P O L I T I Q U E S D E

P R O D U I T S D É R I V É S F I N A N C I E R S

C H E Z L E S D I S T R I B U T E U R S D E G A Z

N A T U R E L C A N A D I E N S

(suivi des décisions D-2001-109 et D-2001-214)

Témoins : Sophie Brochu
René Chouinard

TABLE DES MATIÈRES

P R É A M B U L E

Le présent document fait suite à la décision D-2001-214 et porte sur les moyens utilisés par les distributeurs gaziers canadiens concernant la réduction du coût du gaz naturel qu'ils fournissent. La Régie demandait notamment de quantifier l'impact des dérivés financiers sur l'évolution des prix facturés mensuellement aux clients de SCGM en comparaison à ceux facturés par les autres sociétés de distribution locale (SDL) canadiennes.

D'entrée de jeu, il faut noter que la très grande majorité des SDL déposent leur programme de couverture sur des bases confidentielles et ce, pour des raisons tant commerciales que stratégiques. Par ailleurs, il faut comprendre que chaque distributeur utilise sa propre méthodologie quant au mécanisme de calcul du coût du gaz naturel qu'il fournit. En ce sens, il ne faut pas s'étonner, toute chose étant égale par ailleurs, qu'il y ait un écart ponctuel entre les tarifs de fourniture affichés d'une compagnie à l'autre.

Cela dit, la performance de chaque distributeur gazier repose non seulement sur sa capacité d'utiliser judicieusement les outils financiers mis à sa disposition, mais également à la méthodologie applicable à l'ajustement du coût du gaz. Autrement dit, ce n'est pas parce qu'un distributeur gazier affiche des tarifs de fourniture relativement avantageux pour une période donnée qu'il a pour autant le meilleur programme de couverture. Ce n'est pas non plus parce qu'un distributeur présente un impact relativement marginal qu'il a pour autant marié l'efficience économique avec la couverture optimale.

Précisons finalement que chaque distributeur évolue dans un cadre structurel, économique et d'approvisionnement qui lui est propre et, qu'en ce sens, les éléments de comparaison doivent être traités avec prudence.

SECTION 1 : STRATÉGIES DES DISTRIBUTEURS DE GAZ NATUREL CANADIENS

Afin d'analyser et de comparer la performance des stratégies utilisées, SCGM devait, dans un premier temps, déterminer les actions mises en œuvre par les différents distributeurs gaziers en vue d'atteindre leurs objectifs; actions en terme d'outils, de volumes, de coûts, de durée, etc.

Dans cet ordre d'idées, SCGM a communiqué avec la majorité sinon la totalité des entreprises de distribution gazière au Canada, soit par contact téléphonique et/ou électronique. Tel que présenté aux annexes A à D, les démarches entreprises afin d'obtenir l'information ont été documentées de façon rigoureuse en y incluant le nom de la compagnie et/ou de l'entité de réglementation, le nom des personnes ressources, les dates ainsi que tous les documents pertinents. Le lecteur trouvera dans ce qui suit les résultats par province et, le cas échéant par compagnie.

1.1 Colombie-Britannique

En Colombie-Britannique, les stratégies de couverture inhérente aux dérivés financiers sont déposées à l'organisme de réglementation (BCUC) sous le sceau de la confidentialité (voir l'annexe A). Les entreprises consultées et les personnes ressources sont les suivantes :

BC Gas	Steve Richards General Counsel, Chief Risk Officer and Corporate Secretary BC Gas Inc.
BC Centra Gas	Geoff Higgins Manager of Regulatory Affairs Centra Gas BC
Pacific Northern Gas	Craig P. Donohue Director, Regulatory Affairs & Gas Supply Pacific Northern Gas Ltd.

À la connaissance de SCGM, il n'existe pas de rapport de performance structuré quant aux moyens utilisés afin de réduire la volatilité du coût du gaz naturel fourni par les distributeurs. En vertu de ce qui précède, il est impossible de quantifier l'impact des dérivés financiers sur l'évolution des prix facturés mensuellement aux clients de SCGM en comparaison à ceux facturés par les SDL de la Colombie-Britannique.

1.2 Alberta

En ce qui à trait à l'Alberta, le distributeur albertain ATCO Gas n'utilise pas de stratégies de couverture dans sa gestion des approvisionnements gaziers. Le lecteur peut se référer à la section Frequently Asked Questions du site web de ATCO Gas (annexe B).

1.3 Saskatchewan

Contrairement à ce qui se passe dans les autres provinces canadiennes, il n'y a pas, en Saskatchewan, d'organisme de réglementation rattaché spécifiquement aux questions énergétiques. C'est plutôt un panel *ad hoc* (« Rate Review Panel ») qui ne siège que lorsque des questions tarifaires surviennent. Fait à noter, en date du 14 décembre 2001, le panel a recommandé que SaskEnergy dépose un programme d'approvisionnement gazier et de gestion des risques pour l'année gazière 2002-2003[1] (annexe C).

SCGM a communiqué avec Mme Marilyn Wappel, responsable des Affaires réglementaires chez SaskEnergy, afin d'obtenir une copie dudit document et est toujours en attente d'une réponse.

1.4 Manitoba

SCGM est toujours en attente de réponses de la part des représentants de CentraMan, SDL du Manitoba, quant à la gestion des risques des prix du gaz naturel qu'elle fournit.

1.5 Ontario

En Ontario, les deux SDL, Union Gas (Union) et Enbridge Consumer Gas (ECG), sont assujetties à la réglementation de l'OEB (Ontario Energy Board) en ce qui a trait aux programmes de dérivés financiers. Tel que déjà mentionné dans la pièce SCGM-1, document 4

[1] Dans un document intitulé *Report to the Minister of Crown Investments Corporation on the Proposal from SaskEnergy for a change in the Natural Gas Commodity Rate*.

du dossier R-3463-2001, le programme de gestion des risques chez ces distributeurs a essentiellement les mêmes objectifs que celui de SCGM, soit d'équilibrer la composition du portefeuille d'approvisionnement gazier afin de mitiger la volatilité et les flambées de prix du gaz.

Tant chez ECG que chez Union, les transactions effectuées sont déposées à l'OEB sous le sceau de la confidentialité. Toutefois, les résultats découlant de la politique sont gardés confidentiels par ECG alors que Union, même si elle ne donne aucun indice sur ses stratégies contemplées, dépose suffisamment d'indices afin de répondre, sujet à caution pour les raisons déjà énoncées, à la demande de la Régie.

