐	❐	❐	❐
C1g.	Software e.g., Cumulative Sum of Differences (CUSUM)	❐	❐	❐	❐
C1h.	Lunch & Learns	❐	❐	❐	❐

2.8 Free Ridership Battery

2.8.1 Program Influences

[Ask Questions in this section for all the equipment installed in aggregate.]

I'm going to ask a few more questions about the influence of Enbridge/Union Gas on your customer's decisions to install high efficiency equipment.

D1. On a scale of 1 to 5, where 1 = "not at all important" and 5 = "very important"… Please indicate how important each of the following aspects of your experience with [Enbridge/Union] were in the decision to install energy efficient equipment for your customer at this facility? *{VIP}*

D1a. Financial assistance 1 2 3 4 5 -8 DK -9 Refused
D1b. Project technical assistance 1 2 3 4 5 -8 DK -9 Refused
D1c. Your ongoing relationship with the utility 1 2 3 4 5 -8 DK -9 Refused
(Providing impartial advice and facilitating unbiased contacts, e.g., business partners)
D1d. Utility education activities 1 2 3 4 5 -8 DK -9 Refused
(e.g., case studies, best practice information, training, seminars, conferences, trade shows)
D1e. Marketing assistance 1 2 3 4 5 -8 DK -9 Refused
(e.g., lead generation, printed material)

D2. Did the assistance you received from [Enbridge/Union] in any way influence the type or efficiency level of the equipment, the amount of high efficiency equipment that was installed or efficient features that were added or process changes that were implemented?

1 Yes ➔ *Continue to Question D2a*
2 No (all the same equipment would have been installed at the same high efficiencies) ➔ *Skip to Question D3*
-8 Don't know ➔ *Skip to Question D3*
-9 Refused➔ *Skip to Question D3*

D2a. In what ways did the [Enbridge/Union] assistance change the plans or in any other way influence the decision to install energy efficient equipment? Be sure to identify specific equipment.
[Probe for whether the contractor added efficient features to make a more efficient system.]

____

____

____

D2b. ***[Based on response to D2a, fill in a "1 to 5"score indicating the extent to which the program influenced the decision to install energy efficient equipment. DO NOT ASK RESPONDENT DIRECTLY. "1" indicates that the program had no influence; "5" indicates that the program was the primary reason that energy efficient equipment was installed.]***
{VIP}

(No program influence) 1 2 3 4 5 (Program was primary influence)
-8 Don't know -9 Refused

D3. Did this customer have specific plans in place to install <u>any</u> of the *[list <u>all</u> relevant measure categories]* **equipment prior to contacting your company regarding this project?**

1 Yes ➔ *Continue to Question D3a*
2 No ➔ *Skip to Next Section*
-8 Don't know ➔ *Skip to Next Section*
-9 Refused➔ *Skip to Next Section*

D3a. Please describe the plans to install the equipment prior to contacting you.
[Interviewer note: the goal here is to understand the plans that were in place before being influenced by the trade ally. Had they already planned to install all the measures and at the same level of efficiency and with all the energy saving features? Probe for equipment type, timing, quantity, and efficiency, as well as prior budgeting. Attempt to elicit responses that will provide answers for the "likelihood" or "share of savings" questions (E2a and E2b).]

____

____

____

D3b. *[Based on responses to D3a, fill in a "1 to 5"score indicating the extent to which end user was already planning to install the energy efficient equipment prior to contact with the trade ally. DO NOT ASK RESPONDENT DIRECTLY. "1" indicates that respondent had no plans at all; "5" indicates that respondent had documented plans and had budgeted for all of the efficient equipment.]* ***{VIP}***

(No plans) 1 2 3 4 5 (Documented plans/budget)
-8 Don't know -9 Refused

D4. *[Enbridge only]* **Enbridge offers a higher incentive if three or more measures are implemented. Did this higher incentive figure in the decision process?**

1 Yes ➔ *Continue to Question D4a*
2 No ➔ *Skip to Next Section*
-8 Don't know ➔ *Skip to Next Section*
-9 Refused➔ *Skip to Next Section*

D4a. How?

____

____

____

D4b. *[Based on responses to D4a, fill in a "1 to 5"score indicating how much influence the higher incentive had on the decision. DO NOT ASK RESPONDENT DIRECTLY.] {VIP}*

(No influence) 1 2 3 4 5 (Critical Influence)
-8 Don't know -9 Refused

2.8.2 Direct Decision Making Questions

[Fill in Table 2 for most of these questions.]
[Ask the following questions for each measure category checked under Question B2 in Table 1 above. If previous open-ended questions have provided the necessary information, interviewer may skip the question/measure category. By the end of the interview, interviewer should be able to populate Table 2 below with EITHER a "likelihood" OR a "share of equipment" OR both, for each relevant measure category.]

Let me ask about the ____________*[MEASURE CATEGORY]***.**

E1. Did the ***[Enbridge/Union]*** **assistance in any way change the timing of the installation?**
1. Yes 2. No -8. Do not know -9. Refused

E1a. *[If Yes]* **Was the equipment installed earlier or later than first planned?**
1. Earlier
2. Later

E1b. ***[If Yes to E1]*** **When would it have been installed without the program assistance?** ***{VIP}***
E1bM. ___ Month
E1bY. ___ Year
-7 Never -8. Do not know -9. Refused

Based on earlier responses, ask either the "likelihood" question below or the "share of equipment" question, whichever is more appropriate. For example, if respondent installed a single chiller, then the "likelihood" question may be most appropriate; if they installed multiple measures of various types/sizes, then the "share of equipment" may be more appropriate. Some respondents may be able to offer valid responses to both questions If you are uncertain, ask both questions. If respondent can provide a response to each, then record both responses.

E2a. ***[Likelihood]* What is the likelihood that you would have installed the same or similar ___________ *[MEASURE CATEGORY]* of the same level of energy efficiency or with the same features that affect the overall system efficiency if it had not been for the assistance from [Enbridge/Union]?**
{VIP}

1 Definitely would NOT have installed equipment of the same level of energy efficiency
2 Definitely WOULD have installed equipment of the same level of energy efficiency anyway
3 MAY HAVE installed equipment of the same level of energy efficiency, even without the program
E2a2.About what percent likelihood? _____%
-8 Don't know
-9 Refused

E2b. ***[Share of equipment]* What share of the ___________ *[MEASURE CATEGORY]* would you have installed anyway at the same level of energy efficiency if it had not been for the assistance from [Enbridge/Union]? *{VIP}***

[If necessary, or if the flow of the interview dictates, you may derive this value by asking 1) the share of equipment that would have been installed (at any efficiency) and 2) the share of installed equipment that would have been high efficiency. The value in the table below for Question E2b would be the product of these two values.]
-8 Don't know
-9 Refused

Table 2. Equipment

[Fill in EITHER the "likelihood" value OR the "share of equipment" value OR both values for each relevant measure category. If respondents ask for the timeframe, use the timeframe specified above in Question E1a.

Then enter the appropriate free ridership value (E2c), which will be one of the following, depending on the nature of the project and the responses:

1) *The single value for "likelihood" or "share of equipment" if only one is entered;*
2) *If value provided for both, enter either Likelihood or Share value, whichever best represents the appropriate value*
3) *The product of the two, if appropriate (e.g., if there is a 50% likelihood that 75% of the equipment would have been installed, and respondent definitely wouldn't have done the final 25%)*

Measure Category	E1. Change when the equipment was installed?	E1a. Forward or Slow	E1b. When would it have been installed?	E2a. Likelihood that energy efficient equipment… …would have been installed without the program		E2b. Share of energy efficient equipment that…	E2c. *[Entered by interviewer]* Free Ridership Value
a. Machine/Process	Y N DK R	F S	Months Yrs	%	and/or	%	%
b. HVAC (incl. furnaces, all boilers, A/Cs, chillers, EMS, etc.)	Y N DK R	F S	Months Yrs	%	and/or	%	%
c. Lighting	Y N DK R	F S					
d Controls (boiler controls, variable frequency drive controls	Y N DK R	F S	Months Yrs	%	and/or	%	%
e. Building envelope (incl. insulation, windows)	Y N DK R	F S	Months Yrs	%	and/or	%	%
f. Domestic hot water	Y N DK R	F S	Months Yrs	%	and/or	%	%
g. Refrigeration	Y N DK R	F S	Months Yrs	%	and/or	%	%
h. Agriculture	Y N DK R	F S	Months Yrs	%	and/or	%	%
i. Converted equipment from electricity to gas (fuel substitution)	Y N DK R	F S	Months Yrs	%	and/or	%	%
j. Other: ________________	Y N DK R	F S	Months Yrs	%	and/or	%	%

E2d. *[Additional notes/caveats (e.g., explaining how/why free ridership value was chosen, if necessary)]*

____

E3. Overall, <u>across all equipment</u>, that is the entire project, how much of these <u>extra energy savings</u> would have been achieved anyway, even without the assistance from [Enbridge/Union]. Please provide a lower and upper bound, and then your best estimate. {VIP}

[If needed for clarification:] **For example, 50% means that half of the extra savings from the energy efficient equipment would have been achieved anyway. Remember, I'm asking only about the extra savings from installing energy efficient equipment instead of standard equipment.**

E3A. Lower bound ➔ _____ % E3B. Upper bound ➔ _____ % E3C. Best estimate ➔ _____ %

2.9 PARTICIPANT INSIDE SPILLOVER

G1. Did the assistance from [Enbridge/Union] in any way influence you to help the customer install additional energy efficient equipment *<u>at the same site</u>* **that did not get reported to the program** (i.e., *equipment that would not have been installed without the influence of the program)***?**

1 Yes➔ Continue to Question G2
2 No ➔ Skip to next section
-8 Don't know ➔ Skip to next section
-9 Refused➔ Skip to next section

G2. [*If G1 = "yes"]* **What year did this equipment get installed?**
-8 Don't know
-9 Refused

G3. *[If G1 = "yes"]* **Please briefly <u>describe how</u> the program assistance from [Enbridge/Union] influenced the decisions to install additional energy efficient equipment at the same site.**
[Identify the types of equipment affected.]

G4. Would you estimate the energy savings from this additional equipment to be <u>less than</u>, <u>similar to</u>, or <u>more than</u> the savings from the energy efficient equipment from the original project?
1 Less than the original project ➔
G4a. About what percentage of the savings from the original project?
____*%* *[Enter a number <u>less than</u> 100%]*
2 About the same savings
3 More than the original project ➔
G4b. About what percentage of the savings from the original project?
____*%* *[Enter a number <u>greater than</u> 100%]*
-8 Don't know
-9 Refused

G5. What share of the savings from this additional equipment can reasonably be attributed to the influence of the assistance from [Enbridge/Union]?
______*% [100% or less]*
-8 Don't know
-9 Refused

[Interviewer may be able to complete this based on response to G3, or at least use G3 to check for consistency. Probe if inconsistent to ensure that respondent is correctly interpreting the question.]

2.10 PARTICIPANT OUTSIDE SPILLOVER

H1. Did the assistance from [Enbridge/Union] in any way influence you to help the company to install any additional energy efficient equipment *at other jobs or facilities in Union Gas/Enbridge's Service Territory* beyond what they would have done otherwise?
[Don't include projects that participated in another Union/Enbridge program.]

1 Yes ➔

H1a. How many other facilities were influenced (that did not participate in Union Gas/Enbridge programs)? ____________________________ (-8 Don't know, -9 Refused)

2 No ➔ Skip to next section
-8 Don't know ➔ Skip to next section
-9 Refused ➔ Skip to next section

H2. *[If H1 = "yes"]* **Please briefly describe how the assistance has influenced the decisions to install this equipment. (Probe to identify the types of equipment affected.)**

____

____

H3. On average, would you estimate the energy savings from these other non-program projects to be less than, similar to, or more than the savings from the energy efficient equipment from the program-supported project that we've been discussing?
[E.g., if the same equipment was implemented in a facility twice as big, then savings would be 200%. Be sure to emphasize that this is savings "on average" not in aggregate across the many buildings that might be affected.]

1. Less than the Custom Projects project

   H3A. About what percentage of the savings from the Custom Projects project? ____% *[Enter a number less than 100%]*

2. About the same savings
3. More than the Custom Projects project

   H3B. About what percentage of the savings from the Custom Projects project? ____% *[Enter a number greater than 100%]*

-8 Don't know
-9 Refused

H4. What share of the savings from energy efficient equipment at these facilities can reasonably be attributed to the influence of the assistance from [Enbridge/Union]?
[Interviewer may be able to complete this based on response to H2, or at least use H2 to check for consistency. Probe if inconsistent to ensure that respondent is correctly interpreting the question.]

______% [100% or less]
-8 Don't know
-9 Refused

2.11 CLOSING

Those are all the questions I had.

Z9. Do you have any final comments you would like to make?

____

____

____

Thank you very much for your time!

Z10. Record all additional or supporting comments here.

____

____

____

2. CUSTOM PROJECTS AUDIT-ONLY SURVEY

2.1 CONVENTIONS

- Blue text is spoken.
- *Italics text is instructions for the interviewer.*
- Arial, bold font in brackets is skip instructions **[skip instructions]**
- Underlined in brackets are data from the sample: [sample data]

2.2 INTERVIEWER DATA

Interviewer ID
Survey Date
Survey Duration

2.3 SAMPLE DATA

Sample ID #
Contact Name
Contact Title
Contact Phone Number
Firm Name
Address
Company Phone Number
Audit Date
Recommended measure description (up to 5 per customer)
Recommended measure estimated gas savings (up to 5 per customer)

2.4 Recall Audit, Identify Respondent

[Enbridge] **According to our records, you had an energy or HVAC audit conducted by a third party professional that was co-funded by Enbridge Gas Distribution on [date].**

[Union] **According to our records, you had a boiler audit or feasibility study conducted with financial assistance provided by Union Gas on [date].**

1. Do you recall receiving that audit?

1. Yes........ 2. No -8. Do not know
.... -9. Refused

2. [If not Yes] **Can you suggest someone else at your company who might be familiar with the audit?**

1. Yes........ 2. No -8. Do not know
.... -9. Refused

If yes, get name and phone. Ask to speak with this person. Start again at the beginning.

2.5 Measure-Specific Questions

[The interviewer will repeat these questions for each audit recommendations (limit of 5 recommendations).]

3. The audit recommended that you implement [recommendation]. Do you recall that recommendation?

1. Yes........ 2. No -8. Do not know
.... -9. Refused

4. Has it been installed or implemented?

1. Yes........ 2. No 3. Partial
.... 4. Caveat
-8. Do not know........ -9. Refused

Partial = Some of the recommended equipment was installed but not all.
Caveat = Installed something related to the recommendation but not the exact thing recommended

[If Q4=3]

5. What percent of the items recommended or equipment did you install?

Enter percents as whole numbers, thus 90% would be entered as "90" NOT "0.9".

-8 Don't know........ -9 Refused

[If Q4=4]

6. The audit estimated that this item [or the actual equipment] would save [savings] cubic meters of gas. What percent of that estimated savings do you think you achieved?

Enter percents as whole numbers, thus 90% would be entered as "90" NOT "0.9".

-8 Don't know........ -9 Refused

[If not installed (Q4=2, -8, -9)]

6A. Why have you not implemented this recommendation yet?

1. We plan to but have not yet
2. Do not have the money
3. We do not have that equipment any more
4. Other
   6AOther. **[Capture verbatim]**

-8 Don't know
-9 Refused

[If not installed (Q4=2, -8, -9), skip to the next recommendation. If last recommendation, skip to the next section.]

7. When was it installed?

Record month and year installed

-8 Don't know.. -9 Refused

8. On a scale of 1 to 5 where 1 is "no influence" and 5 is "a great deal of influence", how much influence did the audit have in your decision to implement this item?

1 2 3 4 5 .... -8 Don't know -9 Refused

9. What share of the savings from this item can reasonably be attributed to the influence of the audit?

Enter percents as whole numbers, thus 90% would be entered as "90" NOT "0.9".

-8 Don't know.. -9 Refused

2.6 FIRMOGRAPHICS

Now I have just a few questions about your company.

Z1. Approximately how large is the facility that received the audit? (square feet)?

1. Up to 5,000
2. 5,001 to 10,000
3. 10,001 to 15,000
4. 15,001 to 25,000
5. 25,001 to 50,000
6. 50,001 to 100,000
7. 100,001 to 200,000
8. 200,001 to 500,000
9. Over 500,000

-8 Do not know
-9 Refused

Z2. Is the facility you work in independent, or part of a larger organization?

1. Independent
2. Part of a larger company
3. Other

Z3Other. [Capture verbatim]

-8. Don't know
-9. Refused

Z3. Approximately how many full time employees or full time equivalents does your organization have at your locations in Ontario?

1. Fewer than 5
2. 5 to 9
3. 10 to 19
4. 20 to 49
5. 50 to 99
6. 100 to 249
7. 250 or More

-8 Do not know
-9 Refused

Those are all the questions I had. Thank you very much for your time!

3. CUSTOM PROJECTS NONPARTICIPANT SPILLOVER SURVEY

3.1 CONVENTIONS

- Blue text is spoken.
- Italics text is instructions for the interviewer.
- Arial, bold font in brackets is skip instructions: **[skip instructions]**
- Underlined in brackets are data from the sample: [sample data]

3.2 INTERVIEWER DATA

Interviewer ID
Survey Date
Survey Duration

3.3 SAMPLE DATA

Sample ID # (Per Sample File)
Contact Name
Contact Title
Contact Phone Number
Firm Name
Address
Company Phone Number
Dwtp Code Desc (Per Sample File)
Utility (Enbridge / Union Gas – Per Sample File)

3.4 QUALIFY RESPONDENT, EXPLAIN PURPOSE

Find someone knowledgeable about the company's buildings and equipment.

Q1. May I speak with the plant engineer or facilities manager?

1 Yes **[CONTINUE WITH INTRODUCTION]**
-8 Do Not Know **[PROMPT WITH DESCRIPTION OF APPROPRIATE CONTACT]**
-9 Refused **[THANK AND TERMINATE]**

DESCRIPTION OF APPROPRIATE CONTACT (If necessary):

I would like to speak with someone who is accountable for energy efficiency or who is responsible for your building's operation and is knowledgeable about your company's energy-using equipment, like space and water heating, ventilation, and industrial processes.

INTRODUCTION - Once you have the person on the phone (or if needed to find the person) say:

I am calling on behalf of [<u>Enbridge/Union Gas</u>] to ask some questions about your plant or building operation and equipment to help [<u>Enbridge/Union Gas</u>] improve their energy efficiency programs.

If necessary:

Confidentiality: **We will not report your individual answers to [<u>Enbridge/Union Gas</u>]. We only report results aggregated across all the respondents.**

Record

Q2. Name

Q3. Phone number

3.5 PARTICIPATION SCREENING

P1. Have you heard of <u>[Enbridge/Union Gas']</u> energy efficiency program?

1 Yes **[SKIP TO P3]**
2 No
-8 Don't Know
-9 Refused

P2. The energy efficiency program is designed to provide incentives and technical assistance for implementing projects that save energy. Does that sound familiar?

1 Yes
2 No **[THANK AND TERMINATE]**
-8 Don't Know **[THANK AND TERMINATE]**
-9 Refused **[THANK AND TERMINATE]**

P3. Have you received financial incentives through the program to make energy efficiency improvements or conduct an energy audit?

1 Yes **[THANK AND TERMINATE]**
2 No
-8 Don't Know
-9 Refused

P4. Have you had contact with [Enbridge/Union Gas'] energy efficiency program through a trade show, attending a workshop or receiving a publication?

1 Yes
2 No
-8 Don't Know
-9 Refused

3.6 Equipment Screening

S1. Have you modified or installed any of the following types of equipment since the beginning of 2005?

Read each option.

Equipment	Yes	No	Don't Know	Refused
a. Space Heating	1	2	-8	-9
b. Water Heating	1	2	-8	-9
c. Steam generation	1	2	-8	-9
d. Other kind of heating	1	2	-8	-9
e. Ventilation	1	2	-8	-9
f. Industrial process improvements	1	2	-8	-9
g. Building controls	1	2	-8	-9

[IF 'NO, DK or RF' TO ALL IN S1, THANK AND TERMINATE]

[FOR EACH 'YES' IN S1 ASK]

S2. When did you make that change?

Record month and year.

Equipment	Month	Year	Don't Know	Refused
a. Space Heating	-- --	-- -- -- --	-8	-9
b. Water Heating	-- --	-- -- -- --	-8	-9
c. Steam generation	-- --	-- -- -- --	-8	-9
d. Other kind of heating	-- --	-- -- -- --	-8	-9
e. Ventilation	-- --	-- -- -- --	-8	-9
f. Industrial process improvements	-- --	-- -- -- --	-8	-9
g. Building controls	-- --	-- -- -- --	-8	-9

3.7 Program Influence

[FOR EACH 'YES' IN S1 ASK]

G1. On a scale of 1 to 5 where 1 is "no influence" and 5 is "a great deal of influence", how much influence did the [Enbridge/Union Gas] energy efficiency program have in your decision to install or modify your [Equipment]?

Equipment	No Influence				Great Deal of Influence	Don't Know	Refused
a. Space Heating	1	2	3	4	5	-8	-9
b. Water Heating	1	2	3	4	5	-8	-9
c. Steam generation	1	2	3	4	5	-8	-9
d. Other kind of heating	1	2	3	4	5	-8	-9
e. Ventilation	1	2	3	4	5	-8	-9
f. Industrial process improvements	1	2	3	4	5	-8	-9
g. Building controls	1	2	3	4	5	-8	-9

[FOR EACH 'YES' IN S1 ASK]

G2. What share of the savings from this change can reasonably be attributed to the influence of the [Enbridge/Union Gas] energy efficiency program?

Enter percents as whole numbers, thus 90% would be entered as "90" NOT "0.9".

Equipment	**%**	**Don't Know**	**Refused**
a. Space Heating	-- -- --	-8	-9
b. Water Heating	-- -- --	-8	-9
c. Steam generation	-- -- --	-8	-9
d. Other kind of heating	-- -- --	-8	-9
e. Ventilation	-- -- --	-8	-9
f. Industrial process improvements	-- -- --	-8	-9
g. Building controls	-- -- --	-8	-9

[FOR EACH 'YES' IN S1 ASK]

G3. On a scale of 1 to 5 where 1 is "no influence" and 5 is "a great deal of influence", how much influence did your suppliers or contractors have in your decision to install or modify your [Equipment]?

Equipment	**No Influence**				**Great Deal of Influence**	**Don't Know**	**Refused**
a. Space Heating	1	2	3	4	5	-8	-9
b. Water Heating	1	2	3	4	5	-8	-9
c. Steam generation	1	2	3	4	5	-8	-9
d. Other kind of heating	1	2	3	4	5	-8	-9
e. Ventilation	1	2	3	4	5	-8	-9
f. Industrial process improvements	1	2	3	4	5	-8	-9
g. Building controls	1	2	3	4	5	-8	-9

3.8 Follow-Up Call OK?

[IF P4 > 2 OR P5 > 30% FOR ANY MEASURE FROM S1 THEN CONTINUE. ELSE, TERMINATE]

F1. We want to have one of our engineers ask you some technical questions about the equipment changes you made. Will that be OK?

1 Yes **[VERIFY/COLLECT CONTACT INFORMATION]**
2 No **[THANK AND TERMINATE]**
-8 Don't Know **[THANK AND TERMINATE]**
-9 Refused **[THANK AND TERMINATE]**

May I verify your:

F2. Name ________________________________ [PRE-FILL WITH INFO FROM Q2]
F3. Phone number ________________________________ [PRE-FILL WITH INFO FROM Q3]
F4. Email Address ________________________________

Those are all the questions I had. Thank you very much for your time!

UNION GAS LIMITED

Undertaking of Ms. Brooks
To Mr. Gardner ("LIEN")

To provide specifics on where the 30 new single-family offerings will be located.

Please see the table below.

Proposed Geographical Expansion 2016-2020

2016	2017	2018	2019	2020
Burlington	Brockville	Bracebridge	Elliott Lake	Dryden
Hanmer	Caledonia	Dunnville	Fergus	Fort Frances
Ingersoll	Halton Hills	Napanee	Gananoque	Kapuskasing
Kenora	Prescott	Tecumseh	Gravenhurst/Rama	Kingsville
Leamington	Stratford	Tillsonburg	Huntsville	Port Hope
Oakville	Wallaceburg	Trenton	Kirkland Lake	

UNION GAS LIMITED

Undertaking of Ms. Lynch
To Mr. Poch ("GEC")

Union to provide a copy of an EEA Study by Mr. Sloan and Dr. Lerner.

Please see Attachment 1.

Appendix B

Avoided Cost

(includes correspondence documenting update for 1999 DSM Plan)

REVIEW OF UNION AND CENTRA AVOIDED COSTS

Prepared by:
Dr. Michael O. Lerner and Michael Sloan

June 5, 1998

Union Gas asked Michael Lerner of Lerner Associates and Michael Sloan of EEA to provide a quick review of the inputs and current estimates of the Union Gas and Centra Gas avoided cost estimates prepared in 1997 which were used to analyze the Union/Centra 1998 DSM Plan. The objective of this review was to estimate the likely impact on avoided costs of conducting a full fledged update of the major avoided cost data inputs to reflect more current conditions.

This report documents the results of this review.

I. SUMMARY OF CONCLUSIONS

With the exception of Centra Gas distribution and transmission expansion costs, the avoided cost data inputs do not appear to have changed in a way that would significantly impact the overall estimates of avoided costs prepared in mid-1997 and used in the 1998 DSM plan:

- Gas commodity price forecasts are higher in the short term, but relatively unchanged in the longer term, for a total impact of about one to two percent increase in avoided commodity costs.
- Actual TCPL transmission tariffs have declined in real terms by about one percent.
- Storage costs have not changed significantly.

Overall, an updated set of avoided costs for the Union service territory is likely to be slightly higher than the previous set of avoided costs. We expect this difference to represent about a one to two percent increase in the total value of the avoided cost savings of any DSM program with a life longer than ten years. The impacts of updating avoided costs for programs with a five year impact will be slightly higher than for longer term programs.

For the Centra service area, reductions in avoided transmission costs and avoided distribution costs are likely to have a significant impact on the overall avoided costs. Our review of these cost elements suggests that updating the avoided costs would result in a reduction in the total avoided cost savings of a weather sensitive DSM program of about eight percent and a baseload DSM program by about three percent. These reductions will be partially offset by the higher gas commodity prices. Overall, the avoided costs for the Centra service territory appear likely to decline by roughly six to seven percent for weather sensitive loads and to decline by roughly one to two percent for baseload loads.

