STRATÉGIE DE GESTION DE LA CAPACITÉ D'ENTREPOSAGE CHEZ UNION GAS

(suivi de la décision D-2013-035)

TABLE DES MATIÈRES

INTRODUCTION

Au 1er avril 2013, Société en commandite Gaz Métro (« Gaz Métro ») a décontracté une capacité d'entreposage de 116,1 $10^{6}m^{3}$ chez Union Gas et l'a remplacée par un contrat de « capacité de retrait et injection seulement ». La demande d'approbation quant aux paramètres contractuels reliés à l'entente avec Union Gas a été déposée dans le cadre de la Cause tarifaire 2013 (R-3809-2012, B-0238, Gaz Métro-1, Document 17). La décision D-2013-035 de la Régie de l'énergie (la « Régie ») approuvait la proposition de Gaz Métro.

Dans cette décision, la Régie demandait à Gaz Métro de considérer une gestion active de l'entreposage chez Union Gas. À cet effet, la Régie ordonnait :

> *« [41] […]* ***à Gaz Métro de déposer, dans les 180 jours suivant la présente décision et dans le cadre du prochain dossier tarifaire, un rapport réalisé avec le concours de consultants externes spécialisés, permettant :***
>
> - ***d'identifier les diverses stratégies pour optimiser les retraits;***
> - ***d'évaluer le gain potentiel espéré associé à chacune de ces stratégies ainsi que les risques (variabilité des résultats) en regard du coût de chaque stratégie. Ces analyses doivent prendre en compte la variabilité historique quotidienne (sur une dizaine d'années ou plus, si possible) des conditions climatiques (et des besoins) et des prix;***
> - ***d'identifier les diverses stratégies pour optimiser les injections;***
> - ***d'évaluer le gain potentiel espéré associé à chacune de ces stratégies ainsi que les risques (variabilité des résultats) en regard du coût de chaque stratégie. Ces analyses doivent prendre en compte la variabilité historique quotidienne (sur une dizaine d'années ou plus, si possible) des prix.*** *»*

Le présent document vise à répondre à la demande de la Régie.

1. PRÉSENTATION DU RAPPORT DU CONSULTANT

Gaz Métro a demandé à la firme Sussex Economic Advisors, LLC (« Sussex ») de l'assister dans cette analyse. Ce rapport est présenté à l'annexe 1.

Sommairement, le rapport présenté par Sussex couvre les éléments suivants :

- Rôle de l'entreposage de gaz naturel dans les outils d'approvisionnement d'un distributeur;

- Sommaire des paramètres relatifs aux contrats d'entreposage auprès de Union Gas; et
- Diverses stratégies de retraits et d'injections et une quantification des gains ou coûts en fonction de données historiques de température et de prix.

Pour effectuer une évaluation des gains ou pertes des différentes stratégies, les données de la Cause tarifaire 2013 ont été utilisées, tant au niveau de la demande qu'au niveau des outils d'approvisionnement disponibles, à l'exception de la capacité d'entreposage chez Union Gas qui a été modifiée pour refléter le niveau d'entreposage de 13,2 PJ (349 10^6m³) contracté auprès de Union Gas pour les prochaines années.

En fonction des paramètres qui définissent la demande projetée à la Cause tarifaire 2013, la demande projetée sous les conditions climatiques (après réchauffement) des années 2003 à 2012 a été évaluée et un plan d'approvisionnement pour chacune de ces années a été établi en fonction des règles de gestion actuellement utilisées. Ces plans ont servi de base comparative dans l'évaluation des différentes stratégies.

Gaz Métro a fourni des projections d'approvisionnement à Sussex plutôt que les plans réels historiques, car ceux-ci auraient entraîné des biais dans l'analyse des résultats. En effet, la capacité d'entreposage a été réduite de façon importante au cours des années, passant de 598 10^6m³ en 2003 à 349 10^6m³ en 2013. Ainsi, l'utilisation de données historiques du site d'entreposage n'aurait pas reflété la nouvelle dynamique de l'entreposage. La structure d'approvisionnement a également été modifiée durant cette période, résultant en une baisse des capacités de transport entre Empress et le territoire de Gaz Métro et en une augmentation des achats de gaz naturel à Dawn. Finalement, l'historique aurait pris en compte des variations de demandes qui ne sont pas uniquement reliées à la variation des conditions climatiques. L'utilisation de plans d'approvisionnement projetés sous différentes conditions climatiques dans l'analyse financière des stratégies proposées permet ainsi de capter uniquement l'impact de la température sur l'utilisation de l'entreposage à Dawn.

Il est à noter que l'unité utilisée dans le rapport de Sussex est le gigajoule; pour convertir les données en mètres cubes, il faut diviser par 0,03789.

2. COMMENTAIRES DE GAZ MÉTRO

Le rapport de Sussex ne recommande pas une stratégie spécifique, mais des pistes de modification de gestion des inventaires dans une perspective globale de structure d'approvisionnement.

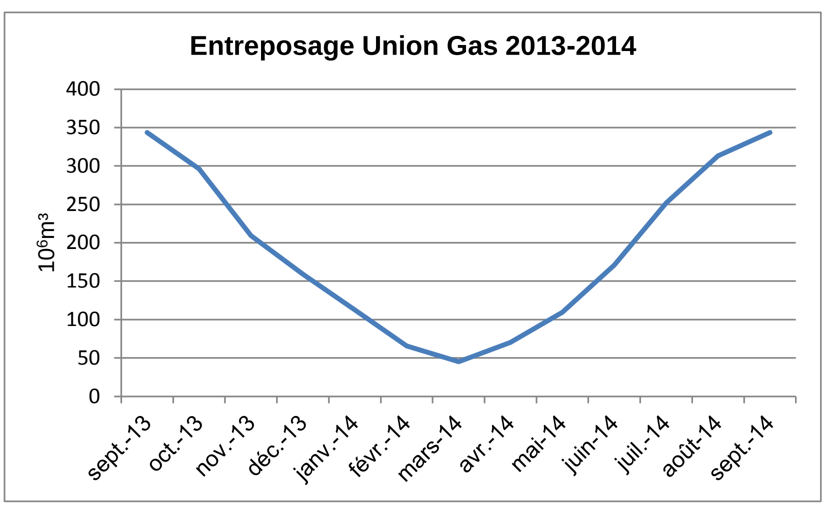
Les stratégies proposées par Sussex ont été analysées dans un contexte statique. Elles pourraient être appliquées dans la planification d'approvisionnement, mais avec discernement, dû à certaines contraintes opérationnelles. Les sections suivantes visent à présenter la stratégie actuelle de Gaz Métro, commenter les stratégies proposées par Sussex ainsi que les résultats et finalement décrire la position de Gaz Métro face à ce rapport.

2.1. Stratégie actuelle de Gaz Métro

Gaz Métro a décrit sa stratégie actuelle de gestion de l'entreposage de Union Gas à la pièce B-0063, Gaz Métro-2, Document 5. De façon sommaire, des retraits sont effectués d'octobre à mars de façon à avoir une diminution graduelle des inventaires jusqu'à 13 % de la capacité totale au 31 mars. Par la suite, les injections sont effectuées au cours de l'été, de façon à avoir une croissance graduelle des inventaires jusqu'à un niveau approximatif de 98 % de la capacité totale au 30 septembre. Ces niveaux cibles sont établis en fonction des besoins opérationnels reliés à la gestion des inventaires.

Le graphique suivant présente le niveau d'inventaire prévu à la fin de chaque mois au site de Union Gas à la Cause tarifaire 2014.

Graphique 1



Le tableau suivant présente la répartition des retraits et injections projetés du site d'entreposage de Union Gas à la Cause tarifaire 2014 ainsi que la répartition des achats de gaz naturel à Dawn.

Tableau 1

Mois	Entreposage Union Gas		Achat Dawn
	Retrait	Injection	
oct-13	13,8%	0,0%	0,0%
nov-13	25,3%	0,0%	7,7%
déc-13	17,9%	3,3%	15,1%
janv-14	15,8%	2,4%	18,2%
févr-14	15,1%	1,4%	16,5%
mars-14	11,4%	5,4%	15,0%
avr-14	0,0%	7,3%	7,8%
mai-14	0,0%	11,4%	4,9%
juin-14	0,0%	17,9%	4,2%
juil-14	0,0%	23,5%	4,3%
août-14	0,0%	17,8%	3,1%
sept-14	0,7%	9,6%	3,1%
Total	100,0%	100,0%	100,0%

2.2. Stratégies de retrait du site d'entreposage

Trois stratégies ont été mises de l'avant par Sussex : déplacement des retraits d'octobre sur les mois d'hiver (décembre ou février), concentration des retraits sur les mois de décembre à février et profil de retraits en fonction des ratios mensuels des degrés-jours (DJ).

Ces stratégies ont pour effet de déplacer les retraits vers les mois où les prix de fourniture sont normalement plus élevés (décembre à février) et de favoriser les achats à Dawn sur les mois où les prix sont normalement moins élevés (octobre, novembre et mars). Sur une base prospective, il y aurait donc un avantage financier à mettre en place ces stratégies. La contrepartie à cet avantage est l'augmentation des coûts de maintien des inventaires découlant du fait de conserver des niveaux d'inventaire élevés pour les premiers mois de l'année.

Les stratégies consistant à ne pas effectuer de retrait en octobre ou novembre (scénarios 1 et 2) comportent des enjeux opérationnels. Au réel, Gaz Métro ne pourrait remplacer la totalité des retraits par des achats à Dawn sur ces mois. Considérant les contraintes contractuelles du site d'entreposage où les injections sont interruptibles en octobre et novembre, un retrait minimum serait requis en sus des achats à Dawn afin de pouvoir faire face à une baisse de la demande en cours de journée et ainsi moduler les outils en conséquence. De plus, les achats de fin de semaine entraîneraient également certaines contraintes quant au niveau à contracter sur les trois jours (samedi, dimanche et lundi). Sur ces trois jours, toutes choses étant égales par ailleurs, une baisse importante de la demande est observée par rapport à la demande de semaine, variant de 850 10^3m^3/jour à 2 000 10^3m^3/jour. Ainsi, des achats variables seraient requis sur ces trois jours, entraînant potentiellement une augmentation du prix d'achat. Pour éviter cette surcharge, une même quantité minimale serait contractée pour les trois jours et des retraits seraient alors effectués pour combler la demande des deux autres journées. Ces contraintes opérationnelles feraient donc en sorte que des retraits seraient tout de même effectués malgré une stratégie de déplacement des retraits vers les mois d'hiver.

La stratégie basée sur les ratios mensuels de DJ (scénario 3), telle qu'évaluée par Sussex, utilise la répartition réelle des DJ pour chacune des années historiques. Il s'agit donc de ratios évalués *a posteriori*. L'application de cette stratégie en mode opérationnel supposerait l'utilisation de la répartition des DJ normaux. Par exemple, en fonction des degrés-jours normaux de 2012-2013, la répartition mensuelle des retraits projetés serait la suivante :

Tableau 2

Oct.	Nov.	Déc.	Jan.	Fév.	Mars
5,4 %	11,7 %	20,7 %	24,8 %	20,8 %	16,6 %

En soi, cette stratégie n'est pas différente de celle actuellement appliquée par Gaz Métro, à l'exception des pourcentages mensuels. D'un point de vue opérationnel, cette stratégie serait légèrement moins contraignante que les scénarios 1 et 2 étant donné que des retraits seraient planifiés sur les mois d'octobre, novembre et mars. Toutefois, elle générerait une variation à la hausse encore plus importante du coût de maintien des inventaires étant donné le niveau d'inventaire plus élevé dès le début de l'année financière.