SECTION 2 : ÉVOLUTION DU PRIX DU GAZ NATUREL FOURNI PAR LES DISTRIBUTEURS

En vue de bien comprendre l'impact des dérivés financiers sur l'évolution des prix facturés, il semble dans un premier temps à propos de donner une brève explication des procédures d'ajustement périodique du prix du gaz de SCGM en comparaison de ce qui se fait en Ontario, chez Union et ECG. Comme leur nom l'indique, ces procédures ont pour but d'établir périodiquement le coût du gaz qui est facturé à la clientèle afin, d'une part, d'en refléter le prix réel d'acquisition et, d'autre part, de moduler l'évolution des prix dans le marché.

2.1 Union Gas

2.1.1 Calcul du coût du gaz naturel fourni par Union

Union utilise une méthodologie selon laquelle elle établit en début d'exercice ses anticipations de prix au cours des 12 mois suivants. Elle procède ensuite à un mécanisme d'ajustement trimestriel où le prix englobe les paramètres suivants :

1. La moyenne des prévisions de cinq firmes spécialisées pour la prochaine année; et
2. L'impact des prix protégés par dérivés financiers au cours de la période.

Voici à cet effet une illustration du calcul du coût moyen du gaz naturel fourni par Union pour les mois de novembre et décembre 2001 et janvier 2002 :

	Coût unitaire ($/GJ)	Quantité (PJ)	Coûts totaux (000 $)
Étape 1			
• Prévision des prix établie en nov. 2001	3,33	36,11	120 248
Étape 2			
• Impact des outils de gestion (dérivés financiers)			11 001
Total :			**131 249**
Prix de référence pour les mois de novembre 2001, décembre 2001 et janvier 2002	3,63		

Il est important de noter que Union calcule sur une base annuelle l'écart entre le coût réel d'acquisition et le prix du gaz effectivement facturé. La différence est par la suite débitée ou créditée aux clients lors des trois derniers trimestres de l'année suivante. Ainsi, la disparité entre le coût affiché et le coût réel des mois de novembre 2001 à octobre 2002 se fera sentir au cours des trois derniers trimestres de 2003. Il est par ailleurs important de noter que cet écart sera imputé au tarif de distribution et non au tarif de fourniture.

2.1.2 Impact des dérivés financiers

Le lecteur pourra se référer à l'annexe D pour les détails de l'impact des produits dérivés financiers sur le prix de référence.

2.2 Enbridge Consumer Gas

2.2.1 Calcul du coût du gaz naturel fourni par ECG

Le calcul annuel du tarif de fourniture de ECG est basé sur une prévision de son coût d'approvisionnement. Le coût anticipé inclut une prévision de prix du gaz naturel de ce que ECG appelle le « *21-day strip* ». Celui-ci se définit comme la moyenne arithmétique des prix à terme sur une période de 21 jours pour un portefeuille reflétant le profil

d'approvisionnement annuel anticipé quant aux échéances, aux points de livraison et aux indices de prix. Le distributeur utilisera cette prévision initiale comme base de calcul du tarif de fourniture qu'il mettra cependant à jour sur une base trimestrielle. Le tarif de fourniture révisé aura préséance sur le tarif en cours dans le cas d'une différence supérieure à 0,13 $/GJ.

Par ailleurs, toute différence, qu'elle soit positive ou négative, entre le coût réel d'acquisition et le prix du gaz effectivement facturé par ECG, est enregistrée dans un compte de frais reportés (PGVA = Purchase Gas Variance Account) et normalement facturée aux clients par la suite.

La méthodologie préconisée par ECG quant au tarif de fourniture de gaz se décompose comme suit:

1. Un mécanisme de prévision (à l'interne) des prix du gaz naturel (*21-day strip*); et
2. L'impact des prix protégés par dérivés financiers au cours de l'année.

Le tableau suivant explique bien l'approche développée par ECG. Il faut noter cependant que tous les chiffres présentés ne le sont qu'à titre indicatif. De fait, ECG ne donne pas suffisamment d'information pour déduire l'impact des dérivés financiers par processus récursif.

	Coût unitaire ($/GJ)	**Quantité (PJ)**	**Coûts totaux (000 $)**
Étape 1			
• Prévision des prix établie en nov. 2001	3,50	220	770 000
Étape 2			
• Impact des outils de gestion (dérivés financiers)			75 000
Total :	**3,85**		**845 000**

2.2.2 Impact des dérivés financiers

Pour les raisons précitées, il est impossible de quantifier l'impact des dérivés financiers sur l'évolution des prix facturés mensuellement.

2.3 Société en commandite Gaz Métropolitain

2.3.1 Évaluation du coût du gaz naturel fourni par SCGM

Le tarif de fourniture de gaz de SCGM pour un mois donné se compose des éléments suivants :

1. Une évaluation mensuelle du coût du gaz prévue pour les 12 prochains mois. SCGM utilise à cet effet la moyenne des prix des contrats d'échange annuel transigés sur le marché financier durant les jours ouvrables du mois précédent. Ces prix sont fournis par une institution financière;
2. L'impact de l'utilisation des dérivés financiers mis en place pour protéger les prix au cours de l'année; et
3. Une évaluation des écarts entre le coût réel d'acquisition et le prix du gaz facturé antérieurement à l'ajustement (écart de prix cumulatif). Ce dernier s'accroît si le prix effectivement payé par SCGM pour un mois donné a été plus élevé que ce qui fut anticipé le mois précédent. En période de hausse systématique des prix, cet écart augmente. À l'inverse, lorsqu'on observe un fléchissement des anticipations financières, cet écart diminue.

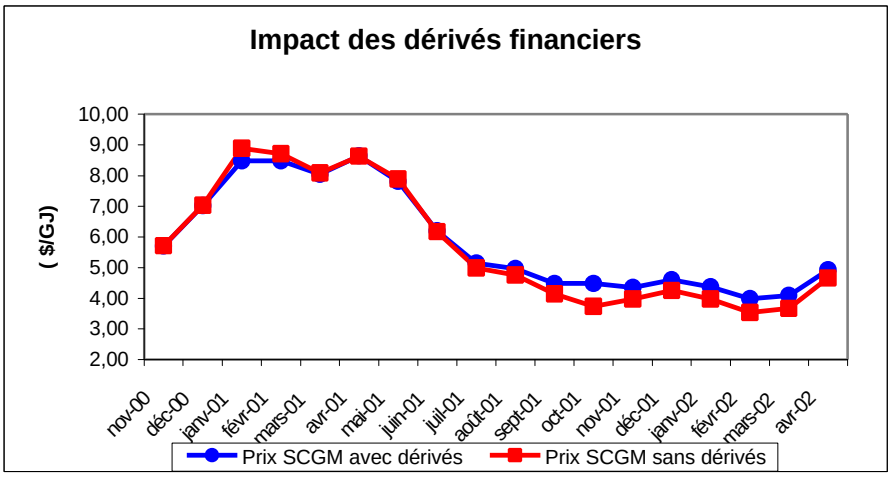
Afin de comprendre les rudiments de la démarche, il semble à propos de résumer les étapes à l'aide d'un exemple quantitatif. Il est à noter que cet exemple se base sur les chiffres observés au mois d'avril courant (2002).

