INPUTS TO BENCOST FOR NATURAL GAS CIPs FOR THE 2013-2015 CONSERVATION IMPROVEMENT PROGRAM TRIENNIUM

The inputs necessary to run the BENCOST FOR GAS CIPs (BENCOST) model are listed below. Following this list, Staff of the Minnesota Division of Energy Resources (DER Staff) provide a description and the source(s) for each of the inputs.

General Inputs	**Specific Project Inputs**
Retail Rate ($/Mcf)	Utility Project Costs ($)
Non-Gas Fuel Retail Rate ($/Fuel Unit)	Administrative Costs ($)
Commodity Cost ($/Mcf)	Incentive Costs ($)
Demand Cost ($/Mcf/Yr)	Total Utility Project Costs ($)
Peak Reduction Factor (%)	Direct Participant Project Costs ($/Participant)
Variable O&M ($/Mcf)	Participant Non-Energy Costs (Annual $/Part)
Non-Gas Fuel Cost ($/Fuel Unit)	Participant Non-Energy Savings (Annual $/Part)
Non-Gas Fuel Loss Factor	Project Life (Years)
Gas Environmental Damage Factor ($/Mcf)	Avg. Mcf/Participant Saved
Non-Gas Fuel Environmental Damage Factor	Avg. Non-Gas Fuel Units/Part. Saved
Participant Discount Rate (%)	Avg. Additional Non-Gas Fuel Units/Part. Used
Utility Discount Rate (%)	Number of Participants
Societal Discount Rate (%)	Total Annual Mcf Saved
General Input Data Year	Incentive/Participant
Project Analysis Year	
Project Analysis Year	
Growth and Escalation Factors (%)	

General data inputs are either directly specified by DER Staff or are utility specific; they are used in analyzing all direct impact CIP projects. By contrast the specific project data inputs may vary from project to project. A description of the data for each BENCOST input is as follows:

Input 1 The *Retail Rate* ($/Mcf) is the natural gas rate for the specific customer class or classes (i.e., commercial, industrial, or residential) that are expected to participate in the project. The *Retail Rate* is calculated by adding the following:

- the utility's currently approved tariffed non-natural gas margin in the customer class that is expected to participate in a project (or a weighted average non-natural gas margin if more than one customer class is expected to participate in the project), which is on file with the DER;
- the *Commodity Cost* of $4.34/Mcf, which is described below in Input No. 3; and
- the per Mcf *Demand Cost* from the utility's March 2012 Purchased Gas Adjustment (PGA) filing, as described below in Input No. 4.

The *Retail Rate* does not include the annual true-up adjustment or the annual Conservation Cost Recovery Adjustment, if applicable. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining the non-

gas margin and demand cost components of this input. The *Retail Rate* is multiplied by the *Annual Escalation Rate* of 4.28 percent.

DER Staff calculated the *Annual Escalation Rate* of 4.28 percent from the average of the following five sources for natural gas price projections, applying an exponential fit to each data series to determine an escalation rate:

- Wood Mackenzie, "Natural Gas Monthly Market Update", December 2011
- Cambridge Energy Research Associates, "IHS CERA Monthly Briefing", December 21, 2011
- ICF International, "Q4 2011 Gas Market Compass", October 24, 2011
- Energy Information Administration, Short-Term Energy Outlook, January 2012
- Global Insights, "Chained Price Index-Household Natural Gas", November 2011

This analysis yielded escalation rates of 5.06 percent, 2.95 percent, 5.38 percent, 5.07 percent, and 2.92 percent, respectively, for an average escalation rate of 4.28 percent. Each of the above sources is widely accepted as a primary source of economic, industrial, and financial information, and is frequently used by financial and industrial experts to analyze trends and cycles in the market.