2.3. Stratégies d'injection du site d'entreposage

Trois stratégies ont également été mises de l'avant par Sussex : injections uniformes sur la saison, injections concentrées en début de saison et injections concentrées en fin de saison.

Le scénario d'injections uniformes (scénario 1), représentant des injections de 16,7 % par mois sur les six mois de la saison, est similaire à l'approche actuelle de Gaz Métro, à l'exception des pourcentages mensuels. Il pourrait donc être mis de l'avant sans créer de problématique opérationnelle. Il entraînerait des achats additionnels en avril et mai et une baisse des achats en juillet. Toutefois, cette stratégie générerait une variation à la hausse du coût de maintien des inventaires étant donné le niveau d'inventaire plus élevé dès le début de la saison d'injection.

Le scénario 2, consistant en des injections concentrées en début de saison, entraînerait des enjeux importants, tant opérationnels que financiers. Afin de maintenir la flexibilité opérationnelle requise en cours de journée sur toute la saison estivale, Gaz Métro ne pourrait concentrer la totalité de ses injections en début de saison. Elle se doit de garder de l'espace au site d'entreposage, permettant ainsi d'injecter pour faire face à une baisse de la demande. De plus, le niveau d'inventaire à partir duquel la capacité d'injection est réduite serait atteint plus tôt dans la saison, réduisant davantage la flexibilité opérationnelle sur le restant de la saison. Ce scénario entraînerait également un coût additionnel de maintien des inventaires.

Le scénario 3, où les injections sont concentrées sur la fin de la saison, serait opérationnellement viable. La date de début des injections serait à établir afin de s'assurer d'atteindre le niveau ciblé au 30 septembre considérant, entre autres, les capacités d'injection qui diminuent lorsque l'inventaire atteint 75 % de la capacité totale. Des achats à Dawn sur les mois d'avril et mai seraient inévitables afin de répondre à la demande quotidienne. Ces mois étant des mois d'épaulement et les retraits du site d'entreposage étant sur une base interruptible, des achats de gaz naturel à Dawn seraient projetés. Des injections résultant de la gestion opérationnelle en cours de journée pourraient également être requises durant ces mois. Le fait de retarder un peu le début des injections entraînerait une baisse des coûts de maintien des inventaires.

2.4. Commentaires sur les résultats du rapport de Sussex

Les résultats présentés dans le rapport de Sussex montrent une fluctuation importante du coût/bénéfice sur les dix ans. Les tableaux suivants reprennent les résultats du scénario de retraits concentrés de décembre à février (scénario 2) et du scénario d'injections concentrés à la fin de la saison (scénario 3), en ajoutant l'information sur les conditions climatiques (hiver) et les prix de gaz naturel à Dawn.

Tableau 3 – Scénario de retraits

Année	DJ oct. à mars	Hiver normal, chaud ou froid	Coût / (bénéfice) (M$)	Prix moyen hiver $/GJ	Écart type des prix $/GJ
2009/2010	2 409	C	(7,8)	5,008	0,940
2003/2004	2 855	F	(5,7)	6,967	0,752
2002/2003	3 023	F	(3,2)	8,115	3,106
2010/2011	2 755	F	(2,2)	4,240	0,305
2007/2008	2 698	C	(1,2)	7,654	1,079
2006/2007	2 612	C	(0,5)	7,688	1,121
2005/2006	2 530	C	1,7	10,756	2,790
2004/2005	2 849	F	2,0	7,637	0,706
2012/2013	2 753	N	2,0	3,602	0,282
2011/2012	2 284	C	2,5	3,186	0,528
2008/2009	2 856	F	5,4	6,754	1,077

Tableau 4 – Scénario d'injections

Année	Coût / (bénéfice) (M$)	Prix moyen été $/GJ	Écart type des prix $/GJ
2007/2008	(10,7)	10,102	1,806
2006/2007	(6,6)	7,147	1,074
2003/2004	(5,1)	7,606	0,827
2002/2003	(5,0)	7,198	0,702
2008/2009	(3,1)	3,928	0,646
2010/2011	(1,6)	4,212	0,192
2005/2006	(1,4)	6,732	0,937
2012/2013	(1,2)	4,099	0,238
2009/2010	(1,1)	4,538	0,349
2011/2012	1,3	2,670	0,320
2004/2005	8,5	9,550	1,873

Ces tableaux permettent de mieux visualiser la volatilité du coût/bénéfice. Les coûts/bénéfices varient différemment en hiver chaud ou froid, considérant des prix plus hauts ou plus bas et des écarts types de différentes ampleurs. Aucune tendance ne peut être énoncée en fonction de ces résultats. Chaque année génère ses propres résultats considérant les volumes déplacés entre les mois et les prix des achats de gaz à Dawn sur ces mêmes mois.

L'analyse présentée par Sussex est établie en fonction de la demande et du plan d'approvisionnement 2013. Une analyse basée sur une autre année ne donnerait pas nécessairement les mêmes résultats. Par exemple, comme illustré au tableau 1 de ce document, les retraits projetés en octobre 2013 représentent 13,8 % des retraits totaux alors que pour octobre 2012, les retraits représentent 20 % (réf. : annexe 1, Table 2 du rapport de Sussex). Ainsi, le niveau des retraits qui seraient reportés sur les mois de décembre à février ne serait pas le même et la stratégie ne générerait pas les mêmes gains ou coûts, toutes choses étant égales par ailleurs.

Considérant l'ensemble des éléments impondérables qui peuvent influencer un plan d'approvisionnement, en planification et au réel, il devient alors impossible de prévoir pour une année donnée si une nouvelle stratégie entraînerait des coûts ou bénéfices par rapport à la stratégie actuelle.

Dans son rapport, Sussex précise en conclusion :

> « *The changing market dynamics coupled with adjusting business strategies will result in a market environment that will change year-to-year making it unlikely that one storage utilization strategy will continuously outperform other options.* »

Cette affirmation renforce l'imprévisibilité des résultats générés par la modification de la stratégie de gestion des inventaires chez Union Gas.

2.5. Autres commentaires généraux

La demande à desservir, incluant les variations en cours de journée, combinée aux approvisionnements mis en place ainsi qu'aux paramètres contractuels des contrats d'entreposage auprès de Union Gas peuvent entraîner des actions opérationnelles au réel qui auront pour effet de retirer ou d'injecter sur des périodes où la stratégie consistait à ne pas réaliser de telles actions.

La stratégie de gestion de la capacité d'entreposage chez Union Gas doit donc être considérée comme des principes de gestion à suivre dans la mesure du possible par le distributeur.

Toute modification à la stratégie de retrait du site d'entreposage de Union Gas entraînera une révision de la stratégie d'achat du gaz naturel à Dawn. Actuellement, une grande partie des achats projetés pour les mois de décembre à mars est contractée d'avance. La portion non contractée permet d'avoir une marge pour moduler les approvisionnements en cas d'hiver chaud. Gaz Métro juge que le fait de concrétiser en avance une certaine quantité des achats est une approche sécuritaire pour un distributeur. Elle ne voudrait pas être dans une position où tout le gaz naturel à acheter à Dawn en hiver soit à 100 % sur une base « spot ». Le niveau à contracter d'avance devra toutefois conserver la flexibilité opérationnelle pour optimiser les retraits du site sur l'hiver et rencontrer les paramètres contractuels du site d'entreposage (principalement en cas d'hiver chaud).

Une modification à la stratégie de gestion de l'entreposage impliquerait également une reconsidération des transactions d'optimisation reliées aux prêts d'espace. Ces transactions consistent à prêter temporairement à une tierce partie, contre rémunération, une portion de l'espace d'entreposage non utilisé et non nécessaire pour les opérations quotidiennes. Les injections des tierces parties débutent normalement en octobre et novembre, période coïncidant avec le début des retraits de Gaz Métro. Si la stratégie de gestion a pour effet de conserver des niveaux d'inventaires élevés en début d'année, les opportunités d'affaires pour les tierces parties seront moins présentes. Il est à noter qu'au cours des dernières années, les revenus générés par ces transactions ont été inférieurs à 0,5 M$ alors que les années précédentes, les revenus se situaient entre 2 M$ et 5 M$. Cette baisse de revenus, découlant de la baisse des opportunités pour les tierces parties, résulte probablement de la baisse des écarts de prix mensuels observés au cours des dernières années.

2.6. Position de Gaz Métro

Considérant les conclusions du rapport de Sussex et les observations mentionnées aux sections précédentes, Gaz Métro est d'avis, qu'en moyenne sur plusieurs années, une modification à sa stratégie de gestion du site d'entreposage de Union Gas pourrait être avantageuse pour la clientèle. Ainsi, une combinaison du scénario 2 pour les retraits - concentrer les retraits sur la période de pointe hiver - et du scénario 3 pour les injections - concentrer les injections sur la fin de la saison - pourrait être envisagée.

L'application de cette stratégie a été évaluée sur le plan d'approvisionnement 2014. L'annexe 2 présente une comparaison des stratégies actuelle et nouvelle pour la gestion de l'entreposage de Union Gas sur le plan d'approvisionnement 2014 ainsi qu'une estimation des coûts d'approvisionnement relatifs.

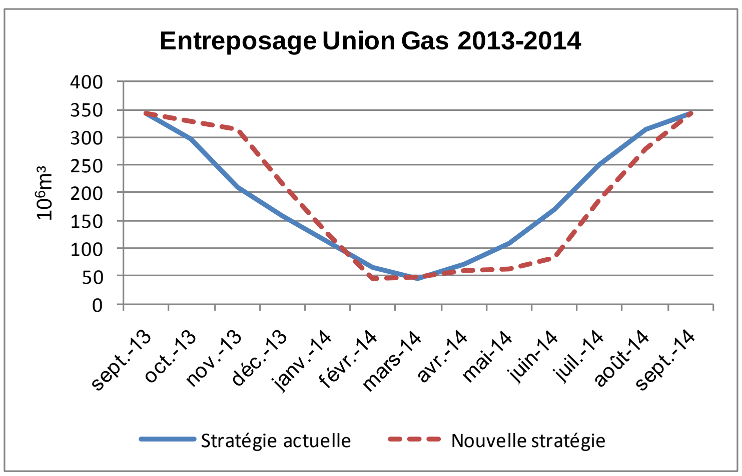
Pour fins d'illustration, les hypothèses suivantes ont été utilisées :

- Les « futures » mensuels pour l'indice AECO pour l'année 2013-2014, évalués au 19 avril 2013, ont été utilisés (plutôt que l'utilisation de prix saisonniers);
- Les blocs d'achats à Dawn, incluant les achats déjà contractés, ont été scindés en achats mensuels afin de capter le déplacement dans le temps de ces achats. Des prix projetés pour chacun des mois, basés sur l'indice AECO, obtenus par un tiers en date du 19 avril 2013, ont été utilisés.

Ces hypothèses de prix permettent d'évaluer l'impact de la nouvelle stratégie de gestion des inventaires sans contrainte reliée aux achats déjà contractés d'avance cette année ou les années antérieures, soit une base d'analyse épurée.

Le graphique suivant présente les niveaux d'inventaire prévus à la fin de chaque mois au site de Union Gas en fonction de la stratégie actuelle et de la nouvelle stratégie.

Graphique 2



Le tableau suivant présente une comparaison des ratios de retraits et d'injections projetés du site d'entreposage de Union Gas ainsi que les achats de gaz naturel à Dawn entre la stratégie actuelle et la nouvelle stratégie.