	Coût unitaire ($/GJ)	Quantité (PJ)	Coûts totaux (000 $)
Étape 1 • Prix moyens des contrats d'échange 1 an	4,60	88,63	407 677
Étape 2 • Impact des outils de gestion (dérivés financiers)			22 071
Étape 3 • Écart de coût cumulatif au 1er avril 2002			6 790
Total :			**436 538**
Tarif de fourniture pour avril 2002	4,93 $/GJ		

Les prix affichés par SCGM reflètent essentiellement les anticipations rationnelles du marché financier. Autrement dit, si le marché demeurait statique au cours des 12 mois prospectifs à la prévision, en excluant l'impact des produits financiers dérivés, le tarif de fourniture (4,93 $/GJ) convergerait progressivement vers le prix moyen des contrats d'échange 1 an (4,60 $/GJ).

2.3.2 Impact des dérivés financiers

Le graphique suivant présente l'impact des dérivés financiers sur le coût du service de fourniture de gaz naturel de SCGM.

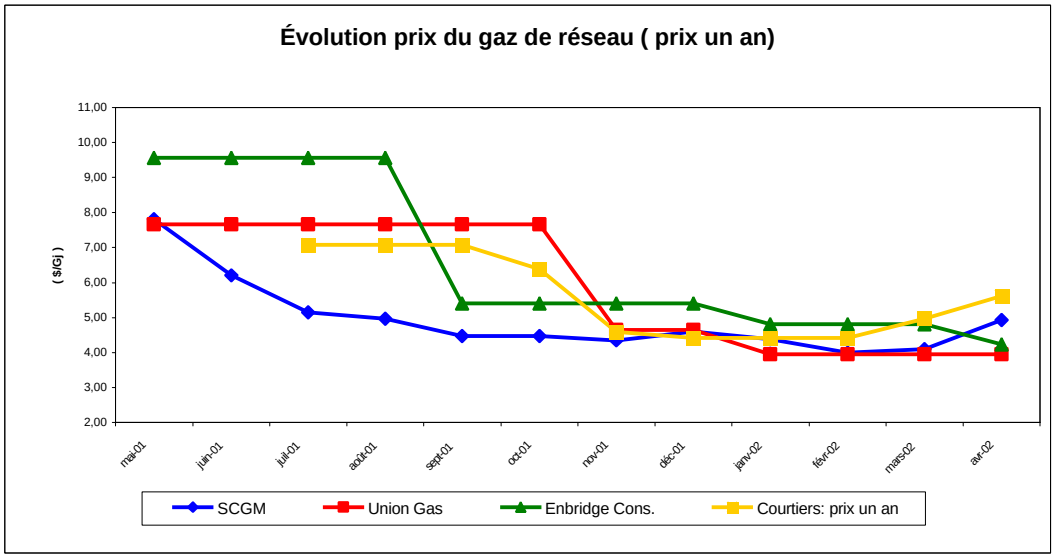


SECTION 3 : ANALYSE COMPARATIVE DES RÉSULTATS

Le lecteur trouvera ci-dessous un résumé comparatif des stratégies de gestion des risques :

Statut et performance des stratégies Tableau récapitulatif			
	Union Gas	**Enbridge Consumers Gas**	**SCGM**
Objectifs annuels			
- Stabilité	Oui	-	Oui
- Protection	Oui	-	Oui
- Opportunités	Oui	-	Oui
Moyens			
- SWAP	n/d	n/d	Oui
- Options	n/d	n/d	Non
- Colliers	n/d	n/d	Oui
- Combinaison	n/d	n/d	Oui
Résultats			
- Volatilité – Réduction	n/d	n/d	40 % de 82 % à 42 %
Primes			
- Impact en % (avril 2002)	n/d	n/d	0,2 %
- Respect des limites	Oui	n/d	Oui

Le graphique suivant compare l'évolution des tarifs de fourniture pour SCGM, Union et ECG. Également sur le graphique, se trouvent les prix 1 an proposés par les courtiers.



A N N E X E S

Annexe A : BC Gas Supply Risk Management Plan

Annexe B : ATCO Gas

Annexe C : The Proposal from SaskEnergy for a Change in the Natural Gas Commodity Rate, December 14, 2001

Annexe D : Union Gas Limited – Alberta Border WAGOC Pricing Calculation – Year ending October 31, 2002

Trudeau, Stéphan
De: Craig Donohue [cdonohue@wei.org]
Envoyé: 12 mars, 2002 10:07
À: 'strudeau@gazmet.com'
Objet: PNG Gas Supply Price Risk Management Plan

Further to our telephone conversation, I confirm that PNG files its annual Gas Supply Price Risk Management Plan with the B.C. Utilities Commission on a confidential basis. The Plan is kept confidential in accordance with a policy letter we sent to the Commission several years ago concerning the need to keep gas supply price information confidential due to its commercial sensitivity.

I can confirm that the objective of PNG's Gas Supply Price Risk Management Plan is to manage price volatility by hedging prices over the winter and summer months for a portion of our firm gas supply requirements. In other words, once the hedging is in place, we do not try to beat the market by going in and out of the market in response to changes in future prices.

I trust the above will assist you. Please contact me if you have any further questions.

Craig P. Donohue
Director, Regulatory Affairs & Gas Supply,
Pacific Northern Gas Ltd.
Tel: (604) 691-5882 Fax: (604) 691-5863
Cell: (604) 868-7955 E-mail: cdonohue@wei.org

Trudeau, Stéphan
De: Barb Condon [BCondon@bcgas.com]
Envoyé: 13 mars, 2002 11:21
À: 'strudeau@gazmet.com'
Objet: FW: BC Gas Supply Risk Management Plan

Mr. Trudeau,

Our risk management plan in not a public document as such can not provide the information you request.

Barb Condon
Risk Manager
BC Gas Utility
ph 604 592 7896

> -----Original Message-----
> From: Kirby Morrow
> Sent: Wednesday, March 13, 2002 8:07 AM
> To: Barb Condon
> Subject: FW: BC Gas Supply Risk Management Plan
>
> Can you follow up
>
> -----Original Message-----
> From: "Trudeau, Stéphan" [SMTP:STrudeau@gazmet.com]
> Sent: Wednesday, March 13, 2002 5:54 AM
> To: 'kmorrow@bcgas.com'
> Subject: BC Gas Supply Risk Management Plan
>
> Mr. Morrow,
>
> Last week I came into contact with Anna Fung and Steve Richards with a
> query
> concerning BC Gas' Commodity Risk Management practices, and Steve thought
> you would be the person most capable of providing me with an answer. I
> will
> paste the message originally sent to Anna and thereafter to Steve, and if
> you have any additional questions please feel free to call or email me at
> the coordinates below. Thanks for your help!
>
> Ms.Fung,
>
> I am regulatory Counsel for Gaz Métropolitain, a Montreal-based LDC. My
> provincial regulator has asked me to file a detailed study of risk
> management manuals, policies, programs or procedures used by other
> canadian
> gas utilities at our upcoming rate case. I therefore hope you can help me
> answer this request.
>
> My questions are the following:
>
> * Is your risk management policy a public document or has it been
> filed as an exhibit in a past rate case?
> * If your risk management policy is of a public nature, would it be
> possible to forward us an up-to-date copy?