II. REVIEW OF AVOIDED COST INPUTS

We have attempted to review each of the key data inputs to the Union and Centra avoided costs to determine where significant changes may have occurred since the avoided costs used in the preparation of the 1998 DSM plan were finalized in mid-1997. The major avoided cost inputs are discussed by category.

<u>Union and Centra Base Case Supply Plans</u>

We have briefly reviewed current Union Gas supply planning projections of pipeline capacity requirements, gas commodity purchases, and use of storage. We also have discussed gas supply planning assumptions with Union Gas staff. While demand forecasts have been updated leading to changes in the absolute levels of gas requirements, the underlying gas supply strategy has not changed in any fundamental way. Based on our review of the current Union Gas supply planning projections and our discussions with Union Gas staff, we would not expect any changes in gas supply planning to have a significant impact on avoided costs.

Gas Commodity Price Forecast

Gas commodity prices are the single largest component of avoided costs. We have reviewed a number of recent industry forecasts of avoided costs in order to perform a rough check on the reference case gas price forecast. A comparison of these newer gas price forecasts indicates that the reference case gas price forecast might be revised upwards by roughly two percent overall. The increase occurs primarily in the near term. The forecasted Union Gas WACOG for 1998 has been increased by about ten percent. The longer term forecasts are roughly equivalent between 1999 and 2005. After 2005, the updated forecast is slightly (one to two percent) higher than the initial reference case forecast. The attached figure shows a comparison of a likely update to the natural gas price forecast to the forecast used in the 1998 avoided cost analysis.

TCPL Transmission Costs

TCPL transmission costs make up the second largest component of avoided costs. Our long-term estimate of TCPL transmission costs has declined by about one percent in real terms.

In nominal dollar terms, the actual TCPL transmission tariffs for Eastern Delivery Zone firm service have increased by about 0.7 percent in the last year, with 100% load factor costs increasing from $89.842 to $90.436 per GJ. In real, inflation adjusted, terms this reflects a decline of about one percent in the base year avoided TCPL transmission costs. Future avoided TCPL costs are estimated starting from the base year values, escalated in real terms to reflect expected long term changes in tariff rates. In the 1998 avoided costs, we assumed that real transmission cost escalation rate would be zero percent per year. At this time we see no reason to revise this assumption.

It is worth noting that there has been a shift in how TCPL tariff rates are structured. In nominal terms, TCPL demand tolls have decreased by about two percent from $1002.97 to $984.29 per 10^3m^3/month, while commodity tolls have increased from $0.959 to $1.671 per 10^3m^3. This shift will not have a significant impact on avoided costs as long as TCPL capacity continues to be used at or near 100 percent load factor. The shift does become more important if TCPL capacity is used at less than 100 percent load factor, reducing the cost of TCPL capacity for weather sensitive load.

Storage Costs

The market for Union Gas storage has changed substantially in the last year. Due to changes in market and regulatory conditions, Union has decided to construct a number of additional storage fields in order to market additional storage capacity to ex-franchise customers. However, we do not expect these changes to significantly impact avoided storage costs.

According to discussions with Union Gas staff, the market value of storage capacity and deliverability is relatively unchanged from the estimates we prepared in 1997. In addition, the representative new storage field used to estimate the longer run incremental cost of storage development is still considered to be representative of future storage field development costs. Hence, while the structure of the storage avoided costs would likely change somewhat if a full fledged avoided cost update were performed, we do not anticipate that the underlying avoided costs would likely change substantially for either the Centra or Union service territories.

Union Gas In-Franchise Transmission Costs

Union Gas has updated the Trafalgar and non-Trafalgar transmission expansion plans since the 1998 avoided cost study was prepared. We have not performed the analysis needed to fully update the transmission avoided cost factors, but based on discussions with Union staff concerning the nature of the changes, we would not anticipate major changes in Union Gas in-franchise transmission expansion avoided costs.

Union Gas In-Franchise Distribution Costs

Union Gas in-franchise distribution costs have been reviewed to consider the most recent capital budget estimates of distribution costs. The distribution expansion costs for 1999 appear to be somewhat higher than the average distribution costs for 1995 through 1998, hence the estimate of long term avoided distribution costs may increase somewhat. We would expect this increase in distribution avoided costs to have an impact of less than one-half of one percent on total Union Gas avoided costs.

Centra Gas In-Franchise Transmission Costs

As noted on page 41 of the 1998 avoided cost documentation, we believed that the avoided costs of Centra transmission included in the analysis probably substantially overstated the true avoided costs. The review of more current Centra transmission cost inputs confirm this belief. We would anticipate that revising these costs to reflect current budgeted transmission expansion projects might reduce Centra transmission avoided costs by as much as 65 percent. The dramatic drop is due to scrapping short term plans to implement the two most expensive of the Centra transmission expansion projects included in last year's capital budget. The Fort Francis transmission reinforcement project has been indefinitely delayed, and the scope and cost of the Sudbury reinforcement project has been substantially cut back. This very likely has a net impact of reducing Centra's weather sensitive avoided costs by up to eight percent.

Centra Gas In-Franchise Distribution Costs

The budgeted distribution expansion costs for 1999 are lower than the average distribution costs from 1996-1998 used to develop the long term estimate of avoidable distribution costs for the Centra service territory. Our initial review of this budget information indicates that updating the long term costs to reflect current budgeted distribution expansion projects might reduce Centra distribution avoided costs by as much as 12 percent. This is a significant cost decline, and a careful review of these costs would be indicated as part of any comprehensive avoided cost update. A decline in avoided distribution costs of this magnitude would have the net effect of reducing the avoided costs for a weather sensitive program by about 0.5 percent.

Other O&M Costs

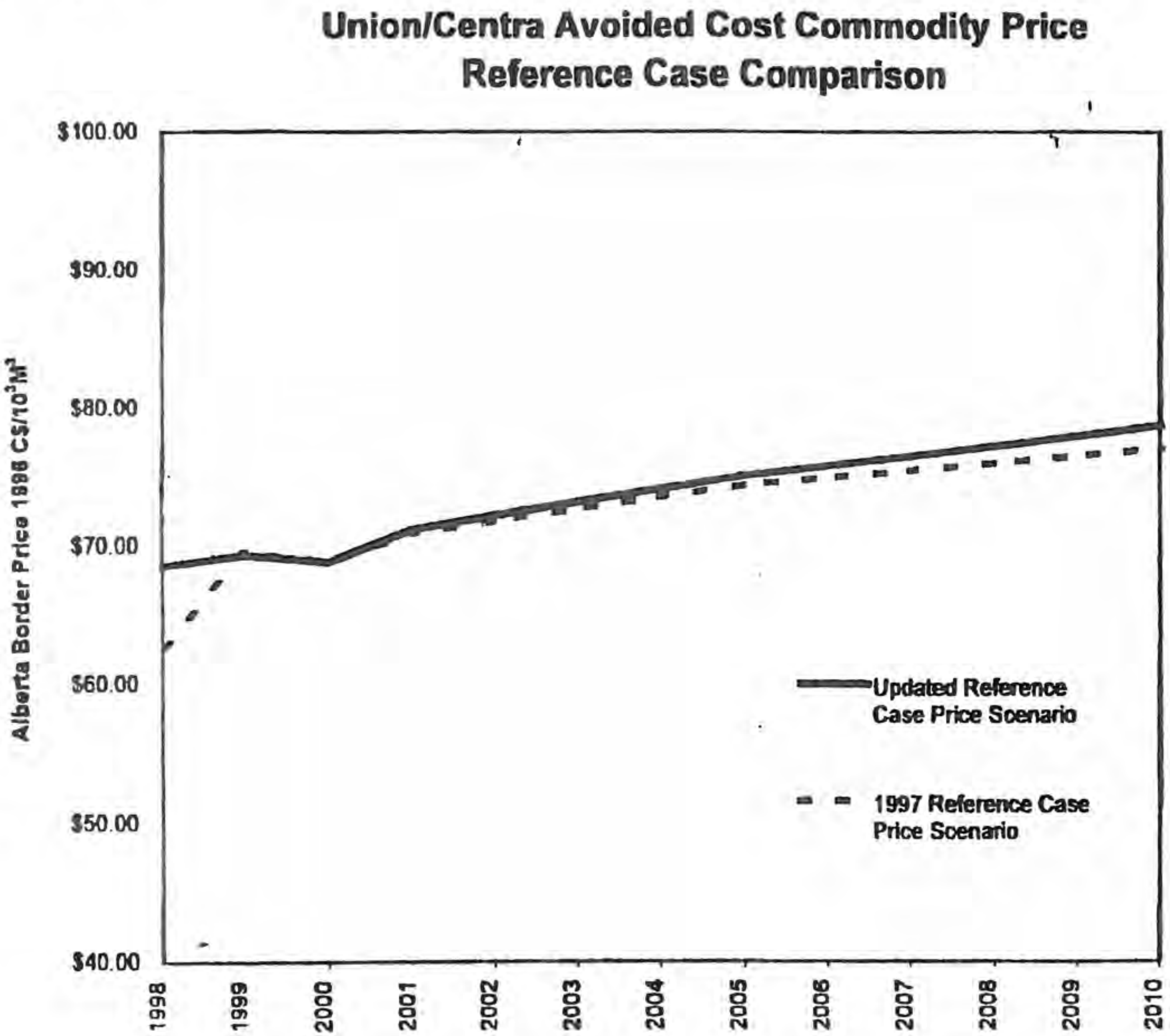
No new data on other O&M costs is currently available. Based on discussions with Union Gas staff, these costs are unlikely to change significantly from the values used last year.

III. OTHER FACTORS CONSIDERED

In the last year Union and Centra have gone through a number of structural changes that we felt might influence the avoided costs for the two service territories. While we have not conducted any empirical analysis of these changes, we have identified several factors and considered the likely nature of any resultant impacts on avoided costs. After this review, we would anticipate that such changes would reduce avoided costs, although the magnitude of the decline is unclear.

The merger of Union Gas Limited and Centra Gas Limited is expected to reduce the overall costs of serving in-franchise customers. Most of these cost savings are administrative and O&M expenses. These cost savings seem to be primarily related to efficiency improvements in areas of the company that are not gas volume dependent. If this is true, then the majority of the cost savings will not be reflected in the avoided costs. However, there may be certain efficiencies in storage operation and the structuring of the gas supply and transportation portfolio that could reduce avoided costs.

Union Gas Limited has "spun off" several categories of service to unregulated subsidiaries. These services include appliance merchandising, and customer information services. The company believes that removing these services from the regulated utility should increase the amount of competition and reduce the costs of these services to Union Gas' ratepayers. In general, the services that have been removed from the regulated utility are related to customer services and are not volume related, hence would not likely change avoided costs. An exception would be deregulation of the merchant function. Customers purchasing natural gas from suppliers other than Union Gas potentially might have a different cost of gas than customers purchasing natural gas from the utility. In the short term, it is possible that these costs may be somewhat lower than the costs incurred by the regulated utility, although the magnitude of any cost reductions is unclear.


Union/Centra Avoided Cost Commodity Price
Reference Case Comparison
Alberta Border Price 1998 C$/10³M³
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Updated Reference Case Price Scenario
1997 Reference Case Price Scenario

DERIVATION OF
AVOIDED GAS COST ESTIMATES
FOR UNION GAS AND CENTRA GAS

Prepared By:
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November, 1997

I. INTRODUCTION

At the request of Union Gas/Centra Gas, EEA developed estimates of avoided costs for both Union Gas and for Centra Gas for use in the evaluation of the 1998 Union and Centra DSM Plans. The methodology described here to estimate avoided costs is the same as the methodology used to prepare the estimates of avoided costs reviewed by the Ontario Energy Board as part of EBRO 493/494. The data inputs to the avoided cost analysis have been updated. Other changes have been made in accordance with the provisions in the ADR agreement in EBRO 493/494 related to the avoided cost analysis, due to differences in Centra corporate structure related to the combination of the two companies, and due to comments and suggestions of Union and Centra staff and by various intervenors. The differences in avoided cost approach between this analysis and the EBRO 493/494 analysis are documented in section eight of this report.

This report describes the overall approach used in deriving the components of avoided gas costs, reviews the level of detail considered and the factors taken into account in deriving these estimates, then presents summary output tables showing the avoided cost results and briefly describes how the data were passed to others at Union and Centra responsible for analysis of DSM program activities. The general methodology discussion applies to both Union Gas and Centra Gas avoided costs except where indicated.

In order to be responsive to Board and intervenor requests for additional data and information on the derivation of avoided costs, we have also added five data appendices to the report. Appendices A and B include the basic input data for the Union and Centra avoided cost analysis which have been updated since prior presentations to the Board. Appendices C and D include the avoided cost results files for Union and Centra used in the DSM program evaluation process. Appendix E documents the electricity avoided costs prepared by EEA using information from publicly available Ontario Hydro data. These appendices include the same level of avoided cost input data and output detail provided to intervenors by Union Gas during the EBRO 493/494 proceeding.

The avoided costs for Union Gas and Centra Gas documented in this report were prepared by EEA with substantial support and collaboration of Union Gas and Centra Gas staff. EEA coordinated the collection of data from different departments including gas supply planning, facility planning, marketing, and regulatory to develop the estimates of the different components of avoided costs. Data inputs concerning avoidable supply options, supply and facility costs, gas commodity costs, etc... were provided by Union Gas and Centra Gas staff.

1.1 OVERVIEW OF AVOIDED COST CONCEPTS

In concept, avoided cost is intended to measure the reduction in the delivered costs of supplying natural gas to customers as a consequence of a Demand Side Management (DSM) program which reduces gas use per customer. In this discussion, the concept of avoided cost is also used to represent the increase in costs of supplying gas to customers as a consequence of DSM programs which result in a net increase in gas use per customer.[1]

Estimates are typically developed for three components of avoided costs:

- Avoided capacity costs - typically fixed charges related to ensuring a maximum level of capacity to deliver gas. Can be one time costs associated with facility construction, or annual costs such as pipeline demand charges.
- Avoided energy (or variable) costs - costs which vary directly in proportion to changes in m^3 of gas consumed, such as purchased gas costs or pipeline commodity charges,
- Avoided customer charges - costs which vary in direct relationship to the number of customers, such as the cost of hooking up a new customer for a sales enhancement program.

It is important to recognize that there is really no single number which represents an estimate of avoided costs. Avoided costs can only be estimated for specific DSM programs or for generic types of programs. For example, DSM programs which tend to result in greater reductions in design day capacity needs will tend to have higher avoided costs, e.g., typically a DSM program which targets space heating gas uses will impact design day demand much more than programs targeting water heating uses. Figure 1 illustrates the steps involved in developing and applying avoided gas costs:

[1] Pure economic theory would refer to the latter concept as marginal costs rather than avoided costs. However, in the practical world of developing estimates, there is very little difference (if any) in estimates of avoided vs. marginal costs.

- Estimating the components of avoided costs,
- Then estimating the energy impacts for the specific DSM programs being evaluated,
- Then calculating avoided costs for the programs as part of the cost-benefit evaluation process by multiplying the estimated avoided cost for each "component" times the assumed energy impacts for that component.

In other words, estimates of avoided gas costs in terms of total dollars are specific to individual DSM program activities (supply or demand side) considered by the utility.

Since we believe that avoided cost components differ among customer classes and for different end uses of natural gas, we developed a "matrix" of generic avoided cost components. This matrix of cost factors was then transferred to Union/Centra staff who are responsible for evaluating and implementing DSM programs. These staff used the avoided cost components as inputs to their analyses of specific DSM programs.

FIGURE 1

Application Of Avoided Costs To Evaluate DSM Programs

Components Of Avoided Costs...

- Avoided ***Capacity*** Costs
- Avoided ***Energy*** Costs
- Avoided ***Customer*** Related Costs

Estimating Avoided Cost Savings From A Specific DSM Program...

Avoided Cost Components X Savings For Each Component Due To Program = ***Total Avoided Costs Due To Program***

For Example...

Avoided Energy Costs... ***$65*** *Per 10^3M^3* X ***100,000*** *10^3M^3 Saved* = ***$6.5 million***

Presentation Of Avoided Costs Of DSM Programs...

Total Avoided Costs = $ Saved

$$\text{Avoided Cost Per } M^3 \text{ Saved} = \frac{\text{Total Avoided Costs}}{M^3 \text{ Saved}}$$

2. METHODOLOGICAL APPROACH EMPLOYED IN COMPARISON TO OTHER APPROACHES TO ESTIMATING AVOIDED GAS COSTS

In order to provide a context for presenting the Union/Centra approach to estimating avoided costs, we will refer here to the 1993 Primer on Gas Integrated Resource Planning prepared for NARUC to outline the different approaches being used to estimate avoided gas costs.[2] In its discussion of avoided cost methodology, the NARUC IRP Primer notes at the outset that major differences between the electric and natural gas industries warrant careful thought in transferring concepts developed for the electric utility industry to the natural gas industry.[3]

The Primer also clearly states that "a consensus does not yet exist within the gas industry or among regulators on appropriate methods [for estimating gas avoided costs]."[4] It goes on to describe four different approaches being used to estimate avoided gas costs:

- Systems approach - relies on computerized supply planning models to develop avoided costs (often referred to as dispatch models).
- Generic proxy approach - uses generic supply options as proxies to calculate avoided capacity and energy costs; analogy for electric utility industry is the use of a peaking unit as a proxy for avoided capacity costs.
- Targeted marginal cost - a composite of the first two approaches in that it need not rely on a complex model, but it attempts to distinguish avoided supply costs in relation to the types of gas demands they serve, such as by load type (winter vs. baseload).
- Average costs - the simplest approach which uses various components of the utility's current average costs as a proxy for avoided costs.

The Primer then goes on to compare the strengths and weaknesses of the four approaches. The views of the authors of the Primer on this comparison can be approximated as follows:

- The average cost and generic proxy approaches are highly oversimplified methods of estimating avoided gas costs, although they are simple to implement.

2 Primer on Gas Integrated Resource Planning, National Association of Regulatory Utility Commissioners, (Washington, D.C.), December 1993.

3 Ibid. p. 97.

4 Ibid.

- The targeted marginal cost approach is more realistic, but leaves many key judgments to the analyst who is matching up supply costs to different types of demands for natural gas.
- The systems approach is the most complex and burdensome to apply, but is characterized as being the most "precise" by the authors of the Primer.

In our view while this classification of approaches is useful, the authors of the Primer seem to be clearly biased in favor of complex modeling approaches.

2.1 Methodological Approach

The approach to estimating avoided gas costs explained in this report is closest to the "targeted marginal cost" approach described in the Primer. As Union noted in its presentation on avoided cost issues in the generic IRP hearings in Ontario, one of the key objectives of gas utility approaches to estimating avoided costs should be to appropriately distinguish how avoided costs may differ among market segments, hence ensuring that analyses of specific DSM programs best reflect how that program (or portfolio of DSM activities) might actually tend to impact Union's supply costs. Hence, EEA has developed avoided costs for gas supplies which serve different types of natural gas demands (such as winter vs. baseload, residential/commercial vs. industrial, existing vs. new customers, etc.).

There are several reasons why EEA used the targeted marginal cost approach instead of the systems approach to estimate Union and Centra avoided costs. First, at this time Union does not rely on any single system planning model to do its supply planning. Union's supply planning issues are very complex, much more so than for most local distribution companies due to the extensive use of storage, the existence of major joint use transmission facilities (Dawn-Trafalgar) within their service area (introducing issues more typically facing natural gas pipelines rather than local distributors), and the complexity of gas movements on the Dawn-Trafalgar system (sometimes gas moves West to East, but at other times reverse movements occur). Although Union is continually reviewing the state of the art in available models, at this time Union does not believe there is any one model available which can deal well with the complexities of Union's entire supply planning situation. Hence, Union relies on several models to help analyze various elements of Union's supply needs.

Second, we are more skeptical of the complex planning models available to gas utilities than are the authors of the Primer[5]. In contrast to the electric utility industry, the models for gas utilities lack a long history of application and review in regulatory arenas, the planning context for electric utilities is also much simpler than for gas utilities (as noted in the Primer), available models also seem to require a great deal of "analyst judgment" in defining appropriate supply options and data inputs, and computer model outputs tend to be very aggregate in nature and are not necessarily well suited to extract outputs on the components of avoided costs which are needed, such as avoided capacity vs. energy costs.

Third, we are reluctant to rely on an approach to avoided costs which requires the continual involvement of the utility's supply side staff in DSM analysis. Current system models require a great deal of care and attention to operate, and must be operated by people who understand the supply issues. Any avoided cost approach that requires numerous system model runs to evaluate alternative scenarios would require a substantial commitment of supply side staff time. Union has been working in an environment which already places significant burdens on its supply staff to adapt to what seems to be constantly changing market conditions. Hence, we have tried to develop an approach to avoided costs where the Union supply staff develops information on the components of avoided costs which are in turn used as inputs by other Union staff responsible for evaluating/developing DSM activities. The supply side staff can thus periodically provide updates on avoided costs yet avoid being constantly pulled off their work on supply issues to help the DSM program people evaluate particular programs or alternative portfolios of activities. This approach permits an efficient separation of functions within the company where the people who analyze DSM programs within the company can use the avoided cost data passed to them to match their own needs/schedule without also being required to understand all the details of the gas supply planning issues.

5 We do believe that gas dispatching models such as SENDOUT can be very useful for utilities such as Centra Gas for addressing some types of gas purchasing and dispatching issues

3. KEY CONCEPTS USED IN ESTIMATING AVOIDED GAS COSTS

3.1 Load Segments Distinguished in This Analysis

This approach to estimating the components of avoided costs distinguishes how such costs might differ between load segments. Figure 2 illustrates a typical load duration curve for a gas distributor and the labels under the load duration curve refer to three basic load segments:

- Needle peak - demand for gas on the coldest 3-6 days of the year,
- Temperature sensitive load - remaining gas load which is sensitive to temperature (space heating loads), and
- Baseload demands - which are not sensitive to temperature and are typically fairly constant throughout the year.

The darker labels shown above the load duration curve indicate typical supply options used by U.S. gas distributors in serving the demands of these load segments. These supply options include: peak shaving approaches to serve the design day (propane air/LNG/storage), storage withdrawals to serve a portion of the temperature sensitive winter load, and pipeline supplies to serve part of the winter load and also to serve the baseload load segment.[6]

There are several reasons for trying to differentiate avoided cost by load segment. First, the costs of providing supplies for these load segments are quite different. Any gas distributor incurs a significant share of its fixed costs (pipeline demand charges, transmission and distribution plant, storage deliverability) with the goal of being able to supply gas on a design day during the winter and satisfy demands during the entire winter. Hence, the distributor incurs fixed costs specifically intended to serve both design day and winter demands. In contrast, the supply costs of serving the baseload load segment are typically substantially lower than supplying winter loads.

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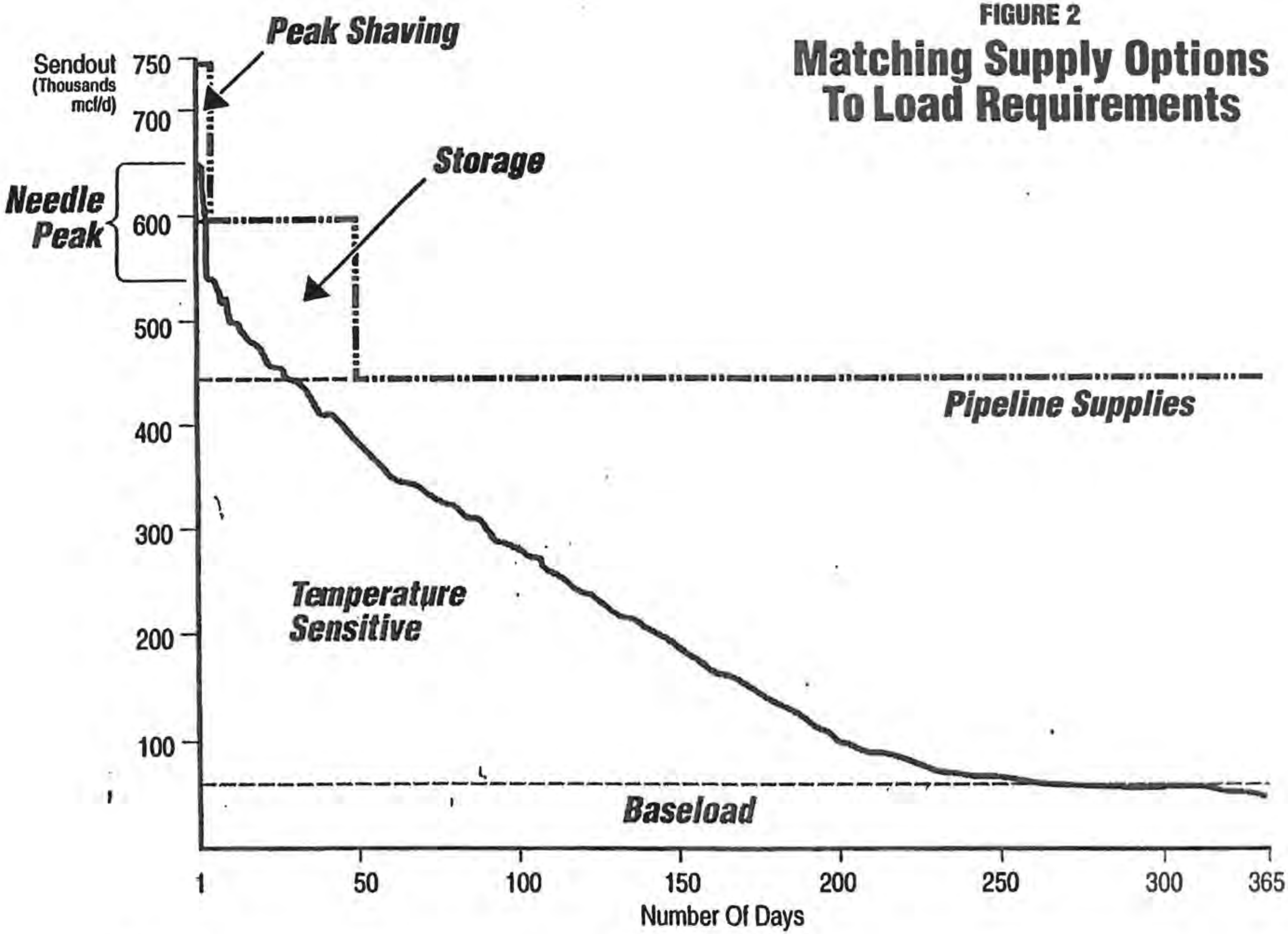
6 The supply strategy shown in this figure is more representative of Centra's supply strategy than Union's supply strategy. Union's supply strategy differs from the one shown in this figure as Union uses storage to meet demand in the block labeled "Peak Shaving". In both cases, our use of the figure is only to illustrate basic concepts, not to attempt to describe specific supply activities.