Tableau 5

Mois	Entreposage Union Gas								Achats à Dawn			
	Retrait				Injection							
	Actuelle		Nouvelle		Actuelle		Nouvelle		Actuelle		Nouvelle	
oct-13	13,8%		5,0%		0,0%		0,0%		0,0%		1,9%	
nov-13	25,3%		5,1%		0,0%		0,0%		7,7%		11,9%	
déc-13	17,9%		32,5%		3,3%		0,6%		15,1%		12,3%	
janv-14	15,8%	48,8%	30,2%	89,6%	2,4%		0,8%		18,2%	49,8%	15,7%	42,5%
févr-14	15,1%		26,9%		1,4%		0,6%		16,5%		14,5%	
mars-14	11,4%		0,0%		5,4%		0,7%		15,0%		16,4%	
avr-14	0,0%		0,0%		7,3%		3,7%		7,8%		7,0%	
mai-14	0,0%		0,0%		11,4%		1,1%		4,9%		2,8%	
juin-14	0,0%		0,1%		17,9%		7,2%		4,2%		1,8%	
juil-14	0,0%		0,0%		23,5%		33,7%		4,3%		5,6%	
août-14	0,0%		0,0%		17,8%	50,9%	30,7%	85,3%	3,1%	10,5%	5,1%	15,8%
sept-14	0,7%		0,1%		9,6%		20,8%		3,1%		5,0%	
Total	100,0%		100,0%		100,0%		100,0%		100,0%		100,0%	

Le tableau démontre le déplacement des retraits et injections à la suite de l'application de la nouvelle stratégie. Tels que visés par la stratégie, les ratios de retrait et d'injection varient de façon significative autant sur la période de l'hiver que de l'été.

L'impact sur les achats à Dawn, quoique présent, est moins prononcé en pourcentage. Ceci résulte du fait que malgré l'augmentation des retraits sur les mois de décembre à février, les achats à Dawn sur cette période demeurent tout de même importants. En effet, sur la période de décembre à février, les retraits passeraient de 168 10^6m^3, en fonction de la stratégie actuelle, à 273 10^6m^3 sous la nouvelle stratégie, soit une augmentation de 63 %, alors que les achats à Dawn passeraient de 834 10^6m^3, en fonction de la stratégie actuelle, à 710 10^6m^3 sous la nouvelle stratégie, soit une baisse de 15 %.

Puisqu'il s'agit d'un plan macro, l'application de la stratégie ne peut être totalement reproduite. Par exemple, en avril, des injections au site de Union Gas sont observées alors qu'au réel, ces injections seraient probablement moindres. De plus, le plan macro ne simule pas les besoins en cours de journée, ces derniers n'étant observés qu'au réel.

Au niveau des coûts, la nouvelle stratégie entraîne une baisse projetée des coûts de 0,6 M$. Cette variation résulte principalement de la baisse des coûts de fourniture à Empress, découlant des indices AECO en été inférieurs à ceux de l'hiver. D'autre part, une légère hausse des coûts de transport et d'équilibrage reliés aux achats à Dawn est observée et résulte des primes en été plus élevées que celles en hiver, selon les prix obtenus par la tierce partie.

En ce qui a trait au coût de maintien des inventaires, l'augmentation du coût résultant du niveau d'inventaire plus élevé en début d'année est compensée par l'impact à la baisse résultant des injections concentrées sur la fin de la saison. La nouvelle stratégie générerait donc un effet presque neutre sur le coût de maintien des inventaires. Le graphique 2 illustre la variation du profil d'inventaire de chaque stratégie.

Comme mentionné précédemment, ces simulations permettent de quantifier l'impact du changement de stratégie, mais dans l'optique où les volumes déplacés et les prix de gaz naturel correspondent à ceux utilisés, ce qui est peu probable.

CONCLUSION

Comme mentionné précédemment, Gaz Métro serait disposée à modifier sa stratégie de gestion des inventaires chez Union Gas qui viserait une concentration des retraits durant les mois de décembre à février et une concentration des injections à la fin de la saison d'injection. Cette stratégie serait appliquée en considérant les différents paramètres contractuels du site d'entreposage de Union Gas ainsi que les contraintes opérationnelles pour assurer la desserte de la demande de façon sécuritaire.

Toutefois, cette stratégie de gestion ne peut être entièrement mise de l'avant pour l'année 2013-2014 étant donné que Gaz Métro a déjà contracté la majorité des achats de gaz naturel projetés en hiver à Dawn. La partie relative à la gestion des injections pourrait néanmoins être appliquée. Ainsi, Gaz Métro viserait à concentrer ses injections à la fin de la saison 2014. Cette approche aurait l'avantage de réduire légèrement les coûts de maintien des inventaires. Quant à l'impact prix associé au déplacement des volumes d'achats sur l'été, il sera fonction des prix mensuels effectifs pour ces mêmes mois.

Si la Régie approuvait cette stratégie, Gaz Métro appliquerait la nouvelle stratégie de gestion des inventaires dans son plan d'approvisionnement de la Cause tarifaire 2015. Toutefois, cette stratégie devra être revue lorsque la structure d'approvisionnement de Gaz Métro sera déplacée à Dawn afin de considérer le changement du contexte gazier dont, entre autres, les capacités de transport qui devront être conservées entre Empress et le territoire de Gaz Métro.

ANNEXES

Annexe 1 : Rapport de Sussex Economics Advisors – Gaz Métro – Gas Strorage Review

Annexe 2 : Comparaison de stratégies de gestion de l'entreposage de Union Gas - Plan d'approvisionnement 2014

Gaz Métro

Gas Storage Review

October 2013

Prepared by

Sussex Economic Advisors, LLC

Introduction

Sussex Economic Advisors, LLC ("Sussex") was retained by Gaz Métro Limited Partnership ("Gaz Métro") to review certain natural gas storage practices. Specifically, pursuant to a Régie de l'énergie ("Régie") Decision in D-2013-035, R-3809-2012 Phase 1, Gaz Métro was directed to file a report that addresses the following issues related to natural gas storage management:

- Identify various strategies to optimize withdrawals;
- Assess the potential expected gain associated with each of these strategies and risk (variability of results) against the cost of each strategy. These analyses must take into account the daily historical variability (over a decade or more, if possible) of climatic conditions (and needs) and prices;
- Identify various strategies to optimize injections;
- Assess the potential expected gain associated with each of these strategies and risk (variability of results) against the cost of each strategy. These analyses must take into account the daily historical variability (over a decade or more, if possible) of climatic conditions (and needs) and prices.[1]

Overview of Sussex and Project Approach

Overview of Sussex

Sussex is a management and economic advisory firm providing consulting services to regulated industries such as natural gas, electricity, water, and thermal energy distribution. The firm's Partners have held senior positions in utility companies, competitive energy suppliers, management consulting firms and business focused academic institutions. Our Consulting Staff, Executive Advisors, and Affiliated Experts have substantial experience and training in matters relating to regulatory strategy and policy development, natural gas infrastructure development and open season processes, gas supply planning and capacity portfolio optimizing, energy market analysis and assessments, financial and economic analysis, retail natural gas transportation and services, rate proceedings and regulatory compliance, due diligence and valuation, and management reviews and audits. Sussex has a substantial list of clients including natural gas distribution companies, electric utilities, combination utilities, electric transmission providers, natural gas transmission/pipeline companies, municipal utilities, state agencies, and non-regulated energy market participants.

[1] Régie de l'énergie, Decision in D-2013-035, R-3809-2012 Phase 1, March 4, 2013, at 9.

Project Approach

Sussex utilized the following five-step approach to assist Gaz Métro with compliance to the Régie request regarding natural gas storage withdrawal and injection strategy options:

1. Review the role of natural gas storage in the resource portfolio of a local distribution company ("LDC");
2. Summarize the natural gas storage contract(s) between Gaz Métro and Union Gas Limited ("Union Gas");
3. Review the approach utilized by Sussex to identify storage withdrawal strategies and discuss the withdrawal scenario analyses and associated results;
4. Review the approach utilized by Sussex to identify storage injection strategies and discuss the injection scenario analyses and associated results; and
5. Summarize our observations and conclusions.

To evaluate withdrawal/injection options associated with the Union Gas natural gas storage contracts and to quantify the benefits and costs of each option, Sussex relied on various data gathering approaches, including:

- On-site meetings with representatives from the Gaz Métro gas supply planning group with overall responsibility for: (i) the development of the gas supply plan; and (ii) the implementation and management of the gas supply plan, including the Union Gas storage contracts;
- Reviewing various Gaz Métro gas supply planning documents, spreadsheets,[2] and certain relevant regulatory submissions and decisions; and
- Researching and analyzing various natural gas pricing information and associated natural gas pricing indices.

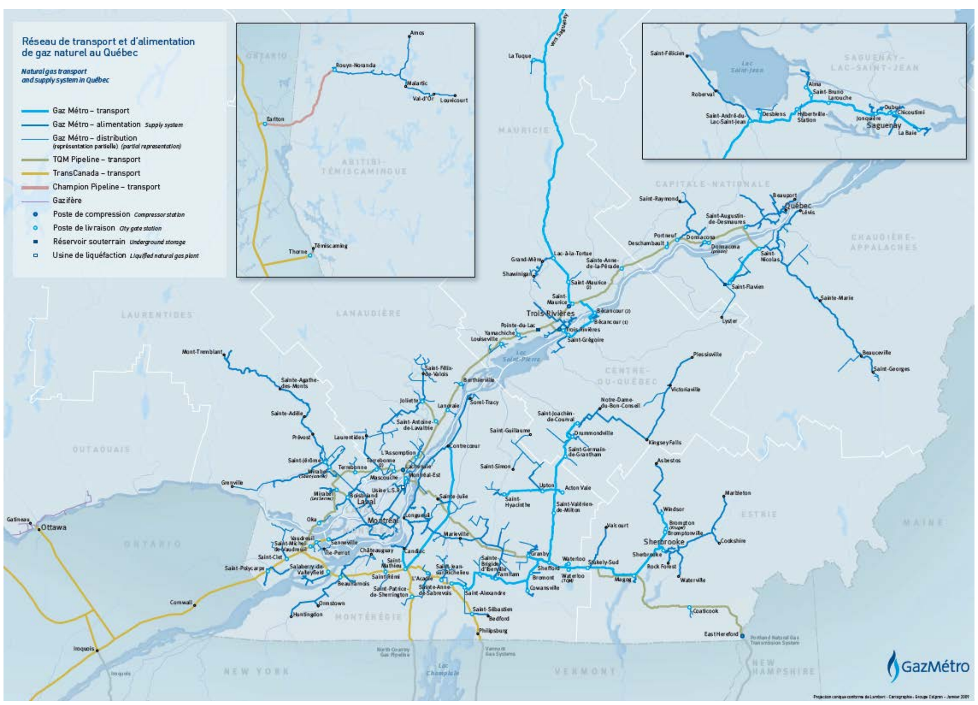
[2] Gaz Métro provided to Sussex the daily natural gas demand, weather conditions, Union Gas storage utilization, and daily/monthly natural gas purchases at Dawn. It is the understanding of Sussex that Gaz Métro estimated the demand for each year using the linear regression model from their 2012/2013 gas supply plan applied to the climatic conditions over the past ten years. Based on these calculated demands, Gaz Métro projected the gas supply plans for each year over the 2002/2003 through 2012/2013 period including use of storage and gas purchased at Dawn, following the 2012/2013 gas supply plan parameters. This methodology included the current parameters of the natural gas storage contracts with Union Gas. Stated differently, the Gaz Métro storage contract parameters with Union Gas have changed over the analysis period; therefore, Gaz Métro provided to Sussex a dataset that reflected the current parameters of the Union Gas storage contracts, yet included the climatic conditions and natural gas prices over the past ten years.

The Sussex assessment and observations/conclusions regarding the potential withdrawal and injection options for the Gaz Métro natural gas storage contracts with Union Gas are based on the analyses discussed herein, the information provided by Gaz Métro or developed by Sussex, and the collective gas supply planning experience and judgment of the Sussex project team.[3]

Prior to our review of the storage analyses approach and results, a brief review of Gaz Métro is provided below.