> * Again, if your policy is public, would it also be possible to send
> us a copy of your "exposure books" or any other amalgamated overview of
> positions taken during the years 2000 and 2001?
> * If, however, your policy is of a confidential nature or has been
> provided to your regulator on a confidential basis, could you please
> provide
> us with a letter confirming that fact or explaining what measures are
> taken
> to limit divulgation of the document.
>
> I thank you for the time spent on my request and please know that if there
> is any similar request with which I can be of assistance, I will be glad
> to
> return the favour.
>
>
> Stéphan Scott Trudeau
>
> Legal Counsel
> Business Development and
> Out of Québec Regulatory Affairs
> Gaz Métropolitain
> T: 514.598.3898
> C: 514.703.1378
> F: 514.598.3725
> E: strudeau@gazmet.com
>

21 MAR 2002

ROBERT J. PELLATT
COMMISSION SECRETARY
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March 13, 2002

Mr. S. Trudeau
Counsel
Gas Metropolitain & Company, Limited Partnership
1717 Duhavre Street
Montreal, Quebec H2K 2X3

Dear Mr. Trudeau:

Re: Gas Supply and Price Risk Management Plans
Confidentiality of Plans filed with the British Columbia Utilities Commission

Section 71 of the Utilities Commission Act requires energy supply contracts to be filed with the B.C. Utilities Commission ("BCUC") and requires the information to be made available to the public unless the BCUC considers that disclosure is not in the public interest. A copy of Section 71 and the Rules for Energy Supply Contracts are enclosed.

Natural gas utilities submit gas supply plans and price risk management plans in support of the gas purchase contracts that they file. They generally request such filings to be held confidential by the Commission on the basis that core market (utility sales) customers could be disadvantaged and may experience additional costs if utility gas supply strategies and contracts are treated differently from those of other gas purchasers. Utilities believe that, within the competitive gas market environment, there is no necessity for public disclosure that may prejudice future contract negotiations. In addition, the B.C. Freedom of Information and Protection of Privacy Act requires the Commission to withhold public disclosure of information about third party commercial contracts, unless it is clearly in the public interest to disclose the information.

In this circumstance, the Commission normally holds energy supply contracts and related gas supply and price risk management plans confidential. Nevertheless, the Commission encourages utilities to include with such filings an Executive Summary that is not confidential that can be made available to the public without disadvantaging utility sales customers. We are enclosing a copy of BC Gas' Executive Summary for its 2001/02 Gas Supply Annual Contracting Plan that was approved by the Commission by Letter No. L-15-01.

Yours truly,

Robert J. Pellatt

JBW/cms
Enclosures

MiscCor/Gas Supply/Risk Management Conf.

Energy supply contracts (see attached Minister's Order M-297)

71 (1) A person who, after this section comes into force, enters into an energy supply contract must

(a) file a copy of the contract with the commission under rules and within the time it specifies, and
(b) provide to the commission any information it considers necessary to determine whether the contract is in the public interest.

(2) The commission may make an order under subsection (3) if the commission, after a hearing, finds that a contract to which subsection (1) applies is not in the public interest by reason of

(a) the quantity of the energy to be supplied under the contract,
(b) the availability of supplies of the energy referred to in paragraph (a),
(c) the price and availability of any other form of energy, including but not limited to petroleum products, coal or biomass, that could be used instead of the energy referred to in paragraph (a),
(d) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (a), or
(e) any other factor that the commission considers relevant to the public interest.

(3) If subsection (2) applies, the commission may

(a) by order, declare the contract unenforceable, either wholly or to the extent the commission considers proper, and the contract is then unenforceable to the extent specified, or
(b) make any other order it considers advisable in the circumstances.

(4) If an energy supply contract is, under subsection (3) (a), declared unenforceable either wholly or in part, the commission may order that rights accrued before the date of the order under that subsection be preserved, and those rights may then be enforced as fully as if no proceedings had been taken under this section.

(5) An energy supply contract or other information filed with the commission under this section must be made available to the public unless the commission considers that disclosure is not in the public interest.

PART 6–COMMISSION JURISDICTION

Jurisdiction of commission to deal with applications

72 (1) The commission has jurisdiction to inquire into, hear and determine an application by or on behalf of any party interested, complaining that a person constructing, maintaining, operating or controlling a public utility service or charged with a duty or power relating to that service, has done, is doing or has failed to do anything required by this Act or another general or special Act, or by a regulation, order, bylaw or direction made under any of them.

(2) The commission has jurisdiction to inquire into, hear and determine an application by or on behalf of any party interested, requesting the commission to

(a) give a direction or approval which by law it may give, or
(b) approve, prohibit or require anything to which by any general or special Act, the commission's jurisdiction extends.

Mandatory and restraining orders

73 (1) The commission may order and require a person to do immediately or by a specified time and in the way ordered, so far as is not inconsistent with this Act, the regulations or another Act, anything that the person is or may be required or authorized to do under this Act or any other general or special Act and to which the commission's jurisdiction extends.

(2) The commission may forbid and restrain the doing or continuing of anything contrary to or which may be forbidden or restrained under any Act, general or special, to which the commission's jurisdiction extends.

IN THE MATTER OF

ENERGY SUPPLY

CONTRACTS

- RULES

September 25, 1997

BRITISH COLUMBIA UTILITIES COMMISSION
RULES FOR ENERGY SUPPLY CONTRACTS

The following rules have been developed to facilitate the review by the Commission of energy supply contracts pursuant to Section 71 of the Utilities Commission Act. The review is to ensure that the terms of the contract are in the public interest having regard to the following:

- the quantity of the energy to be supplied under the contract;
- the availability of supplies of the energy;
- the price and availability of any other form of energy, including but not limited to petroleum products, coal or biomass, that could be used instead of the energy,
- in the case only of an energy supply contract that is entered into by a public utility, the price of the energy; or
- any other factor that the Commission considers relevant to the public interest.

NATURAL GAS SUPPLY CONTRACTS

In the case of natural gas supply contracts, the rules have been updated as a result of the continuing development of an efficient gas market in British Columbia.