FIGURE 2

Matching Supply Options To Load Requirements



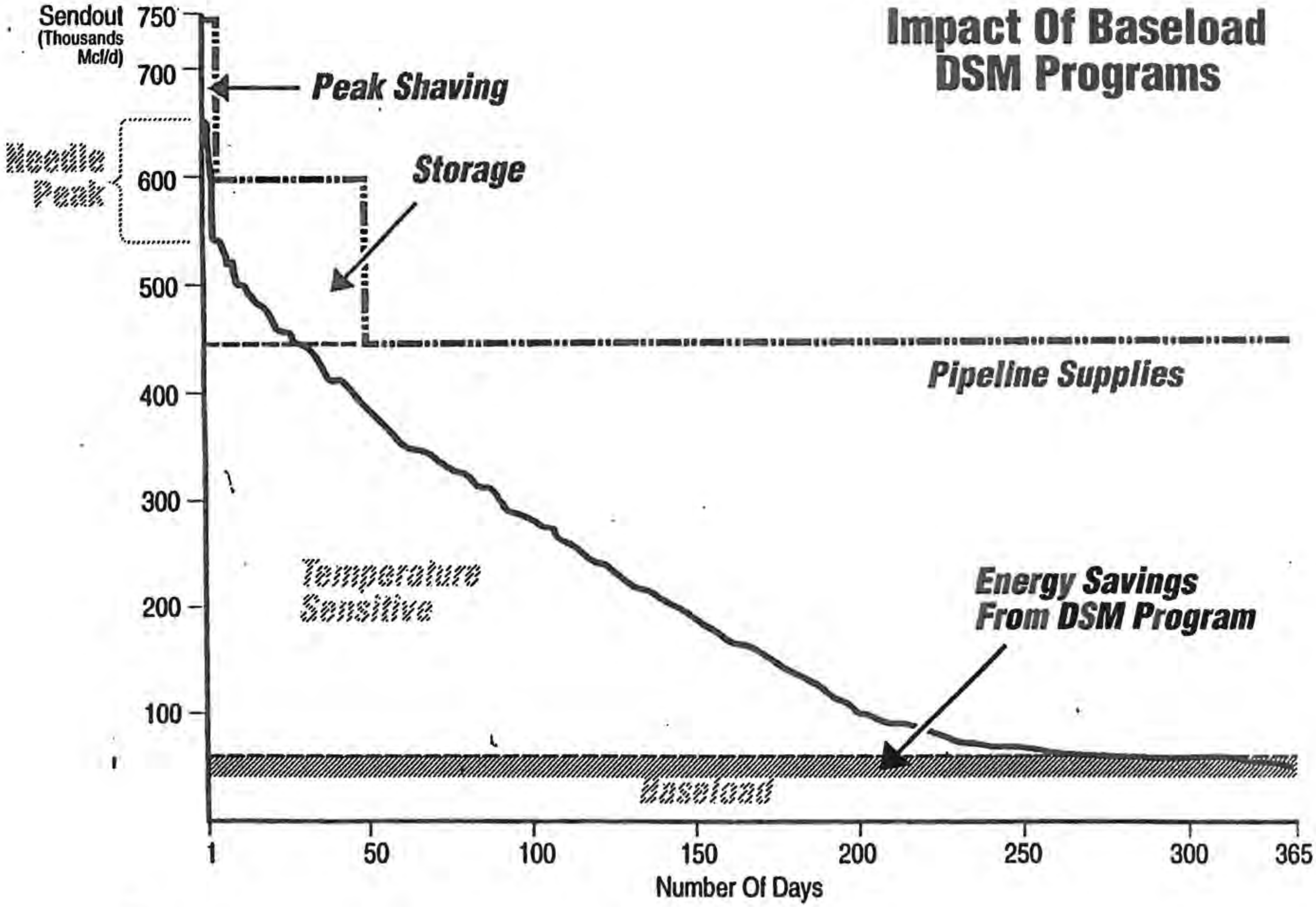
Second, DSM programs typically target customer groups/end uses of gas which also differ by load segment. For example, a furnace efficiency program reduces gas demand during the winter while a water heater efficiency program reduces gas needs during the baseload load segment. One would typically expect the avoided costs of a DSM program aimed at reducing winter gas use, such as furnace upgrades, to have a substantially higher avoided cost than the avoided cost of a water heating program. Hence, differentiating avoided cost by load segment helps to identify which DSM programs would actually tend to bring about the largest change in supply costs.

Using the load segments, our intent is to estimate the various components of avoided supply costs which serve that portion of the utility load.[7] Figure 3 illustrates in the shaded area the energy cost savings of a DSM program intended to reduce baseload demands. Similarly, we would focus on the capacity costs of reducing baseload demand which would include pipeline demand charges per unit of capacity, but not storage which is used to serve winter demands. Hence, the avoided cost component per unit of capacity (m^3 per day) would tend to be lower for the baseload than for the winter load segment.

In addition, analyzing gas demand changes by load segment is consistent with traditional gas distributor supply planning efforts which must consider how gas supply options match up to these load segments. In a broad sense, supply planning has the objective of providing the least cost mix of supply options to serve varying demand patterns across these load segments, subject to practical constraints such as reliability of supply, maximizing leverage in negotiations, etc.

7 We realize that this is a simplification of reality since this approach assumes that the supply options to serve each load segment are independent. We recognize that, in reality, there can be considerable interdependence among supply options and that a change in one element of the utility's supply strategy can affect the method of serving several load segments. However, this approach is intended to be a realistic, but simplified representation of supply planning activities.

FIGURE 3
Impact Of Baseload DSM Programs



Our analysis of avoided gas costs distinguishes two load segments: winter (including both design day and winter gas demand) reflecting temperature sensitive, space heating related loads and the baseload load segment which reflected constant, year-round loads such as water heating.

3.2 Market Segments/Customer Classes Distinguished in This Analysis

In addition to our effort to distinguish estimates of avoided cost components between two load segments, this analysis also differentiates avoided costs by residential/commercial customers vs. industrial customers. The costs of serving customers tend to differ between residential/commercial customers and industrial customers due to differences in the load factor of typical usage and differences in transmission/distribution system requirements.

3.3 Scope of Avoided Cost Analysis Relates to In-Franchise Avoided Costs

All of this work is focused on estimating avoided costs related to potential changes in in-franchise demand for natural gas within each utility's service area. Whether we are estimating avoided costs for DSM programs which result in net increases in gas demand or conservation oriented efforts which reduce demand per customer, the utilities' efforts to serve their customers through DSM activities can only be targeted at in-franchise gas demands.

3.4 Base Case Supply Plan as Reference Point to Estimate Avoided Costs

Estimates of avoided gas costs must be developed from a reference point, or Base Case supply plan. The Base Case generally reflects Union's and Centra's supply plan/capital budget over the calendar year 1997-2001 period. The Base Case plan was developed in response to a forecast of gradual growth of firm in-franchise general service gas demand plus estimated expansions in out-of-franchise sales. Since estimates of avoided gas costs are needed over a 15-30 year forecast period in order to match the useful life of DSM equipment programs (such as efforts to promote more efficient furnaces), we have made long term growth and cost assumptions to extend current planning assumptions beyond 2001.

In their supply planning actions, both Union and Centra utilize a mix of gas supply options to serve certain load requirements. In particular, to serve winter design day delivery requirements, both utilities utilize a mix of gas delivered directly from pipeline purchases via TCPL and U.S. pipelines during the winter as well as gas withdrawn from storage fields. In addition, Centra uses LNG to meet a substantial share of design day demand. Hence, in order to derive avoided costs, we must estimate not only the avoided cost components (capacity, energy and customer components) of each relevant supply option, but we must also estimate the shares (or weights) among supply options used to supply needed gas services. For example, in considering how a reduction in space heating demands due to DSM programs might affect supply costs, we need to estimate what share of the reduction in both design day delivery requirements and total gas volumes delivered would come from storage vs. TCPL capacity purchases, e.g., for each 1 m^3 of reduction in design day demand, there might be 0.8 m^3 of reduced need for storage delivery capacity and a 0.2 m^3 reduction in pipeline deliverability[8].

3.5 Derivation of Avoided Costs is Based on Hypothetical Scenarios

These estimates of avoided gas costs are being used to help evaluate potential new DSM activities as well as existing activities, hence to support the development of the Union and Centra DSM plans. At this point, we do not know what the impact of potential new DSM activities might actually have on the utilities' load forecasts. In concept, we recognize that potential changes in gas demand due to a new portfolio of DSM activities might alter the utilities' current supply planning assumptions, which in turn might change some of our avoided cost estimates - although such changes in demand patterns would have to be quite substantial to alter these avoided cost estimates in any substantive way.

3.6 Treatment of Avoided Facility Costs

As noted above, at this stage of analysis we cannot predict either the timing or magnitude of the impact of future new DSM programs on the utilities' need for facilities (storage, transmission and distribution) since the avoided costs developed here are being used to help screen and evaluate potential new DSM programs that might be incorporated into the DSM plans. Depending on the nature and magnitude of the impact of potential new DSM activities there might, for example, be delays in initiating investments in new supply facilities in future years.

8 These numbers are illustrative only. Actual weights differ for Centra and Union, and are included in Section 3 of data Appendix A for Union, and Section 3 of data Appendix B for

Therefore, in this analysis we have developed avoided facility costs by assuming that potential new DSM programs would impact the entire, multi-year facility investment program assumed in the Base Case supply plan. Thus, for each of the three types of potential facility investments that would be appropriate for each utility we have calculated a time-weighted average facility avoided cost per unit of capacity, where this average cost is derived using a present value calculation which takes account of: the cost per unit of each element/module of the multi-year facility plan, when that module is being constructed, and size of the capacity increment being added by each module. This approach thus calculates an average cost per unit for the entire set of planned facilities (such as the transmission facility expansion plan) which would weight the cost per unit of modules constructed in the near term more heavily than those constructed in later years and would also place greater weight on the costs of large capacity modules in the multi-year plan.

Hence, the avoided costs related to adding delivery capacity by investing in new facilities was represented by this time-weighted, average cost per unit of the calendar 1997 - 2001 investment plan, taking account of simple assumptions made to extend this capital plan beyond 2001 over the entire time period required for this analysis.

Implies Bias Which Tends to "Overstate" Avoided Facility Costs

It is important to recognize that this approach to estimate avoided facility costs tends to overstate avoided facility costs because it implies that new facility projects will always be altered by DSM programs. To illustrate this point, suppose 1000 units of new design day delivery capacity are planned over the next 5 years at a time-valued, average cost of $12/m^3/design day. If conservation oriented DSM programs were to reduce design day requirements by 10 units over this planning horizon, our assumptions imply that facility costs could in fact be avoided over this period and that the average avoided cost for the 10 units of capacity avoided would be $12 per unit. In fact, the impact of this magnitude of load reduction might not have any effect at all on the 5 year capacity plan (because of the lumpiness and economies of scale of each module of the facility plan) or it might delay construction of

Centra.

one module in the plan from year 4 to year 5. The "actual" avoided cost of either no change in facility costs or the effect of a delay in constructing a module on the actual avoided facility costs would be substantially lower than $12.[9] Hence, we are in fact using a proxy for "average" avoided facility costs that clearly tends to overstate avoided gas costs by assuming that potential DSM programs will always impact facility plans and that facility plans are "perfectly divisible," so that a reduction of even 1 m^3 of design day demand would have a cost savings of $12/$m^3$. In the subsequent analysis of potential DSM programs, this bias tends to make conservation oriented DSM programs appear more cost-effective while implying that other DSM programs which have a net positive impact on gas sales appear to be less cost-effective than they would tend to be in reality.

3.7 Distinguishing Avoided Gas Cost Estimates by Type of Cost/Benefit Test

In the Board's generic ruling on IRP (EBO 169III) for natural gas utilities in Ontario (EBO 169-III) a variety of cost/benefit tests are prescribed to evaluate DSM programs. Avoided gas costs are used as inputs in applying three major tests:

- The Rate Impact Test (RIM)
- The Total Resource Cost Test (TRC)
- The Societal Test (SCT)

These tests differ in perspective, with RIM focusing only on rate impact, TRC focusing on net resource cost benefits (regardless of who pays) and the SCT providing a broader version of the TRC test by adding quantified environmental and social impacts to the scope of the test[10].

The avoided gas costs used in the RIM vs. the TRC/SCT tests differ in three basic respects:

- The RIM test adjusts avoided costs to an after tax basis, TRC/SCT makes no adjustments for income taxes.
- Avoided costs for RIM are discounted using a 7.5 percent, after tax discount rate while Union uses a 10 percent discount rate for the TRC/SCT tests.

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9 If in fact DSM programs did not cause any change in the facility plan, then avoided facility costs would literally equal zero.

10 For Union/Centra purposes the TRC test is equivalent to the SCT test with externality values set to zero.

- When used in the RIM test, avoided costs do not incorporate any adjustments for cost escalation over time (except for facility-related costs), while costs for TRC/SCT incorporate both real and general inflation adjustments.

These adjustments are made in the DSM evaluation software. The avoided cost outputs are no longer provided separately for the RIM test vs. the TRC/SCT test. However, the facility cost components of the avoided cost analysis rely on calculating the discounted value of planned facility costs. For these elements of the analysis, the avoided costs include a factor to account for differences in depreciation treatment, and differences in the discount rate used to determine annualized capital costs between the two tests.

3.8 Estimates of Avoided Costs Focus on Marginal Reductions in Gas Load

The estimates of avoided gas costs derived here begin with a focus on how gas supply costs would likely be reduced below our Base Case forecast of increasing natural gas demand as a result of potential new conservation oriented DSM programs[11]. We recognize that potential new DSM activities will include programs which are conservation oriented (hence have a net impact of reducing gas use per customer) as well as programs which simultaneously improve energy efficiency and add either new gas services for existing customers or add new customers. We believe that the avoided costs estimated using this approach will be applicable to DSM programs which tend to have the effect of reducing demand below our Base Case assumptions and to potential DSM activities which will tend to result in net gas sales increases.

11 "New" programs refer to potential new DSM activities which reflect changes from the existing DSM activities, since the latter have already been incorporated into the Base Case gas demand forecast.

3.9 Avoided Cost Estimates Must Be Revised Periodically

It must be emphasized that estimates of avoided gas costs need to be revised on a periodic basis, hence, in a sense, we can never really "finalize" such estimates. Union's avoided gas costs will have to be updated periodically as information changes and elements of Union's supply strategy change in response to market situations.

4. DEGREE OF DETAIL AND FACTORS CONSIDERED IN THE ANALYSIS FOR UNION GAS

4.1 Introduction

This section addresses the factors considered in preparing estimates of avoided cost components for each element of Union's cost of service: cost of purchased gas, pipeline transport charges to the utility service area, storage facility/tariff costs, transmission and distribution plant within Union's service area plus other non-gas O&M costs.

The avoided cost components for many elements of the utilities' gas supply activities will differ by load segment (winter vs. baseload) and also between the customer classes/market segments identified earlier.

4.2 Union Gas Base Case Supply Plan

The Union Gas Base Case plan was developed in response to a forecast of gradual growth of about 2.1% per annum for the 1997 -2001 period for firm in-franchise general service gas demand plus estimated expansions in out-of-franchise sales. Since estimates of avoided gas costs are needed over a 15-30 year forecast period in order to match the useful life of DSM equipment programs (such as efforts to promote more efficient furnaces), we have made assumptions to extend current planning assumptions beyond 2001. Key assumptions in the Base Case supply plan that relate to serving firm customers are:

- Union will continue to rely primarily on long term firm gas supplies under firm transport agreements, although a portion of the increase in gas supplies required to satisfy demand growth in this Base Case plan is assumed to come from short term gas purchase agreements to introduce greater flexibility into Union's gas purchase portfolio.
- No incremental new storage fields are assumed to be needed to meet demand growth until after 2007. Near term growth in in-franchise storage demand is to be met by reducing the amount of storage capacity released to M12 customers. Hence the avoided costs of storage are determined by the opportunity cost (value) of releasing storage to M12 customers. We have assumed that additional investment in storage fields will be needed after 2007 and each year thereafter in order to serve continued growth in winter demands for in-franchise customers.

- New transmission and distribution facilities are planned, with costs derived from the calendar 1997-2001 capital budget and from long term Trafalgar expansion plans. Although Trafalgar transmission facility expansion will be primarily to serve ex-franchise customers, these are joint use facilities which also serve the growth of in-franchise demand.
- This Base Case strategy assumes that the growth in temperature sensitive gas demand from in-franchise residential/commercial customers in the winter season is satisfied by a combination of storage and direct pipeline purchases:
  - Reliance on storage is maximized by purchasing gas at close to a 100% load factor, injecting gas into storage during the non-winter months then relying on storage withdrawal plus some direct pipeline deliveries to serve both design day and winter loads.
- Baseload demands are being generally served by pipeline purchases via TCPL as well as U.S. pipeline suppliers at the western end of Union's system. As previously discussed with DSM Working Group members, while baseload demands do have some seasonal variability (we have assumed a 20 percent difference between average daily winter and average daily annual demand when determining baseload and winter load demand profiles), we do not expect DSM program design day impacts to reflect this of seasonal variability. Hence, the avoided baseload supply option is 100 percent load factor TCPL firm service transportation.
- Base Case gas demand estimates already incorporate the impact of Union's existing DSM programs, assuming those programs continue into the future at existing levels of activity.

4.3 Avoided Gas Costs (Purchased Gas and Pipeline Tariffs)

Purchased gas cost is the largest single element of the components of avoided costs and projections of this component are also relatively uncertain, given quickly changing market conditions which constantly require reevaluations of Union's and Centra's gas purchasing forecasts. In concept, our approach requires that we identify the "marginal" sources of gas supplies which would in fact be cut back if gas demand were to be reduced (or increased) as a result of DSM program activities.

In preparing reference case estimates of avoided purchased gas costs for the 1997-2001 period, we used the gas purchased costs per unit which are in the utilities' Base Case gas supply plans, and the short term gas price forecast used by Union Gas for demand forecasting. These costs are dominated by the costs of long term gas purchase contract agreements with suppliers in Western Canada which is being transported on TCPL to the utilities' service areas.

To develop a gas price forecast for the period after 2001, we reviewed a number of industry gas forecasts of the Alberta border price of gas, and used the average gas price escalation rate from a range of these industry forecasts. In addition to this reference case, pursuant to the EBRO 493/494 ADR agreement, we also developed a high gas price scenario by averaging several higher than average industry forecasts, and a low gas price scenario by averaging several lower than average industry forecasts.

In order to determine the total avoided city-gate costs of gas, we next focused on estimates of the pipeline costs associated with transporting the purchased gas. TCPL firm transport cost tariffs were assumed to be the "marginal" means of transportation that would be cut back in the face of lower gas demand. We used the most recent estimates provided by TCPL showing how tariffs might change in the near term. Our analysis accounted for the three components of pipeline transport charges (demand, commodity and fuel volumetric loss rates).

Inputs related to gas purchase patterns, gas dispatching patterns, and gas commodity costs associated with the Union base case supply plan were derived from SENDOUT model projections for 1998.

4.4 Storage Related Costs

As noted earlier, we are assuming that investments in new storage fields to meet demand growth are not required until after 2007. Instead, increases in in-franchise storage requirements will be satisfied by reducing the amount of storage capacity released to M12 customers. The avoided cost value of this storage is determined by the opportunity cost of releasing the storage to M12 customers, which was determined based on responses to Union's recent open season offering of Bentpath-Rosedale storage capacity.

After 2007 we assumed that new storage fields will again be required in each year in order to serve continued growth in gas demands. To derive a proxy for the capacity costs of storage, we used costs of potential new fields which might be developed. O&M costs were based on current, typical costs. Our estimates considered six components of storage costs:

- Two facility cost components: one related to design day delivery capacity and another facility component related to creating storage space (e.g., Y days of storage space capable of delivering X m^3/day).
- Three O&M components directly related to storage: compressor fuel, dehydration costs,[12] other storage O&M costs.
- Plus carrying costs related to the value of average gas volumes being held in storage.

Storage related avoided cost components are applicable only for estimating avoided costs for the winter load segment, since storage utilization is really not avoided if year round baseload demands for gas were reduced/increased by DSM activities.

4.5 Mix of Storage vs. Pipeline Gas Supplies to Serve Winter Loads

As noted earlier, Union's supply strategy relies on a mix of gas from storage and direct pipeline deliveries to serve winter gas needs of firm customers. As described above, we generated the avoided capacity cost per m^3/design day and the energy costs/10^3m^3 for both the gas delivered directly from the pipeline (WACOG including both purchased gas and TCPL transport costs) and separately for gas withdrawn from storage during the winter. We then developed the shares or "weights" to apply to costs per unit for these two major gas supply options which are utilized by Union to serve winter loads.

We generated the mix between these supply options using a hypothetical but realistic scenario of how the winter load might change in response to DSM activities. This approach accounts for the interaction between the two supply options since pipeline capacity is used to fill up storage in the non-winter months then used to deliver gas directly to customers in the winter months. In developing the scenario, we assumed that both design day and total winter gas demand would both be reduced by the same proportions by potential DSM program activity.

12 Related to need to dehydrate storage withdrawal volumes taken out near the end of the winter season.

We developed separate supply option weights for residential/commercial demand and for industrial demand. For residential/commercial demand, the bulk of the reduction in design day supply in response to a reduction in peak gas demand would come from the storage option, since Union relies heavily on low cost storage as its primary means of supplying winter gas requirements. The load factor for industrial demand is much flatter than for residential/ commercial demand, and a majority of the reduction in design day demand comes from the pipeline option.

As noted earlier, for the "baseload" load segment the situation is much simpler, since firm gas supplies delivered by TCPL, purchased at 100% load factor, is assumed to be the gas supply option used to satisfy avoided baseload gas demands. Hence, there is no need to derive the mix of different types of supply options avoided for the baseload load segment.

4.6 Transmission Capacity Costs and Impact of DSM on Capacity Requirements

As noted earlier, our estimates of avoided transmission costs are based on the assumption that any change in expected in-franchise load due to potential DSM programs could impact transmission capacity requirements. Since transmission capacity planning is based on design day demand requirements, DSM programs which might alter design day demand volumes can potentially affect transmission capacity needs. Using numbers from the capital budgets and from a long term expansion scenario for the Trafalgar system, we calculated the time-valued, average cost per volume unit of capacity additions projected over a 30 year time horizon, extrapolating beyond the last year (2001) covered in the capital budget. In effect, we are using as our estimate of avoided cost per unit the "average" cost of an entire future transmission capacity expansion program.

This analysis included costs for all planned Union transmission lines (not just Dawn-Trafalgar). Avoided transmission costs were calculated for three categories of Union transmission:

- **Trafalgar Transmission**: Capacity expansion on the Trafalgar system to meet incremental demand growth served by the Trafalgar system.
- **Trafalgar Branch Transmission**: Other transmission originating from the Trafalgar system, such as the Owen Sound transmission line, and

- **Non-Trafalgar Transmission**: Other transmission capacity not originating from the Trafalgar system, such as the Panhandle and Sarnia lines.

The distinction is important since demand growth in areas served by the Trafalgar system also requires branch transmission, hence Trafalgar costs and branch transmission costs must be added to arrive at a total Trafalgar system avoided cost. In contrast, for demand not served by Trafalgar, costs are based on other "non-Trafalgar Transmission" projects. The Trafalgar system avoided cost is averaged with the avoided cost of the non-Trafalgar system based on volume to determine the weighted average avoided cost for Union's overall transmission system.

In estimating avoided transmission costs, we also had to account for how Trafalgar transmission requirements and costs might change if **only** in-franchise demand were to decrease or increase by 1 m^3/design day in response to future DSM programs. This adjustment is necessary since the projection of future increases in Trafalgar delivery capacity and associated costs is based on the sum of both in-franchise and M12 demand growth. An adjustment is necessary since the costs per m3 of design day delivery capacity are different to serve in-franchise growth in comparison to M12 growth.[13] Consequently, Union staff calculated two adjustment factors which were applied to adjust projected Trafalgar costs (based on serving both in-franchise and M12 customers) to reflect how Trafalgar costs would change when only in-franchise demand was altered. Two adjustment factors needed to be calculated, one to reflect service for Weather Sensitive loads and another to reflect Baseload service (constant year round demand), since transmission services are provided differently for these two load segments.

13 This is simply because gas service to Parkway requires, on average, gas to be moved over longer distances on the Trafalgar system than gas delivered to in-franchise customers. Hence, costs per unit of "delivered gas" at Parkway are higher.

4.7 Distribution Plant Costs

Distribution plant costs were determined separately for costs related to volumes of sales (design hour delivery requirements) and costs that relate to the number of customers, which are primarily hookup costs to attach new customers to Union's system.

Plant related to volumetric demand requirements are different for services for existing communities vs. new communities where Union does not currently provide gas services. We have updated avoided costs only for existing customers in existing communities.

Most of Union's existing service area can be characterized by growing gas demand where new gas uses and customer additions have tended to outweigh the effect of enhanced energy efficiency trends. In this environment of net positive gas demand growth, the existing distribution system will need to be periodically upgraded to increase net gas flow capacity to the communities being served. Hence, DSM programs which reduce gas consumption in existing buildings can contribute to avoiding or delaying investments to upgrade the existing distribution system. In this situation, programs which focus on reducing gas usage per customer for existing customers will tend to reduce the need for upgraded distribution services required to serve new customers being added or new gas uses adopted by existing customers. Consequently, DSM programs targeted at existing customers in communities already being served might avoid some portion of planned distribution plant costs.

For residential/commercial customers and industrial customers, estimates of the time-weighted, average cost/m^3 design hour for planned distribution plant expansion related to demand growth in existing communities were derived from Union's 1996 - 1998 capital budgets. These distribution system expansion costs reflect costs that would be affected by changes in demand volume rather than changes in customer counts. Expansion of distribution capacity beyond 1998 was based on assuming the average growth in design hour demand over 1996 - 1998 would continue into the future.