Gaz Métro Overview

Gaz Métro is the largest natural gas distributor in Québec servicing 97% of the provincial natural gas demand. Gaz Métro provides natural gas service to approximately 190,000 customers in over 300 municipalities utilizing a 10,000 km underground distribution network. The Gaz Métro residential, commercial and industrial segments represent approximately 76%, 21% and 3% of the total customers, respectively. Conversely, the industrial segment throughput of 115 Bcf represents almost 60% of the total Gaz Métro throughput, while the residential and commercial segments represent 10% and 30% of the total throughput, respectively.[4] The following map illustrates the Gaz Métro service area:[5]



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[3] Biographies of the Sussex project team are included as Appendix A.
[4] Valener Energy Company, "A Solid Investment", Investor Presentation, August 2013, at 13-14.
[5] Gaz Métro, "Natural gas transport and supply system in Quebec", January 26, 2009.

From a gas supply planning perspective, the Gaz Métro natural gas supply portfolio consists of various assets including, pipeline capacity on the TransCanada PipeLines Limited ("TCPL") Canadian Mainline, natural gas storage contracts with Union Gas, on-system natural gas storage facilities, and on-system liquefied natural gas ("LNG") peaking facilities. The focus of the Sussex withdrawal/injection scenario analyses is the off-system natural gas storage contracts with Union Gas.

Sussex Storage Analyses Approach and Results

Step 1: Overview of Natural Gas Storage

Prior to a review of potential natural gas storage withdrawal and injection strategies, the first step in the Sussex analysis is a brief review of the role of natural gas storage in the resource portfolio of an LDC. Specifically, this storage overview will provide the necessary context for the evaluation of potential strategies associated with the optimization of storage withdrawals and injections.

In general, natural gas storage provides an LDC with four primary benefits: (i) winter or peak season source of natural gas supply; (ii) mechanism to balance the intra-day and inter-month LDC demand fluctuations; (iii) physical price hedge for a certain portion of the natural gas supply portfolio; and (iv) service and supply reliability. Please find below a brief discussion of each of these attributes.

Winter or Peak Season Supply

Market area natural gas storage provides winter or peak season natural gas supply, thus allowing the LDC to avoid upstream natural gas pipeline demand charges for a portion of its natural gas transportation portfolio. Specifically, given the typical demand profile of Canadian LDCs (i.e., in general, higher natural gas demand requirements during the winter or peak season), natural gas storage provides a cost effective approach for serving the winter or peak season demand. Stated differently, by entering into a market area natural gas storage contract, the LDC could avoid contracting for a certain volume of annual long-haul capacity from a natural gas supply source to the LDC distribution area to serve winter or peak season demand load. As such, the LDC would avoid annual contract charges for capacity that may not be utilized at one hundred percent on an annual basis.

Demand/Supply Balancing

LDCs not only need to manage the variation in seasonal demand, but also the monthly, daily and intra-day fluctuations between forecasted and actual natural gas demand. Specifically, the LDC needs to have resources in their natural gas supply portfolio that can respond to changes in natural gas demand across and within days resulting from various factors including, actual weather compared to forecasted weather. Natural gas storage provides the LDC with a "shock absorber" asset whereby short-term demand changes (i.e., both increases and decreases in demand) are managed by withdrawing or injecting from/into natural gas storage facilities. Absent a natural gas storage asset or a similar type of asset or service, LDCs would likely be more exposed to pipeline balancing costs and penalties.

Physical Price Hedge

Given the winter peaking nature of most of the North American natural gas market, natural gas prices tend to reflect a seasonal pricing pattern. Specifically, natural gas prices and price indices typically follow a trend whereby a positive price differential (i.e., premium) exists between peak (i.e., winter) and off-peak (i.e., summer) periods. As such, LDCs are able to procure natural gas during the off-peak period and pay the lower off-peak price, inject gas into storage, and withdraw volumes during the winter period, thus avoiding winter prices for that stored quantity of gas. In other words, a natural gas storage contract provides an LDC with the ability to purchase certain natural gas supply during the off-peak season at off-peak prices for dispatch during the peak season and avoid peak season prices – thus storage provides a physical price hedge.

Service Reliability

Finally, market area natural gas storage provides LDCs with an asset to manage a disruption in the production or transmission segments (upstream of storage) of the natural gas delivery chain. Specifically, market area natural gas storage allows the LDC to withdraw natural gas from storage to replace gas supply that is subject to interruption from a physical failure in natural gas production or transmission equipment. Although natural gas production and transmission equipment failure has historically been a low probability event, nonetheless, it is considered a high impact event as the cost and implications from un-served firm natural gas demand could be significant.

Step 2: Natural Gas Storage Contract(s) Between Gaz Métro and Union Gas

One of the primary assumptions in the Sussex analysis of the Union Gas storage contracts is the specific parameters of the storage contracts (e.g., storage or capacity volume, maximum daily withdrawal quantity, maximum daily injection quantity, and the associated ratchet provisions). Table 1 (below) provides a summary of the Gaz Métro natural gas storage contracts with Union Gas.

Table 1: Gaz Métro – Union Gas Storage Contractual Parameters

	THRESHOLDS				
	MAXIMUM STORAGE BALANCE	RATCHET UP >=75%	RATCHET DOWN < 25%	EARLY STORAGE BALANCE March 31- April 30 <=	LATE STORAGE BALANCE Oct 1st - Nov 1st >=
LST057	5,849,700	4,387,275	1,462,425	2,632,365	4,387,275
LST064	2,974,880	2,231,160	743,720	1,338,696	2,231,160
LST065	4,400,000	3,300,000	1,100,000	1,980,000	3,300,000
LST068					
Total	**13,224,580**	**9,918,435**	**3,306,145**	**5,951,061**	**9,918,435**

	INJECTION			WITHDRAWAL			
	BEFORE RATCHET	AFTER RATCHET		BEFORE RATCHET	AFTER RATCHET		
	Dec 1st - Sept 30	Dec 1st - Sept 30	Oct 1st - Nov 30	June 1st - March 31	June 1st - March 31		April 1st - May 31
	Firm	Firm	Interruptible	Firm	Firm	Interruptible	Interruptible
LST057	43,873	29,249	29,249	70,196	46,798	23,399	70,196
LST064	22,312	14,874	14,874	35,699	23,799	11,900	35,699
LST065	33,000	22,000	22,000	52,800	35,200	17,600	52,800
LST068	33,000	22,000	22,000	52,800	35,200	17,600	52,800
Total	**132,185**	**88,123**	**88,123**	**211,495**	**140,997**	**70,499**	**211,495**

Although Gaz Métro has four natural gas storage contracts with Union Gas, the Sussex analyses assumed one storage contract with the following parameters (please see the highlighted total row in Table 1 above):

- Natural gas storage capacity or space of approximately 13,000,000 GJ;
- Required early storage balance of less than or equal to approximately 6,000,000 GJ at the end of at least one day between March 31st through April 30th;
- Required late storage balance of greater than or equal to approximately 10,000,000 GJ at the end of at least one day between October 1st and November 1st;
- Injection capability of approximately 132,000 GJ/day declining to 88,000 GJ/day when the inventory level is equal to or greater than approximately 10,000,000 GJ;
- Firm injection rights are available between December through September and interruptible injection rights are available in October and November;
- Withdrawal capability of approximately 212,000 GJ/day declining to 141,000 GJ/day when the inventory level is at or below approximately 3,300,000 GJ; and

- Firm withdrawal rights are available between June and March and interruptible withdrawal rights are available in April and May.

In addition to the storage parameters outlined above, the Sussex analyses also included certain Gaz Métro operating practices such as having the storage inventory at or near full capacity by October 1st to avoid any risk associated with reliance on interruptible injections during the months of October and November.

Step 3: Storage Withdrawal Strategies and Associated Results

To facilitate the identification of potential storage withdrawal strategies, Sussex analyzed the Gaz Métro 2012/2013 planned storage withdrawals associated with the Union Gas natural gas storage contract. This review of the 2012/2013 storage-dispatching plan and the application of that plan to the prior ten years of data served two purposes: first, Sussex was able to use the results as the baseline for comparison to other storage withdrawal strategies. Second, the baseline provided guidance regarding the development of withdrawal strategies. That is, the analysis of the Gaz Métro 2012/2013 plan and the associated annual natural gas storage dispatching results for the ten-year analysis period provided Sussex with, not only the comparator for the withdrawal analyses, but also insight into the identification of alternative strategies for storage withdrawal options.

Chart 1 and Table 2 (below) provide the Gaz Métro withdrawal pattern (i.e., monthly storage withdrawal volumes associated with the Union Gas contract) for the 2012/2013 storage plan. In addition, Sussex calculated the monthly average of the daily natural gas prices at the Dawn Hub for the past ten years and superimposed the three-year, five-year and ten-year monthly averages on the monthly volume withdrawal pattern.

Chart 1: Gaz Métro – 2012/2013 Withdrawal Pattern

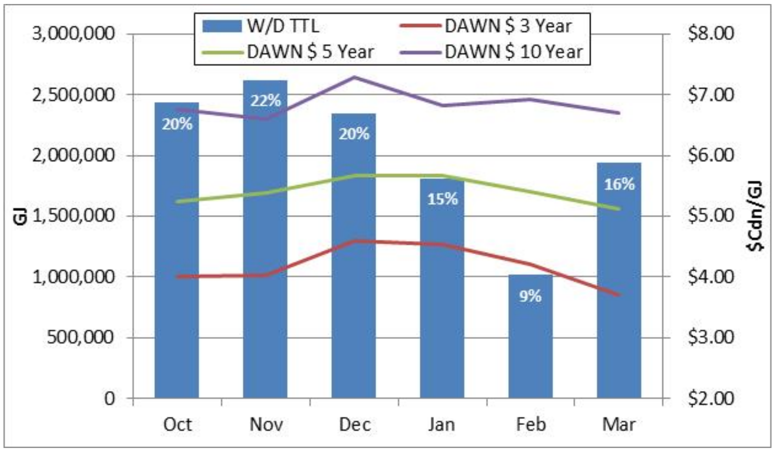

Table 2: Gaz Métro – 2012/2013 Withdrawal Pattern

MONTH	HDD	HDD % OF TTL	W/D TTL	W/D % OF TTL	DAWN $ 3 Year	DAWN $ 5 Year	DAWN $ 10 Year
Oct	150	5%	2,433,566	20%	$ 4.01	$ 5.25	$ 6.77
Nov	323	12%	2,621,644	22%	$ 4.02	$ 5.38	$ 6.61
Dec	573	21%	2,346,702	20%	$ 4.59	$ 5.68	$ 7.29
Jan	685	25%	1,809,904	15%	$ 4.54	$ 5.67	$ 6.82
Feb	573	21%	1,016,529	9%	$ 4.22	$ 5.40	$ 6.92
Mar	457	17%	1,935,689	16%	$ 3.70	$ 5.12	$ 6.70
Apr	208	8%	0	0%	$ 3.53	$ 5.09	$ 6.61
May	46	2%	0	0%	$ 3.78	$ 5.40	$ 6.68
Jun	4	0%	0	0%	$ 4.02	$ 5.74	$ 6.78
Jul	0	0%	0	0%	$ 4.02	$ 5.42	$ 6.34
Aug	1	0%	0	0%	$ 3.87	$ 4.71	$ 6.20
Sep	23	1%	44,432	0%	$ 3.73	$ 4.38	$ 5.89
Total	3,043		12,208,467				
Average					$ 4.00	$ 5.27	$ 6.63

As indicated by Chart 1 and Table 2 (above), the Gaz Métro 2012/2013 planned[6] withdrawal pattern associated with the Union Gas storage contract is predicated on a significant portion of the storage being dispatched early in the peak season (i.e., October and November). Specifically, the October and November monthly withdrawal volumes represent approximately 42% of the total planned volumes withdrawn from the Union Gas storage contract over the winter period. December and January represent approximately 35%, while February and March represent approximately 25% of the winter period monthly withdrawal volumes from the Union Gas storage contract.