1.0 GENERAL RULES for All Natural Gas Contract Categories

1.1 Under Section 71(1)(a), all natural gas purchasers in British Columbia, other than those purchasing exclusively from a gas utility, must file their supply contracts and all subsequent amendments with the Commission. Any approvals required by these rules should be obtained before delivery of natural gas occurs.

1.2 In the case of a buy-sell arrangement involving a gas supply contract between an agent/broker/marketer ("ABM"), on behalf of consumers, and a utility, the utility shall file the contract as part of its baseload portfolio. The Commission's approval of such a contract is subject to the ABM meeting the requirements of Section 3.0 of these rules.

1.3 Parties filing gas supply contracts with the Commission under Section 71, either directly or through an LDC, and wishing confidentiality, shall provide written justification as to why, in their view, it is in the public interest that the filed contract be kept confidential. Regardless of the Commission's ruling on confidentiality, price information is only required for utility gas supply contracts.

1.4 The reserves, deliverability and delivery arrangements supporting all gas supply contracts requiring approval shall be confirmed by independent third party expert review, or be backed by a corporate warranty from an appropriately qualified supplier which provides indemnification for substitute supply. The initial pre-approval review will be followed up with reviews at intervals as required by the Commission.

1.5 Where approval is required, the Commission will issue Orders approving all gas supply contracts which meet the requirements of these rules. Notwithstanding Commission approval, core market purchasers who contract for direct purchase of their natural gas supplies do so at their own risk of availability and price.

1.6 Purchasers who wish to displace direct purchases with utility purchases will be accommodated providing they give proper notice. Proper notice will require the customer to be on direct purchase for at least one year, and to give at least 60 days notice to be effective at the beginning of a calendar month. Where the purchaser has not given proper notice, the customer will be accommodated providing that the utility can contract sufficient gas and transportation to meet the additional load and, providing the purchaser assumes responsibility for any resulting incremental LDC costs that are approved by the Commission.

1.7 Notwithstanding 1.1 above, purchasers who have satisfied Commission requirements for long-term supply security as per Section 2.0 below and who wish to operate in the "spot" market will be permitted to make special arrangements with the Commission to facilitate timely approvals. Where feasible, this will consist of a verbal request for approval in advance of gas flow followed by filing of an executed contract as soon as possible thereafter. Daily and other short-term spot purchases may require filing of the purchaser's buying procedures and criteria, to be followed by timely filings of purchase contracts and reports of actual purchases.

1.8 It is the intention of the Commission to review and approve contracts expeditiously, normally without the requirement for a hearing. It is also the Commission's intention to avoid retroactive Orders. The hearing process, pursuant to Section 71(2) of the Act, will become necessary where the Commission initially determines that the contract may not be in the public interest. A hearing could also be required as a result of a third-party complaint.

1.9 The Commission may reconsider the duration of energy supply commitments required by Section 2.0 as gas supply market conditions change. Any change would be prospective and it is the Commission's intent that parties honour existing contracts.

2.0 SPECIFIC CONTRACT RULES by Category of Purchaser

2.1 Purchasers not Subject to Full Review

The Commission will require purchasers in this category to provide the Commission with a statutory declaration which confirms their alternative fuel capability, their use of natural gas mainly for manufacturing purposes rather than space heating, or their normal use of 2000 GJ of gas or more per year. If these purchasers have been buying gas on a non-core basis, or were previously sales customers of the LDC under rate schedules that confirm compliance with the criteria for this category, no statutory declaration will be required.

Purchasers in this category need only file a copy of their gas supply contracts and all subsequent amendments with the Commission. No approval will be required or issued.

2.2 Utility and Core Market Direct Purchasers

Utilities, and all core market direct purchasers that normally use less than 2000 GJ per year must submit gas supply contracts to the Commission for approval, together with all other related contracts which support the gas supply and any information required by 1.4 above. Each gas supply contract shall provide for:

2.2.1 in the case of baseload gas supply contracts, a minimum one year term and supply commitment and a minimum 60-day notice period for the supplier to terminate or extend the contract (and, in the case of new seasonal and peaking contracts, equivalent term and termination notice provisions); and

2.2.2 in the case of each portfolio, sufficient supply to meet the purchasers' total firm requirements at the level of the current year and a mix of one year and longer term contracts that is appropriate for the security needs of its customers, considering current market conditions; and

2.2.3 diversity of supply including where possible a range of suppliers positioned behind alternative processing facilities, or backstopping arrangements; and

2.2.4 in the case of utilities only, a prudent combination of terms, conditions, and price.

3.0 RULES PERTAINING to ABM's

3.1 Code of Conduct

All ABM's will be required to comply with the Code of Conduct for Agents/Brokers/Marketers that is approved by the Commission.

3.2 Licencing

Any person intending to act in the capacity of an ABM in order to provide advice to, or act on behalf of, core market consumers that normally use less than 2000 GJ per year and who are purchasing gas directly either under T-Service or a buy-sell arrangement will be required to apply to the Commission for a license. Licenses will be issued subject to receipt of a $100 fee and compliance with the following requirements.

Persons acting as ABM's on their own behalf and purchasing gas solely for their own use and who are not selling to third-party core market consumers, will not be required to comply with Rules 3.3, 3.5, 3.6, and 3.9.

3.3 Bonding

In order to receive a license, the ABM will be required to post a gas delivery performance bond of $250,000. The Commission may waive the requirement to post a bond if the ABM is delivering gas exclusively using non-bundled transportation service.

3.4 Code of Conduct and Licensing of ABM's

Failure to comply with the approved Code of Conduct will result in the license being revoked.

3.5 Standard Form of Gas Supply Contract

Licensees will be required to incorporate, in their contracts with gas suppliers, all clauses relating to security of supply from the buy/sell gas supply contract between the ABM and the utility approved by the Commission.

3.6 Disclosure Statement and Appointment of Agent Form

It is expected that the arrangements between end-use consumers and ABM's will require the use of some form of "agency agreement". Licensees will be required to receive Commission approval of their form of agreement. The Commission's review of such agreements will not require all agreements to be identical, but will focus on certain key requirements which shall include a minimum term of one year, and confirmation that the consumer understands the risks associated with direct gas purchases. Different forms of agreement may be appropriate for different categories of customers.

3.7 Standard Information Booklet

The Commission requires each gas distribution utility, in co-operation with ABM's, to develop a standard information booklet for their service area which outlines the procedures for direct purchase, and which discloses potential benefits and costs of direct purchase.

The Commission will require Licensees to distribute these booklets to all prospective clients and to include reference to the Booklet in their Disclosure Statement and Appointment of Agent Form.

3.8 Administration Fees and Minimum Contract Volumes

The commission will require utilities to collect fees to cover the cost of buy-sell administration. Initially the fee shall be $150/gas supply contract per month plus $6/customer account per year. Fees will be subject to periodic review by the Commission. The Commission may require minimum contract volumes if such action becomes necessary in future.