Input 2 The *Non-Gas Fuel Retail Rate* ($/Fuel Unit) is the estimated non-natural gas (e.g., electricity) retail rate for the specific customer class or classes (i.e., commercial, industrial, or residential) that is or are expected to participate in a project, if applicable. If this input is an electric retail rate, it should be based on a tariffed rate for the customer class that is expected to participate in a project (or a weighted average retail rate if more than one customer class is expected to participate in a project). Each utility that chooses to use this input must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used to calculate the *Non-Gas Fuel Retail Rate*. In addition, the *Non-Gas Fuel Retail Rate* is multiplied by an Annual Escalation Rate of 2.80 percent. This rate was developed using a projected price index entitled "Chained price index--household electricity" for the period 2013 to 2034, which was provided by Global Insight via the Minnesota Department of Finance (Finance).

Input 3 The *Commodity Cost* ($/Mcf) is $4.34/Mcf, which is the weighted average of CenterPoint Energy, Minnesota Energy Resources Corporation-PNG, and Northern States Power Company (Xcel Energy) purchased gas adjustments (PGAs) from April 2010 through March 2012, weighted by each utility's gas sales to non-exempt customers. The *Commodity Cost* input is also multiplied by the *Annual Escalation Rate* of 4.28 percent, which is described above in Input No. 1.

Input 4 The *Demand Cost* ($/Mcf/Year) is the estimated annual fixed demand costs that the utility would save from buying one fewer Mcf of demand services. The source

for this figure is the utility's March 2012 PGA, which reflects the demand costs from that peaking season. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input. The *Demand Cost* is multiplied by the *Annual Escalation Rate* of 4.28 percent, which is described above in Input No. 1.

Input 5 The *Peak Reduction Factor* (1 percent) is the estimated average annual effect of the project on system peak. The factor is presented as the percent of energy savings occurring on peak, which is estimated at one percent for most projects.

Input 6 *Variable O&M* ($/Mcf) is the variable costs, other than fuel and purchased energy costs, that are included as expenses in delivering energy to the end use consumer. For utilities that have flexible rate tariffs, *Variable O&M* is the minimum transportation flexible rate, which is generally based on the utility's best estimate of variable costs. Each utility must fully explain how it determines the *Variable O&M* input. This cost is multiplied by the *Annual Escalation Rate* of 4.28 percent, which is described above in Input No. 1.

Input 7 The *Non-Gas Fuel Cost* ($/Fuel Unit) is used to project society's avoided or increased costs of non-natural gas fuels (e.g., electricity) associated with participation in a natural gas CIP project, if applicable. DER Staff calculated an average cost of $26.82/MWh, equal to the average of daily average locational marginal prices (LMP) at the Minnesota Hub from June 24, 2010 to June 23, 2011 using data from Midwest Independent System Operator (MISO). This cost is multiplied by the *Annual Escalation Rate* of 2.80 percent, which is described above in Input No. 2. At this time, DER Staff are not issuing a proxy for electric transmission and distribution costs. If a utility wishes to propose such costs, or if a utility wishes to propose non-natural gas fuel costs other than those associated with electricity, it must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining such a proposed cost amount.

Input 8 The *Non-Gas Fuel Loss Factor* (5.8 percent) reflects line losses associated with electric transmission and electric distribution line losses associated with participating in a natural gas CIP project, if applicable. DER Staff used the weighted average of the loss factors reported by IPL, MP, Xcel Energy, and OTP in 2009, weighted by 2009 retail kWh sales, to arrive at a *Non-Gas Fuel Loss Factor* of 5.8 percent.

Input 9 The *Gas Environmental Damage Factor* ($0.35/Mcf) is the long-term "external" cost to society and the environment of burning natural gas. This factor is based on using the upper range of the final urban environmental cost values for certain natural gas emissions that were approved by the Minnesota Public Utilities Commission (Commission) in its July 2, 1997 *Order Affirming in Part and Modifying in Part Order Establishing Environmental Cost Values* (Docket No. E999/CI-93-583), along with the estimated natural gas emission factor or factors

for each emission provided by the United States Environmental Protection Agency in its *AP-42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*. In its May 3, 2001 *Order Updating Externality Values and Authorizing Comment Period on CO_2, $PM_{2.5}$, and Application of Externality Values to Power Purchases*, Docket No. E999/CI-00-1636, the Commission required that externality values be updated using the Gross National Product Price Deflator Index as much as possible. Consistent with this directive, the *Environmental Damage Factor* has been updated to 2012 dollars by including the use of externality values from the Commission's June 10, 2011 *Notice of Updated Environmental Externality Values* in Docket Nos. E999/CI-93-583 and E999/CI-00-1636, which inflated the environmental externality values to 2010 dollars, and further inflating to 2012 dollars using the *Annual Esclation Rate* of 1.73 percent, which is described below.