6 The 2012/2013 storage withdrawal plan is based on certain Union Gas contract parameters as discussed above (e.g., 13 PJ of storage space); as well as gas supply planning objectives (e.g., sufficient inventory in place to support full withdrawal volumes in February).

In terms of the natural gas prices at the Dawn Hub, there are certain observations that are germane to the storage analysis:

- Natural gas prices have declined over time from the ten-year average of $6.63/GJ to the three-year average of $4.00/GJ.[7]
- In general, the peak season prices, on average, are higher than the off-peak season prices; although certain individual years do not necessarily follow that pattern.

The 2012/2013 linear regression model was utilized by Gaz Métro to develop the monthly withdrawal volumes for each year of the 11-year period (i.e., 2002/2003 through 2012/2013) using conditions specific for that year.[8] The baseline monthly withdrawal volume by year is summarized in Table 3 below.

Table 3: Gaz Métro – Monthly Withdrawal Volumes (GJ) – Baseline

Split-Year (Oct. - Sep.)	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Total
2002/03	2,420,214	2,673,286	1,823,430	2,024,894	877,458	2,456,870	12,276,153
2003/04	2,421,317	2,661,457	2,138,782	2,364,760	1,041,249	1,484,441	12,112,007
2004/05	2,455,083	2,618,503	2,357,155	1,937,582	680,872	2,245,965	12,295,159
2005/06	2,472,829	2,675,201	2,847,458	1,409,795	1,213,848	2,150,187	12,769,320
2006/07	2,448,487	2,562,895	1,388,049	1,957,335	1,938,580	2,524,206	12,819,552
2007/08	2,440,023	2,662,618	2,472,602	1,264,171	772,420	2,761,248	12,373,083
2008/09	2,436,987	2,630,660	2,339,277	2,376,474	889,931	1,520,969	12,194,298
2009/10	2,491,427	2,632,858	2,937,068	2,163,803	1,242,852	588,961	12,056,968
2010/11	2,475,750	2,606,619	2,254,176	1,907,813	945,991	1,847,695	12,038,043
2011/12	2,487,972	2,629,511	1,670,396	2,550,937	1,129,805	1,199,377	11,667,997
2012/13	2,433,566	2,621,644	2,346,702	1,809,904	1,016,529	1,935,689	12,164,035

Once Sussex established the baseline monthly withdrawal pattern and volume for each year (i.e., see Table 3 above) for the Union Gas natural gas storage contract, Sussex identified three withdrawal scenario strategies for evaluation, specifically:

- Scenario 1 – Winter Period
- Scenario 2 – Peak Period
- Scenario 3 – Weather Driven

For each of the three storage withdrawal scenarios identified, Sussex evaluated the storage dispatch scenario relative to the baseline over the 11-year period from 2002/2003 through

7 Please note that all monetary figures are reported in Canadian dollars.
8 Please note that the gas supply plan for the 2012/2013 year reflects normal weather conditions as provided in the 2013 rate case.

2012/2013. This 11-year time period covers a variety of weather conditions and natural gas prices; and, therefore, satisfies the Régie's objective that the storage analysis consider "daily historical variability (over a decade or more, if possible) of climatic conditions (and needs) and prices." By comparing each scenario to the baseline, Sussex determined whether the identified scenario resulted in a net cost or benefit relative to the baseline. Therefore, this approach met the Régie's objective that each scenario be evaluated to assess the "potential expected gain associated with each of these strategies and risk (variability of results) against the cost of each strategy."

Scenario 1 – Winter Period

In this first scenario, the storage withdrawal volumes associated with the Union Gas storage contract occur only during the winter period, which for purposes of this scenario is defined as November to March. As a result, Sussex re-allocated the October monthly withdrawal volumes under the baseline scenario to a defined winter period month. By way of example, as illustrated in Table 3 (above), the baseline October withdrawal volumes for 2002/2003 was 2,420,214 GJ, which, under Scenario 1 – Winter Period, is re-allocated to a winter period month (i.e., November through March). Therefore, the 2002/2003 October storage withdrawal volume of 2,420,214 GJ will be replaced by daily gas purchases of equivalent volume at the Dawn Hub price, and that storage withdrawal volume will be re-allocated to another winter period month. In this scenario, Sussex developed two cases (i.e., Case A and Case B):

- In Case A, Sussex re-allocated the planned October withdrawal volume to December (i.e., Sussex modeled increased natural gas purchases at the Dawn Hub in October in lieu of October storage withdrawals and decreased Dawn purchases in December as a result of the withdrawal of additional storage volume in December).
- In Case B, Sussex re-allocated the planned October withdrawal volume to February (i.e., Sussex modeled increased natural gas purchases at the Dawn Hub in October in lieu of October storage withdrawals and decreased Dawn purchases in February as a result of the withdrawal of additional storage volume in February).
- In both Cases A and B, the re-allocated October storage withdrawal volumes are distributed equally across all the available days for withdrawals (i.e., days in which natural gas was not injected into storage) in December and February, respectively.
- In addition, Sussex implemented certain manual adjustments to the Case A and Case B withdrawal volumes to keep within the parameters of the Union Gas storage contract.

- Finally, additional purchased gas costs in October and potential avoided natural gas costs in December and February, for Case A and Case B, respectively, were calculated based on the historical daily Dawn Hub index.

Tables 4 and 5, below, provide a summary of the results for Withdrawal Scenario 1, Case A and Case B.

Table 4: Storage Withdrawal Scenario 1 – Winter Period, Case A Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs in October ($ millions)	Potential Avoided Natural Gas Costs in December ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs[9]
2002/03	16.6	(17.9)	0.2	(1.2)	(0.2)%
2003/04	15.5	(18.8)	0.2	(3.1)	(0.6)%
2004/05	19.3	(19.3)	0.2	0.2	0.0%
2005/06	36.2	(34.3)	0.2	2.1	0.4%
2006/07	17.8	(18.9)	0.2	(0.9)	(0.2)%
2007/08	15.4	(17.4)	0.2	(1.8)	(0.3)%
2008/09	19.3	(17.9)	0.2	1.7	0.4%
2009/10	12.0	(14.3)	0.2	(2.1)	(0.7)%
2010/11	9.3	(11.0)	0.2	(1.5)	(0.5)%
2011/12	9.4	(8.8)	0.1	0.8	0.5%
2012/13	8.4	(8.5)	0.1	0.0	0.0%
2002/03-2007/08 Avg.	20.1	(21.1)	0.2	(0.8)	(0.2)%
2008/09-2012/13 Avg.	11.7	(12.1)	0.2	(0.2)	(0.1)%
Total Period Average	16.3	(17.0)	0.2	(0.5)	(0.1)%

9 For purposes of this analysis, total purchased gas costs is equal to the Gaz Métro daily gas volume purchased at Dawn priced at the daily Dawn Hub natural gas price index.

Table 5: Storage Withdrawal Scenario 1 – Winter Period, Case B Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs in October ($ millions)	Potential Avoided Natural Gas Costs in February ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs
2002/03	16.6	(28.3)	0.3	(11.4)	(2.0)%
2003/04	15.5	(17.6)	0.4	(1.7)	(0.3)%
2004/05	19.3	(18.4)	0.4	1.3	0.2%
2005/06	36.2	(20.3)	0.5	16.5	2.9%
2006/07	17.8	(21.1)	0.4	(2.9)	(0.6)%
2007/08	15.4	(20.4)	0.4	(4.7)	(0.8)%
2008/09	19.3	(14.3)	0.5	5.5	1.4%
2009/10	12.0	(14.5)	0.3	(2.1)	(0.7)%
2010/11	9.3	(10.4)	0.3	(0.7)	(0.3)%
2011/12	9.4	(6.9)	0.3	2.8	1.6%
2012/13	8.4	(8.4)	0.2	0.2	0.1%
2002/03-2007/08 Avg.	20.1	(21.0)	0.4	(0.5)	(0.1)%
2008/09-2012/13 Avg.	11.7	(10.9)	0.3	1.1	0.4%
Total Period Average	16.3	(16.4)	0.4	0.3	0.1%

As illustrated by Tables 4 and 5 above, when compared to the baseline withdrawal pattern, the Storage Withdrawal Scenario 1 analysis results in an average net benefit over the 2002/2003 to 2012/2013 time period of ($500,000) in Case A (i.e., re-allocate October withdrawals to December); and an average net cost of $300,000 in Case B (i.e., re-allocate October withdrawals to February). With respect to the variability of results, in Case A, the net cost/benefit ranges from a net cost increase of $2,100,000 in 2005/2006 to a benefit of ($3,100,000) in 2003/2004. While in Case B, the net cost/benefit ranges from a net cost increase of $16,500,000 in 2005/2006 to a benefit of ($11,400,000) in 2002/2003.

An additional observation with respect to the Storage Withdrawal Scenario 1 analysis is the difference between the net cost/benefit results over the 2002/2003 to 2007/2008 time period compared to the results over the 2008/2009 to 2012/2013 time period as evidenced by the sub-period average calculations in Tables 4 and 5, specifically:

- In Storage Withdrawal Scenario 1 – Case A (i.e., Table 4), the average benefit declined from ($800,000) in the 2002/2003 to 2007/2008 time period to ($200,000) in the 2008/2009 to 2012/2013 time period (i.e., a swing of $600,000).
- In Storage Withdrawal Scenario 1 – Case B (i.e., Table 5), over the 2002/2003 to 2007/2008 time period the net benefit was ($500,000), while over the 2008/2009 to 2012/2013 time period the net cost is $1,100,000 (i.e., a swing of $1,600,000).

Finally, in both Case A and Case B, the net cost/benefit represents, on average less than 0.5% of the total purchased gas costs. Specifically, the average net benefit of ($500,000) in Case A and average net cost of $300,000 in Case B represent on average 0.1% of the purchased gas costs over the total time period reviewed. In Case A, the net cost/benefit for each year was below 1% of the total purchased gas costs; while in Case B, the net cost/benefit ranged from +/- 3%.

Scenario 2 – Peak Period

In Storage Withdrawal Scenario 2, the storage volumes are withdrawn only during the peak winter months, which for purposes of this scenario are defined as December, January and February. As a result, Sussex re-allocated the October, November and March monthly withdrawal volumes under the baseline scenario to the peak period months. Specifically, for the months of October, November and March, it is assumed that Gaz Métro purchases natural gas at the Dawn Hub in lieu of storage withdrawals from the Union Gas storage contract. Conversely, the additional storage volumes are distributed equally across all available withdrawal days (i.e., days in which natural gas was not injected into storage) for the December, January and February time period. By way of example, as illustrated by Table 3 (page 9), the baseline October, November and March volumes for 2002/2003 was 7,550,370 GJ, which was re-allocated to the peak period (i.e., December 2002 to February 2003). Similar to the Storage Withdrawal Scenario 1 analysis, Sussex implemented certain manual adjustments to keep within the parameters of the Union Gas storage contract. Please find below Table 6, which is a summary of the Scenario 2 results.