3.9 Requirements for Assignment of Westcoast Transmission Capacity

An LDC will provide Westcoast Zone 4 transportation capacity to an ABM when it is able to do so. Where Zone 4 capacity is available from the LDC, it shall be used. Where an ABM holds Zone 4 and has been using it to serve core market customers, but no longer needs it to serve these customers, and it would otherwise be returned to the Westcoast service queue, the ABM shall offer such capacity to the LDC on a right of first refusal basis.

3.10 Limitation on Direct Sales

Aside from buy-sell arrangements, no utility shall engage in the direct sale of natural gas other than through a non-regulated subsidiary which will be considered to be an ABM subject to these rules. The utility will be required to demonstrate a complete operational separation from any such subsidiary.

Executive Summary

BC Gas Utility Ltd.'s ("BC Gas" or "Company") Annual Contracting Plan ("ACP") is a key short term planning document filed with the British Columbia Utilities Commission ("BCUC") in the spring of each year. The ACP sets out the Core customers' anticipated demand for gas, and outlines the Company's strategy to contract for gas commodity, storage facilities, and pipeline transportation resources to meet the needs for the coming winter. The strategies, outlined in the ACP, provide the transition to the objectives of the long range Integrated Resource Plan (IRP).

The proposed ACP for the upcoming year remains consistent with these IRP objectives. The ACP is set out as follows:

- An overview of the ACP that outlines the major issues and recommendations that comprise the report.
- A review of the Core customers' requirements to meet peak day demand.
- A review of the marketplace developments which impact BC Gas' strategy and final recommendations.
- The detailed recommendations set out in the key contracting decisions.
- An outline of the contracting decisions that BC Gas must make over the next three years.

Demand

Firm customer additions are estimated at 5,000 this year, which would represent a 16 TJ/d demand increase consistent with BC Gas' trending analysis. BC Gas will not fully determine overall demand expectations until it has completed an analysis of customer demand response precipitated by recent rate increases effective July 2000 and January 2001. Therefore for the time being, BC Gas

estimates the peak day volume requirements to remain the same as those approved for the 2000/01 ACP plan. BC Gas will finalize peak volume requirements later in the second quarter of 2001 based on completed analysis of customer demand response and forecast migration of Transportation Service customers back to firm sales.

Market Overview

North American energy markets have seen unprecedented price increases and volatility in the last year. The surplus gas and electric supply balance of the previous few years became shortfalls in 2000 moving commodity rates to levels that confirmed the inelasticity of most of the market. Demand growth was significant in 2000 due to a strong economy and increased gas use for electric generation, while supply growth was negligible.

It is too early to tell if the significant drilling activity in 2000 and winter 2000/01 will result in production increases later this year. What has been alarming is the continuing increase in existing production draw down levels that requires accelerated new production to just keep up. There has been an estimated 5-10% market demand reduction with the higher price levels, but this may be offset over the next year by the addition of new gas fired generation facilities particularly in the western region.

Therefore, North American market prices over the next year should remain historically high until the market is satisfied that the supply demand balance has been rectified. Western North America should remain particularly volatile over the next year due to:

- **Regional infrastructure constraints (pipeline and transmission) that currently limit access to supply sources.**
- **Expected low levels of Hydro electric generation availability based on current low snowpack conditions in critical basins.**

- **Continued high demand for electricity especially in California, where residential price discovery and conservation is just beginning to occur.**
- **An increased number of temporary and long term natural gas power generation facilities coming on line to meet the electricity load not being met by hydro generation.**

These conditions set the stage for higher demand for natural gas fired generation, as existing and new power generation facilities come on line. For winter 2001/02, BC Gas estimates over 1000 MW, or over 200 TJ/D, of incremental natural gas generation load that is scheduled to come on line in the PNW. This increased natural gas demand will put pressure on the existing regional pipeline and storage resources as gas users and power generators in the western region compete for finite gas supply. This should have a significant impact on regional prices and availability of storage and transportation capacity. Currently, price signals confirm that insufficient pipeline capacity exists to satisfy growing regional demand requirements.

BC Gas Supply Portfolio

BC Gas has anticipated the market shortfalls in the West and has pro-actively responded. BC Gas has developed a comprehensive portfolio of pipeline, storage, and commodity contracts that provide supply security at minimum cost for Firm customers. These assets proved to be invaluable this past winter and have been further enhanced for the coming year.

BC Gas will maintain existing supply portfolio flexibility and optionality by continuing to minimize contract terms when possible, while maintaining the ability to secure longer term integrated planning options. This provides for the ability to meet market transitions that occur if circumstances change.

The table below compares the changes in the peak day supply portfolio from 2000/01 to 2001/02.

Table 1: Comparative Peak Day Supply Portfolios 2000/01and 2001/02, TJ/d

	2000/01 Filed ACP	2001/02 Range
Ft Nelson Division	4	4
Baseload	415	380-420
Buy/Sell	0	0
Storage	388	388-404
Synthetic Storage	-	21-42
Seasonal	95	53-120(1)
Peaking	113	113
Spot	104	120-180(1)
LNG	164	164
Ind. Curtailment	26	26
Total	1309	1309

(1) The wide range of seasonal and spot contracts results from the uncertainty of the mix of seasonal and spot purchases, due to possible shaping of Sumas, Kingsgate and Stanfield for the coming year.

The principal recommended actions to take place over the next three years are:

- Continue to target term supply contracts with B.C. producers that have significant BC reserves and long-term commitments to B.C. markets.
- Work closely with producers, end users, pipelines and gas fired electrical generators to ascertain fuel switching capabilities for options to enhance overall portfolio economics for Core customers.
- Encourage and foster the development of cost effective transport infrastructure to Huntingdon.
- Maintain existing supply portfolio flexibility and optionality by continuing to minimize contract terms when possible, while maintaining the ability to secure longer term integrated planning options.
- Anticipated business review of tolls in the upcoming Westcoast Settlement, unbundling of commodity from transportation, and discussion of Westcoast T-North Pool issues that have yet to be resolved and may impact longer-term portfolio decisions made on behalf of Core customers.

- Contract for incremental downstream storage to replace expiring contracts if economical.

- Develop and implement a strategy to incorporate cost-effective spot purchases into the supply portfolio while incurring no increase in physical supply risk to the Core market.

This 2001/02 ACP is being filed for BCUC approval. BC Gas requests that the document, except for the Executive Summary, remain confidential, given its commercially sensitive information.

Frequently Asked Questions

Our customers are interested in knowing about the rates they are being charged by ATCO Gas. Following you will find information about the topics that currently hold the greatest interest.