4.8 Non-Gas O&M Costs

Very few of the O&M activities of a gas distributor would be affected by changes in the volume of gas sales. Typical types of O&M activities include:

- Overhead expenses - either administrative overhead (general building plant, accounting/legal) or system operations overhead (the costs of operating the distribution system) which are determined by the physical system size and design,
- Return on rate base and various taxes - return and income taxes are a function of the size of rate base and regulatory or legislative determinations of the applicable taxes and rates or return,
- Costs generally related to the number of customers being served - such as billing, meter reading and installation of new meters or service lines,
- Costs determined by a mix of the types of services offered and the number of customers - service/safety support for gas equipment in the customers residence.

Only a few types of non-gas O&M costs are related to changes in gas demand if the number of customers served remains unchanged. Other than O&M costs identified previously related directly to gas storage activities, we could identify only two other O&M costs which would be increased/decreased by volume changes:

- Compressor fuel - compression fuel losses for gas moved within Union's service area (excluding compressor losses for storage injection and withdrawal which are included under storage O&M),
- Other unaccounted for O&M expenses - miscellaneous expenses believed to be volume related.

For utility DSM programs which add to the number of customers being served, certain O&M costs which are customer related would tend to increase, such as meter reading. Union has derived these estimates of per customer O&M costs from Union's existing cost allocation methodology.

5. DEGREE OF DETAIL AND FACTORS CONSIDERED IN THE ANALYSIS FOR CENTRA GAS

5.1 Introduction

Most elements of the methodology used to generate the Centra Gas avoided costs are the same as used to generate the Union Gas avoided costs. However, there are a few key differences between the utilities that affect the avoided costs for the two utilities and the methodologies we used to estimate avoided costs for the two utilities. These differences are highlighted in this section of the report. In addition, the data inputs used in the avoided cost analysis differ between the two utilities. The key data inputs to the Centra DSM plan are provided in Appendix B to this report.

The Centra avoided cost structure and inputs are influenced by two key assumptions. First, the Centra distribution territory covers a great deal of territory, ranging from Manitoba to Eastern and Northern Ontario. We have estimated avoided costs only for Centra's Eastern Delivery Area since this region includes the majority of Centra's market within the province of Ontario.

Second, Centra Gas and Union Gas are currently owned by the same parent company, and merger discussions are well underway. This set of avoided costs is calculated as if the two companies are actually two separate regions of the same company. Hence, in this analysis, if a reduction in demand by Centra's customers avoids the use of storage space on Union's system, the avoided cost of the storage is based on Union's storage avoided costs. This represents a change from previous avoided cost practice.

5.2 Centra Gas Base Case Supply Plan

The Centra Gas Base Case plan was developed in response to a forecast of gradual growth of 0.9% per annum for firm in-franchise general service gas demand. Since estimates of avoided gas costs are needed over a 15-30 year forecast period in order to match the useful life of DSM equipment programs (such as efforts to promote more efficient furnaces), we have made assumptions to extend current planning assumptions beyond 2001. Key assumptions in the Centra Gas Base Case supply plan that relate to serving firm customers are:

- Centra will continue to rely primarily on long term firm gas supplies under firm transport agreements, although a portion of the increase in gas supplies required to satisfy demand growth in this Base Case plan is assumed to come from short term gas purchase agreements to introduce greater flexibility into Centra's gas purchase portfolio.
- Centra and Union will use the same storage options to provide incremental storage capacity to meet growth. The storage option is considered more likely than additional LNG capacity for meeting incremental design day demand growth.
- The Centra Base Case strategy assumes that any change in temperature sensitive gas demand from in-franchise residential/commercial customers in the winter season is satisfied by a combination of additional storage and direct pipeline purchases.
  - The mix of storage/peaking capacity and pipeline capacity to meet incremental temperature sensitive load is assumed to remain the same as at present.
- Baseload demands are being generally served by pipeline purchases via TCPL as well as U.S. pipeline suppliers at the western end of Union's system. As previously discussed with DSM Working Group members, while baseload demands do have some seasonal variability (we have assumed a 20 percent difference between average daily winter and average daily annual demand when determining baseload and winter load demand profiles), we do not expect DSM program design day impacts to reflect this of seasonal variability. Hence, the avoided baseload supply option is 100 percent load factor TCPL firm service transportation.
- Base Case gas demand estimates already incorporate the impact of Centra's existing DSM programs, assuming those programs continue into the future at existing levels of activity.

5.3 Avoided Gas Costs (Purchased Gas and Pipeline Tariffs)

The methodology used to determine Centra's total avoided city gate cost of gas (gas commodity cost plus gas transportation cost) is the same as for Union Gas. Inputs related to gas purchase patterns, gas dispatching patterns, and gas commodity costs associated with Centra base case supply plan were derived from SENDOUT model projections for 1998.

5.4 Storage Related Costs

We have assumed that Union and Centra storage requirements will be met using the company's own storage instead of purchasing incremental storage services from other storage providers or expanding its LNG facilities. Hence, we have used current Union long term storage avoided costs for Centra as well as for Union. Since storage cannot be provided to Centra's Eastern Delivery Area without additional transportation, we have included the avoided costs of firm transportation on Union's Trafalgar system, and the tariff costs of TCPL Eastern Delivery Area STS transportation to the overall avoided costs of storage services in Centra's service territory.

5.5 Mix of Storage vs. Pipeline Gas Supplies to Serve Winter Loads

Similar to Union, Centra's supply strategy relies on a mix of gas from storage and direct pipeline deliveries to serve winter gas needs of firm residential and commercial customers. As described for Union, we generated the avoided capacity cost per m^3/design day and the energy costs per 10^3m^3 for both the gas delivered directly from the pipeline (WACOG including both purchased gas and TCPL transport costs) and separately for gas withdrawn from storage during the winter. We then developed the shares or "weights" to apply to costs per unit for these two major gas supply options which are utilized by Centra to serve winter loads.

Different weights (mix of supply options) were calculated for residential/commercial demand vs. industrial demand based on the load shapes of each customer class. For residential/commercial demand, the bulk of the reduction in design day supply in response to a reduction in design day gas demand would come from the storage option, since Centra relies heavily on low cost storage as its primary means of supplying winter gas requirements. The load factor for industrial customers is much flatter than for residential/commercial customers, and a majority of the reduction in design day demand comes from the pipeline supply option.

5.6 Transmission Capacity Costs and Impact of DSM on Capacity Requirements

The methodology used to estimate the Centra transmission costs is the same as used to estimate Union's avoidable transmission costs without the complications caused by the complexity of Union's transmission system. The transmission expansion projects used to estimate Centra's avoidable transmission costs include the only currently planned transmission expansion projects in the Centra service territory, which are the Sudbury and Fort Francis projects. These projects are relatively costly, and probably overstate the long run avoided costs of transmission capacity in other areas of Centra's system, particularly eastern Ontario.

5.7 Distribution Plant Costs

The methodology used to estimate the Centra distribution costs is the same as used to estimate Union's avoidable distribution costs.

5.8 Non-Gas O&M Costs

The Union non-gas O&M costs were used as a proxy for Centra non-gas O&M costs.

6. DERIVING AVOIDED GAS COST OUTPUTS USED TO ANALYZE POTENTIAL DSM PROGRAMS

At this point, the various cost elements reflect an "apples and oranges" collection of numbers. For example:

- Various cost elements are treated differently in Union's cost of service - facility related costs are capital costs which go into rate base compared to other types of costs (pipeline demand charges) which are "passed through" in the cost of service each year.
- Costs occur in different time periods - facility costs are assumed to be avoided in the first year of DSM program activity, while most other costs could be avoided in every year of DSM program life.
- Cost components are expressed in different units - most fixed capacity costs are treated as $/m^3/design day but distribution facilities are expressed in terms of $/m^3/design hour. Other costs are expressed as $/10^{3}m^3 of gas volumes consumed during the winter.

The different components of avoided costs are combined into a format suitable for use by Union and Centra DSM staff for the evaluation of DSM programs.

The format of the avoided cost outputs provided by EEA to the Union and Centra DSM staff for the evaluation of DSM programs has changed somewhat from the format documented in the EBRO 493/494 avoided cost evidence. Union and Centra are using an updated DSM evaluation software package with slightly different input requirements. In the past, facility investment costs have been accounted for in the year of the avoided facility investment. However, this approach did not easily allow the DSM evaluation model to differentiate the value of an avoided facility investment for DSM programs with different impact lives. In order to facilitate this evaluation issue, the avoided cost outputs for facility investments were annualized, and are now accounted for over the life of the DSM program rather than during the first year of the DSM program.

The Union/Centra staff responsible for analyzing DSM activities specified a format which would present avoided cost outputs as defined by the following table:

Avoided Cost Element	Cost/units	Cost Impact in Time Frame of DSM Program
Design Hour Facilities	$/m^3/design hour	Annualized over life of asset
Design Day Facilities	$/m^3/design day	Annualized over life of asset
Throughput Facilities	$/m^3	Annualized over life of asset
Design Day Capacity	$/m^3/design day	Incurred each year
Energy/Variable	$/m^3	Incurred each year
Per Customer	$/customer	Incurred each year
Per Customer	$/customer	Annualized over life of asset

Each of the seven elements in the avoided cost output vector is described below:

1. Facility Design Hour Costs: Costs avoided in the first year of DSM program implementation based on the impact of a DSM program on design hour demand such as distribution system expansion costs. Costs are annualized over the life of the facility. Units: $/m^3 avoided on the design hour.

2. Facility Design Day Costs: Costs avoided in the first year of DSM program participation based in the impact of a DSM program on design day demand such as investments to increase design day storage deliverability or in-franchise transmission capacity. Costs are annualized over the life of the facility. Units: $/m^3 avoided on the design day.

3. Facility Throughput Costs: Costs avoided in the first year of DSM program participation based in the impact of a DSM program on demand throughput such as investments in facilities to expand storage space. Costs are annualized over the life of the facility. Units: $/m^3 avoided in the first year.

4. Design Day Capacity Costs: Costs avoided in every year of a DSM program life based on the impact of a DSM program on design day demand such as TCPL transportation capacity tariff costs. Units: $/m^3 avoided on the design day for each year of program life.

5. Energy/Variable Costs: Energy related costs - costs that vary in direct proportion to the quantity of gas consumed, such as gas purchase costs and some other O&M expenses. Units: $/m^3 avoided in each year of program life.

6. Annual Customer O&M Costs: Annual costs per customer resulting from implementation of a DSM program resulting in customer growth, such as meter reading costs. Units: $/Customer for each year of program life.

7. First Year Customer Costs: First year costs associated with a new customer. Typically include hookup costs related to service installation, metering, etc... Costs are annualized over the life of the facility. Units: $/Customer in the first year of customer participation.

The facility costs are annualized using the TRC/SCT discount rate of ten percent, straight line depreciation of assets, and a facility life of thirty years. This results in an annualization factor of 10.23 percent per year, which was used to convert the first year facility costs into an equivalent annual stream of costs over the life of the facility.

The avoided cost outputs are calculated for the TRC/SCT test. There are two significant differences between the TRC test and the RIM test. Tax depreciation is considered in the DSM evaluation software for the RIM test, but is not considered in the TRC/SCT test. In addition, the annualization factor is calculated using the TRC/SCT discount rate of ten percent In order to allow calculation of the RIM test, we have added a RIM test adjustment factor to the avoided cost outputs to account for these differences.

All of the avoided cost components are calculated in nominal dollars on a pre-tax basis. A value for each component is provided for the period 1998 to 2027 for each set of avoided cost outputs provided. The format of the avoided cost outputs is illustrated in table 6-1[14].

The distinctions made in earlier sections of this report result in different sets of avoided cost vectors which are combinations of 3 different distinctions:

- Rate class (2) - residential/commercial vs. industrial
- Load segment (2) - winter vs. baseload
- Utility (2) - Union vs. Centra

As a result we generated 6 sets[15] of reference case avoided cost output vectors (four sets for residential/ commercial demand, and two sets for industrial demand) in a format identical to Table 6-1.

14 Table 6-1 shows a truncated avoided cost input file showing data for only the first few years of analysis.

We also generated a complete set of avoided cost output vectors for a high gas price scenario and a low gas price scenario, for a total of 18 sets of avoided cost output vectors. A complete set of the avoided cost output vectors for Union Gas is included in Appendix C. A complete set of avoided cost output vectors for Centra Gas is included in Appendix D.

15 At this time, the avoided costs for the industrial sector have not been broken out by baseload vs. winter load. Hence only one avoided cost file per utility has been generated for

TABLE

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
ENERGY AND ENVIRONMENTAL ANALYSIS, 08/05/97 05:15 PM PAGE -1-								
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$1.27	$1.30	$1.33	$1.36	$1.38	$1.41	$1.45
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$2.70	$2.77	$2.83	$2.88	$2.94	$3.01	$3.08
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.073	$0.083	$0.084	$0.088	$0.090	$0.094	$0.097
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UWR#R1 08/05/97 NOTES: Union Weather Sensitive M2 Load - Reference Gas Prices 08/05/97

7. AVOIDED COST RESULTS FOR REALISTIC, BUT ILLUSTRATIVE TYPES OF DSM PROGRAMS

In order to indicate the magnitude of the avoided cost estimates we have developed, this section presents summary results for two illustrative but realistic DSM programs: a program targeted at helping to upgrade the efficiency of furnaces that existing customers would select when replacing an old furnace and another program targeted at improving water heater energy efficiency. For each type of program, we estimated program impacts per customer on design day demand and annual gas use.

By combining the avoided cost components with the assumed energy impacts, we calculated total avoided cost per customer for the capacity and energy/commodity components then divided these costs by total annual m^3 of gas impacted so that we could show avoided costs for both major components on a comparable basis - cents/annual m^3 of gas use. Tables 7-1 and 7-2 show the results for both illustrative DSM programs for both Union and Centra. For the space heating program the total avoided gas costs for Union are about 15.5 cents/m^3, which can be compared to customer rates[16] (on a before tax basis) of about 24.1 cents/m^3. You can see that capacity costs (related to design day or design hour requirements) are a substantial portion (roughly one/third) of avoided costs for the space heating program. Both capacity and energy related costs are slightly lower for the water heating program on a cents/m^3 basis and total avoided cost is about 10 percent less at 14 cents/m^3. As noted earlier, avoided capacity costs/m^3 tend to be higher for DSM programs which target winter loads compared to baseload end use markets such as water heating. Avoided energy costs for water heating are lower because there are no storage throughput related costs associated with serving the baseload load segment. Also, because Union is able to purchase gas for winter load at close to 100 percent load factor, its energy cost components for winter load are only slightly higher than for baseload uses of gas.

The Centra avoided costs for the space heating program are about 37 percent higher than Union's avoided costs for the same furnace DSM program reflecting the higher cost of storage capacity and pipeline transmission capacity required to serve Centra's eastern delivery area. These costs are higher for Centra than for Union since:

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16 Value reflects average cost per m^3 consumed by a residential customer, instead of tariff based rates.

- Centra's supply strategy implies a lower load factor use of TCPL capacity relative to Union's use of TCPL capacity. This results in higher TCPL fixed costs per unit of throughput for Centra than for Union.
- The Centra service territory is further from the available incremental storage fields than the Union service territory. Hence delivery of storage gas requires additional transportation services not required by Union Gas.
- Transmission capacity expansion, particularly in Centra's outlying areas, tends to be more expensive than for Union Gas. In addition, the current transmission costs are based on two relatively expensive projects (per unit of capacity added on a systemwide basis), which may result in a substantial overstatement of the long run transmission avoided costs.

For the water heater program, Centra costs are about six percent higher than Union costs.

Table 7-1

AVOIDED GAS COSTS FOR UNION GAS

Levelized Cost (Before Tax)
(cents / m^3)

Cost Element	Space Heating	Water Heating
Avoided Costs		
Capacity related	4.94	4.07
Energy related	10.52	9.95
Per Customer	0	0
Total Avoid Cost/m^3	15.46	14.02
Current Customer Rates	24.1	24.1

Program definition:
- Residential customer
- Existing community
- Existing customer
- 20 year DSM program life
- Discount rate = 10 %

Table 7-2

AVOIDED GAS COSTS FOR CENTRA GAS

Levelized Cost (Before Tax)
(cents / m^3)

Cost Element	Space Heating	Water Heating
Avoided Costs		
Capacity related	10.11	4.86
Energy related	10.44	9.95
Per Customer	0	0
Total Avoid Cost/m^3	21.17	14.81
Current Customer Rates	29	29

Program definition:
- Existing residential customer
- Existing community
- 20 year DSM program life
- Discount rate = 10 %

8. SUMMARY OF KEY CHANGES IN AVOIDED COST METHODOLOGY AND RESULTS

8.1 Changes in Avoided Cost Methodology

There have been a few important changes in the development of the Union Gas and Centra Gas avoided cost estimates since the last avoided cost study was submitted as part of EBRO 493/494 in addition to updating data inputs.

Several changes were made to respond to the provisions of the EBRO 493/494 ADR agreement relating to avoided costs. These changes include:

- The reference case gas commodity price forecast used in the analysis was developed using an average of available industry forecasts in order to reflect industry gas price expectations and account for relevant market trends.

- High and low gas price scenarios were developed in addition to the reference case gas price scenario.

- The avoided costs were more clearly defined to reflect "design day" avoided costs. In addition, the baseload demand profile, and associated supply portfolio was modified to reflect the impacts of expected moderate seasonal variation in baseload demand on avoided supply costs.

- TCPL expansion costs were reviewed to evaluate the potential for developing TCPL upstream avoided costs. We determined that the upstream costs that might be avoided by Union and Centra DSM activity could not easily be calculated from publicly available data.

Other changes were made to address specific issues raised by interveners in EBRO 493/494, in response to changes in market structure, and the corporate structure of Union Gas and Centra gas. The major changes of this nature are summarized below:

- Centra and Union are now treated as two regions of the same company, instead of two separate companies. The major impact of this change is the treatment of Centra avoided storage costs. Centra avoided storage costs were revised to reflect the avoided costs of Union and Centra storage facilities rather than using Union storage tariffs.

- The costs of transporting gas from Union storage to the Centra service territory have been revised to include the avoided cost of capacity on the Trafalgar system and the tariff costs of TCPL STS transportation.

- The avoided cost output format has been revised to accommodate changes in the DSM evaluation software. The major change is that facility investment costs have been annualized over the life of the facilities rather than being reported as a first year investment cost.

- The definition of the industrial sector has been expanded from M7 customers to include all firm transportation and contract customers in order to more accurately represent avoided costs for the full range of industrial customers.

8.2 Comparison of Avoided Cost Results to Previous Analysis

The estimates of both Union and Centra Gas avoided costs have increased relative to the avoided cost estimates prepared for EBRO 493/494. The primary cause for the increase was a substantial increase in the long term reference case forecast of the Alberta border price of gas. The previous avoided cost analysis gas price forecast projected Alberta border to prices to remain constant in real terms, with an average nominal increase of 2.66 percent per year. The updated reference case gas price forecast includes an average nominal increase in Alberta border gas prices of 4.3 percent per year

For the hypothetical Union Gas space heating DSM illustrated in Table 7-1, the avoided costs of the program increased from $0.125 per cubic meter to $0.155 per cubic meter, and the avoided costs associated with the hypothetical water heating program increased from $.112 to $0.14 per cubic meter. About 90 percent of the increase is due to the increase in Alberta border gas price forecast between the two sets of avoided cost estimates.

For the hypothetical Centra Gas space heating DSM program illustrated in Table 7-2, the avoided costs of the program increased from $0.149 per cubic meter to $0.212 per cubic meter. About 40 percent of the increase is due to the increase in Alberta border gas price forecast between the two sets of avoided cost estimates. The remaining increase results from inclusion of several newly defined transmission capacity expansion projects in the Centra service territory, which increased the cost of transmission capacity serving design day demand, and an increase in the cost of storage to account for transportation costs of moving storage gas to the Centra service territory. Given the substantial increase in winter avoided costs, it is probably advisable to conduct further analysis of these changes, particularly the Centra design day transmission costs, which appear to be overstated.

The impacts were much less substantial for Centra baseload avoided costs, the avoided costs associated with a Centra water heating program increased from \$.117 to \$0.148 per cubic meter, primarily due to the increase in gas commodity costs.

APPENDIX A: SUPPORTING DATA FOR UNION GAS AVOIDED COSTS

This appendix includes the basic data used in the Union Gas avoided cost analysis. We have included the same level of avoided cost input data detail provided to intervenors by Union Gas for EBRO 493/494 The appendix is organized into three sections based on the type of data:

- Section 1: Union Data Inputs: The first section includes the basic data inputs provided by Union Gas and used in the avoided cost calculations.

- Section 2: Intermediate Data Inputs: The second section includes the levelized facility costs for Union Gas facility investments used in the avoided cost analysis, and calculated based on the inputs in section 1.

- Section 3: Supply Option Weights: The final section includes the specific supply option weights used to determine the avoided supply costs for specific load segments and end uses. These inputs were not requested by intervenors in EBRO 486.

Each table includes a "notes" section that describes the source and uses of the data.

APPENDIX A: SECTION 1
UNION GAS AVOIDED COST DATA INPUTS

Appendix A, section 1 includes the basic data inputs provided by Union Gas and used in the avoided cost analysis. Data tables include:

- Table A-1A: Union In-Franchise Monthly Throughput Volume Forecast (1998 - 2002)
- Table A-1B Union Gas Design Day Peak Demand
- Table A-2A Union/Centra Gas Purchase Costs
- Table A-2B Industry Natural Gas Price Forecasts
- Table A-3A TCPL Pipeline Costs
- Table A-3B TCPL Pipeline Tariff Sheets
- Table A-4 Union Storage Facility Cost Inputs
- Table A-5A Union Trafalgar Facility Expansion Cost Inputs
- Table A-5B Union Non-Trafalgar Transmission Facility Expansion Cost Inputs
- Table A-5C Union In-Franchise Transmission Facility Costs By Load Segment
- Table A-6 Union Volume Related Distribution Cost Inputs
- Table A-7 Union Volume Related O&M Costs

Table A-1A
UNION IN-FRANCHISE MONTHLY THROUGHPUT FORECAST
1998 - 2001

See attached sheets for 1998, 1999, 2000, and 2001 Monthly throughput forecasts.

Notes On Table A-1

Data Source: Union Gas, June 5, 1997.