Table 6: Storage Withdrawal Scenario 2 – Peak Period Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs in Oct., Nov. & Mar. ($ millions)	Potential Avoided Natural Gas Costs in Dec., Jan. & Feb. ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs
2002/03	63.6	(67.1)	0.3	(3.2)	(0.6)%
2003/04	43.1	(49.2)	0.4	(5.7)	(1.1)%
2004/05	57.1	(55.5)	0.3	2.0	0.4%
2005/06	83.4	(82.2)	0.4	1.7	0.3%
2006/07	60.2	(61.1)	0.4	(0.5)	(0.1)%
2007/08	59.9	(61.4)	0.3	(1.2)	(0.2)%
2008/09	51.0	(46.0)	0.5	5.4	1.4%
2009/10	25.2	(33.4)	0.4	(7.8)	(2.6)%
2010/11	28.1	(30.6)	0.3	(2.2)	(0.8)%
2011/12	23.0	(20.8)	0.3	2.5	1.5%
2012/13	26.2	(24.4)	0.2	2.0	0.8%
2002/03-2007/08 Avg.	61.2	(62.7)	0.4	(1.2)	(0.2)%
2008/09-2012/13 Avg.	30.7	(31.0)	0.3	0.0	0.1%
Total Period Average	47.3	(48.3)	0.3	(0.6)	(0.1)%

As illustrated by Table 6 above, when compared to the baseline withdrawal pattern, the Storage Withdrawal Scenario 2 analysis results in an average benefit of ($600,000) with a range of $5,400,000 of additional cost in 2008/2009 to a net benefit of ($7,800,000) in 2009/2010. In other words, in the back-to-back years of 2008/2009 and 2009/2010, there was a swing in the Scenario 2 results of $13,200,000. In relation to total purchased gas costs, the average net benefit of ($600,000) represents approximately 0.1% of the purchased gas costs.

Similar to the Storage Withdrawal Scenario 1 results, the Storage Withdrawal Scenario 2 results have a declining trend in net benefit. Specifically, the average net benefit declined from ($1,200,000) in the 2002/2003 to 2007/2008 time period to no impact (i.e., net zero) in the 2008/2009 to 2012/2013 time period.

Scenario 3 – Weather Driven

In this third scenario, the storage volumes are withdrawn based on the monthly heating degree day ("HDD") levels; specifically, the HDDs for each month are calculated and assigned a percentage based on the actual HDDs in a particular month compared to the HDDs for the total winter period for each year. For example, if the HDDs in October represented 10% of the HDDs for a particular winter period, then 10% of the storage inventory would be dispatched in October. To continue with the example and using the Table 3 information, in 2002/2003, if 10% of the HDDs for that winter occurred in October then 10% of the total storage withdrawal volume for that year (i.e., 10% of 12,276,153 GJ or 1,227,615 GJ) was dispatched in October. The difference between the 2002/2003 baseline October withdrawal volume of 2,420,214 GJ (see Table 3) and the weather driven value of 1,227,615 GJ is natural gas purchases at the Dawn Hub index. Next, the monthly withdrawal volume was allocated to each available withdrawal day based on the actual daily withdrawal percentage, which was calculated as the actual daily withdrawal volume divided by the total monthly withdrawal volume. Table 7 below provides a summary of the Scenario 3 results.

Table 7: Storage Withdrawal Scenario 3 – Weather Driven Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs ($ millions)	Potential Avoided Natural Gas Costs ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs
2002/03	23.9	(32.4)	0.3	(8.2)	(1.4)%
2003/04	19.7	(23.1)	0.4	(3.0)	(0.6)%
2004/05	25.0	(24.3)	0.4	1.1	0.2%
2005/06	40.8	(28.3)	0.5	13.0	2.3%
2006/07	24.5	(25.5)	0.4	(0.6)	(0.1)%
2007/08	23.4	(27.8)	0.4	(4.0)	(0.7)%
2008/09	26.4	(20.7)	0.5	6.2	1.6%
2009/10	13.4	(16.6)	0.3	(2.8)	(0.9)%
2010/11	12.0	(13.2)	0.3	(0.9)	(0.3)%
2011/12	12.6	(10.0)	0.3	2.9	1.7%
2012/13	11.0	(10.5)	0.2	0.7	0.3%
2002/03-2007/08 Avg.	26.2	(26.9)	0.4	(0.3)	(0.1)%
2008/09-2012/13 Avg.	15.1	(14.2)	0.3	1.2	0.5%
Total Period Average	21.2	(21.1)	0.4	0.4	0.2%

As illustrated by Table 7 above, when compared to the baseline withdrawal pattern, the Storage Withdrawal Scenario 3 analysis results in an average net cost of $400,000, which represents approximately 0.2% of the total purchased gas costs. The average benefit declined from ($300,000) in the 2002/2003 to 2007/2008 time period to a net cost of $1,200,000 in the 2008/2009 to 2012/2013 time period. With respect to the variability of results, the net cost/benefit ranges from a net cost increase of $13,000,000 in 2005/2006 (i.e., approximately 2.3% of total purchased gas costs) to a benefit of ($8,200,000) in 2002/2003 (i.e., approximately 1.4% of total purchased costs); which is a swing of $21,200,000.

Step 4: Storage Injection Strategies and Associated Results

To facilitate the identification of potential storage injection strategies, Sussex analyzed the Gaz Métro 2012/2013 planned storage injections associated with the Union Gas natural gas storage contract. Similar to the storage withdrawal analysis, the analysis of the Gaz Métro 2012/2013 storage injection plan and the application of that plan to the prior ten years of data provided Sussex with, not only the comparator for the storage injection analyses, but also insight into the identification of alternative strategies for storage injections.

Chart 2 and Table 8 (below) provide the Gaz Métro injection pattern (i.e., monthly storage injection volumes associated with the Union Gas storage contract) for the 2012/2013 storage plan. In addition, Sussex calculated the monthly average of the daily natural gas prices at the Dawn Hub for the past ten years and superimposed the three-year, five-year and ten-year monthly averages on the monthly volume injection pattern.

Chart 2: Gaz Métro – 2012/2013 Injection Pattern

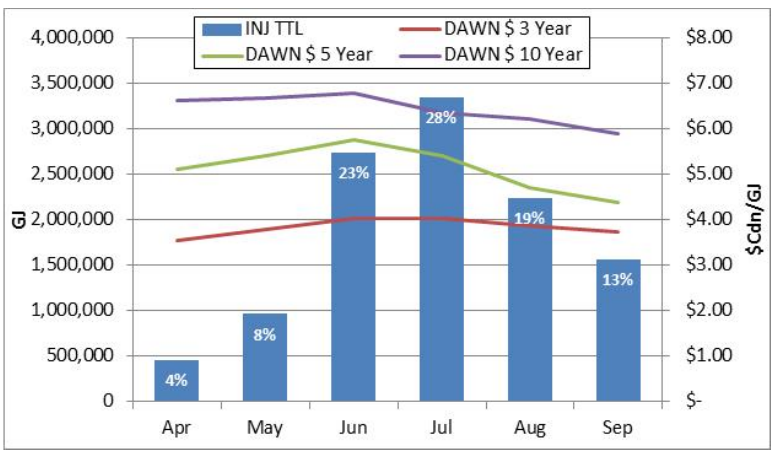

Table 8: Gaz Métro – 2012/2013 Injection Pattern

MONTH	HDD	HDD % OF TTL	INJ TTL	INJ % OF TTL	DAWN $ 3 Year	DAWN $ 5 Year	DAWN $ 10 Year
Oct	150	5%	0	0%	$ 4.01	$ 5.25	$ 6.77
Nov	323	12%	0	0%	$ 4.02	$ 5.38	$ 6.61
Dec	573	21%	229,571	2%	$ 4.59	$ 5.68	$ 7.29
Jan	685	25%	191,050	2%	$ 4.54	$ 5.67	$ 6.82
Feb	573	21%	133,877	1%	$ 4.22	$ 5.40	$ 6.92
Mar	457	17%	352,421	3%	$ 3.70	$ 5.12	$ 6.70
Apr	208	8%	460,283	4%	$ 3.53	$ 5.09	$ 6.61
May	46	2%	961,763	8%	$ 3.78	$ 5.40	$ 6.68
Jun	4	0%	2,733,303	23%	$ 4.02	$ 5.74	$ 6.78
Jul	0	0%	3,343,918	28%	$ 4.02	$ 5.42	$ 6.34
Aug	1	0%	2,239,320	19%	$ 3.87	$ 4.71	$ 6.20
Sep	23	1%	1,562,541	13%	$ 3.73	$ 4.38	$ 5.89
Total	3,043		12,208,047				
Average					$ 4.00	$ 5.27	$ 6.63

As indicated by Chart 2 and Table 8 (above), the Gaz Métro 2012/2013 planned injection pattern associated with the Union Gas storage contract is predicated on a significant portion of the storage injections in the middle two months (i.e., June and July). Specifically, the April and May monthly injection volumes represent approximately 12%; June and July represent approximately 51%, while August and September represent approximately 32% of the monthly injection volumes into the Union Gas storage contract.

The 2012/2013 linear regression model was utilized by Gaz Métro to develop the monthly injection volumes for each year of the 11-year period from 2002/2003 through 2012/2013 using conditions specific for that year. The baseline monthly injection volume by year is summarized in Table 9 below.

Table 9: Gaz Métro – Monthly Injection Volumes (GJ) – Baseline

Split-Year (Oct. - Sep.)	Apr.	May	Jun.	Jul.	Aug.	Sep.	Total
2002/03	257,939	1,106,232	2,875,055	3,298,820	2,113,498	1,666,386	11,317,930
2003/04	447,747	1,136,177	2,781,751	3,131,696	2,124,844	1,662,426	11,284,642
2004/05	413,757	770,929	2,861,150	3,439,525	2,282,649	1,537,645	11,305,655
2005/06	549,034	1,034,409	2,666,996	3,254,602	2,204,774	1,591,630	11,301,445
2006/07	402,015	910,451	2,837,149	3,435,458	2,266,778	1,457,603	11,309,453
2007/08	781,025	820,175	2,692,050	3,252,994	2,187,276	1,551,090	11,284,610
2008/09	508,383	1,037,415	2,661,654	3,283,006	2,266,760	1,535,623	11,292,841
2009/10	629,288	826,243	2,432,621	3,007,675	2,157,553	1,619,673	10,673,054
2010/11	236,879	998,235	2,849,476	3,439,525	2,159,787	1,582,554	11,266,456
2011/12	226,170	588,409	2,274,591	2,823,223	2,221,509	1,532,015	9,665,917
2012/13	460,283	961,763	2,733,303	3,343,918	2,239,320	1,562,541	11,301,128

Once the monthly injection baseline was established for each year, Sussex identified three injection scenarios for evaluation, specifically:

- Scenario 1 – Even Injections
- Scenario 2 – Front Load Injections
- Scenario 3 – Back Load Injections

Similar to the storage withdrawal analysis, for each of the three storage injection scenarios identified above, Sussex evaluated the storage dispatch pattern results over the 11-year period from 2002/2003 through 2012/2013. This 11-year time period covers a variety of weather conditions and natural gas prices,[10] which meets the Régie's objective that the storage analysis consider "daily historical variability (over a decade or more, if possible) of climatic conditions

10 Given the timing of this analysis, natural gas prices for 2012/2013 were only available through September 13, 2013. The natural gas prices for the remainder of September 2013 were assumed to be equal to the price on September 13, 2013.

(and needs) and prices." In addition, each year was compared to the baseline to determine whether the identified scenario resulted in a net cost or benefit relative to the baseline, which meets the Régie's objective that each scenario be evaluated to assess the "potential expected gain associated with each of these strategies and risk (variability of results) against the cost of each strategy."

<u>Scenario 1 – Even Injections</u>

In the first storage injection scenario, the injection volumes associated with the Union Gas storage contract were evenly distributed across the entire injection period. Specifically, the monthly storage injection volume was identical from April through September (i.e., the storage injection volume for each month was equivalent to 1/6 of the total storage injection volumes). By way of example and using the data from Table 9 (above), the 2002/2003 total injection volume was 11,317,930 GJ, so the monthly even injection volume was approximately 1,886,322 GJ. In other words, the 2002/2003 baseline injection for April was 257,939 GJ compared to a Scenario 1 – Even Injections volume of 1,886,322 GJ. Table 10 below provides a summary of the Scenario 1 results.

