RÉPONSES D'HYDRO-QUÉBEC DISTRIBUTION À LA DEMANDE DE RENSEIGNEMENTS N^O 4 DE LA RÉGIE

DEMANDE DE RENSEIGNEMENTS N^O^ 4 DE LA RÉGIE DE L'ÉNERGIE (LA RÉGIE) DANS SES ACTIVITÉS DE DISTRIBUTION RELATIVE À LA DEMANDE TARIFAIRE 2015-2016

PRINCIPES RÉGLEMENTAIRES ET CONVENTIONS COMPTABLES

Référentiel comptable

1. Références : (i) Pièce B-0073, p. 4;
(ii) Rapport annuel 2013, pièce HQD-2, document 2.1, p. 4, tableau 1;
(iii) Rapport annuel 2013, pièce HQD-2, document 2.1, p. 6, tableau 2;
(iv) Dossier R-3768-2011, pièce B-0033, p. 4 et 5;
(v) Dossier R-3768-2011, pièce B-0034, p. 2.

Préambule :

(i) En complément de réponse à la demande de renseignements no 1 de la Régie dans le cadre du dossier tarifaire 2015, le Distributeur indique que :

« *La principale raison ayant incité Hydro-Québec à vouloir effectuer un changement de référentiel comptable en faveur des US GAAP est l'incertitude entourant la comptabilité des activités à tarifs réglementés. En janvier 2014, l'International Accounting Standards Board (IASB) a publié la norme provisoire IFRS 14 permettant aux premiers adoptants des IFRS de maintenir la comptabilisation des pratiques comptables réglementaires aux états financiers. Cette norme provisoire a des impacts importants sur la présentation des états financiers. Un projet à plus long terme abordera la question de savoir si les comptes de report réglementaires répondent à la définition d'un actif ou d'un passif. Ce projet pourrait se poursuivre pendant plusieurs années. Selon les conclusions de ce projet, l'IASB pourrait publier une norme définitive ou ne formuler aucune exigence précise. La finalité relative aux travaux de l'IASB est fondamentale pour Hydro-Québec. En effet, l'issue de ce projet pourrait influer sur la situation financière et accroître la volatilité des résultats. Les US GAAP permettent de maintenir la comptabilisation des actifs et passifs réglementaires et ainsi éviter la volatilité sur les résultats financiers.* » [nous soulignons]

(ii) Dans son rapport annuel 2013, le Distributeur présente au tableau 1, la conciliation des résultats statutaires et réglementaires pour l'exercice terminé le 31 décembre 2013, dont l'élément suivant :

« *Actifs et passifs financiers liés à la réglementation des tarifs* » au montant créditeur de 9,7 M$ en vertu des PCGR et des IFRS.

La Régie note que les composantes des « *Actifs et passifs financiers liés à la réglementation des tarifs* » sont reconnues tant au niveau des PCGR qu'au niveau des IFRS dans les rapports annuels 2013 et 2012.

La Régie note également qu'un rapport des auditeurs indépendants portant spécifiquement sur la conciliation entre les états financiers statutaires et réglementaires a été déposé dans les rapports annuels 2013 et 2012, en vertu de l'article 75 de la Loi.

(iii) Dans son rapport annuel 2013, le Distributeur présente au tableau 2, les composantes de l'ajustement d) concernant le reclassement de la rubrique statutaire « *Actifs et passifs financiers liés à la réglementation des tarifs* » au montant créditeur de 9,7 M$ dans les rubriques des résultats réglementaires.

DT / (CT)	Actifs et passifs financiers liés à la réglementation des tarifs
Pass-on pour l'achat d'électricité 2013	47,7
Nivellement pour aléas climatiques de l'année 2013	(42,0)
Compte d'écarts de combustible de l'année 2013	(1,1)
Compte d'écarts pannes majeures de l'année 2013	25,4
Écarts coût de retraite de l'année 2013	57,1
Écarts Bureau de l'efficacité et de l'innovation énergétiques de l'année 2013	(4,0)
Amortissement - *Pass-on* pour l'achat d'électricité 2011 et 2012	(14,4)
Amortissement - Nivellement aléas climatiques des soldes de 2006 à 2011	(56,5)
Amortissement - Compte d'écarts de combustible 2011 et 2012	(0,8)
Amortissement - Compte d'écarts de transport 2012	17,5
Amortissement - Compte d'écarts pannes majeures 2012	(5,9)
Amortissement - Écarts coût de retraite 2011 et 2012	(13,3)
Total	9,7