The C1990 Merger Rate Case Forecast - Update
UNION GAS TOTAL THROUGHPUT VOLUMES FORECAST
In 10^3 m3

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SALES	Year 1998 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Rate M2													
Residential	372,408	322,620	283,855	183,809	99,092	48,830	47,646	47,365	61,587	123,227	200,412	315,106	2,165,964
Sm. Commercial	211,220	197,064	175,396	116,059	60,456	34,694	24,608	34,371	34,168	81,181	137,758	198,441	1,284,418
Lg. Commercial	10,209	11,516	11,046	9,277	6,570	3,796	2,376	2,471	2,612	4,621	5,624	7,374	77,492
Tobacco	380	380	380	388	426	380	380	5,919	16,799	7,263	417	380	33,492
NGV	1,345	1,419	1,342	1,439	1,469	1,370	1,262	1,281	1,409	1,418	1,489	1,409	16,660
Commercial Total	223,154	210,179	188,364	127,164	68,921	40,240	28,636	34,043	54,988	94,483	145,289	207,603	1,414,062
Sm. Industrial	45,029	42,332	36,905	24,372	13,373	8,246	8,194	8,027	12,584	21,052	32,383	42,957	299,454
Lg. Industrial	9,253	10,966	9,459	7,723	5,863	4,357	3,817	3,671	4,823	5,854	8,378	9,809	83,972
Industrial Total	54,281	53,298	46,364	32,095	19,236	12,603	12,011	11,698	17,407	26,906	40,761	52,767	379,426
Total Rate M2	649,843	587,106	518,583	343,060	187,249	91,673	88,282	93,105	133,982	244,617	386,461	575,476	3,899,492
Contract Sales													
Rate M4 - Comm.	11,206	10,456	9,329	6,979	4,691	2,539	1,943	2,059	2,806	4,951	6,613	9,537	73,189
Rate M4 - Ind.	29,903	28,373	26,144	20,285	18,750	16,022	14,078	14,900	14,253	17,480	20,312	28,734	241,313
Total Rate M4	41,109	38,829	35,473	27,264	23,441	18,561	16,021	17,039	17,059	22,431	26,925	38,271	314,502
Rate M5 - Comm.	18,033	17,547	16,263	12,266	8,852	5,794	4,173	4,154	5,658	8,217	10,880	14,391	126,226
Rate M5 - Ind.	9,710	9,318	9,473	8,078	8,226	7,825	6,990	8,260	8,102	8,993	8,129	6,683	99,789
Total Rate M5	27,743	26,864	25,736	20,344	17,077	13,619	11,164	12,413	13,760	17,211	19,009	21,074	226,014
Rate M6	0	0	0	0	0	294	350	268	280	30	0	0	1,231
Rate M7	3,950	4,113	4,284	0	0	0	0	0	0	0	0	0	12,349
Rate M9	46,685	40,868	37,366	24,368	14,087	9,100	7,690	9,542	11,319	20,255	31,036	40,971	293,367
Rate M10	709	819	572	393	204	55	42	63	107	230	339	531	4,149
Total Contract	120,356	111,496	103,431	72,368	54,817	41,710	35,271	39,325	42,526	60,157	77,309	92,847	851,612
Total Sales	770,199	698,602	622,014	415,436	242,065	133,398	123,553	132,430	176,508	304,773	463,770	668,323	4,751,064
TRANSPORTATION SERVICE													
T2 Residential	15	13	11	7	4	2	2	2	3	5	8	12	83
T2 Commercial	4,802	4,477	3,988	2,653	1,468	675	636	664	842	2,002	3,782	4,552	30,542
T2 Industrial	5,401	5,280	4,501	3,025	1,615	970	932	948	1,345	2,297	3,371	4,825	34,906
Sub total T2	10,218	9,770	8,501	5,686	3,097	1,647	1,560	1,612	2,189	4,304	7,361	9,489	65,530
Rate T4 - Comm.	1,480	1,538	1,212	1,040	660	313	270	276	421	624	959	1,210	10,012
Rate T4 - Ind.	57,325	54,894	53,832	45,602	41,865	30,319	32,692	38,110	39,921	43,971	50,164	48,064	546,759
Total Rate T4	58,805	56,432	55,044	46,643	42,525	30,632	32,970	38,386	40,343	44,594	51,123	49,275	554,771
Rate T5 - Comm.	16,216	15,588	14,334	10,773	8,040	5,849	4,501	4,827	6,412	9,355	11,177	13,932	121,084
Rate T5 - Ind.	19,429	18,413	18,005	16,787	14,220	13,002	10,266	13,956	20,849	17,913	18,647	18,314	199,802
Total Rate T5	35,645	34,001	32,339	27,560	22,261	18,851	14,840	18,783	27,261	27,269	29,823	32,246	320,886
Rate T7	179,153	156,753	160,924	147,763	136,643	123,330	117,298	129,444	135,547	151,636	170,284	181,958	1,792,733
Rate T9	3,033	2,655	2,427	1,503	915	595	500	620	735	1,316	2,016	2,662	19,058
Sub total T4579	276,636	249,841	250,734	223,349	202,343	181,409	165,616	187,234	203,885	228,815	253,247	266,141	2,689,448
T1	173,064	158,244	169,882	152,362	154,211	150,968	148,374	156,142	155,724	157,274	173,367	176,545	1,926,157
Sp. Ind.	0	0	0	0	0	0	0	0	0	0	0	0	0
Total T-Service	459,910	417,863	429,197	381,596	359,651	334,024	315,589	344,980	361,798	390,393	433,974	452,175	4,681,135
Total Throughput	1,230,116	1,116,465	1,051,210	797,033	601,716	467,410	439,112	477,410	538,306	695,166	897,744	1,120,498	9,432,199

The C1999 Margin Rate Case Forecast - Update
UNION GAS TOTAL THROUGHPUT VOLUMES FORECAST
(in 10^3 m3

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Year 1999

SALES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Rate M2													
Residential	391,555	330,179	290,333	188,923	101,792	50,032	40,156	40,807	63,130	136,232	204,160	320,678	2,135,000
Sm. Commercial	217,370	204,242	179,446	118,540	61,843	25,200	25,105	34,963	33,046	83,167	140,906	202,963	1,308,071
Lg. Commercial	10,325	11,330	11,020	9,203	6,575	3,799	2,577	2,471	3,610	4,617	5,019	7,360	77,534
Tobacco	300	300	300	380	424	300	300	5,919	16,799	7,363	417	300	33,092
NGV	1,442	1,323	1,420	1,543	1,575	1,476	1,322	1,376	1,500	1,519	1,597	1,511	37,064
Commercial Total	229,325	217,074	192,346	129,755	70,419	30,554	28,304	34,731	53,965	96,346	148,539	212,225	1,447,730
Sm. Industrial	43,677	43,250	37,220	24,610	13,520	8,344	8,200	8,129	12,760	21,342	32,830	43,492	209,500
Lg. Industrial	9,232	10,965	9,401	7,726	5,666	4,361	3,021	3,673	4,827	3,050	8,306	9,043	84,043
Industrial Total	54,920	54,225	46,601	32,344	19,394	12,705	12,115	11,004	17,596	27,300	41,216	53,337	303,540
Total Rate M2	665,800	603,070	520,370	350,011	190,000	94,071	80,905	90,340	136,700	240,970	393,922	584,220	3,900,200
Contract Sales													
Rate M4 - Comm.	11,363	10,533	9,404	7,049	4,799	2,665	1,947	2,043	2,819	4,953	6,617	9,543	73,640
Rate M4 - Ind.	24,963	24,952	23,203	17,910	16,339	14,073	12,126	13,913	14,307	17,340	20,165	20,601	219,902
Total Rate M4	36,326	35,485	32,609	24,967	21,090	16,477	14,073	15,970	17,017	22,295	26,782	30,143	293,549
Rate M5 - Comm.	18,000	17,393	16,305	12,290	8,883	5,821	4,129	4,184	5,685	8,347	10,916	14,425	126,632
Rate M5 - Ind.	6,656	6,345	6,343	5,176	5,226	4,926	4,253	3,460	5,493	6,315	6,902	5,304	60,600
Total Rate M5	24,736	23,938	22,648	17,474	14,108	10,747	8,655	8,631	11,178	14,560	17,816	19,809	193,119
Rate M6	0	0	0	0	0	294	330	260	288	30	0	0	1,231
Rate M7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate M9	47,790	41,035	30,231	24,945	14,421	9,397	7,272	8,760	11,367	20,734	31,771	41,941	300,312
Rate M10	815	843	591	465	309	37	40	63	110	239	357	350	4,205
Total Contract	109,407	102,100	94,270	67,011	49,043	37,372	30,790	33,730	40,171	57,000	76,726	92,450	794,500
Total Sales	778,476	704,170	433,006	418,020	241,447	131,343	131,303	124,073	176,044	297,837	470,640	675,000	4,700,200
TRANSPORTATION SERVICE													
T2 Residential	15	15	11	7	4	3	3	3	3	3	3	11	83
T2 Commercial	4,309	4,471	3,954	2,632	1,450	671	631	660	857	1,900	3,730	4,316	30,344
T2 Industrial	3,347	3,257	4,322	3,003	1,616	943	927	942	1,339	2,237	3,347	4,081	34,434
Sub total T2	10,131	9,741	8,487	5,643	3,070	1,618	1,561	1,604	2,170	4,280	7,313	9,400	63,063
Rate T4 - Comm.	3,379	3,456	3,010	2,439	1,758	911	777	775	1,120	1,732	2,538	3,109	23,192
Rate T4 - Ind.	58,300	54,518	52,674	44,550	41,163	37,300	31,040	37,046	38,887	44,693	46,633	45,733	533,615
Total Rate T4	61,869	57,974	55,684	46,989	42,921	38,503	32,624	37,821	40,007	46,415	49,191	48,841	556,907
Rate T3 - Comm.	16,216	15,308	14,334	10,723	8,040	3,849	4,581	4,027	6,412	9,333	11,177	13,932	121,004
Rate T3 - Ind.	21,197	20,092	19,613	17,446	14,699	13,663	11,071	11,549	19,113	16,211	14,661	14,359	196,036
Total Rate T3	37,413	35,400	33,947	28,179	22,740	19,513	15,652	15,776	25,525	25,547	25,838	28,291	317,130
Rate T7	191,033	171,497	170,995	154,813	143,363	130,601	121,374	136,030	131,348	170,608	168,043	174,324	1,843,239
Rate T9	3,139	2,765	2,320	1,649	923	631	520	646	766	1,370	2,100	2,772	19,849
Sub total T4/T9	294,383	267,097	262,734	231,631	210,176	189,325	170,171	193,272	197,066	224,040	245,170	254,420	2,741,014
T1	186,314	172,817	184,275	164,956	167,334	162,370	161,070	147,235	168,181	164,333	185,415	189,543	2,073,372
Sp. Ind	0	0	0	0	0	0	0	0	0	0	0	0	0
Total T-Service	490,620	450,236	455,516	402,330	380,580	353,333	332,831	342,111	368,320	392,673	437,899	453,100	4,877,640
Total Throughput	1,269,105	1,154,420	1,079,072	821,048	622,036	484,779	464,164	426,182	545,164	700,510	916,548	1,131,040	9,660,002

The C1998 Merger Rate Case Forecast - Update
UNION GAS TOTAL THROUGHPUT VOLUMES FORECAST
(in 10^3 m3)

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Year 2000

SALES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Rate M2													
Residential	387,957	346,971	293,992	193,109	104,064	51,090	50,357	50,021	64,527	128,918	207,537	325,813	2,206,551
Sm. Commercial	222,360	311,277	183,528	121,190	63,242	25,055	25,760	25,530	35,859	84,903	143,879	207,124	1,330,604
Lg. Commercial	10,225	11,530	11,059	9,285	6,575	3,799	2,377	2,471	2,610	4,617	5,619	7,369	77,534
Tobacco	300	300	300	300	426	300	300	5,919	16,799	7,363	417	300	33,493
NGV	1,555	1,642	1,551	1,642	1,698	1,520	1,455	1,405	1,624	1,636	1,721	1,631	19,249
Commercial Total	234,130	234,828	196,510	132,325	71,941	31,623	29,901	35,412	56,892	98,500	151,635	216,903	1,480,879
Sm. Industrial	46,440	44,315	37,733	24,927	13,692	8,444	8,393	8,229	12,935	21,404	33,208	43,882	305,800
Lg. Industrial	9,252	10,966	9,461	7,726	5,866	4,361	3,821	3,673	4,827	5,857	8,341	9,811	84,006
Industrial Total	55,692	55,281	47,194	32,653	19,558	13,005	12,214	11,902	17,762	27,461	41,549	53,693	387,806
Total Rate M2	678,168	637,080	520,504	358,586	195,563	96,134	98,052	97,330	139,180	254,880	400,763	596,410	4,075,236
Contract Sales													
Rate M4 - Comm.	11,343	10,533	9,404	7,049	4,730	3,009	1,947	2,063	2,810	4,955	6,617	9,542	73,648
Rate M4 - Ind.	24,963	24,952	23,285	17,938	16,339	14,072	12,126	13,915	14,207	17,340	20,165	20,601	219,902
Total Rate M4	36,306	35,485	32,689	24,987	21,098	16,677	14,073	15,978	17,017	22,295	26,782	30,143	293,549
Rate M5 - Comm.	18,080	17,593	16,305	12,298	8,882	5,821	4,199	4,184	5,665	8,247	10,914	14,425	126,632
Rate M5 - Ind.	6,656	6,345	6,343	5,176	5,226	4,926	4,235	5,448	5,493	6,313	6,902	5,384	68,488
Total Rate M5	24,736	23,938	22,648	17,474	14,108	10,747	8,435	9,631	11,170	14,560	17,816	19,809	195,119
Rate M6	0	0	0	0	0	294	350	348	280	30	0	0	1,231
Rate M7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate M9	48,922	42,825	20,156	25,533	14,762	8,420	8,059	10,000	11,861	21,225	32,523	42,933	307,423
Rate M10	237	963	607	415	213	50	50	64	112	247	373	378	4,419
Total Contract	110,033	103,111	90,099	68,411	50,180	37,396	20,507	35,561	40,440	58,350	77,494	93,463	801,740
Total Sales	788,989	730,191	634,023	426,097	245,741	133,519	133,539	132,202	179,620	313,237	478,256	690,073	4,876,976
TRANSPORTATION SERVICE													
T2 Residential	14	13	11	7	4	2	2	2	2	3	8	12	82
T2 Commercial	4,736	4,405	3,937	2,613	1,449	667	620	656	832	1,975	3,736	4,484	30,185
T2 Industrial	5,350	5,294	4,510	2,999	1,613	863	925	930	1,334	2,277	3,530	4,854	34,596
Sub total T2	10,100	9,792	8,458	5,621	3,066	1,533	1,554	1,597	2,160	4,257	7,274	9,350	64,864
Rate T4 - Comm.	5,677	5,334	4,809	3,837	2,836	1,510	1,275	1,273	1,818	3,020	4,156	5,007	40,378
Rate T4 - Ind.	55,750	52,100	50,384	42,360	39,377	33,060	29,318	34,516	36,237	42,383	46,633	45,733	509,979
Total Rate T4	61,427	57,443	55,192	46,206	42,233	34,570	30,593	35,789	38,055	45,404	50,789	50,740	550,331
Rate T5 - Comm.	16,216	15,580	14,334	10,773	8,040	5,849	4,501	4,027	6,412	9,315	11,177	13,932	121,084
Rate T5 - Ind.	16,318	15,714	15,313	14,087	12,362	11,729	10,222	12,025	18,610	15,002	15,321	15,019	171,720
Total Rate T5	32,534	31,303	29,647	24,860	20,402	17,577	14,503	16,051	25,022	24,317	26,497	28,951	292,804
Rate T7	193,409	173,133	172,231	156,449	145,111	131,700	129,751	144,607	139,545	158,645	175,665	182,147	1,902,501
Rate T9	3,200	2,879	2,633	1,717	993	647	543	472	797	1,437	2,187	2,887	20,479
Sub total T4-T9	290,739	264,757	259,703	229,123	208,739	185,502	175,089	197,919	203,419	229,833	255,138	264,725	2,766,306
T1	197,343	183,087	194,502	174,280	175,060	170,723	167,540	173,393	176,074	172,412	189,095	192,344	2,167,775
Sp. Ind.	0	0	0	0	0	0	0	0	0	0	0	0	0
Total T-Service	498,088	457,637	462,664	409,028	386,865	358,007	344,002	374,909	380,644	406,522	451,507	466,418	4,998,947
Total Throughput	1,287,079	1,187,828	1,097,043	835,711	632,606	492,376	460,341	508,211	560,291	719,759	929,763	1,158,093	[illegible]

The C1998 Merger Rate Case Forecast - Update
UNION GAS TOTAL THROUGHPUT VOLUMES FORECAST
In 10^3 m3

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Year	2001

SALES	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Rate M2													
Residential	504,315	341,530	300,131	197,165	106,336	32,870	31,513	31,147	65,918	131,705	319,871	331,817	2,236,311
Sm. Commercial	230,023	214,133	187,737	123,917	64,666	26,441	26,330	26,117	36,609	90,338	146,967	211,420	1,379,508
Lg. Commercial	10,225	11,330	11,009	9,185	6,575	3,750	2,377	2,471	2,610	4,617	5,619	7,360	77,534
Tobacco	380	380	380	388	426	380	380	5,919	16,799	7,263	417	380	33,492
NGV	1,674	1,770	1,670	1,709	1,829	1,700	1,565	1,601	1,747	1,745	1,832	1,737	20,721
Commercial Total	240,304	227,511	200,845	135,179	73,496	32,330	30,672	36,108	57,834	103,960	154,835	220,994	1,511,055
Sm. Industrial	46,670	44,131	37,839	24,981	13,725	8,469	8,431	8,259	12,985	21,672	33,330	44,070	304,547
Lg. Industrial	9,232	10,966	9,461	7,726	5,866	4,361	3,821	3,675	4,827	5,857	8,381	9,811	84,004
Industrial Total	55,927	55,097	47,300	32,707	19,591	12,830	12,242	11,934	17,812	27,529	41,711	53,881	388,551
Total Rate M2	800,547	624,417	540,376	365,351	199,334	98,030	94,428	99,189	141,340	259,732	488,436	606,632	4,135,817
Contract Sales													
Rate M4 - Comm.	11,363	10,333	9,404	7,049	4,759	2,005	1,947	2,063	3,810	4,935	4,617	9,542	73,648
Rate M4 - Ind.	24,963	24,952	23,285	17,938	16,339	14,072	12,126	13,915	14,207	17,340	20,165	20,601	219,903
Total Rate M4	36,326	35,285	32,689	24,987	21,098	16,077	14,073	15,978	17,017	22,275	24,782	30,143	293,549
Rate M5 - Comm.	18,000	17,593	16,305	12,298	8,882	5,821	4,199	4,184	5,683	8,247	10,914	14,425	126,653
Rate M5 - Ind.	6,436	6,345	6,345	5,176	5,226	4,926	4,233	5,468	5,495	6,319	6,902	5,384	68,458
Total Rate M5	24,736	23,938	22,440	17,474	14,108	10,747	8,432	9,651	11,178	14,560	17,816	19,809	195,110
Rate M6	0	0	0	0	0	294	330	260	290	30	0	0	1,231
Rate M7	0	0	0	0	0	0	0	0	0	0	0	0	0
Rate M9	30,079	43,839	40,082	28,140	15,111	9,947	8,240	10,236	12,141	21,727	33,293	43,940	314,695
Rate M10	156	300	420	423	216	99	51	68	114	353	386	396	4,321
Total Contract	111,397	104,341	95,030	69,834	50,540	37,024	31,178	36,201	40,731	58,866	76,377	94,497	809,113
Total Sales	920,544	728,758	644,314	434,375	249,063	128,600	125,606	135,390	182,279	318,598	464,714	700,129	4,944,938
TRANSPORTATION SERVICE													
T2 Residential	16	12	11	7	4	2	2	3	2	3	8	12	81
T3 Commercial	4,722	4,427	3,900	2,603	1,443	664	625	634	335	1,968	3,724	4,460	30,037
T3 Industrial	5,301	5,200	4,472	2,960	1,597	953	914	929	1,330	2,252	3,495	4,812	34,222
Sub total T3	10,037	9,640	8,393	5,390	3,043	1,619	1,542	1,383	2,131	4,223	7,227	9,293	64,340
Rate T4 - Comm.	5,773	5,433	4,907	3,935	2,955	1,808	1,573	1,378	1,516	2,919	4,254	5,105	41,552
Rate T4 - Ind.	55,750	52,108	50,384	42,268	39,377	35,060	29,310	34,316	34,337	42,383	46,633	45,733	509,939
Total Rate T4	61,523	57,541	55,291	46,196	42,331	36,868	30,891	35,897	36,133	45,302	50,887	50,838	551,311
Rate T5 - Comm.	16,316	15,328	14,334	10,773	8,060	5,849	4,581	4,827	6,412	9,355	11,177	13,932	121,084
Rate T5 - Ind.	16,318	15,714	15,315	14,087	12,363	11,729	10,222	12,025	18,610	15,002	15,331	15,019	171,730
Total Rate T5	32,334	31,303	29,647	24,860	20,403	17,577	14,903	16,851	25,022	24,357	26,497	28,951	292,804
Rate T7	200,440	180,093	179,191	143,429	152,071	134,660	129,771	144,607	139,343	159,663	175,663	182,147	1,944,361
Rate T9	3,434	2,995	2,741	1,787	1,033	673	544	700	830	1,484	2,276	3,005	21,517
Sub total T4/T9	297,933	271,933	266,860	234,252	215,837	193,566	173,309	198,046	203,550	230,019	253,336	264,941	2,810,093
T1	197,345	183,087	194,302	174,280	175,060	170,723	167,560	175,385	176,074	172,411	189,093	192,344	2,167,775
Sp. Ind.	0	0	0	0	0	0	0	0	0	0	0	0	0
Total T-Service	505,315	464,670	469,703	414,321	393,941	365,918	344,911	375,033	383,775	406,647	451,647	466,577	5,043,380
Total Throughput	1,307,730	1,193,230	1,114,077	850,306	643,005	501,567	470,516	516,414	546,054	723,343	958,362	1,167,706	9,987,138

Revenue Forecasting \FIN\REVFCST\98RC\UNION\UGC98RC.WK4 08/05/97

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Table A-1B

UNION DESIGN DAY DEMAND
(10^3 M^3 per Day)

Calendar Year	Trafalgar System		Other In-Franchise	Total In-Franchise
	In-Franchise	Ex-Franchise		
1997	37,893	94,698	16,352	54,245
1998	38,959	100,052	16,666	55,625
1999	39,899	100,052	16,999	56,898
2000	40,333	100,364	17,256.	140,697
2001	40,869	102,913	17,343.	58,212.

Notes On Table A-1C

1. Data Source: Union Gas Dawn-Trafalgar System Load Forecast, May 23, 1997.

TABLE A-2A
UNION/CENTRA GAS PURCHASE COSTS
($/10^{3}m^3)

	Reference Case	High Price Case	Low Price Case	CPI Escalation
1996	$58.25	$58.25	$58.25	
1997	$65.18	$63.76	$60.84	1.7%
1998	$64.12	$68.02	$63.23	2.2%
1999	$72.78	$72.71	$65.85	2.4%
2000	$73.70	$77.57	$68.45	2.2%
2001	$77.22	$80.72	$69.61	1.8%
2002	$79.71	$84.18	$70.92	2.0%
2003	$82.52	$88.04	$72.47	2.3%
2004	$85.65	$92.33	$74.28	2.6%
2005	$89.02	$96.94	$76.20	2.7%
2006	$92.19	$100.93	$78.41	2.8%
2007	$95.57	$105.17	$80.74	2.9%
2008	$99.28	$109.81	$83.32	3.1%
2009	$103.11	$114.66	$85.99	3.1%
2010	$107.11	$119.73	$88.72	3.1%
2011	$111.26	$125.01	$91.55	3.1%
2012	$115.67	$130.65	$94.57	3.1%
2013	$120.38	$136.68	$97.77	3.1%
2014	$125.41	$143.13	$101.19	3.1%
2015	$130.64	$149.88	$104.72	3.1%
2016	$136.09	$156.95	$108.37	3.1%

Table A-2
UNION/CENTRA GAS PURCHASE COSTS
(Continued)

Notes On Table A-2

1. Gas purchase price reflects Alberta border price.

2. Gas purchase price for all three scenarios based on actual 1996 gas purchase price of $58.25 per 10^3M^3.

3. Near term (1997-2000) reference case gas prices are based on the gas price forecast used by Union Gas to project gas demand. Data Source: Union Gas.

4. Longer term reference case gas price escalation is based on a review of industry estimates of future gas price escalation. The reference gas price scenario was developed by aggregating the natural gas price growth rates of a range of industry forecasts.

5. The high gas price scenario was developed by aggregating the natural gas price growth rate of industry forecasts with substantially higher than average gas price growth rates.

6. The low gas price scenario was developed by aggregating the natural gas price growth rate of industry forecasts with substantially lower than average gas price growth rates.

7. All gas price scenarios are provided in nominal dollars, and include nominal price escalation using the forecasted Canadian CPI. Data Source for CPI forecast: DRI/McGraw Hill Fall Winter 196-1997 Canadian Market Outlook.

TABLE A-3A
TCPL PIPELINE COSTS

TCPL Canadian Firm Service – Eastern Zone

Cost Element	Initial Year Costs ($97)	Units
Demand Charge	$12.04	$/m^3/peak day
Commodity	$0.959	$/10^{3}m^3
Fuel	8.06%	% of purchased fuel cost

Real Price Escalation: 0 percent per annum applied to demand charge

Real Price Escalation: 0 percent per annum applied to commodity costs

TCPL Storage Transportation Service – Centra Gas EDA

Cost Element	Initial Year Costs ($97)	Units
Demand Charge	$1.64	$/m^3/peak day
Commodity	$0.107	$/10^{3}m^3

Real Price Escalation: 0 percent per annum applied to demand charge

Real Price Escalation: 0 percent per annum applied to commodity costs

Notes On Table A-3A

1. Data Source: TCPL Tariffs shown in table A-3B, and Union Gas.
2. TCPL Canadian Firm Service is considered to be the incremental pipeline supply option for both Centra and Union service territories.
3. TCPL Storage Transportation Service required to transport storage volumes to Centra's service territory.

TransCanada

TABLE A-3B.
TCPL TARIFF SHEETS

Proposed Canadian and Export
Interim Tolls Effective January 1, 1997

LINE NO.	PARTICULARS (a)	DEMAND TOLL ($/10 3m3/mo) (b)	COMMODITY TOLL ($/10 3m3) (c)	100% LF TOLL (cents/GJ) (d)
	CANADIAN FIRM SERVICE			
1	Saskatchewan Zone	92.37	0.055	8.186
2	Manitoba Zone	335.89	0.297	30.024
3	Welwyn to Manitoba Zone	130.72	0.097	11.635
4	Western Zone	533.17	0.492	47.712
5	Northern Zone	824.05	0.773	73.776
6	Eastern Zone	1002.97	0.959	89.842
7	Eastern Zone FST		24.241	64.181
	EXPORT FIRM SERVICE			
8	Empress to Spruce	366.26	0.328	32.749
9	Empress to Emerson	373.34	0.335	33.384
10	Empress to Niagara Falls	1046.59	0.991	93.724
11	Empress to Iroquois	1051.69	0.996	94.181
12	Empress to Cornwall	1065.95	1.010	95.459
13	Empress to Sabrevois	1112.76	1.056	99.656
14	Empress to Philipsburg	1123.35	1.066	100.604
15	Empress to Napierville	1117.49	1.060	100.078
16	Empress to Chippawa	1047.40	0.992	93.797
	MISC POINT-TO-POINT FIRM SERVICE			
17	Herbert to Emerson	308.69	0.272	27.590
18	St. Clair to Chippawa	139.69	0.107	12.443
19	Kirkwall to Chippawa	68.41	0.037	6.053

* All tolls are expressed and payable in Canadian Dollars.

TransCanada

TABLE A-3B
TCPL TARIFF SHEETS
(Continued)

Proposed Canadian and Export
Interim Tolls Effective January 1, 1997

LINE NO.	PARTICULARS	DEMAND TOLL ($/10 3m3/mo)	COMMODITY TOLL ($/10 3m3)
	(a)	(b)	(c)
	STORAGE TRANSPORTATION SERVICE		
1	Centra Gas (Manitoba) - MDA	72.85	0.043
2	Centra Gas (Ontario) - NDA	206.46	0.177
3	Centra Gas (Ontario) - EDA	136.47	0.107
4	Kingston	129.04	0.099
5	Gaz Metropolitain - EDA	232.40	0.203
6	Consumers Gas - CDA	30.30	0.000
7	Consumers Gas - EDA	84.69	0.055
8	Cornwall	182.92	0.153
9	Philipsburg	238.67	0.209

TABLE A-4
UNION STORAGE AVOIDED COSTS

Cost Element	Costs ($97)	New Year Project Initiated	Rate of Real Price Escalation
Facility/Capital Costs (1997 - 2007)			
Deliverability Capacity	$1.02/m³/peak day /Year		0%
Space Costs	$9.77/10³m³ /Year		0%
Carrying Costs	2.01% of WACOG		
Facility/Capital Costs(2008 - End)			
Deliverability Capacity	$14.71/m³/peak day	2008	0%
Space Costs	$72.00/10³m³	2008	0%
Carrying Costs	2.01% of WACOG	Each Year	____
Variable Costs			
Compressor Fuel	.22% of WACOG	Each Year	____
Other Storage O&M	$.22/10³m³	Each Year	0%
Dehydration Costs	$.068/10³m³	Each Year	0%

TABLE A-4
UNION STORAGE AVOIDED COSTS
(Continued)

Notes On Table A-4

1. No new avoidable storage facilities are planned before 2008. Between 1997 and 2007, the avoided cost of storage is determined by the opportunity cost associated with storage release to M12 customers.