Table 10: Storage Injection Scenario 1 – Even Injections Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs ($ millions)	Potential Avoided Natural Gas Costs ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs
2002/03	20.1	(19.0)	0.2	1.3	0.2%
2003/04	18.9	(19.0)	0.2	0.1	0.0%
2004/05	26.6	(26.1)	0.2	0.7	0.1%
2005/06	17.7	(16.5)	0.2	1.4	0.2%
2006/07	23.4	(19.7)	0.2	3.9	0.8%
2007/08	25.4	(28.0)	0.2	(2.4)	(0.4)%
2008/09	11.5	(10.1)	0.2	1.7	0.4%
2009/10	9.8	(11.0)	0.2	(1.0)	(0.3)%
2010/11	11.9	(12.1)	0.2	0.0	0.0%
2011/12	5.8	(7.1)	0.1	(1.1)	(0.7)%
2012/13	11.5	(10.9)	0.1	0.8	0.3%
2002/03-2007/08 Avg.	22.0	(21.4)	0.2	0.8	0.2%
2008/09-2012/13 Avg.	10.1	(10.2)	0.2	0.1	(0.1)%
Total Period Average	16.6	(16.3)	0.2	0.5	0.1%

As illustrated by Table 10 above, when compared to the baseline injection pattern, the Storage Injection Scenario 1 analysis results in an average net cost of $500,000, which represents on average 0.1% of the total purchased gas costs. With respect to the variability of results, the net cost/benefit ranges from a net cost increase of $3,900,000 in 2006/2007 to a benefit of ($2,400,000) in 2007/2008 (i.e., a year-over-year swing of $6,300,000). In terms of the two time periods, there was a net cost of $800,000 over the 2002/2003 to 2007/2008 time period compared to a net cost of $100,000 over the more recent period (i.e., 2008/2009 to 2012/2013).

Scenario 2 – Front Load Injections

In Scenario 2, the storage injection volumes are maximized in the beginning of the injection period. Specifically, for this scenario, Sussex calculated the total storage injections over the entire injection period (i.e., April through September) and maximized the daily injection volume on each available injection day (i.e., days in which natural gas was not withdrawn from storage) beginning in April until the total required injection volume for each year was reached. For example, using the 2002/2003 total injection volume of 11,317,930 GJ (see Table 9), the front load injection scenario assumes that injections at the maximum daily quantity begins on April 1st and continues with sequential injections until the injection ratchet is triggered and then the lower volume is injected until the injection volume of 11,317,930 GJ is reached. A summary of the Scenario 2 results is provided in Table 11 below.

Table 11: Storage Injection Scenario 2 – Front Load Injections Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs ($ millions)	Potential Avoided Natural Gas Costs ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs
2002/03	52.4	(45.2)	1.0	8.2	1.4%
2003/04	52.7	(46.7)	0.9	7.0	1.4%
2004/05	57.9	(70.7)	1.0	(11.8)	(2.2)%
2005/06	48.1	(43.5)	1.1	5.7	1.0%
2006/07	56.8	(42.3)	1.0	15.5	3.1%
2007/08	69.1	(59.8)	1.0	10.2	1.8%
2008/09	29.9	(22.9)	0.8	7.8	2.0%
2009/10	29.1	(30.8)	0.8	(0.9)	(0.3)%
2010/11	29.1	(28.3)	0.7	1.5	0.5%
2011/12	15.7	(20.0)	0.5	(3.8)	(2.2)%
2012/13	28.9	(26.4)	0.5	3.0	1.2%
2002/03-2007/08 Avg.	56.2	(51.4)	1.0	5.8	1.1%
2008/09-2012/13 Avg.	26.6	(25.7)	0.7	1.5	0.2%
Total Period Average	42.7	(39.7)	0.8	3.9	0.7%

As illustrated by Table 11 above, when compared to the baseline injection pattern, the Storage Injection Scenario 2 analysis results in an average net cost of $3,900,000 with a range of $15,500,000 of additional cost in 2006/2007 to a net benefit of ($11,800,000) in 2004/2005. In other words, there was a swing in the Scenario 2 results of $27,300,000. The average net cost declined significantly from $5,800,000 in the 2002/2003 to 2007/2008 time period to a net cost of $1,500,000 in the 2008/2009 to 2012/2013 time period. On average, the total net cost of $3,900,000 represents 0.7% of the total purchased gas costs.

Scenario 3 – Back Load Injections

In this scenario, Sussex assumed that the storage injection volumes are injected only during the latter half of the injection period. As a result, Sussex re-allocated the April, May and June monthly injection volumes under the baseline scenario to July, August and September. In addition, Sussex implemented certain manual adjustments to keep within the parameters of the Union Gas storage contract. For example, using the 2002/2003 total injection volume of 11,317,930 GJ from Table 9 (above), the back load injection scenario maximizes injections at the end of the injection period and as such in 2002/2003 the following volumes are injected by month: 661,205 GJ in June 2003, 4,097,735 in July 2003, 3,921,487 GJ in August 2003, and 2,643,691 GJ in September 2003. Please find below Table 12, which is a summary of the Scenario 3 results.

Table 12: Storage Injection Scenario 3 – Back Load Injections Results

Split-Year (Oct. – Sep.)	Additional Purchased Gas Costs ($ millions)	Potential Avoided Natural Gas Costs ($ millions)	Additional Carrying Costs ($ millions)	Net Cost (Benefit) ($ millions)	Net Cost (Benefit) as % of Total Purchased Gas Costs
2002/03	24.1	(28.7)	(0.4)	(5.0)	(0.9)%
2003/04	26.3	(31.0)	(0.4)	(5.1)	(1.0)%
2004/05	37.5	(28.6)	(0.4)	8.5	1.6%
2005/06	24.2	(25.2)	(0.5)	(1.4)	(0.2)%
2006/07	21.9	(28.1)	(0.4)	(6.6)	(1.3)%
2007/08	32.1	(42.3)	(0.5)	(10.7)	(1.9)%
2008/09	12.3	(15.0)	(0.4)	(3.1)	(0.8)%
2009/10	17.8	(18.5)	(0.4)	(1.1)	(0.4)%
2010/11	14.3	(15.6)	(0.3)	(1.6)	(0.5)%
2011/12	9.2	(7.8)	(0.1)	1.3	0.8%
2012/13	12.9	(13.9)	(0.2)	(1.2)	(0.5)%
2002/03-2007/08 Avg.	27.7	(30.7)	(0.4)	(3.4)	(0.6)%
2008/09-2012/13 Avg.	13.3	(14.2)	(0.3)	(1.1)	(0.3)%
Total Period Average	21.1	(23.2)	(0.4)	(2.4)	(0.5)%

As illustrated by Table 12 above, when compared to the baseline injection pattern, the Storage Injection Scenario 3 analysis results in an average benefit of ($2,400,000). The average benefit declined from ($3,400,000) in the 2002/2003 to 2007/2008 time period to ($1,100,000) in the

2008/2009 to 2012/2013 time period. The annual benefit ranges from ($10,700,000) in 2007/2008 to an additional cost of $8,500,000 in 2004/2005 (i.e., a swing in the Scenario 3 results of $19,200,000). Similar to the Storage Injection Scenarios 1 and 2, the average net benefit in Scenario 3 represents less than 1% of the total purchased gas costs.

Step 5: Observations and Conclusion

The final step in the Sussex withdrawal/injection strategy options analysis is to summarize the results and provide certain observations and conclusions based on the results of the analyses described herein as well as the overall judgment and experience of the Sussex project team. It is important to note that the Sussex analyses required certain simplifying assumptions (e.g., maximize storage withdrawal volumes on certain days even though operating conditions may require less withdrawals to retain flexibility for balancing). Also, the scenario results should be considered as indicative or illustrative since Sussex did not include potential operational considerations that may influence daily dispatch decisions, and, therefore, reduce the calculated values to reflect “real world” operating restrictions (e.g., the scenario results would likely be reduced as Sussex did not consider the storage volume required for intraday nominations and balancing). Finally, it should be noted that any change in storage withdrawals/injections would impact the contracting and dispatch of other Gaz Métro portfolio assets, which was not considered in the Sussex analysis. A summary of the storage withdrawal and injection scenarios and associated results are provided in Tables 13 and 14 below.

Table 13: Summary of Storage Withdrawal Analysis Results

Scenario	Description	2002/03-2007/08 Average – Net Costs (Benefit) ($ millions)	2008/09-2012/13 Average – Net Costs (Benefit) ($ millions)	Total Period Average – Net Costs (Benefit) ($ millions)	Total Period Average – % of Total Purchased Gas Costs
Scenario 1 – Winter Period, Case A	Purchase gas at the Dawn Hub in lieu of storage withdrawals in October and replace gas purchases at the Dawn Hub with storage withdrawals in December; Re-allocate October withdrawal volumes to December	(0.8)	(0.2)	(0.5)	(0.1)%
Scenario 1 – Winter Period, Case B	Purchase gas at the Dawn Hub in lieu of storage withdrawals in October and replace gas purchases at the Dawn Hub with storage withdrawals in February; Re-allocate October withdrawal volumes to February	(0.5)	1.1	0.3	0.1%
Scenario 2 – Peak Period	Purchase gas at the Dawn Hub in lieu of storage withdrawals in October, November and March, and replace gas purchases at the Dawn Hub with storage withdrawals in December, January and February; Re-allocate Oct., Nov. and Mar. withdrawal volumes to Dec., Jan. and Feb.	(1.2)	0.0	(0.6)	(0.1)%
Scenario 3 – Weather Driven	Assume winter storage withdrawal patterns were consistent with winter HDD distribution	(0.3)	1.2	0.4	0.2%

Table 14: Summary of Storage Injection Analysis Results

Scenario	Description	2002/03-2007/08 Average – Net Costs (Benefit) ($ millions)	2008/09-2012/13 Average – Net Costs (Benefit) ($ millions)	Total Period Average – Net Costs (Benefit) ($ millions)	Total Period Average – % of Total Purchased Gas Costs
Scenario 1 – Even Injections	Assume equal storage injections over the entire injection period (i.e., April through September)	0.8	0.1	0.5	0.1%
Scenario 2 – Front Load Injections	Maximize storage injections in the beginning of the injection period (beginning in April)	5.8	1.5	3.9	0.7%
Scenario 3 – Back Load Injections	Maximize storage injections in the later months of the injection period (i.e., July through September)	(3.4)	(1.1)	(2.4)	(0.5)%

Observations

Based on the analyses described herein and the associated results, Sussex has the following observations:

- Withdrawal Analysis
  - None of the withdrawal scenarios, as measured on an average basis, provides a significant benefit relative to the baseline.
  - Of the four withdrawal scenarios reviewed over the 11-year analysis period, two had an average benefit of approximately ($500,000) (i.e., Scenario 1 – Case A and Scenario 2). Conversely, the Scenario 1 – Case B and Scenario 3 analysis results in an average net cost of approximately $300,000.
  - When the time period of the withdrawal analysis is restricted to the more recent years (i.e., 2008/2009 through 2012/2013) only Scenario 1 – Case A provides a net benefit – approximately ($200,000).
- Injection Analysis
  - Two of the injection scenarios result in additional costs, while Scenario 3 provides a net benefit.
  - Of the three injection scenarios reviewed over the 11-year analysis period, two had relatively significant deviations from the baseline; specifically, Scenario 2 averaged $3,900,000 of additional annual cost, while Scenario 3 averaged ($2,400,000) of additional annual benefit.
  - When the time period of the injection analysis is restricted to the more recent years (i.e., 2008/2009 through 2012/2013) the additional cost from Scenario 2 is reduced to $1,500,000, a reduction of over 60%; and the additional benefit from Scenario 3 is reduced to ($1,100,000), a reduction of approximately 55%.