(iv) Dans sa demande relative aux modifications de méthodes comptables découlant du passage aux IFRS (dossier R-3768-2011), le Distributeur indique dans sa réponse R1.3 :

« Les actifs et passifs réglementaires du Distributeur qui répondent à la définition d'un actif ou passif financier selon l'IAS 32 sont essentiellement ceux découlant, pour des éléments spécifiques, des écarts entre les résultats prévus dans les dossiers tarifaires et les résultats réels d'une année donnée. Ces actifs et passifs sont les suivants :

- *Écarts de revenus liés aux aléas climatiques;*
- *Écarts du coût annuel du service de transport pour la charge locale;*
- *Écarts dans les coûts d'approvisionnement en électricité postpatrimoniale;*
- *Écarts dans les coûts d'approvisionnement en combustible;*
- *Écarts dans le coût de retraite.*

Le Distributeur a un droit, ou une obligation, légal et contractuel de récupérer, ou rembourser, les écarts comptabilisés dans les actifs et passifs réglementaires, dès que les résultats réels sont connus. Ce droit ou obligation, selon le cas, est lié à un service déjà rendu (livraison d'électricité) et non à une vente future. Ils se qualifient donc aux définitions d'actifs et passifs financiers de l'IAS 32.

Ce lien légal et contractuel découle des principes de la Loi sur la Régie de l'énergie. Pour chacun des éléments spécifiques mentionnés précédemment, le Distributeur et la clientèle ne peuvent retirer des avantages liés au processus de prévisions nécessaires pour établir les tarifs d'une année donnée, puisque les comptes d'écarts afférents assurent cette neutralité. »
[nous soulignons]

(v) Dans le cadre du dossier R-3768-2011, les auditeurs indépendants (KPMG et Ernst & Young) indiquent que :
« *Nous avons pris connaissance de la réponse donnée par Hydro-Québec à la question 1.3 et nous souscrivons à la position de la direction d'Hydro-Québec.* »

Demandes :

1.1 Veuillez confirmer que les IFRS permettent de maintenir la comptabilisation des actifs et passifs réglementaires, tels qu'ils ont été présentés dans les rapports annuels 2013 et 2012 pour lesquels un rapport des auditeurs indépendants a été émis. Si non, veuillez expliquer.

Réponse :

À compter du 1er janvier 2016, avec application anticipée autorisée, la norme provisoire IFRS 14 *Comptes de report réglementaires* permet aux premiers adoptants des IFRS de maintenir la comptabilisation des pratiques comptables réglementaires aux états financiers jusqu'à ce qu'une norme définitive sur la comptabilisation des activités assujetties à la réglementation des tarifs soit adoptée, et les dispositions de la norme IFRS 1 en matière de première application des IFRS permettent de maintenir la comptabilisation des actifs et passifs réglementaires constatés dans le passé. Toutefois, le solde des comptes de report réglementaires doit être présenté sur une ligne distincte au bilan après le total des actifs et/ou des passifs, et les mouvements correspondants doivent l'être sur une ligne distincte à l'état des résultats.

L'IFRS 14 est une norme provisoire. Un projet de norme à plus long terme pourrait aborder la question de savoir si les comptes de report réglementaires répondent à la définition d'un actif ou d'un passif selon le Cadre conceptuel. En septembre 2014, dans le cadre de l'analyse d'un tel projet, l'IASB a publié, pour fins de commentaires, un document de travail sur la présentation des incidences financières de la réglementation des tarifs. Ce document expose

notamment quatre approches que l'IASB pourrait examiner pour décider comment rendre compte sur les effets financiers de la réglementation des tarifs. Une des approches possibles serait d'interdire la comptabilisation des effets de la réglementation des tarifs mais, d'en considérer toutefois une divulgation spécifique. Selon les conclusions de ce projet, l'IASB pourrait publier une norme définitive ou ne formuler aucune exigence précise.

1.2 Veuillez concilier la norme IAS 32 qui permet de maintenir la comptabilisation des actifs et passifs réglementaires (dont le compte de nivellement pour aléas climatiques) et ainsi éviter la volatilité sur les résultats financiers, avec la finalité du projet de l'IASB qui pourrait influer sur la situation financière et accroître la volatilité des résultats. Veuillez expliquer.