2. Data Source: Union Gas

TABLE A-5A
UNION TRAFALGAR FACILITY EXPANSION COSTS

Calendar Year	Demand Growth (10^3M^3/Design Day)	Cost Per Unit ($/$M^3$ / Design Day)
1998	6,420	$ 4.96
1999	940	$ 1.46
2000	746	$ 0.83
2001	3,085	$12.03
2002	1,772	$ 2.41
2003	3,268	$11.25
2004	2,510	$ 4.34
2005	2,354	$20.56
2006	4,764	$ 7.90
2007	3,032	$ 8.14
2008	3,102	$15.52
2009	3,169	$13.38
2010	3,229	$ 0.38

Notes On Table A-5A

1. Data Source: Union Gas
2. Trafalgar facility expansion costs incurred prior to 1998 and associated IDC costs have been excluded when calculating avoidable facility costs per unit.
3. All costs in nominal dollars.

TABLE A-5B
UNION NON-TRAFALGAR TRANSMISSION FACILITY EXPANSION COSTS

	Trafalgar "Branch" Transmission[1]		"Other" Transmission[2]	
Calendar Year	Demand Growth (10^3M^3/Peak Day)	Cost Per Unit ($/M^3 /Peak Day)	Demand Growth (10^3M^3/Peak Day)	Cost Per Unit ($/M3/Peak Day)
1998	1,066	$1.71	314	$0.00
1999	939	$2.32	333	$0.00
2000	434	$0.00	257	$0.00
2001	536	$0.00	88	$0.00
2002	638	$2.14	226	$0.00
2003	860	$1.42	226	$9.79
2004	811	$1.54	226	$0.00
2005	798	$1.60	226	$0.00
2006	846	$1.54	226	$4.05
2007	828	$1.67	226	$1.58
2008	862	$1.71	226	$1.62
2009	892	$1.75	226	$1.66
2010	920	$1.80	226	$1.71
2011	948	$1.90	226	$1.75

TABLE A-5B

UNION NON-TRAFALGAR TRANSMISSION FACILITY EXPANSION COSTS
(Continued)

Notes On Table A-5B

1. Trafalgar "Branch" Transmission refers to transmission capacity such as Union's Owen Sound line which branches off the Trafalgar system, hence requires use of the Trafalgar system to deliver gas to Union customers.

2. "Other" Transmission refers to transmission capacity such as Union's Panhandle or Sarnia lines which deliver gas to Union customers without any reliance on the Trafalgar system.

3. All costs are presented in nominal dollars. Costs after 2006 are based on average annual cost per unit of costs for the 1998 - 2005 time period, adjusted for inflation.

4. In the years when cost per unit equals $0, the existing transmission system is projected to be sufficient to meet demand growth, and no transmission system expansion costs would be avoided.

5. Data Source for "Trafalgar Branch Transmission" costs: Union Gas 1997 Capital Budget.

6. Data Source for "Other Transmission" costs: Union Gas

TABLE A-5C
UNION IN-FRANCHISE TRANSMISSION COST INPUTS BY LOAD SEGMENT

Calendar Year	Demand Growth (10^3M^3/Peak Day)	Weather Sensitive Load Cost Per Unit* ($/$M^3$ /Peak Day)	Base Load Cost Per Unit* ($/M3/Peak Day)
1998	1,381	$ 3.88	$0.65
1999	1,272	$ 2.44	$1.52
2000	691	$ 0.35	($0.09)
2001	624	$ 6.91	($1.80)
2002	864	$ 2.77	$1.27
2003	1,086	$ 9.12	$1.61
2004	1,037	$ 3.47	$0.61
2005	1,022	$ 11.95	($1.55)
2006	1,072	$ 6.24	$0.98
2007	1,053	$5.92	$0.53
2008	1,087	$ 9.91	($0.45)
2009	1,117	$ 8.87	($0.13)
2010	1,146	$ 1.99	$1.73
2011	1,174	$ 1.83	$1.83

TABLE A-5C
UNION IN-FRANCHISE TRANSMISSION COST INPUTS BY LOAD SEGMENT
(Continued)

Notes On Table A-5C

1) Table A-5C summarizes Union avoidable transmission costs. The general approach used to estimate Union in-franchise avoidable transmission costs is described in section 4-6. Table A-5C has been calculated based on the weighted average of Trafalgar system expansion costs shown in Table A-5A, and Trafalgar Branch Transmission and Other Transmission costs shown in Table A-5B.

2) The Trafalgar system expansion costs shown in Table A-5A are adjusted based on load segment as discussed in section 4.6 to determine Trafalgar system expansion costs attributable to in-franchise load:

   - **Weather Sensitive Load**: For weather sensitive load, Union estimates that for each 1 m^3/day change in in-franchise demand, total Trafalgar System requirements would change by about .67 m^3/day.
   - **Base Load**: For baseload demand, Union estimates that for each 1 m^3/day change in in-franchise demand, total Trafalgar System requirements would change by about -.17 m^3/day.

   The avoided transmission cost inputs shown in table A-6C already reflect these adjustment factors.

3) Costs include inflation adjustments. Costs escalated beyond 2011 at 3.1% per year.

TABLE A-6
UNION VOLUME RELATED DISTRIBUTION PLANT COSTS

Residential/Commercial	1997	1998	1999	2000	2001	2002	....	2016
Capacity Additions (m^3/peak hour)	58,056	54,096	57,311	57,311	57,311	57,311	....	57,311
Cost/Unit (\$$m^3$/peak hour)	45.00	16.84	32.28	32.99	34.02	34.76	....	52.43

Notes On Table A-6

1. Cost per unit includes inflation adjustments using CPI deflator from Table A-2.
2. Data Source: Union Gas

TABLE A-7

UNION VOLUME RELATED O&M COSTS

Compressor Fuel	.18% of WACOG
Unaccounted for O&M	.22% of WACOG

Notes On Table A-7

1. Data Source: Union Gas

APPENDIX A: SECTION 2

UNION GAS AVOIDED COST INTERMEDIATE FACILITY COST OUTPUTS

The avoided facility costs used to develop the avoided cost outputs that would be relevant to a DSM program activity (such as installation of a high efficiency furnace) are shown in table A-9. These costs are derived by EEA from the facility cost inputs shown in tables A-4 through A-6 that correspond to Union's facility planning. Section 3.6 of the avoided cost documentation describes the general approach to deriving the values in this table. Sections 4.4. 4.6. and 4.7 describe the basic supply planning assumptions used to derive the values in this table.

The costs shown in Table A-8 are applicable for a DSM activity in 1998. When the first facility investment likely to be impacted by a DSM activity does not occur until future years (e.g.. Union Gas storage), the avoided facility costs account for the lag between DSM activity. and the potential impact of the activity by valuing the facility cost savings at $0/unit until the first planned investment activity occurs.

TABLE A-8
UNION AVOIDED FACILITY COSTS
FOR NEW DSM ACTIVITIES IN 1997

Type of Facility	Average Levelized Cost/Unit (97$)	Average Annualized Cost/Unit (97$)
Transmission ($/m³/design day)		
Weather Sensitive Load	$4.34	$0.44
Baseload	$0.58	$0.06
Distribution ($/m³/design hour)	$ 30.64	3.13
Storage Deliverability ($/m³/design day)		
1998 -2007	na	1.02
2008 - END	$ 14.71	1.51
Storage Space ($/10³m³)		
1998 - 2007	na	9.77
2008 - END	$ 72.00	7.37

TABLE A-8

UNION AVOIDED FACILITY COSTS
FOR NEW DSM ACTIVITIES IN 1997

Notes On Table A-8

1. Table represents the avoided volume related facility costs applicable to DSM activities initiated in the 1998 DSM program year.

2. Average levelized avoided facility costs reflect the average investment cost per unit for new facilities accounted for in the year of the facility investment.

3. Annualized facility costs represent the average real investment cost per year of a facility investment where the costs are spread over the life of the investment. The levelized costs have been annualized using an annualization factor of 10.23 percent per year, reflecting the 10 percent TRC discount rate, and a facility life of 30 years.

4. Storage costs for 1998 through 2007 reflect the opportunity cost of releasing storage space to M12 customers. Storage costs for 2008 -end reflect the costs of constructing additional storage facilities.

APPENDIX A: SECTION 3

UNION GAS AVOIDED COST SUPPLY OPTION WEIGHTS

Union uses a mix of gas supply options to serve certain load requirements. In particular, to serve winter peak day delivery requirements Union uses a mix of gas delivered directly from pipeline purchases via TCPL and U.S. pipelines during the winter as well as gas withdrawn from storage fields. Hence, in order to derive avoided costs, we needed to estimate not only the avoided cost components (capacity, energy and customer components) of each relevant supply option, but also the shares (or weights) among supply options used to supply needed gas services.

The supply option weights used in the avoided cost analysis are shown in table A-9. Sections 3.4 and 4.5 of the avoided cost documentation describe the derivation and usage of these weights.

Different supply option weights are calculated for the residential/commercial sector and for industrial sector customers due to differences in the load shape between the two customer classes. As noted in the discussion of supply option weights in section 4.6 of the documentation, industrial sector load tends to be influenced much less by weather than demand in the residential/commercial sector, hence industrial load shows much smaller seasonal swings in demand. As a result storage provides a much smaller share of peak day demand than is the case for residential/commercial demand.

TABLE A-9

UNION GAS INCREMENTAL SUPPLY OPTION WEIGHTS

	Residential/Commercial Sector	Industrial Sector[11]
WEATHER SENSITIVE LOAD SEGMENT		
Share Of Design Day Requirements		
TCPL Transmission Capacity	.22	.76
Storage Deliverability	.78	.24
T&D Facilities[12]	1	1
Share Of Incremental Annual Requirements		
TCPL Commodity & Fuel Costs[13]	1	1
Storage Space	.40	.06
Storage O&M Costs	.40	.06
BASELOAD LOAD SEGMENT		
Share Of Peak Day Requirements		
TCPL Transmission Capacity	1	
Storage Deliverability	0	
T&D Facilities[12]	1	
Share Of Incremental Annual Requirements		
TCPL Commodity & Fuel Costs[13]	1	
Storage Space	0	
Storage O&M Costs	0	

TABLE A-9

UNION GAS SUPPLY OPTION WEIGHTS
(Continued)

Notes On Table A-9

1. Industrial sector avoided costs have been calculated for only one load segment (total load). Industrial sector weights are based on the total Union load for firm contract and firm transportation customers.

2. Since in-franchise Transportation and Distribution (T&D) facilities are required to meet peak demand for all customer classes and load types, the T&D facility weights are always 1.0 (or 100%).

3. All incremental annual gas requirements are provided via TCPL so the weight for TCPL commodity and fuel costs is always 1.0 (or 100%)

APPENDIX B: SUPPORTING DATA FOR CENTRA GAS AVOIDED COSTS

This appendix includes the basic data used in the Centra Gas avoided cost analysis. We have included the same level of avoided cost input data detail as provided for the Union Gas avoided cost analysis The appendix is organized in the same manner as Appendix A, and includes three sections based on the type of data:

- Section 1: Centra Data Inputs: The first section includes the basic data inputs provided by Centra Gas and used in the avoided cost calculations.

- Section 2: Intermediate Data Inputs: The second section includes the levelized and annualized facility costs for Centra Gas facility investments used in the avoided cost analysis, and calculated by EEA based on the inputs in section 1.

- Section 3: Supply Option Weights: The final section includes the specific supply option weights calculated by EEA and used to determine the avoided supply costs for specific load segments and end uses.

A number of Centra data inputs are the same as the Union Gas data inputs. These inputs are included in Appendix A, and have not been duplicated here. These data inputs include:

- Table A-2 Union/Centra Gas Purchase Costs
- Table A-3A TCPL Pipeline Costs
- Table A-3B TCPL Pipeline Tariffs
- Table A-4 Avoided Storage Facility Costs
- Table A-7 Volume Related O&M Costs

APPENDIX B: SECTION 1

CENTRA GAS AVOIDED COST DATA INPUTS

Section 1 of Appendix B 1 includes the basic data provided by Centra Gas and used by EEA in the avoided cost analysis. Data tables include:

- Table B-1A Centra In-Franchise Annual Demand Forecast
- Table B-1B Centra In-Franchise Monthly Throughput Volume Forecast
- Table B-1C Centra Gas Peak Day Firm Demand Forecast
- Table B-2 Centra In-Franchise Transmission Cost Inputs
- Table B-3 Centra Distribution Cost Inputs

Table B-1A

CENTRA IN-FRANCHISE MONTHLY THROUGHPUT FORECAST

1998 - 2001

See attached sheets for 1998, 1999, 2000, and 2001 monthly throughput forecasts.

<u>Notes On Table B-1</u>

Data Source: Union Gas, June 5, 1997.

/: Heather Shaw

CENTRA GAS ONTARIO INC.
VOLUME FORECAST
(10*3m*3)

1998	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
GAS SALES													
Rate 01	160,368	145,611	115,469	74,070	41,864	22,918	17,606	20,816	34,029	63,733	99,476	134,552	929,412
Residential	117,075	106,683	85,128	55,398	32,672	18,017	13,909	15,941	26,400	46,981	73,412	98,465	690,081
Commercial	42,293	38,828	30,341	18,672	9,192	4,901	3,697	4,875	7,629	16,752	26,064	36,087	239,331
Rate 10	65,922	51,667	44,589	31,405	19,146	12,573	10,081	11,022	14,345	27,444	40,728	61,628	370,530
Commercial	39,178	35,267	30,252	20,289	11,274	6,867	5,392	5,440	8,152	17,916	27,365	36,252	243,644
Industrial	10,655	10,665	8,968	6,993	4,896	3,471	3,069	3,691	3,893	6,278	9,045	10,941	82,563
Large Industrial Billing	6,089	5,735	5,351	4,123	2,976	2,235	1,620	1,891	2,300	3,250	4,318	4,435	44,323
Rate 16	3,365	1,661	2,911	2,567	2,691	3,197	3,764	3,799	4,128	5,456	4,132	3,308	40,999
Commercial	1,951	810	1,607	1,305	849	616	596	599	663	1,030	1,459	1,932	13,417
Industrial	1,414	851	1,304	1,262	1,842	2,581	3,168	3,200	3,465	4,426	2,673	1,376	27,582
Total General Service	218,655	198,839	162,949	108,042	63,701	38,688	31,471	35,637	52,502	96,633	144,336	189,488	1,340,941
Rate 20	50,295	45,587	44,953	41,669	33,652	29,980	28,723	29,410	31,891	39,601	45,368	50,021	471,150
Rate 25	40,922	30,167	24,460	21,138	16,085	13,922	12,863	13,695	15,254	24,440	25,074	30,701	268,721
Rate 100	95,319	85,964	92,104	84,023	80,306	76,083	71,412	77,526	76,611	82,766	87,689	95,228	1,005,031
Total Contract	186,536	161,718	161,517	146,830	130,043	119,985	112,998	120,631	123,756	146,807	158,131	175,950	1,744,902
Rate 20T	3,914	4,019	3,817	3,611	2,938	3,078	2,846	3,120	3,300	3,607	3,924	3,629	41,803
Rate 25T	5,696	4,975	5,207	341	261	261	212	212	262	430	1,925	2,512	22,294
Rate 100T	72,261	67,049	72,511	69,112	102,849	96,301	96,737	92,989	96,503	105,898	74,906	76,105	1,023,221
Rate 20BT	3,910	3,665	3,775	3,480	3,350	3,220	3,220	3,250	3,500	3,425	3,520	3,685	42,000
Rate 100BT	16,523	14,924	16,523	15,875	16,250	14,636	14,575	14,675	15,090	16,313	15,960	16,156	187,500
Total Transportation Service	102,304	94,632	101,833	92,419	125,648	117,496	117,590	114,246	118,655	129,673	100,235	102,087	1,316,818
Total General Service	218,655	198,839	162,949	108,042	63,701	38,688	31,471	35,637	52,502	96,633	144,336	189,488	1,340,941
Total Contract	288,840	256,350	263,350	239,249	255,691	237,481	230,588	234,877	242,411	276,480	258,366	278,037	3,061,720
Wholesale Rate 77	146	139	114	75	44	19	19	19	26	49	77	127	854
Total Gas Throughput	507,641	455,328	426,413	347,366	319,436	276,188	262,078	270,533	294,939	373,162	402,779	467,652	4,403,515

Prepared by: Heather Shaw

CENTRA GAS ONTARIO INC.
VOLUME FORECAST
(10^3m^3)

1999	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
GAS SALES													
Rate 01	161,157	145,960	118,161	74,608	41,815	23,020	17,305	20,702	34,077	63,618	100,132	137,938	938,490
Residential	118,322	106,812	87,025	55,720	32,621	18,171	13,683	15,960	26,660	47,263	74,323	101,465	698,025
Commercial	42,835	39,148	31,136	18,885	9,194	4,849	3,622	4,742	7,417	16,355	25,809	36,473	240,465
Rate 10	57,236	52,641	45,789	31,714	19,294	12,631	9,892	11,263	14,304	27,196	40,279	52,193	374,432
Commercial	39,950	35,714	31,035	20,250	11,147	6,868	5,202	5,682	8,119	17,678	26,914	36,833	245,392
Industrial	11,215	11,218	9,435	7,371	5,197	3,550	3,088	3,714	3,918	6,320	9,122	11,008	85,156
Large Industrial Billing	6,071	5,709	5,319	4,093	2,950	2,213	1,602	1,867	2,267	3,198	4,243	4,352	43,884
Rate 16	3,365	1,661	2,911	2,567	2,691	3,197	3,784	3,799	4,128	5,456	4,132	3,308	40,999
Commercial	1,951	810	1,607	1,305	849	616	596	599	663	1,030	1,459	1,932	13,417
Industrial	1,414	851	1,304	1,262	1,842	2,581	3,188	3,200	3,465	4,426	2,673	1,376	27,582
Total General Service	221,758	200,262	166,861	108,886	63,800	38,848	30,981	35,764	52,509	96,270	144,543	193,439	1,353,921
Rate 20	50,295	45,587	44,953	41,669	33,652	29,980	28,723	29,410	31,891	39,601	45,368	50,021	471,150
Rate 25	40,922	30,167	24,460	21,138	16,085	13,922	12,863	13,695	15,254	24,440	25,074	30,701	268,721
Rate 100	95,319	85,964	92,104	84,023	80,306	76,083	71,412	77,526	76,611	82,766	87,689	95,228	1,005,031
Total Contract	186,536	161,718	161,517	146,830	130,043	119,985	112,998	120,631	123,756	146,807	158,131	175,950	1,744,902
Rate 20T	3,914	4,019	3,817	3,611	2,938	3,078	2,846	3,120	3,300	3,607	3,924	3,629	41,803
Rate 25T	5,696	4,975	5,207	341	261	261	212	212	262	430	1,925	2,512	22,294
Rate 100T	72,261	67,049	72,511	69,112	102,849	96,301	96,737	92,989	96,503	105,898	74,906	76,105	1,023,221
Rate 20BT	3,910	3,665	3,775	3,480	3,350	3,220	3,220	3,250	3,500	3,425	3,520	3,685	42,000
Rate 100BT	16,523	14,924	16,523	15,875	16,250	14,636	14,575	14,675	15,090	16,313	15,960	16,156	187,500
Total Transportation Service	102,304	94,632	101,833	92,419	125,646	117,496	117,590	114,246	118,655	129,673	100,235	102,087	1,316,818
Total General Service	221,758	200,262	166,861	108,886	63,800	38,848	30,981	35,764	52,509	96,270	144,543	193,439	1,353,921
Total Contract	288,840	256,350	263,350	239,249	255,691	237,481	230,588	234,877	242,411	276,480	258,366	278,037	3,061,720
Wholesale Rate 77	174	166	138	89	53	22	23	23	31	59	92	152	1,020
Total Gas Throughput	510,772	456,778	430,347	348,224	319,544	276,351	261,592	270,664	294,951	372,809	403,001	471,628	4,416,661

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EEA Avoided ... Union Gas/Centra November, 1

CENTRA GAS ONTARIO INC.
VOLUME FORECAST
(10^3m^3)

2000	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
GAS SALES													
Rate 01	163,912	148,948	119,914	75,942	42,566	23,306	17,724	20,953	34,558	64,549	101,799	139,836	954,007
Residential	120,802	109,442	88,610	56,900	33,297	18,423	14,071	16,183	27,094	48,074	75,801	103,140	711,837
Commercial	43,110	39,506	31,304	19,042	9,269	4,883	3,653	4,770	7,464	16,475	25,998	36,696	242,170
Rate 10	56,110	51,748	44,900	31,550	19,225	12,567	9,848	11,316	14,209	27,037	40,048	51,758	370,314
Commercial	38,895	34,634	30,077	19,938	10,985	6,747	5,122	5,699	7,972	17,447	26,515	36,162	240,393
Industrial	11,250	11,302	9,506	7,435	5,231	3,562	3,094	3,713	3,924	6,324	9,201	11,154	85,696
Large Industrial Billing	5,965	5,610	5,317	4,177	3,009	2,258	1,632	1,904	2,313	3,266	4,332	4,442	44,225
Rate 16	3,365	1,661	2,911	2,567	2,691	3,197	3,764	3,799	4,128	5,456	4,132	3,308	40,999
Commercial	1,951	810	1,607	1,305	849	616	596	599	663	1,030	1,459	1,932	13,417
Industrial	1,414	851	1,304	1,262	1,842	2,581	3,168	3,200	3,465	4,428	2,673	1,376	27,582
Total General Service	223,387	202,355	167,725	110,059	64,482	39,070	31,356	36,068	52,895	97,042	145,979	194,902	1,365,320
Rate 20	50,295	45,587	44,953	41,669	33,652	29,980	28,723	29,410	31,891	39,601	45,368	50,021	471,150
Rate 25	40,922	30,167	24,460	21,138	16,085	13,922	12,863	13,695	15,254	24,440	25,074	30,701	268,721
Rate 100	95,319	85,964	92,104	84,023	80,306	76,083	71,412	77,526	76,611	82,766	87,689	95,228	1,005,031
Total Contract	186,536	161,718	161,517	146,830	130,043	119,985	112,998	120,631	123,756	146,807	158,131	175,950	1,744,902
Rate 20T	3,914	4,019	3,617	3,611	2,938	3,078	2,846	3,120	3,300	3,607	3,924	3,629	41,803
Rate 25T	5,696	4,975	5,207	341	261	261	212	212	262	430	1,925	2,512	22,294
Rate 100T	72,261	67,049	72,511	69,112	102,849	96,301	96,737	92,989	96,503	105,898	74,906	76,105	1,023,221
Rate 20BT	3,910	3,665	3,775	3,480	3,350	3,220	3,220	3,250	3,500	3,425	3,520	3,685	42,000
Rate 100BT	16,523	14,924	16,523	15,875	16,250	14,636	14,575	14,675	15,090	16,313	15,960	16,156	187,500
Total Transportation Service	102,304	94,632	101,633	92,419	125,648	117,496	117,590	114,246	118,655	129,673	100,235	102,087	1,316,818
Total General Service	223,387	202,355	167,725	110,059	64,482	39,070	31,356	36,068	52,895	97,042	145,979	194,902	1,365,320
Total Contract	288,840	256,350	263,350	239,249	255,691	237,481	230,588	234,877	242,411	276,480	258,366	278,037	3,061,720
Wholesale Rate 77	208	199	163	107	63	26	28	27	37	70	110	182	1,220
Total Gas Throughput	512,435	458,904	431,238	349,415	320,236	276,577	261,972	270,972	295,343	373,592	404,455	473,121	4,428,260

Prepared by: Heather Shaw

CENTRA GAS ONTARIO INC.
VOLUME FORECAST
(10^3m^3)

2001	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
GAS SALES													
Rate 01	166,188	150,872	121,639	77,033	43,096	23,637	17,923	21,241	35,076	65,502	103,155	141,802	967,163
Residential	122,823	111,133	90,133	57,894	33,782	18,727	14,233	16,435	27,567	48,942	77,002	104,880	723,551
Commercial	43,365	39,739	31,506	19,139	9,314	4,910	3,690	4,806	7,508	16,560	26,153	36,922	243,612
Rate 10	56,125	51,681	44,839	31,410	19,157	12,535	9,804	11,335	14,173	26,970	39,889	51,622	369,540
Commercial	38,662	34,579	29,932	19,812	10,917	6,726	5,085	5,712	7,932	17,370	26,385	36,084	239,196
Industrial	11,371	11,370	9,567	7,491	5,281	3,589	3,113	3,750	3,966	6,389	9,244	11,170	86,301
Large Industrial Billing	6,092	5,732	5,340	4,107	2,959	2,220	1,606	1,873	2,275	3,211	4,260	4,368	44,043
Rate 16	3,365	1,661	2,911	2,567	2,691	3,197	3,784	3,799	4,128	5,456	4,132	3,308	40,999
Commercial	1,951	810	1,607	1,305	849	616	596	599	663	1,030	1,459	1,932	13,417
Industrial	1,414	851	1,304	1,262	1,842	2,581	3,188	3,200	3,465	4,426	2,673	1,376	27,582
Total General Service	225,678	204,214	169,389	111,010	64,944	39,369	31,511	36,375	53,376	97,928	147,176	196,732	1,377,702
Rate 20	50,295	45,587	44,953	41,669	33,652	29,980	26,723	29,410	31,891	39,601	45,368	50,021	471,150
Rate 25	40,922	30,167	24,460	21,138	16,085	13,922	12,863	13,695	15,254	24,440	25,074	30,701	268,721
Rate 100	95,319	85,964	92,104	84,023	80,306	76,083	71,412	77,526	76,611	82,766	87,689	95,228	1,005,031
Total Contract	186,536	161,718	161,517	146,830	130,043	119,985	112,998	120,631	123,756	146,807	158,131	175,950	1,744,902
Rate 20T	3,914	4,019	3,617	3,611	2,938	3,078	2,646	3,120	3,300	3,607	3,924	3,629	41,803
Rate 25T	5,696	4,975	5,207	341	261	261	212	212	262	430	1,925	2,512	22,294
Rate 100T	72,261	67,049	72,511	69,112	102,849	96,301	96,737	92,989	96,503	105,898	74,906	76,105	1,023,221
Rate 20BT	3,910	3,665	3,775	3,480	3,350	3,220	3,220	3,250	3,500	3,425	3,520	3,685	42,000
Rate 100BT	16,523	14,924	16,523	15,875	16,250	14,636	14,575	14,675	15,090	16,313	15,960	16,156	187,500
Total Transportation Service	102,304	94,632	101,833	92,419	125,648	117,496	117,590	114,246	118,655	129,673	100,235	102,087	1,316,818
Total General Service	225,678	204,214	169,389	111,010	64,944	39,369	31,511	36,375	53,376	97,928	147,176	196,732	1,377,702
Total Contract	288,840	256,350	263,350	239,249	255,691	237,481	230,588	234,877	242,411	276,480	258,366	278,037	3,061,720
Wholesale Rate 77	249	237	194	127	76	32	33	32	44	84	132	217	1,457
Total Gas Throughput	514,767	460,801	432,933	350,386	320,711	276,882	262,132	271,284	295,831	374,492	405,674	474,986	4,440,879

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Table B-1C

CENTRA DESIGN DAY FIRM DEMAND
(10^3 M^3 per Day)

Calendar Year	Design Day (10^3M^3)
1997	15,326
1998	15,635
1999	15.750
2000	15,844
2001	15,926

Notes On Table B-1C

1. Data Source: Centra Gas

TABLE B-2

CENTRA IN-FRANCHISE TRANSMISSION COST INPUTS

Element	1998	1999	2000	2001	2002	2003	....	2016
Demand Growth* (10^3m^3/Design Day)	309	115	94	82	150	150	....	150
Cost/Unit** ($\$m^3$/peak day)	0	$122.50	$0.0	$182.80	$0.0	$0.0	....	30.26

Notes On Table B-3

1. In the years when cost per unit equals $0, the existing transmission system is projected to be sufficient to meet demand growth, and no transmission system expansion costs would be avoided until new capacity is required.