How does ATCO Gas set it's gas rate?
There are specific time periods used to determine the gas rate, depending on the type of customer (see below).

ATCO Gas arbitrarily selects a day, close to the start of the period, when the forward market price for natural gas will be used to determine what ATCO Gas will have to pay for natural gas for its customers to the end of the period.

Throughout each period, utilities constantly monitor the amount collected from customers and the amount paid to suppliers. In times of extreme price volatility, the gas rate initially set at the beginning of the period can be either too high or too low. If ATCO Gas believes it will be out of balance by the greater of + / - $2,000,000 or + / - 3% of the initial forecast of gas costs for the period, it is required to file a rate adjustment with the Alberta Energy and Utilities Board (AEUB).

For residential and small commercial customers
The gas cost rate for these customers is determined by the forecast of market prices for the coming 12 months. ATCO Gas was given approval for an annual gas rate for this group of customers in January 2001. An annual rate evens out the highs and lows of the market, protecting our customers from volatile prices.

For large commercial, industrial and agricultural customers
There are two distinct gas cost rate periods. The winter period runs from November 1 to March 31. The summer period runs from April 1 to October 31.

How does ATCO Gas make its money?
Through our service charges, specifically our delivery charges – both fixed and variable.

ATCO Gas installs, operates and maintains pipelines across Alberta. As part of this service agreement, ATCO Gas provides 24-hour response to natural gas emergencies. We also respond to requests to check natural gas furnace and gas appliances for safe and efficient operation. ATCO Gas bills its customers for all services through its delivery charges. To be fair to its customers, ATCO Gas has developed a two-part rate: a fixed charge and a variable charge.

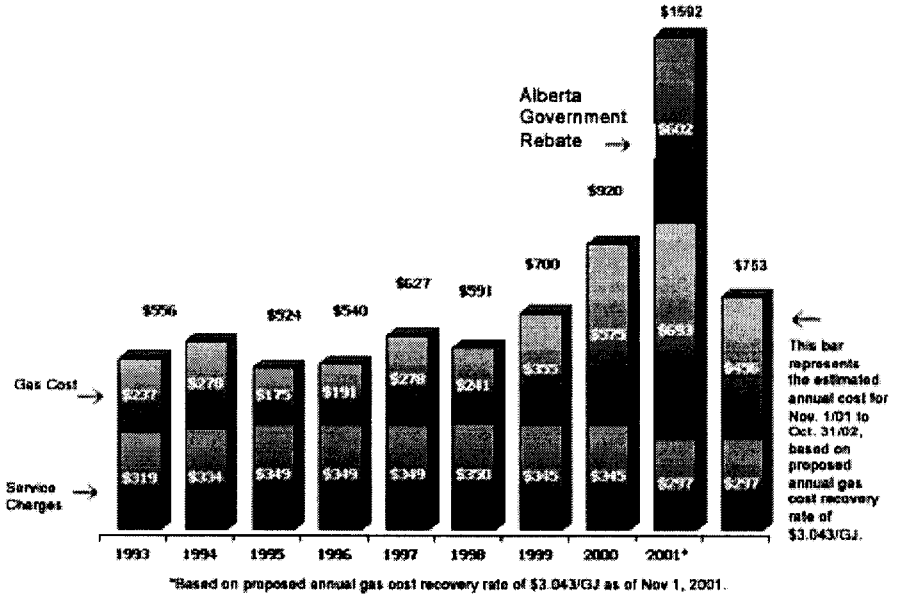
The fixed charge is a monthly flat amount that recovers a portion of the delivery charges. It is intended to recover expenses for services that are related to the number of customers – not how much gas is consumed. For example, the cost to provide a bill does not change if a customer uses 100 GJ or 200 GJ of natural gas. The fixed charge, however, is not sufficient to recover the full cost of providing all

customer services.

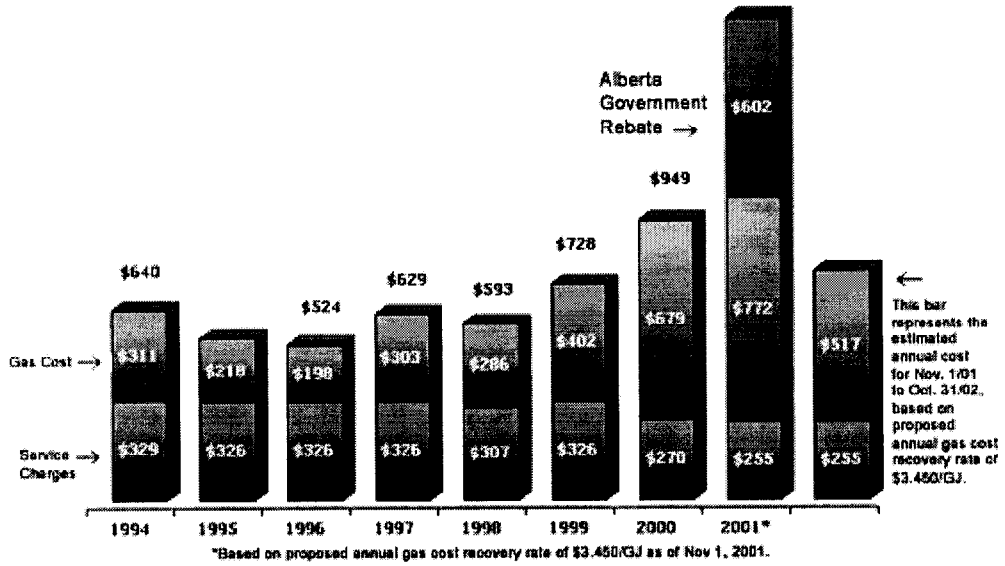
The remainder of the total delivery charges is recovered through the variable charge. Customers pay the variable charge based on a rate per gigajoule of natural gas consumed that month. The more natural gas consumed, the larger the total variable charge paid by the customer.

History of Costs
The typical ATCO Gas residential customer uses 150 GJ of natural gas in one year. Approximately 100 GJ of natural gas are consumed during the five-month period of November 1 to March 31. Shown are averaged North and South rates.

Comparison of Annual Costs for Residential Customers - North



Comparison of Annual Costs for Residential Customers - South



Delivery Costs
Our delivery charges are lower than 7 years ago. Our typical residential customer will pay us an average of $298 for service this year. In 1994, they paid an average of $332. In 2001, here is what a typical residential customer can expect to pay its utility company for service:

ATCO Gas $298
Sask Energy $411
BC Gas $472
Centra Manitoba $419
Gazifere $789
Union Gas North $542
Union Gas South $435
Enbridge Consumers $716

What is "hedging"?
Simply, hedging is locking in the price at which you agree to buy natural gas in the future.