Réponse :

Les comptes qui comptabilisent l'écart relatif à certains éléments spécifiques entre le montant réel et le montant prévu dans les dossiers tarifaires, de par l'obligation du Distributeur de remettre à la clientèle ce montant ou de le recevoir, répondent à la définition d'actifs et passifs financiers selon la norme IAS 32. La comptabilisation des actifs et passifs financiers liés à la réglementation des tarifs pourrait être maintenue dans les états financiers statutaires, même si la conclusion du projet à long terme de l'IASB sur les activités à tarifs réglementés était l'interdiction de la comptabilisation des effets de la réglementation des tarifs.

Cependant, tous les comptes réglementaires qui ne rencontrent pas les critères de constatation à titre d'actif ou de passif selon les IFRS, comme par exemple, le compte d'écarts comptabilisant les coûts relatifs à l'entente de suspension temporaire des livraisons de la centrale de TCE, ne pourraient pas être comptabilisés aux états financiers statutaires, ce qui pourrait avoir pour effet d'accroître la volatilité des résultats.

1.3 Veuillez expliquer en quoi l'issue des travaux de l'IASB pourrait influencer le traitement comptable présentement appliqué par le Distributeur sur les actifs et passifs réglementaires (dont le compte de nivellement pour aléas climatiques) qui répondent à la définition d'un actif ou passif financier selon l'IAS 32.

Réponse :

Voir la réponse à la question 1.2.

1.4 Veuillez déposer l'opinion des auditeurs indépendants pour les questions 1.1 à 1.3.

Réponse :

Voir la pièce HQD-15, document 1.6.

1.5 Veuillez indiquer la date prévue pour le passage des normes US GAAP aux normes IFRS pour les sociétés publiques américaines. Veuillez élaborer.

Réponse :

Aucune date n'est prévue pour le passage aux IFRS pour les sociétés publiques américaines. L'IASB et le Financial Accounting Standards Board (FASB) travaillent conjointement sur la convergence des US GAAP et des IFRS, afin d'éliminer ou de minimiser les différences. Toutefois, la Securities and Exchange Commission n'a pas encore pris de décision relativement au basculement aux IFRS aux États-Unis.

2. Références : (i) Pièce B-0073, p. 5;
(ii) Pièce B-0073, p. 4.

Préambule :

(i) « *Hydro-Québec analyse et évalue présentement de façon détaillée l'incidence du passage aux US GAAP, tant pour les états financiers statutaires que pour les états financiers réglementaires. Cette analyse, lorsqu'elle sera terminée, devra être présentée aux auditeurs afin d'être approuvée.*

Le Distributeur et le Transporteur prévoient être en mesure de présenter à la Régie une demande relative aux modifications de méthodes comptables découlant du passage aux US GAAP en décembre 2014 ou en janvier 2015. À ce jour, la transition aux US GAAP ne devrait pas avoir d'incidence importante sur les tarifs. Le Distributeur évalue toutefois la possibilité de demander à la Régie la création d'un compte d'écarts afin d'y comptabiliser les impacts relatifs à l'incidence de l'adoption des US GAAP. » [nous soulignons]

(ii) « *En 2013, la norme IAS 19 Avantages du personnel a été modifiée. Dorénavant, le rendement prévu des actifs correspond au taux d'actualisation de l'obligation. Ainsi, dans un contexte où les taux d'intérêt sont bas, l'impact à la hausse sur le coût de retraite et sur l'établissement des tarifs est important. Les US GAAP permettent d'utiliser un rendement prévu correspondant au taux de rendement prévu à long terme des actifs du régime de retraite.* »
[nous soulignons]

Demande :

2.1 Veuillez concilier les deux affirmations suivantes : « *la transition aux US GAAP ne devrait pas avoir d'incidence importante sur les tarifs* » (référence (i)) et l'impact qualifié d'important de norme IAS 19 sur le coût de retraite et sur l'établissement des tarifs contrairement aux US GAAP et aux PCGR (référence (ii)). Veuillez expliquer.

Réponse :

Comme présenté au tableau C-2 de l'annexe C de la pièce HQD-8, document 1 (B-0023), la prévision du coût de retraite de l'année témoin 2015, établie selon les IFRS pour le dossier, a été effectuée à partir d'un taux d'actualisation de 4,56 %.