2. Design day demand growth estimated based on 1997 design day firm demand (excluding Bundled-T and T-Service) of 15,326 10^3m^3 per day growing at the annual demand growth rate.

3. Per unit costs based on estimated costs of potential Sudbury and Fort Francis expansion projects

4. Costs include inflation adjustments. and are extrapolated beyond 2001 using the CPI inflator in Table A-2.

5. Data Source: Centra Gas

TABLE B-3

CENTRA VOLUME RELATED DISTRIBUTION PLANT COSTS EXISTING COMMUNITIES

Residential/Commercial	1997	1998	1999	2000	2001	2002	....	2016
Capacity Additions (m^3/peak hour)	25,787	22,654	25,145	25,145	25,145	25,145	....	25,145
Cost/Unit[1] ($\$m^3$/peak hour)	127.00	96.01	114.16	116.67	120.29	122.93	....	185.40

Notes On Table B-3

1. Cost per unit includes inflation adjustments.

2. Data Source: Centra Gas

APPENDIX B: SECTION 2

CENTRA GAS AVOIDED COST INTERMEDIATE FACILITY COST OUTPUTS

The Centra Gas avoided facility costs used to develop the avoided cost outputs that would be relevant to a DSM program activity (such as installation of a high efficiency furnace) are shown in table B-4. These costs are derived from the facility cost inputs shown in tables B-2 and B-3 that correspond to Centra's facility planning. Section 3.6 of the avoided cost documentation describes the general approach to deriving the values in this table. Sections 5.6 and 5.7 describe the basic supply planning assumptions used to derive the values in this table.

The costs shown in Table B-4 are applicable for a DSM activity in 1998.

TABLE B-4

CENTRA AVOIDED FACILITY COSTS FOR NEW DSM ACTIVITIES IN 1998

Type of Facility	Average Levelized Cost/Unit (97\$)	Average Annualized Cost/Unit (97\$)
Transmission ($/m³/design day)	$ 20.69	$2.12
Distribution ($/m³/design hour)	$ 107.68	$11.02

Notes On Table B-4

1. Table represents the avoided volume related facility costs applicable to DSM activities initiated in the 1998 DSM program year.

2. Average levelized avoided facility costs reflect the average investment cost per unit for new facilities accounted for in the year of the facility investment.

3. Annualized facility costs represent the average real investment cost per year of a facility investment where the costs are spread over the life of the investment. The levelized costs have been annualized using an annualization factor of 10.23 percent per year, reflecting the 10 percent TRC discount rate, and a facility life of 30 years.

APPENDIX B: SECTION 3

CENTRA GAS AVOIDED COST SUPPLY OPTION WEIGHTS

Centra uses a mix of gas supply options to serve certain load requirements. In particular, to serve winter peak day delivery requirements Union uses a mix of gas delivered directly from pipeline purchases via TCPL and U.S. pipelines during the winter as well as gas withdrawn from storage fields. Hence, in order to derive avoided costs, we needed to estimate not only the avoided cost components (capacity, energy and customer components) of each relevant supply option, but also the shares (or weights) among supply options used to supply needed gas services.

The supply option weights used in the Centra avoided cost analysis are shown in table B-5. Sections 3.4 and 5.5 of the avoided cost documentation describe the derivation and usage of these weights.

Different supply option weights are calculated for the residential/commercial customers and for industrial sector customers due to differences in the load shape between the two customer classes.

TABLE B-5

CENTRA SUPPLY OPTION WEIGHTS

	Residential/Commercial Sector[11]	Industrial Sector[12]
WEATHER SENSITIVE LOAD SEGMENT		
Share Of Peak Day Requirements		
TCPL Transmission Capacity	.28	.72
Storage Deliverability	.72	.28
T&D Facilities[13]	1	1
Share Of Annual Requirements		
TCPL Commodity & Fuel Costs[14]	1	1
Storage Space	.35	.03
Storage O&M Costs	.35	.03
BASELOAD LOAD SEGMENT		
Share Of Peak Day Requirements		
TCPL Transmission Capacity	1	
Storage Deliverability	0	
T&D Facilities	1	
Share Of Annual Requirements		
TCPL Commodity & Fuel Costs	1	
Storage Space	0	
Storage O&M Costs	0	

TABLE B-5

CENTRA SUPPLY OPTION WEIGHTS
(Continued)

Notes On Table B-5

1. Residential/commercial sector weights calculated using total General Rate demand used as proxy for residential/commercial customer demand.

2. Industrial sector weights calculated using total Contract Demand as a proxy for industrial customer demand.

3. Since in-franchise Transportation and Distribution (T&D) facilities are required to meet peak demand for all customer classes and load types, the T&D facility weights are always 1.0 (or 100 percent).

4. All incremental annual gas requirements are provided using TCPL capacity, so the weight for TCPL commodity and fuel costs is always 1.0 (or 100 percent).

APPENDIX C

UNION GAS AVOIDED COST OUTPUTS

This appendix includes avoided cost outputs for Union Gas for three different load segments for each of three gas price scenarios. Specific scenarios include:

C-1 Union Gas Residential Commercial Sector - Weather Sensitive Load Segment - Reference Case Gas Prices

C-2 Union Gas Residential Commercial Sector - Base Load Segment - Reference Case Gas Prices

C-3 Union Gas Industrial Sector - Total Load - Reference Case Gas Prices

C-4 Union Gas Residential Commercial Sector - Weather Sensitive Load Segment - High Case Gas Prices

C-5 Union Gas Residential Commercial Sector - Base Load Segment - High Case Gas Prices

C-6 Union Gas Industrial Sector - Total Load - High Case Gas Prices

C-7 Union Gas Residential Commercial Sector - Weather Sensitive Load Segment - Low Case Gas Prices

C-8 Union Gas Residential Commercial Sector - Base Load Segment - Low Case Gas Prices

C-9 Union Gas Industrial Sector - Total Load - Low Case Gas Prices

APPENDIX C: Section 1

**Union Gas Residential Commercial Sector - Weather Sensitive Load Segment
Reference Case Gas Prices**

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	2000	08/05/97 2001	05:15 PM 2002	PAGE -1- 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$1.27	$1.30	$1.33	$1.36	$1.38	$1.41	$1.45
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$2.70	$2.77	$2.83	$2.88	$2.94	$3.01	$3.08
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.073	$0.083	$0.084	$0.088	$0.090	$0.094	$0.097
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UWR#R1 08/05/97 NOTES: Union Weather Sensitive M2 Load - Reference Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:15 PM	PAGE -2-		ENERGY AND ENVIRONMEN		
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$1.49	$1.53	$2.06	$2.12	$2.19	$2.26	$2.33	$2.40	$2.48
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$3.17	$3.26	$3.35	$3.45	$3.56	$3.67	$3.79	$3.91	$4.04
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.005	$0.005	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.101	$0.104	$0.108	$0.112	$0.117	$0.121	$0.126	$0.131	$0.136
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

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NOTES: Union Wealher Sensitive M2 Load - Reference Gas Prices

08/05/97 NOTES: Union Weather

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS, 08/05/97 05:15 PM PAGE -3- ENERGY AND ENVIRONMENTAL ANALYSIS, 03/22/96								
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$2.56	$2.65	$2.74	$2.83	$2.93	$3.03	$3.13	$3.24	$3.35
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$4.17	$4.31	$4.46	$4.61	$4.77	$4.93	$5.10	$5.27	$5.45
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.005	$0.005	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.142	$0.148	$0.154	$0.160	$0.167	$0.174	$0.181	$0.189	$0.197
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

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DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:15 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	2027	03/22/96	05:15 PM	PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114			
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0			
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0			
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157			
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0			
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0			
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64			
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.46	$3.58	$3.70	$3.83	$3.96			
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$5.64	$5.83	$6.03	$6.23	$6.44			
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.006	$0.007	$0.007	$0.007	$0.007			
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.205	$0.213	$0.222	$0.232	$0.241			
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0 00	$0.00	$0.00	$0.00	$0.00			
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00			
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0			
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0			

FILE: as Prices 08/05/97 NOTES: Union Weather Sensitive M2 Load - Reference Gas Prices

APPENDIX C: Section 2

Union Gas Residential Commercial Sector - Baseload Load Segment
Reference Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
	ENERGY AND ENVIRONMENTAL ANALYSIS,				08/05/97	05:15 PM	PAGE -1-	
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$12.30	$12.60	$12.87	$13.10	$13.37	$13.67	$14.03
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.072	$0.081	$0.082	$0.086	$0.089	$0.092	$0.096
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UBR#R1 08/05/97 NOTES: Union Baseload M2 Load -Reference Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:15 PM	PAGE -2-		ENERGY AND ENVIRONMEN		
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.41	$14.81	$15.24	$15.71	$16.20	$16.70	$17.22	$17.77	$18.36
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.100	$0.103	$0.107	$0.111	$0.115	$0.120	$0.124	$0.129	$0.134
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Baseload M2 Load -Reference Gas Prices 08/05/97 NOTES: Union Baseload

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS,	08/05/97	05:15 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.10	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	$0.13	$0.13
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.98	$19.63	$20.30	$20.99	$21.70	$22.44	$23.20	$23.99	$24.80
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.140	$0.146	$0.152	$0.158	$0.165	$0.172	$0.179	$0.186	$0.194
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: M2 Load -Reference Gas Prices 08/05/97 NOTES: Union Baseload M2 Load -Reference Gas Price

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:15 PM PAGE -4- 2023	2024	ENERGY AND ENVIRONMENTAL ANALYSIS, 2025	2026	03/22/96 05:15 PM PAGE -5- 2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.14	$0.14	$0.15	$0.15	$0.16
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$25.65	$26.52	$27.42	$28.35	$29.32
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.202	$0.211	$0.219	$0.229	$0.238
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: 08/05/97 NOTES: Union Baseload M2 Load -Reference Gas Prices

APPENDIX C: Section 3

Union Gas Industrial Sector - Reference Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	2000	08/05/97 2001	05:19 PM 2002	PAGE -1- 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$0.26	$0.26	$0.27	$0.28	$0.28	$0.29	$0.30
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$9.32	$9.54	$9.75	$9.93	$10.13	$10.36	$10.63
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.072	$0.082	$0.083	$0.087	$0.089	$0.092	$0.096
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UI#R1 08/05/97 NOTES: Union Industrial Load -Reference Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:19 PM	PAGE -2-		ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.30	$0.31	$0.47	$0.48	$0.50	$0.52	$0.53	$0.55	$0.57
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$10.92	$11.22	$11.55	$11.90	$12.27	$12.65	$13.05	$13.46	$13.91
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.100	$0.103	$0.107	$0.111	$0.115	$0.120	$0.125	$0.130	$0.135
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Industrial Load -Reference Gas Prices 08/05/97 NOTES: Union Industria

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS, 2014	08/05/97 2015	05:19 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL ANALYSIS, 2019	2020	2021	03/22/96 2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.59	$0.61	$0.63	$0.65	$0.67	$0.69	$0.72	$0.74	$0.77
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.38	$14.87	$15.38	$15.90	$16.44	$17.00	$17.58	$18.17	$18.79
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.140	$0.146	$0.152	$0.159	$0.165	$0.172	$0.179	$0.187	$0.195
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Load -Reference Gas Prices 08/05/97 NOTES: Union Industrial Load -Reference Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:19 PM PAGE -4- ENERGY AND ENVIRONMENTAL ANALYSIS, 03/22/96 05:19 PM PAGE -5-				
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.79	$0.82	$0.85	$0.88	$0.90
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$19.43	$20.09	$20.77	$21.48	$22.21
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.203	$0.211	$0.220	$0.229	$0.239
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: 08/05/97 NOTES: Union Industrial Load -Reference Gas Prices

APPENDIX C: Section 4

Union Gas Residential Commercial Sector - Weather Sensitive Load Segment
High Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
ENERGY AND ENVIRONMENTAL ANALYSIS, 08/05/97 05:25 PM PAGE -1-								
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$1.27	$1.30	$1.33	$1.36	$1.38	$1.41	$1.45
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$2.70	$2.77	$2.83	$2.88	$2.94	$3.01	$3.08
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.077	$0.083	$0.088	$0.092	$0.095	$0.100	$0.105
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UWR#H1 08/05/97 NOTES: Union Weather Sensitive M2 Load - High Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,	08/05/97	05:25 PM	PAGE -2-			ENERGY AND ENVIRONMEN		
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$1.49	$1.53	$2.06	$2.12	$2.19	$2.26	$2.33	$2.40	$2.48
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$3.17	$3.26	$3.35	$3.45	$3.56	$3.67	$3.79	$3.91	$4.04
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.005	$0.005	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.110	$0.114	$0.119	$0.124	$0.130	$0.135	$0.141	$0.148	$0.154
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Weather Sensitive M2 Load - High Gas Prices 08/05/97 NOTES: Union Weather

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS,	08/05/97	05:25 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$2.56	$2.65	$2.74	$2.83	$2.93	$3.03	$3.13	$3.24	$3.35
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$4.17	$4.31	$4.46	$4.61	$4.77	$4.93	$5.10	$5.27	$5.45
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.005	$0.005	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.162	$0.169	$0.177	$0.186	$0.194	$0.203	$0.213	$0.223	$0.234
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: ensitive M2 Load - High Gas Prices 08/05/97 NOTES: Union Weather Sensitive M2 Load - High Gas P

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:25 PM	PAGE -4-	ENERGY AND ENVIRONMENTAL ANALYSIS,	03/22/96	05:25 PM PAGE -5-
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.46	$3.58	$3.70	$3.83	$3.96
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$5.64	$5.83	$6.03	$6.23	$6.44
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.006	$0.007	$0.007	$0.007	$0.007
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.244	$0.256	$0.268	$0.281	$0.294
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: Ices 08/05/97 NOTES: Union Weather Sensitive M2 Load - High Gas Prices

APPENDIX C: Section 5

Union Gas Residential Commercial Sector - Baseload Load Segment
High Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	08/05/97 2000	2001	05:25 PM 2002	PAGE -1- 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$12.30	$12.60	$12.87	$13.10	$13.37	$13.67	$14.03
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.076	$0.081	$0.087	$0.090	$0.094	$0.098	$0.103
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UBR#H1 08/05/97 NOTES: Union Baseload M2 Load -High Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,	08/05/97	05.25 PM	PAGE -2-			ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.41	$14.81	$15.24	$15.71	$16.20	$16.70	$17.22	$17.77	$18.36
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.108	$0.113	$0.117	$0.123	$0.128	$0.134	$0.139	$0.146	$0.152
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Baseload M2 Load -High Gas Prices 08/05/97 NOTES: Union Baseload

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS, 08/05/97 05:25 PM PAGE -3- ENERGY AND ENVIRONMENTAL ANALYSIS, 03/22/96								
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.10	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	$0.13	$0.13
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.98	$19.63	$20.30	$20.99	$21.70	$22.44	$23.20	$23.99	$24.80
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.160	$0.167	$0.175	$0.183	$0.192	$0.201	$0.210	$0.220	$0.231
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: M2 Load -High Gas Prices 08/05/97 NOTES: Union Baseload M2 Load -High Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:25 PM PAGE -4- 2023	2024	2025 ENERGY AND ENVIRONMENTAL ANALYSIS,	2026	2027 03/22/96
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.14	$0.14	$0.15	$0.15	$0.16
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$25.65	$26.52	$27.42	$28.35	$29.32
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.241	$0.253	$0.265	$0.277	$0.290
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: 08/05/97 NOTES: Union Baseload M2 Load -High Gas Prices

APPENDIX C: Section 6

Union Gas Industrial Sector - High Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS. 1998	1999	2000	08/05/97 2001	05:27 PM 2002	PAG 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$0.26	$0.26	$0.27	$0.28	$0.28	$0.29	$0.30
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$9.32	$9.54	$9.75	$9.93	$10.13	$10.36	$10.63
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.076	$0.082	$0.087	$0.090	$0.094	$0.099	$0.103
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UI#H1 08/05/97 NOTES: Union Industrial Load -High Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05.27 PM	PAGE -2-		ENERGY AND ENVIRONMEN		
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.30	$0.31	$0.47	$0.48	$0.50	$0.52	$0.53	$0.55	$0.57
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$10.92	$11.22	$11.55	$11.90	$12.27	$12.65	$13.05	$13.46	$13.91
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.109	$0.113	$0.118	$0.123	$0.128	$0.134	$0.140	$0.146	$0.153
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Industrial Load -High Gas Prices 08/05/97 NOTES: Union Industria

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS,	08/05/97	05:27 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0 098	$0 101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.59	$0.61	$0.63	$0.65	$0.67	$0.69	$0.72	$0.74	$0.77
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.38	$14.87	$15.38	$15.90	$16.44	$17.00	$17.58	$18.17	$18.79
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.160	$0.167	$0.175	$0.184	$0.192	$0.201	$0.211	$0.221	$0.231
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Load -High Gas Prices 08/05/97 NOTES: Union Industrial Load -High Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:27 PM PAGE -4-		ENERGY AND ENVIRONMENTAL ANALYSIS,		03/22/96 05:27 PM PAGE -5
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.79	$0.82	$0.85	$0.88	$0.90
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$19.43	$20.09	$20.77	$21.48	$22.21
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.242	$0.253	$0.265	$0.278	$0.291
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: 08/05/97 NOTES: Union Industrial Load -High Gas Prices

APPENDIX C: Section 7

**Union Gas Residential Commercial Sector - Weather Sensitive Load Segment
Low Case Gas Prices**

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
ENERGY AND ENVIRONMENTAL ANALYSIS. 08/05/97 05:29 PM PAGE -1-								
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.50	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$1.27	$1.30	$1.33	$1.36	$1.38	$1.41	$1.45
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$2.70	$2.77	$2.83	$2.88	$2.94	$3.01	$3.08
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.002	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.072	$0.075	$0.078	$0.079	$0.081	$0.082	$0.084
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UWR#L1 08/05/97 NOTES: Union Weather Sensitive M2 Load - Low Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:29 PM	PAGE -2-		ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$1.49	$1.53	$2.06	$2.12	$2.19	$2.26	$2.33	$2.40	$2.48
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$3.17	$3.26	$3.35	$3.45	$3.56	$3.67	$3.79	$3.91	$4.04
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.005	$0.005	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.087	$0.089	$0.092	$0.095	$0.098	$0.101	$0.104	$0.108	$0.111
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Weather Sensitive M2 Load - Low Gas Prices 08/05/97 NOTES: Union Weather

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS,	08/05/97	05:29 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$2.56	$2.65	$2.74	$2.83	$2.93	$3.03	$3.13	$3.24	$3.35
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$4.17	$4.31	$4.46	$4.61	$4.77	$4.93	$5.10	$5.27	$5.45
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.005	$0.005	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.115	$0.119	$0.123	$0.127	$0.132	$0.137	$0.141	$0.146	$0.151
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: ensitive M2 Load - Low Gas Prices 08/05/97 NOTES: Union Weather Sensitive M2 Load - Low Gas P

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:29 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	2027	03/22/96	05:29 PM	PAGE -5
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114			
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0			
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0			
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157			
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0			
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0			
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64			
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.46	$3.58	$3.70	$3.83	$3.96			
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$5.64	$5.83	$6.03	$6.23	$6.44			
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.006	$0.007	$0.007	$0.007	$0.007			
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.157	$0.162	$0.168	$0.174	$0.180			
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00			
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00			
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0			
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0			

FILE: Icns 08/05/97 NOTES: Union Weather Sensitive M2 Load - Low Gas Prices

APPENDIX C: Section 8

Union Gas Residential Commercial Sector - Baseload Load Segment
Low Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
	ENERGY AND ENVIRONMENTAL ANALYSIS,				08/05/97	05:29 PM	PAGE 4	
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3 65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0 692	$0.07	$0 07	$0 07	$0 07	$0 07	$0.07	$0 08
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$12.30	$12.60	$12.87	$13.10	$13.37	$13.67	$14 03
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.071	$0.074	$0.077	$0.078	$0.079	$0.081	$0.083
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0 00	$0 00	$0.00	$0.00	$0 00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0 00	$0 00	$0 00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UBR#L1 08/05/97 NOTES: Union Baseload M2 Load -Low Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,			08/05/97	05.29 PM	PAGE -2-		ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0 074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4 48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.41	$14 81	$15.24	$15.71	$16.20	$16.70	$17.22	$17.77	$18.36
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.085	$0.088	$0.090	$0.093	$0.096	$0.099	$0.103	$0.106	$0.110
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE. NOTES: Union Baseload M2 Load -Low Gas Prices 08/05/97 NOTES: Union Baseload

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS, 2014	08/05/97 2015	05:29 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL 2019	ANALYSIS, 2020	2021	03/22/96 2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.10	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	$0.13	$0.13
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.98	$19.63	$20.30	$20.99	$21.70	$22.44	$23.20	$23.99	$24.80
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.113	$0.117	$0.121	$0.126	$0.130	$0.135	$0.139	$0.144	$0.149
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: M2 Load -Low Gas Prices 08/05/97 NOTES: Union Baseload M2 Load -Low Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:29 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	03/22/96 2027	05:29 PM	PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114		
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0		
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0		
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157		
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0		
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0		
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64		
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.14	$0.14	$0.15	$0.15	$0.16		
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$25.65	$26.52	$27.42	$28.35	$29.32		
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00		
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.154	$0.160	$0.165	$0.171	$0.177		
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00		
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00		
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0		
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0		

FILE: 08/05/97 NOTES: Union Baseload M2 Load -Low Gas Prices

APPENDIX C: Section 9

Union Gas Industrial Sector - Low Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS		ENERGY AND ENVIRONMENTAL ANALYSIS.			08/05/97	05.31 PM	PAGE -1-	
	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$3.20	$3.28	$3.35	$3.41	$3.48	$3.56	$3.65
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$0.26	$0.26	$0.27	$0.28	$0.28	$0.29	$0.30
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$9.32	$9.54	$9.75	$9.93	$10.13	$10.36	$10.63
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.071	$0.074	$0.077	$0.078	$0.080	$0.081	$0.083
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97UI#L1 08/05/97 NOTES: Union Industrial Load -Low Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:31 PM	PAGE -2-			ENERGY AND ENVIRONMEN
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$3.75	$3.86	$3.97	$4.09	$4.22	$4.35	$4.48	$4.63	$4.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.30	$0.31	$0.47	$0.48	$0.50	$0.52	$0.53	$0.55	$0.57
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$10.92	$11.22	$11.55	$11.90	$12.27	$12.65	$13.05	$13.46	$13.91
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.086	$0.088	$0.091	$0.094	$0.097	$0.100	$0.103	$0.106	$0.110
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Union Industrial Load -Low Gas Prices 08/05/97 NOTES: Union Industria

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	AL ANALYSIS, 2014	08/05/97 2015	05:31 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL ANALYSIS, 2019	2020	2021	03/22/96 2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$4.94	$5.11	$5.29	$5.47	$5.65	$5.84	$6.04	$6.25	$6.46
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.59	$0.61	$0.63	$0.65	$0.67	$0.69	$0.72	$0.74	$0.77
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.38	$14.87	$15.38	$15.90	$16.44	$17.00	$17.58	$18.17	$18.79
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.114	$0.118	$0.122	$0.126	$0.130	$0.135	$0.140	$0.144	$0.150
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Load -Low Gas Prices 08/05/97 NOTES: Union Industrial Load -Low Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE UNION GAS	05:31 PM PAGE -4- ENERGY AND ENVIRONMENTAL ANALYSIS, 03/22/96 05:31 PM PAGE -5-				
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$6.68	$6.91	$7.14	$7.38	$7.64
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$0.79	$0.82	$0.85	$0.88	$0.90
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$19.43	$20.09	$20.77	$21.48	$22.21
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.155	$0.160	$0.166	$0.171	$0.177
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: 08/05/97 NOTES: Union Industrial Load -Low Gas Prices

APPENDIX D

CENTRA GAS AVOIDED COST OUTPUTS

This appendix includes avoided cost outputs for Centra Gas for three different load segments and for each of three gas price scenarios. Specific scenarios include:

D-1 Centra Gas Residential Commercial Sector - Weather Sensitive Load Segment - Reference Case Gas Prices

D-2 Centra Gas Residential Commercial Sector - Base Load Segment - Reference Case Gas Prices

D-3 Centra Gas Industrial (M7) Sector - Total Load - Reference Case Gas Prices

D-4 Centra Gas Residential Commercial Sector - Weather Sensitive Load Segment - Reference Case Gas Prices

D-5 Centra Gas Residential Commercial Sector - Base Load Segment - Reference Case Gas Prices

D-6 Centra Gas Industrial (M7) Sector - Total Load - Reference Case Gas Prices

D-7 Centra Gas Residential Commercial Sector - Weather Sensitive Load Segment - Reference Case Gas Prices

D-8 Centra Gas Residential Commercial Sector - Base Load Segment - Reference Case Gas Prices