The Commission's final environmental cost values include costs for the following emissions: sulfur dioxide, particulate matter, carbon monoxide, nitrogen oxides, lead, and carbon dioxide. However, the Commission's final environmental cost values do not assign costs for all emissions resulting from the combustion of natural gas, such as methane, propane, and volatile organic compounds. In addition, the Commission's final environmental cost values do not include emissions from natural gas production at the wellhead, transmission of natural gas from the wellhead to the consumer, or the environmental effects of laying and maintaining pipes and pumping stations. For these reasons, DER Staff conclude that it is reasonable to use the upper range of the Commission's final environmental cost values to calculate the inflation-adjusted *Gas Environmental Damage Factor* of $0.35/Mcf.

The *Gas Environmental Factor* is multiplied by an *Annual Escalation Rate* of 1.73 percent. DER calculated an *Annual Escalation Rate* of 1.73 percent by applying an exponential fit to a projected price index entitled "Chained Price Index-Gross Domestic Product," as provided to DER by Global Insight via Finance.

Input 10 The *Non-Gas Fuel Environmental Damage Factor* is an environmental damage factor based on the long-term "external" cost to society and the environment of generating electricity. DER Staff calculated a *Non-Gas Fuel Environmental Damage Factor* of $21.32/MWh using the upper range of the Commission's final urban environmental cost values reported in Docket Nos. E999/CI-93-583 and E999/CI-00-1636 for particulate matter (PM10), carbon monoxide (CO), and lead (Pb), inflation-adjusted to 2012 dollars. Internal environmental cost values used by Xcel Energy for sulfur dioxide (SO2) and nitrous oxides (NOx) were used in place of the Commission values for these emissions, consistent with the current practice in integrated resource plans (IRP) to use utility-specific values for these emissions. A cost of $21.50 per ton of carbon dioxide (CO2) emissions was used in place of the Commission's updated environmental externality value of $4.22/ton in Docket Nos. E999/CI-93-583 and E999/CI-00-1636, consistent with

a February 9, 2012 Commission Order pertaining to Otter Tail Power Company's 2011-2025 Integrated Resource Plan (Docket No. E017/RP-10-623), in which the Commission ordered the company to include in its base case carbon dioxide costs equal to the mid-point of the Commission-approved range of likely future carbon dioxide regulatory costs. A cost of $21.50 per ton of carbon dioxide is equal to the mid-point of the range of $9 to $34 per ton of carbon dioxide approved by the Commission in its June 3, 2011 Order Establishing 2011 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. § 216H.06. If a utility proposes to use an environmental damage factor associated with a type of fuel other than electricity, it must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to supporting documents) used in determining this input. This input is multiplied by the Annual Escalation Rate of 1.73 percent, which is described above in Input No. 9.

Input 11 The *Participant Discount Rate* (%) for residential customers is the *Societal Discount Rate* of 2.67 percent, as discussed below in Input No. 13. Such a discount rate would reflect a residential customer's likely opportunity costs (i.e., the return on investment that a residential customer would likely give up in order to invest in CIP). The *Participant Discount Rate* for commercial and industrial customers is the *Utility Discount Rate*, as discussed below in Input No. 12. Although this discount rate may be lower than the actual discount rate for a particular commercial/industrial customer, it represents an attempt to reflect in a simple manner a reasonable estimate of a business customer's opportunity costs.

Input 12 The *Utility Discount Rate* (percent) is the utility's after-tax weighted cost of capital approved in the utility's most recent rate case. This rate is used to value, in current dollars, the future stream of internal benefits and costs (excluding benefits resulting from avoided environmental damage, as discussed above in Input No. 9) resulting from a utility conservation investment. Since the *Utility Discount Rate* is the utility's cost for its capital, it is a reasonable measure of the value society places on a utility investment.