Typically, a utility will use fixed price contracts to hedge. When market prices are high, hedging always looks like the best approach. But, there is a cost and customers pay it. The utility knows when the market price drops, it won't be able to reduce the rate charged to its customers. So, the utility that chooses fixed price contracts hopes the market price stays higher than the price the utility has committed to paying suppliers. Otherwise, customers are angry because their rate is higher than the market price.

Why doesn't ATCO Gas hedge?
Our objective, and the direction of our customer representatives, is to provide natural gas at the least possible cost to customers.

That's why our portfolio is predominantly daily and monthly AECO-indexed gas bought under firm contracts. Our experience has been that this strategy does result

in least cost gas for our customers because we are able to quickly react when gas prices drop. We did this most recently a year ago, when the market price dropped and stayed down despite months of reports about higher market prices yet to come. Customers enjoyed a gas rate reduction in February 2000 because market prices were lower than the rate we had set at the start of the winter period.

Isn't hedging better?
No. One utility's objective for rate setting is not superior to another's rate setting process. Market prices for natural gas prices are volatile and forward market prices change daily so the best any utility can do is establish its objective based on what its customers have said they want.

Saskatchewan

Rate Review Panel

Report to the Minister of Crown Investments Corporation on:

The Proposal from SaskEnergy for a Change in the Natural Gas Commodity Rate

December 14, 2001

Panel Conclusions and Recommendations

The Panel met with the consultant and subsequently sought additional information from SaskEnergy officials on the rate proposal.

The consultant prepared a report and assessment of the SaskEnergy submission (attached as Appendix B).

Load Forecast

All differences between forecast and actual costs of purchasing gas accumulate to the Gas Cost Variance Account (GCVA). Consequently variances between forecast and actual volumes are not as critical as they might be in a delivery charge rate application. Based on a limited review and comparison to SaskEnergy's forecast for 2000/01, the consultant indicated the 2001/02 forecast should be accepted as reasonable.

The Panel concurs with the consultant's assessment.

Supply Portfolio

The consultant noted Saskatchewan consumers benefit greatly from the available storage in close proximity to load requirements. The consultant also noted SaskEnergy had extensively (84 percent) hedged its purchases by buying call options to set a cap price.

SaskEnergy uses financial hedging strategies to provide customers with upward price protection but allow downward price participation. For 2001/02 SaskEnergy extensively hedged purchases by buying call options to set a cap price. Some of the call options were associated with the sale of put options to provide a 'costless' collar for a portion of the hedges. Premiums from the sale of put options offset some of the costs of the call options but the put options establish a floor price (ie. set a minimum price) for related gas purchases.

The Panel particularly notes the consultant's observations regarding the preferred time to review the composition of a supply portfolio is before gas supplies are contracted. The consultant reiterated greater oversight of SaskEnergy's gas contracting and price risk management strategy would be preferable prior to implementation and recommended the Panel implement such a process for SaskEnergy for the 2002/03 gas contract year.

The Panel notes that earlier involvement may better allow it to meet its mandate to balancing the needs of the customer, the Crown corporation and the public.

The Panel recommends SaskEnergy file with the Panel its Gas Supply and Price Risk Management Plan for 2002/03, setting out the Utility's strategy for buying a sufficiently reliable supply of gas at the lowest overall cost prior to entering into significant new supply contracts or hedges for this period.

UNION GAS LIMITED
Alberta Border WACOG Pricing Calculation
Year Ending October 31, 2002

Particulars	2001 Nov-01	Dec-01	2002 Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Total or Average
1 Days	30	31	31	31	31	30	28	30	31	31	30	31	365
2 Heat Content (1)	37.63	37.63	37.63	37.63	37.63	37.63	37.63	37.63	37.63	37.63	37.63	37.63	37.63
Conversion of Henry Hub ($US/MMBtu) to Alberta Border ($Cdn/GJ)													
3 Consensus Henry Hub ($US/MMBtu) (1)	2.40	2.60	2.73	2.70	2.575	2.48	2.51	2.63	2.74	2.81	2.88	2.98	2.67
4 Basis Differential (Southern Ops. Contracts)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
5 Basis Differential (Northern and Eastern Ops. Contracts)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-
6 Exchange Rate	0.658	0.658	0.669	0.669	0.6688	0.675	0.675	0.675	0.678	0.678	0.678	0.682	0.672
7 Conversion (MMBtu to GJ)	1.055	1.055	1.055	1.055	1.055	1.055	1.055	1.055	1.055	1.055	1.055	1.055	1.055
8 Alberta Border Price ($Cdn/GJ) (Southern Ops.)													
9 Alberta Border Price ($Cdn/GJ) (Northern and Eastern Ops.)													
10 Consensus Alberta Border ($Cdn/GJ)	3.06	3.37	3.30	3.32	3.11	2.98	3.00	3.37	3.45	3.53	3.65	3.80	3.33
CGPR Price Based Contracts Price Calculation													
11 Total Volume (Board Approved - Continue to Rollover Volumes)	76,626	79,180	82,763	74,754	82,763	80,820	83,514	80,820	83,514	79,546	76,980	79,546	960,826
12 Cost at Consensus Alberta Border Price ($000s)	$ 8,820	$ 10,047	$ 10,287	$ 9,336	$ 9,689	$ 9,051	$ 9,434	$ 10,255	$ 10,830	$ 10,551	$ 10,564	$ 11,384	120,248
13 Impact of Risk Management	2,409	2,022	2,244	1,890	2,436	-	-	-	-	-	-	-	11,001
14 Total CGPR Based Contracts	$ 11,229	$ 12,069	$ 12,531	$ 11,226	$ 12,125	$ 9,051	$ 9,434	$ 10,255	$ 10,830	$ 10,551	$ 10,564	$ 11,384	131,249
15 Subtotal: Total Alberta Volume excluding Buy/Sell (10^3 m3)	76,626	79,180	82,763	74,754	82,763	80,820	83,514	80,820	83,514	79,546	76,980	79,546	960,826
16 Total Supply Cost	$ 11,229	$ 12,069	$ 12,531	$ 11,226	$ 12,125	$ 9,051	$ 9,434	$ 10,255	$ 10,830	$ 10,551	$ 10,564	$ 11,384	$ 131,249
17 Average Price ($/10^3 m^3)	$ 146.549	$ 152.421	$ 151.408	$ 150.174	$ 146.498	$ 111.990	$ 112.963	$ 126.887	$ 129.679	$ 132.640	$ 137.230	$ 143.112	$ 136.597
18 Average Price ($/GJ)	$ 3.89	$ 4.05	$ 4.02	$ 3.99	$ 3.89	$ 2.98	$ 3.00	$ 3.37	$ 3.45	$ 3.52	$ 3.65	$ 3.80	$ 3.63

(1) There are no volumes forecasted to be purchased at the Alberta border with NYMEX based pricing provisions.