D-9 Centra Gas Industrial (M7) Sector - Total Load - Reference Case Gas Prices

APPENDIX D: Section 1

Centra Gas Residential Commercial Sector - Weather Sensitive Load Segment Reference Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	08/05/97 2000	05:44 PM 2001	PAGE -1- 2002	2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$4.59	$4.70	$4.80	$4.89	$4.99	$5.10	$5.23
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$3.48	$3.56	$3.64	$3.71	$3.78	$3.87	$3.97
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.073	$0.082	$0.083	$0.087	$0.090	$0.093	$0.097
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97CWR#R1 08/05/97 NOTES: Cenlra Wealher Sensilive Rate01 Load - Reference Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:44 PM	PAGE -2-		ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$5.38	$5.53	$6.13	$6.32	$6.52	$6.72	$6.93	$7.15	$7.38
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$4.08	$4.19	$4.31	$4.45	$4.58	$4.73	$4.87	$5.03	$5.20
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.004	$0.004	$0.003	$0.003	$0.004	$0.004	$0.004	$0.004	$0.004
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.101	$0.104	$0.108	$0.112	$0.116	$0.121	$0.126	$0.131	$0.136
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Weather Sensitive Rate01 Load - Reference Gas Prices 08/05/97 NOTES: Centra Weather

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS,	08/05/97	05:44 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$7.64	$7.89	$8.16	$8.44	$8.73	$9.02	$9.33	$9.65	$9.98
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$5.37	$5.55	$5.74	$5.94	$6.14	$6.35	$6.57	$6.79	$7.02
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.004	$0.004	$0.004	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.142	$0.147	$0.154	$0.160	$0.167	$0.174	$0.181	$0.188	$0.196
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Sensitive Rate01 Load - Reference Gas Prices 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - Refere

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:44 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	03/22/96 2027	05:44 PM PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114	
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157	
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79	
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$10.32	$10.67	$11.03	$11.40	$11.79	
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$7.26	$7.50	$7.76	$8.02	$8.30	
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.006	$0.006	$0.006	$0.006	$0.006	
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.204	$0.213	$0.222	$0.231	$0.241	
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	

FILE: ce Gas Prices 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - Reference Gas Prices

APPENDIX D: Section 2

Centra Gas Residential Commercial Sector - Baseload Load Segment
Reference Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	2000	08/05/97 2001	05:44 PM 2002	PAGE -1- 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$2.16	$2.22	$2.26	$2.30	$2.35	$2.40	$2.47
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$12.30	$12.60	$12.87	$13.10	$13.37	$13.67	$14.03
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.072	$0.081	$0.082	$0.086	$0.089	$0.092	$0.096
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97CBR#R1 08/05/97 NOTES: Centra Baseload Rate01 Load - Reference Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:44 PM	PAGE -2-		ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$2.53	$2.60	$2.68	$2.76	$2.85	$2.94	$3.03	$3.13	$3.23
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.41	$14.81	$15.24	$15.71	$16.20	$16.70	$17.22	$17.77	$18.36
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.100	$0.103	$0.107	$0.111	$0.115	$0.120	$0.124	$0.129	$0.134
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Baseload Rate01 Load - Reference Gas Prices 08/05/97 NOTES: Centra Baseloa

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS, 2014	08/05/97 2015	05:44 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL ANALYSIS, 2019	2020	2021	03/22/96 2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.34	$3.45	$3.57	$3.69	$3.82	$3.95	$4.08	$4.22	$4.36
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.98	$19.63	$20.30	$20.99	$21.70	$22.44	$23.20	$23.99	$24.80
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.140	$0.146	$0.152	$0.158	$0.165	$0.172	$0.179	$0.186	$0.194
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Rale01 Load - Reference Gas Prices 08/05/97 NOTES: Centra Baseload Rale01 Load - Reference Ga

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:44 PM 2023	PAGE -4- 2024	ENERGY AND ENVIRONMENTAL ANALYSIS, 2025	2026	03/22/96 2027	05:44 PM	PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114		
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0		
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0		
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157		
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0		
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0		
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79		
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$4.51	$4.66	$4.82	$4.99	$5.16		
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$25.65	$26.52	$27.42	$28.35	$29.32		
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00		
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.202	$0.211	$0.219	$0.229	$0.238		
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00		
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00		
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0		
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0		

FILE: Prices 08/05/97 NOTES: Centra Baseload Rate01 Load - Reference Gas Prices

APPENDIX D: Section 3

Centra Gas Industrial Sector - Reference Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS		RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS,			08/05/97	05:44 PM	PAGE -1-	
			1998	1999	2000	2001	2002	2003	2004
SUMMER ON-PEAK CAPACITY (KW)			$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)			$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)			$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)			$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)			$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)			$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)			$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH			$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH			$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)			$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH			$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH			$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	Y)	0.692	$3.11	$3.18	$3.25	$3 31	$3.37	$3.45	$3.54
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)			$8.88	$9.09	$9.29	$9.46	$9.65	$9.87	$10.12
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)		0.692	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ANNUAL THROUGHPUT COST(ANNUAL $/M3)			$0.072	$0.082	$0.083	$0.086	$0.089	$0.092	$0.096
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)		0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)			$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)			$0	$0	$0	$0	$0	$0	$0

FILE: 97CI#R1 08/05/97 NOTES: Centra Industrial Load - Reference Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:44 PM	PAGE -2-		ENERGY AND ENVIRONMEN		
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.64	$3.74	$4.02	$4.14	$4.27	$4.41	$4.54	$4.69	$4.84
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$10.40	$10.69	$11.00	$11.34	$11.69	$12.05	$12.43	$12.82	$13.25
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.100	$0.103	$0.107	$0.111	$0.115	$0.120	$0.124	$0.129	$0.135
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Industrial Load - Reference Gas Prices 08/05/97 NOTES: Centra Industri

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS.	08/05/97	05:44 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$5.01	$5.18	$5.35	$5.53	$5.72	$5.92	$6.12	$6.33	$6.54
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$13.70	$14.16	$14.65	$15.14	$15.66	$16.19	$16.74	$17.31	$17.90
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.140	$0.146	$0.152	$0.158	$0.165	$0 172	$0.179	$0.187	$0.194
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: I Load - Reference Gas Prices 08/05/97 NOTES: Centra Industrial Load - Reference Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:44 PM	PAGE -4-	ENERGY AND ENVIRONMENTAL ANALYSIS,	03/22/96	05:44 PM PAGE -5-
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$6.76	$6.99	$7.23	$7.48	$7.73
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.51	$19.14	$19.79	$20.46	$21.16
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.202	$0.211	$0.220	$0.229	$0.238
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: 08/05/97 NOTES: Centra Industrial Load - Reference Gas Prices

APPENDIX D: Section 4

**Centra Gas Residential Commercial Sector - Weather Sensitive Load Segment
High Case Gas Prices**

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
		ENERGY AND ENVIRONMENTAL ANALYSIS,			08/05/97	05:41 PM	PAGE -1-	
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$4.59	$4.70	$4.80	$4.89	$4.99	$5.10	$5.23
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$3.48	$3.56	$3.64	$3.71	$3.78	$3.87	$3.97
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.077	$0.082	$0.088	$0.091	$0.095	$0.099	$0.104
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE: 97CWR#H1 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - High Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,	08/05/97	05:41 PM	PAGE -2-			ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$5.38	$5.53	$6.13	$6.32	$6.52	$6.72	$6.93	$7.15	$7.38
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$4.08	$4.19	$4.31	$4.45	$4.58	$4.73	$4.87	$5.03	$5.20
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.004	$0.004	$0.003	$0.003	$0.004	$0.004	$0.004	$0.004	$0.004
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.109	$0.114	$0.119	$0.124	$0.129	$0.135	$0.141	$0.147	$0.154
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Wealher Sensilive Rale01 Load - High Gas Prices 08/05/97 NOTES: Centra Wealher

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS,	08/05/97	05:41 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$7.64	$7.89	$8.16	$8.44	$8.73	$9.02	$9.33	$9.65	$9.98
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$5.37	$5.55	$5.74	$5.94	$6.14	$6.35	$6.57	$6.70	$7.02
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.004	$0.004	$0.004	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.161	$0.169	$0.177	$0.185	$0.194	$0.203	$0.212	$0.222	$0.233
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Sensitive Rate01 Load - High Gas Prices 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - High G

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:41 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	03/22/96 2027	05:41 PM	PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0		
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114		
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0		
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0		
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0 157		
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0		
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0		
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79		
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$10.32	$10.67	$11.03	$11.40	$11.79		
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$7.26	$7.50	$7.76	$8.02	$8.30		
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.006	$0.006	$0.006	$0.006	$0.006		
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.244	$0.255	$0.267	$0.280	$0.293		
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00		
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00		
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0		
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0		

FILE: s Prices 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - High Gas Prices

APPENDIX D: Section 5

Centra Gas Residential Commercial Sector - Baseload Load Segment
High Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	08/05/97 2000	2001	05:41 PM 2002	PAGE -1- 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$2.16	$2.22	$2.26	$2.30	$2.35	$2.40	$2.47
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$12.30	$12.60	$12.87	$13.10	$13.37	$13.67	$14.03
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.076	$0.081	$0.087	$0.090	$0.094	$0.098	$0.103
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

FILE. 97CBR#H1 08/05/97 NOTES: Centra Baseload Rate01 Load - High Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:41 PM	PAGE -2-			ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13 17	$13.54	$13.93	$14 36	$14.00	$15 26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$2.53	$2.60	$2.68	$2.76	$2.85	$2.94	$3.03	$3.13	$3 23
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.41	$14.81	$15.24	$15.71	$16.20	$16 70	$17.22	$17.77	$18 36
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.108	$0.113	$0.117	$0.123	$0.128	$0.134	$0.139	$0.146	$0.152
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0 00	$0.00	$0.00	$0 00	$0.00	$0 00	$0 00	$0.00	$0 00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Baseload Rate01 Load - High Gas Prices 08/05/97 NOTES Centra Baseloa

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS.	08/05/97	05:41 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS.			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.34	$3.45	$3.57	$3.69	$3.82	$3.95	$4.08	$4.22	$4.36
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.98	$19.63	$20.30	$20.99	$21.70	$22.44	$23.20	$23.99	$24.80
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.160	$0.167	$0.175	$0.183	$0.192	$0.201	$0.210	$0.220	$0.231
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Rate01 Load - High Gas Prices 08/05/97 NOTES: Centra Baseload Rate01 Load - High Gas Pric

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:41 PM	PAGE -4-		ENERGY AND ENVIRONMENTAL ANALYSIS,	03/22/96 05:41 PM PAGE -5-
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.100	$0.100	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$4.51	$4.66	$4.82	$4.99	$5.16
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$25.65	$26.52	$27.42	$28.35	$29.32
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.241	$0.253	$0.265	$0.277	$0.290
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

FILE: s 08/05/97 NOTES: Centra Baseload Rate01 Load - High Gas Prices

APPENDIX D: Section 6

Centra Gas Industrial Sector - High Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$3.11	$3.18	$3.25	$3.31	$3.37	$3.45	$3.54
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$8.88	$9.09	$9.29	$9.46	$9.65	$9.87	$10.12
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.076	$0.081	$0.087	$0.090	$0.094	$0.098	$0.103
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

ENERGY AND ENVIRONMENTAL ANALYSIS, 08/05/97 05:40 PM PAGE -1-

FILE: 97CI#H1 08/05/97 NOTES: Centra Industrial Load - High Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:40 PM	PAGE -2-		ENERGY AND ENVIRONMEN		
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.64	$3.74	$4.02	$4.14	$4.27	$4.41	$4.54	$4.69	$4.84
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$10.40	$10.69	$11.00	$11.34	$11.69	$12.05	$12.43	$12.82	$13.25
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.108	$0.113	$0.118	$0.123	$0.128	$0.134	$0.140	$0.146	$0.153
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Industrial Load - High Gas Prices 08/05/97 NOTES: Centra Industri

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS, 2014	08/05/97 2015	05:40 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL ANALYSIS, 2019	2020	2021	03/22/96 2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$5.01	$5.18	$5.35	$5.53	$5.72	$5.92	$6.12	$6.33	$6.54
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$13.70	$14.16	$14.65	$15.14	$15.66	$16.19	$16.74	$17.31	$17.90
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.160	$0.167	$0.175	$0.183	$0.192	$0.201	$0.211	$0.220	$0.231
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: I Load - High Gas Prices 08/05/97 NOTES: Centra Industrial Load - High Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:40 PM 2023	PAGE -4- 2024	ENERGY AND ENVIRONMENTAL ANALYSIS, 2025	2026	03/22/96 2027	05:40 PM PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114	
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0 157	
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79	
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$6.76	$6.99	$7.23	$7.48	$7.73	
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.51	$19.14	$19.79	$20.46	$21.16	
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001	
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.242	$0.253	$0.265	$0.277	$0.290	
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	

FILE: 08/05/97 NOTES: Cenlra Industrial Load - High Gas Prices

APPENDIX D: Section 7

Centra Gas Residential Commercial Sector - Weather Sensitive Load Segment
Low Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	ENERGY AND ENVIRONMENTAL ANALYSIS, 1998	1999	2000	08/05/97 2001	05:38 PM 2002	PAGE -1- 2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0 049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11 76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$4.59	$4.70	$4.80	$4.89	$4.99	$5.10	$5.23
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$3.48	$3.56	$3 64	$3.71	$3.78	$3.87	$3.97
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.004	$0.004	$0 004	$0.004	$0.004	$0.004	$0.004
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.072	$0.075	$0.078	$0.079	$0.080	$0.082	$0.084
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0'	$0	$0	$0	$0	$0	$0

FILE: 97CWR#L1 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - Low Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,		08/05/97	05:38 PM	PAGE -2-		ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$8	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$5.38	$5.53	$6.13	$6.32	$6.52	$6.72	$6.93	$7.15	$7.38
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$4.08	$4.19	$4.31	$4.45	$4.58	$4.73	$4.87	$5.03	$5.20
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.004	$0.004	$0.003	$0.003	$0.004	$0.004	$0.004	$0.004	$0.004
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.086	$0.089	$0.092	$0.094	$0.097	$0.101	$0.104	$0.107	$0.111
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Weather Sensitive Rate01 Load - Low Gas Prices 08/05/97 NOTES: Centra Weather

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS,	08/05/97	05:38 PM	PAGE -3-		ENERGY AND ENVIRONMENTAL ANALYSIS,			03/22/96
	2014	2015	2016	2017	2018	2019	2020	2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$7.64	$7.89	$8.16	$8.44	$8.73	$9.02	$9.33	$9.65	$9.98
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$5.37	$5.55	$5.74	$5.94	$6.14	$6.35	$6.57	$6.79	$7.02
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.004	$0.004	$0.004	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.115	$0.119	$0.123	$0.127	$0.132	$0.136	$0.141	$0.146	$0.151
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: Sensitive Rate01 Load - Low Gas Prices 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - Low G

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:38 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	2027	03/22/96	05:38 PM	PAGE -5
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0			
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114			
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0			
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0			
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157			
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0			
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0			
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79			
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$10.32	$10.67	$11.03	$11.40	$11.79			
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$7.26	$7.50	$7.76	$8.02	$8.30			
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.006	$0.006	$0.006	$0.006	$0.006			
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.156	$0.162	$0.167	$0.173	$0.179			
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00			
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00			
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0			
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0			

FILE: s Prices 08/05/97 NOTES: Centra Weather Sensitive Rate01 Load - Low Gas Prices

APPENDIX D: Section 8

Centra Gas Residential Commercial Sector - Baseload Load Segment
Low Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0.040	$0.041	$0.043	$0.045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0.042	$0.045	$0.049	$0.053	$0.054	$0.058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK OUR)	0.692	$11.24	$11.51	$11.76	$11.97	$12.21	$12.50	$12.82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D Y)	0.692	$2.16	$2.22	$2.26	$2.30	$2.35	$2.40	$2.47
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$12.30	$12.60	$12.87	$13.10	$13.37	$13.67	$14.03
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.071	$0.074	$0.077	$0.078	$0.079	$0.081	$0.083
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

ENERGY AND ENVIRONMENTAL ANALYSIS. 08/05/97 05:38 PM PAGE

FILE: 97CBR#L1 08/05/97 NOTES: Centra Baseload Rate01 Load - Low Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS, 08/05/97 05:38 PM PAGE -2- ENERGY AND ENVIRONMEN 2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16 78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$2.53	$2.60	$2.68	$2.76	$2.85	$2.94	$3.03	$3.13	$3.23
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$14.41	$14.81	$15.24	$15.71	$16.20	$16.70	$17.22	$17.77	$18.36
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.085	$0.088	$0.090	$0.093	$0.096	$0.099	$0.103	$0.106	$0.110
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Cenlra Baseload Rale01 Load - Low Gas Prices 08/05/97 NOTES: Cenlra Baseloa

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS, 2014	08/05/97 2015	05:38 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL ANALYSIS, 2019	2020	03/22/96 2021	2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.34	$3.45	$3.57	$3.69	$3.82	$3.95	$4.08	$4.22	$4.36
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.98	$19.63	$20.30	$20.99	$21.70	$22.44	$23.20	$23.99	$24.80
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.113	$0.117	$0.121	$0.126	$0.130	$0.135	$0.139	$0.144	$0.149
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE. Rale01 Load - Low Gas Prices 08/05/97 NOTES: Cenlra Baseload Rale01 Load - Low Gas Pilce

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:38 PM 2023	PAGE -4- 2024	2025	ENERGY AND ENVIRONMENTAL ANALYSIS, 2026	2027	03/22/96 05:38 PM PAGE -5-
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114	
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157	
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79	
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$4.51	$4.66	$4.82	$4.99	$5.16	
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$25.65	$26.52	$27.42	$28.35	$29.32	
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.00	$0.00	$0.00	$0.00	$0.00	
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.154	$0.160	$0.165	$0.171	$0.177	
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	

FILE: 08/05/97 NOTES: Centra Baseload Rate01 Load - Low Gas Prices

APPENDIX D: Section 9

Centra Gas Industrial Sector - Low Case Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS, RIM TEST ADJUSTMENT FACTOR	1998	1999	2000	2001	2002	2003	2004
SUMMER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)		$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)		$0.032	$0.034	$0.038	$0 040	$0.041	$0 043	$0 045
SUMMER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)		$0 042	$0.045	$0.049	$0 053	$0.054	$0 058	$0.061
WINTER MID-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH		$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK HOUR)	0.692	$11 24	$11 51	$11 76	$11.97	$12.21	$12 50	$12 82
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK DAY)	0.692	$3 11	$3.18	$3.25	$3.31	$3.37	$3.45	$3.54
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)		$8.88	$9.09	$9.29	$9.46	$9.65	$9.87	$10.12
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	0.692	$0.000	$0.000	$0 000	$0 000	$0.000	$0 000	$0.000
ANNUAL THROUGHPUT COST(ANNUAL $/M3)		$0.071	$0.074	$0.077	$0.078	$0.080	$0 081	$0.083
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	0.692	$0 00	$0.00	$0 00	$0 00	$0.00	$0 00	$0 00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)		$0 00	$0.00	$0 00	$0.00	$0.00	$0 00	$0.00
ALT FUEL 1 (UNITS)		$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)		$0	$0	$0	$0	$0	$0	$0

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FILE: 97CI#L1 08/05/97 NOTES: Centra Industrial Load - Low Gas Prices 08/05/97

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	ENERGY AND ENVIRONMENTAL ANALYSIS,	08/05/97	05:39 PM	PAGE -2-			ENERGY AND ENVIRONMEN	
	2005	2006	2007	2008	2009	2010	2011	2012	2013
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.048	$0.054	$0.059	$0.063	$0.068	$0.073	$0.078	$0.079	$0.081
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.065	$0.074	$0.082	$0.089	$0.096	$0.101	$0.107	$0.109	$0.111
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$13.17	$13.54	$13.93	$14.36	$14.80	$15.26	$15.74	$16.24	$16.78
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$3.64	$3.74	$4.02	$4.14	$4.27	$4.41	$4.54	$4.69	$4.84
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$10.40	$10.69	$11.00	$11.34	$11.69	$12.05	$12.43	$12.82	$13.25
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.085	$0.088	$0.091	$0.093	$0.096	$0.100	$0.103	$0.106	$0.110
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: NOTES: Centra Industrial Load - Low Gas Prices 08/05/97 NOTES: Centra Industri

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	AL ANALYSIS, 2014	08/05/97 2015	05:39 PM 2016	PAGE -3- 2017	2018	ENERGY AND ENVIRONMENTAL ANALYSIS, 2019	2020	2021	03/22/96 2022
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.083	$0.085	$0.087	$0.089	$0.091	$0.094	$0.096	$0.098	$0.101
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.114	$0.117	$0.120	$0.123	$0.126	$0.129	$0.132	$0.136	$0.139
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$17.35	$17.94	$18.55	$19.18	$19.83	$20.50	$21.20	$21.92	$22.67
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$5.01	$5.18	$5.35	$5.53	$5.72	$5.92	$6.12	$6.33	$6.54
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$13.70	$14.16	$14.65	$15.14	$15.66	$16.19	$16.74	$17.31	$17.90
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.113	$0.117	$0.122	$0.126	$0.130	$0.135	$0.139	$0.144	$0.149
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0	$0	$0	$0	$0

FILE: I Load - Low Gas Prices 08/05/97 NOTES: Centra Industrial Load - Low Gas Prices

DEMAND SIDE STRATEGIST AVOIDED COST FILE CENTRA GAS	05:39 PM	PAGE -4-	ENERGY AND ENVIRONMENTAL ANALYSIS,		03/22/96
	2023	2024	2025	2026	2027
SUMMER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
SUMMER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER ON-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER MID-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
WINTER OFF-PEAK CAPACITY (KW)	$0	$0	$0	$0	$0
BASELOAD LOAD SEGMENT ($/KWH)	$0.103	$0.106	$0.109	$0.111	$0.114
SUMMER MID-PEAK KWH	$0	$0	$0	$0	$0
SUMMER OFF-PEAK KWH	$0	$0	$0	$0	$0
WEATHER SENSITIVE LOAD SEGMENT ($/KWH)	$0.142	$0.146	$0.150	$0.153	$0.157
WINTER MID-PEAK KWH	$0	$0	$0	$0	$0
WINTER OFF-PEAK KWH	$0	$0	$0	$0	$0
PEAK HOUR FACILITY COST (ANNUALIZED $/M3/PEAK	$23.44	$24.23	$25.06	$25.91	$26.79
PEAK DAY FACILITY COST (ANNUALIZED $/M3/PEAK D	$6.76	$6.99	$7.23	$7.48	$7.73
PEAK DAY CAPACITY COST (ANNUAL $/M3/PEAK DAY)	$18.51	$19.14	$19.79	$20.46	$21.16
ANN THRUPUT FACILITY COST (ANNUALIZED $/M3)	$0.001	$0.001	$0.001	$0.001	$0.001
ANNUAL THROUGHPUT COST(ANNUAL $/M3)	$0.155	$0.160	$0.166	$0.171	$0.177
NEW GAS CUSTOMER FACILITY COST (1=YES, 0=NO)	$0.00	$0.00	$0.00	$0.00	$0.00
NEW GAS CUSTOMER O&M COST (ANNUAL $/CUST)	$0.00	$0.00	$0.00	$0.00	$0.00
ALT FUEL 1 (UNITS)	$0	$0	$0	$0	$0
ALT FUEL 2 (UNITS)	$0	$0	$0	$0	$0

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FILE: 08/05/97 NOTES: Centra Industrial Load - Low Gas Prices

UNION GAS LIMITED

Undertaking of Ms. Lynch
To Mr. Chernick ("GEC")

Union to disaggregate the first column of commodity on Page 5, 6 and 7 on a best-efforts basis.

Please see Attachment 1.

Page 5 Particulars ($/m^3)	2015	2016	2017
Total Avoided Cost	0.20926	0.19268	0.19206
Empress Supply	0.01218	0.01703	0.01644
Dawn Supply	0.16108	0.14156	0.14147
South Transportation	-	-	-
North Transportation & Storage	0.00090	0.00067	0.00072
Unaccounted For Gas (UFG)	0.03510	0.03342	0.03343
Total Avoided Cost	0.20926	0.19268	0.19206

Page 6 Particulars ($/m^3)	2015	2016	2017
Total Avoided Cost	0.21388	0.19796	0.19613
Empress Supply	0.01699	0.01423	0.01377
Dawn Supply	0.15909	0.14643	0.14496
South Transportation	-	-	-
North Transportation & Storage	0.00394	0.00346	0.00353
Unaccounted For Gas (UFG)	0.03386	0.03385	0.03387
Total Avoided Cost	0.21388	0.19796	0.19613

Page 7 Particulars ($/m^3)	2015	2016	2017
Total Avoided Cost	0.20104	0.19690	0.19381
Empress Supply	0.02004	0.01756	0.01677
Dawn Supply	0.14678	0.14566	0.14391
South Transportation	-	-	-
North Transportation & Storage	0.00084	0.00031	- 0.00025
Unaccounted For Gas (UFG)	0.03337	0.03337	0.03337
Total Avoided Cost	0.20104	0.19690	0.19381

UNION GAS LIMITED

Undertaking of Ms. Lynch
To Mr. Chernick ("GEC")

On a best-efforts basis, Union to confirm the storage cost of 19 cents per gigajoule; to indicate how those different components of storage charges were utilized in the calculation.

The storage charge of $0.19/GJ was based on Union's 2013 Board approved Rate M1 storage rate and is used as a proxy for the avoided cost of storage for Union's bundled customers included in the gas supply plan. This rate is applied to the amount of storage space required. The Rate M1 storage rate is a bundled rate and includes the fixed and variable costs associated with storage space, deliverability and dehydration.

UNION GAS LIMITED

Undertaking of Mr. Tetreault
To Mr. Poch ("GEC")

Union to make best efforts to confirm that the table referred to captures all volumes that are utilized in Ontario, exclusive of Enbridge, and does not capture volumes which would leave the Province.

The table below provides M12 and M12X throughput volumes for Kingston Utilities on the Dawn-Parkway system. These throughput volumes do not necessarily represent Kingston Utilities' consumption. Union does not know the ultimate usage of Kingston Utilities' M12 and M12X throughput volumes.

Year	**Total ($10^{*6}m^3$)**	**1425445 Ontario Limited o/a Utilities Kingston M12 and M12X Throughput ($10^{*6}m^3$)**
1997	14,476	
1998	13,274	
1999	14,602	
2000	14,857	
2001	13,889	
2002	14,915	
2003	14,822	
2004	14,453	
2005	14,203	
2006	13,211	
2007	13,877	53
2008	13,843	47
2009	12,849	30
2010	13,314	35
2011	14,142	45
2012	14,435	43
2013	14,545	46
2014	14,747	50