Input 13 The *Societal Discount Rate* (2.67 percent) is the rate used to discount the future stream of benefits resulting from avoided environmental damage. Since environmental costs are not captured and reflected in market prices, it is necessary to impute and impose a societal discount rate for these costs. The *Societal Discount Rate* is to equal the United States Department of the Treasury's (Treasury) 20-year Constant Maturity (CMT) Rate, which was 2.67 percent as of January 3, 2012. The Treasury's 20-year Daily CMT Rate captures the market's expectations regarding inflation, along with a small risk factor. At this time, DER Staff conclude that a rate including inflation expectations and a small risk factor is a reasonable method for estimating a social discount rate for externalities. DER Staff note that the future stream of benefits resulting from avoided environmental damage is also escalated by the *Annual Escalation Rate* of 1.73 percent described above in Input No. 9.

Input 14 The *General Input Data Year* for the 2013-2015 benefit/cost analysis is 2012.

Input 15a *Project Analysis Year 1* is 2013.
Input 15b *Project Analysis Year 2* is 2014
Input 15c *Project Analysis Year 3* is 2015.

Input 16 The *Utility Project Costs* is the sum of all of the utility's estimated project costs. Examples of these costs include administrative and operating costs and incentive costs paid to the participant.

Input 17 *Direct Participant Costs* ($/Participant) is incremental "out-of-pocket" expenses that the participant would pay to install the conservation measure. For example, the cost to a customer to install a high efficiency furnace is the difference in installation costs between high efficiency equipment and equipment that meets code. This input is <u>not</u> reduced by the amount of any rebate that the utility will provide to the participant through the CIP project. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input.

Input 18 *Participant Non-Energy Costs* (Annual $/Participant). Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input. This figure is entered as an annual cost and is escalated at the *Annual Escalation Rate* of 1.73 percent described in Input No. 1 above.

Input 19 *Participant Non-Energy Savings* (Annual $/Participant). This figure is entered as an annual benefit and is escalated by the *Annual Escalation Rate* of 1.73 percent described above in Input No. 1.

Input 20 The *Project Life* is the expected lifetime of a particular energy conservation measure, expressed in number of years. The project life used in the BenCost model is based on specific energy conservation measures. Projects with expected lives shorter than 20 years use lower figures. Each utility must show the reasonableness of its expected lifetime for a particular energy conservation measure or project. In most cases, the maximum life used is limited to 20 years for the following reasons:

a) benefits are more uncertain the further out in time the model is extended;
b) benefit streams diminish further out in time and have lesser effects on cost-effectiveness than more current years;
c) the further out in time the model is extended, the more uncertain it becomes that current ratepayers, who are funding CIP, receive the full benefits of CIP; and
d) if a project cannot pay for itself within 20 years, ratepayers should instead be funding other, more cost effective projects.

Input 21 The *Average Mcf/Participant Saved* is the estimated annual amount of Mcfs saved from the energy conservation measure. Each utility must identify and fully explain in its CIP filing all calculations and underlying assumptions used in determining this input.

Input 22 The *Average Non-Gas Fuel Units/Participant Saved* is the estimated amount of non-natural gas fuel (e.g., electricity) saved per participant in a project. Each utility that includes such fuel savings must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining this input.

Input 22a The *Average Additional Non-Gas Fuel Units/Participant Saved* is the amount of non-natural gas fuel (e.g., electricity) used per participant in a project. Each utility that includes such fuel usage must identify and fully explain in its CIP filing all calculations and underlying assumptions (including references to any supporting documents) used in determining this input.

Inputs 23 The *Number of Participants* is the estimated number of participants based on the utility's expected market penetration levels, on past experience in a similar project, or on marketing penetration studies for similar projects.

Input 24 The *Total Annual Mcf Saved* is the total amount of savings projected for a year. The savings are computed by the model by multiplying Input No. 23 by Input No. 21.

Input 25 The *Incentive per Participant* is the utility incentive costs identified in Input No. 16 divided by the *Number of Participants* identified in Input No. 23. This figure is computed within the model.