Conclusion

As an LDC, the primary responsibility of Gaz Métro is the provision of safe and reliable natural gas deliveries to firm customers. As such, the contracting and utilization of natural gas storage provides Gaz Métro with a flexible asset in the furtherance of that reliability objective. On a secondary basis, natural gas storage can provide cost benefits as a physical hedge.

With respect to the Gaz Métro utilization of natural gas storage, and as discussed herein, the storage withdrawal and injection scenarios identified and analyzed by Sussex illustrate that Gaz Métro's existing natural gas storage management practices are reasonable. Nevertheless, Sussex recommends that Gaz Métro continue to evaluate storage withdrawal and injection strategies and options, specifically:

- A storage withdrawal strategy that allows for more storage withdrawals during peak period months, as this would more likely reduce exposure to volatile natural gas prices during the high demand periods. In other words, by maintaining a higher inventory balance heading into the peak winter months (i.e., December, January, and February) Gaz Métro may reduce its exposure to peak winter price spikes.
- A storage injection strategy that allows for more injections later in the injection cycle, as this may provide more opportunity for Gaz Métro to purchase lower priced gas for storage injections. Stated differently, if Gaz Métro plans for more injections during the late summer shoulder period it may have access to lower priced natural gas supplies.
- It is important to note that the various strategies reviewed may introduce certain constraints that were not analyzed, including:
    - An injection strategy that fills inventory early in the off-peak season may reduce the flexibility of Gaz Métro to manage daily swings during the latter half of the off-peak season.
    - An injection strategy that relies on injections in the latter half of the injection season may need to address gas supply availability or other operational issues (e.g., storage limitations).
    - A withdrawal strategy that focuses on mid-to-late winter withdrawals may result in contract parameter issues should the winter be warmer than normal.
    - A withdrawal strategy that does not include early peak season withdrawals may reduce the flexibility of Gaz Métro to manage warmer than normal weather in November and December.

Finally, Sussex observes that the market and commercial dynamics associated with natural gas supply planning are becoming more complex as market area natural gas production sources (e.g., Marcellus Shale) will continue to influence natural gas pipeline flows. The changing pattern of natural gas flows not only influences price signals (i.e., natural gas pricing indices and capacity values), but also the regulatory environment as entities adjust business strategies to effectively compete. Some examples of these adjusting business strategies include:

- TCPL Canadian Mainline toll changes and the potential conversion of portions of the TCPL Canadian Mainline from natural gas infrastructure to oil transportation infrastructure;

- Continued development of various natural gas production basins including areas in western Canada and the U.S. mid-Atlantic/mid-west;
- New infrastructure projects to deliver Marcellus Shale gas to various import/export points including: Dawn, Niagara, and Waddington;
- Reduced LNG importation volumes at certain market area facilities (e.g., Canaport LNG); and
- Introduction of LNG export facilities at various North American locations including western Canada.

The changing market dynamics coupled with adjusting business strategies will result in a market environment that will change year-to-year making it unlikely that one storage utilization strategy will continuously outperform other options.

Sussex Project Team Biographies

<u>James M. Stephens, Partner</u>

Mr. Stephens has twenty-five years of experience in the energy industry and he has held senior management positions at consulting firms, energy marketing companies and natural gas utilities. Most recently, Mr. Stephens served as Senior Vice President for Concentric Energy Advisors, Inc. He has assisted numerous clients with regulatory policy strategy/tactics and energy market analyses/assessments including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure (e.g., pipeline expansions); the evaluation of new markets/opportunities (e.g., distributed LNG); market entry/exit strategies (e.g., service territory or product/service expansions); market implications of new energy infrastructure (e.g., LNG facilities and pipelines); integrated resource plans (e.g., natural gas demand forecasting and resource portfolio analysis); natural gas supply portfolio evaluation and optimization (e.g., asset management agreements); and management prudence (e.g., implementation of risk management/portfolio strategies). In addition to his consulting experience, Mr. Stephens served as the President of a retail energy marketing firm where he was responsible for all aspects of business unit management including front, mid and back office functions. Mr. Stephens was also responsible for the Gas Supply Procurement and Portfolio Optimization function for a local distribution company. Mr. Stephens holds a B.S. in Management and an M.B.A. with a concentration in Operations Management from Bentley College.

<u>Peter Newman, Executive Advisor</u>

Mr. Newman, who is an Executive Advisor with Sussex, has over thirty-five years of experience in various natural gas supply management roles for WE Energies. Specifically, Mr. Newman was responsible for managing all the natural gas supply functions including: long term supply planning and acquisition; natural gas purchasing strategies and execution; capacity portfolio optimization; development and implementation of risk management objectives and policies; and management of the gas control function. In addition, Mr. Newman participated in numerous Federal Energy Regulatory Commission proceedings with respect to natural gas pipeline expansions, rate proceedings, new services and other regulatory issues. Mr. Newman was also a key member of the management team that developed and built the Guardian Pipeline and, in that role, Mr. Newman contributed to a variety of activities, including: market development and project management, developing and implementing the open season process, market assessment, regulatory strategy and proceedings, capacity marketing and tariff development. Mr. Newman is an engineering graduate of the University of Wisconsin-Platteville.

James Voss, Executive Advisor

Mr. Voss, who is an Executive Advisor with Sussex, has twenty-five years of experience in the natural gas industry having held management positions at major Midwestern LDCs as well as unregulated energy marketing firms. He has extensive background and knowledge of gas trading and asset optimization, nominating and scheduling operations, pipeline-LDC system interfaces, gas supply portfolio planning, and related federal and state regulatory oversight. Mr. Voss is a graduate of the University of Wisconsin-Madison with a Masters in Finance from the University of Wisconsin-Milwaukee.

Kim Nguyen, Consultant

Ms. Nguyen has over eight years of experience in providing economic and strategic advisory services to clients in the energy and utility industries. She has contributed to engagements involving regulatory support, energy market assessments, and benchmarking analysis. Ms. Nguyen also has extensive experience in database development, researching regulatory and energy market issues, performing statistical analysis, supporting expert witness testimony, and financial analysis and modeling. Ms. Nguyen holds a B.A. in Economics from Clark University, where she graduated summa cum laude and was a member of the Omicron Delta Epsilon Society.

ANNEXE 2 - COMPARAISON DE STRATÉGIES DE GESTION DE L'ENTREPOSAGE DE UNION GAS - PLAN D'APPROVISIONNEMENT 2013-2014

		Stratégie actuelle			Nouvelle stratégie			Variation		
		Hiver (10^6m^3) (1)	**Eté** (10^6m^3) (2)	**Total** (10^6m^3) (3)	**Hiver** (10^6m^3) (4)	**Eté** (10^6m^3) (5)	**Total** (10^6m^3) (6)	**Hiver** (10^6m^3) (7)	**Eté** (10^6m^3) (8)	**Total** (10^6m^3) (9)
	DEMANDE									
1	Continue	2 811	2 093	4 904	2 811	2 093	4 904	0	0	0
2	Interruptible	378	298	676	378	298	676	0	0	0
3	Client biogaz en réseau dédié	13	15	28	13	15	28	0	0	0
4	Gaz d'appoint concurrence	17	25	42	17	25	42	0	0	0
5	*Sous-Total Demande*	3 220	2 432	5 651	3 220	2 432	5 651	0	0	0
6	Gaz perdu, usage de la compagnie et autres	47	27	74	46	27	74	0	0	0
7	Ventes GNL	5	9	15	5	9	15	0	0	0
8	SOUS-TOTAL AVANT INJECTION	3 272	2 468	5 740	3 271	2 468	5 739	0	0	0
	INVENTAIRES INJECTIONS									
9	Union Gas	43	301	344	8	297	305	-35	-4	-39
10	LSR	10	18	28	10	18	28	0	0	0
11	Pointe-du-Lac	16	3	19	16	11	26	0	7	7
12	Saint-Flavien	10	110	119	10	110	119	0	0	0
13	Échanges de gaz	0	0	0	0	0	0	0	0	0
14	SOUS-TOTAL INJECTIONS & ÉCHANGES	79	432	511	44	436	479	-35	3	-32
15	**TOTAL DE LA DEMANDE**	**3 350**	**2 900**	**6 251**	**3 315**	**2 904**	**6 219**	**-35**	**3**	**-32**
	APPROVISIONNEMENT									
16	FTLH Empress - GMIT	1 257	1 781	3 038	1 257	1 781	3 038	0	0	0
17	Cessions d'optimisation	60	93	153	60	93	153	0	0	0
18	Transport par échange (EMP - GMIT)	156	247	403	156	247	403	0	0	0
19	Transport fourni par les clients	149	239	387	149	239	387	0	0	0
20	Gaz d'appoint	17	25	42	17	25	42	0	0	0
21	*Sous-Total Transports*	*1 638*	*2 385*	*4 023*	*1 638*	*2 385*	*4 023*	*0*	*0*	*0*
22	FT non utilisé	0	-29	-29	0	-29	-29	0	0	0
23	Cessions / ventes de transport	0	0	0	0	0	0	0	0	0
24	Achats dans le territoire	2	2	4	2	2	4	0	0	0
25	Achats à Dawn (GR)	1 214	459	1 673	1 184	489	1 673	-30	30	0
26	Biogaz	13	15	28	13	15	28	0	0	0
27	Autres réceptions	0	0	0	0	0	0	0	0	0
28	SOUS-TOTAL TRANSPORT	2 866	2 833	5 699	2 836	2 862	5 699	-30	30	0
	INVENTAIRES RETRAITS									
29	Union gas	294	50	344	289	16	305	-5	-34	-39
30	LSR	10	16	27	10	16	27	0	0	0
31	Pointe-du-Lac	17	2	19	17	9	26	0	7	7
32	Saint-Flavien	120	0	120	120	0	120	0	0	0
33	Échanges de gaz	0	0	0	0	0	0	0	0	0
34	SOUS-TOTAL RETRAITS & ÉCHANGES	441	68	509	436	41	478	-5	-26	-32
35	**TOTAL APPROVISIONNEMENT**	**3 308**	**2 900**	**6 208**	**3 272**	**2 904**	**6 176**	**-35**	**3**	**-32**
36	**INTERRUPTIONS BRUTES**	-43	0	-43	-43	0	-43	0	0	0

COMPARAISON DE STRATÉGIES DE GESTION DE L'ENTREPOSAGE DE UNION GAS
PLAN D'APPROVISIONNEMENT 2013-2014
ESTIMATION DES COÛTS (000 $)

		Stratégie actuelle	Nouvelle stratégie	Variation
	Coûts de transport			
1	Transport clients	n/a	n/a	n/a
2	FTLH (primaire, secondaire & échange)	225 089 336	225 089 336	0
3	STS	43 170 221	43 168 217	-2 004
4	FTSH (Dawn, Parkwway & échange)	46 654 002	46 645 930	-8 072
5	Vente de transport FTLH non utilisé	-2 189 412	-2 189 412	0
6	Achats de gaz - transport & équilibrage	45 613 746	45 808 094	194 348
7	Total - coûts de transport	358 337 893	358 522 164	184 272
8	Coûts d'entreposage	37 258 359	37 203 426	-54 934
9	Sous-total transport et équilibrage	395 596 252	395 725 590	129 338
10	Fourniture	888 864 461	888 219 054	-645 407
11	Gaz de compression	22 364 700	22 363 249	-1 450
12	Maintien des inventaires	4 246 612	4 189 198	-57 414
13	**TOTAL DES COÛTS**	**1 311 072 025**	**1 310 497 091**	**-574 933**