La baisse des taux d'intérêt, subséquente au dépôt du dossier, entraîne en vertu des IFRS, une hausse du coût de retraite pour 2015. L'utilisation des US GAAP fait, quant à elle, en sorte que le coût de retraite 2015 se maintient au niveau de la prévision établie pour le dossier.

Ainsi, les revenus requis du Distributeur établis en IFRS pour l'année témoin 2015, en fonction des hypothèses utilisées au printemps 2014, sont équivalents aux revenus requis établis en US GAAP en date d'aujourd'hui.

On peut donc conclure que l'ajustement tarifaire au dossier pour l'année témoin 2015 établie selon les IFRS correspond à un tarif qui serait établi en US GAAP.

3. Références : (i) Pièce B-0073, p. 4;
(ii) Rapport annuel statutaire 2012 d'Hydro-Québec.

Préambule :

(i) « *Finalement, la décision d'abandonner le projet de réfection de la centrale Gentilly-2 en 2012 a entraîné pour Hydro-Québec un nouvel enjeu en IFRS, qui n'existe pas en US GAAP. La similitude entre les US GAAP et les PCGR du Canada fait en sorte que la transition ne devrait pas avoir d'incidence importante pour Hydro-Québec et ainsi, assurer une continuité avec les pratiques comptables actuelles retenues pour la préparation des états financiers statutaires.* »

(ii) Dans son rapport annuel statutaire 2012 établi en vertu des PCGR, Hydro-Québec indique, à la page 55, que :
« *Hydro-Québec Production a par ailleurs enregistré un résultat provenant d'activités abandonnées négatif de 1 867 M$, attribuable à la fermeture définitive de la centrale nucléaire de Gentilly-2 à la fin 2012.* »

Il explique, à la note 7 de la page 82, les activités abandonnées en 2012 provenant de la centrale nucléaire de Gentilly-2 :

NOTE 7 Activités abandonnées

En septembre 2012, la décision a été prise d'abandonner le projet de réfection de la centrale nucléaire de Gentilly-2 et de mettre fin aux activités nucléaires. La centrale a continué de produire de l'électricité jusqu'à la fin de 2012, conformément aux conditions de son permis d'exploitation, après quoi Hydro-Québec a entamé les préparatifs nécessaires à sa mise en dormance en vue de son démantèlement, à l'horizon 2060.

L'abandon du projet de réfection a entraîné la radiation des immobilisations corporelles en cours liées à ce projet, d'une valeur de 990 M$.

Le résultat d'exploitation de la centrale de Gentilly-2 est présenté au titre des activités abandonnées dans les états consolidés des résultats, et ce, pour tous les exercices visés. Aux fins de la présentation des informations sectorielles, les activités abandonnées relèvent des secteurs Production et Transport.

De plus, comme il est indiqué à la note 12, Obligations liées à la mise hors service d'immobilisations, les hypothèses clés sur lesquelles étaient fondés les paramètres de calcul et le montant estimé des obligations liées au démantèlement de la centrale à la fin de sa vie utile ont dû faire l'objet d'une révision, notamment en ce qui a trait à la date de début des travaux, qui a été devancée. Cette révision a entraîné une augmentation de 365 M$ des obligations liées à la mise hors service d'immobilisations et de la valeur comptable de la centrale.

Par suite de l'abandon du projet de réfection, Hydro-Québec a également dû procéder à un test de dépréciation de tous les actifs liés aux activités nucléaires. La valeur comptable de ces actifs, y compris l'augmentation des obligations liées au démantèlement de la centrale, a été comparée à leur juste valeur, qui a été établie au moyen de la méthode de l'actualisation des flux de trésorerie. Une dépréciation de 827 M$ a été comptabilisée, ce qui a ramené la valeur comptable des actifs liés aux activités nucléaires à zéro.

Le tableau suivant présente le détail du résultat provenant des activités abandonnées :

	2012	2011
Résultat d'exploitation		
Produits	**144**	147
Charges	**203**	222
	(59)	(75)
Radiation des immobilisations corporelles en cours	**(990)**	–
Dépréciation des actifs de la centrale nucléaire		
Immobilisations corporelles[a]	**(795)**	–
Matériaux, combustible et fournitures	**(32)**	–
	(827)	–
	(1 876)	(75)

a) Y compris l'augmentation de 365 M$ des obligations liées au démantèlement de la centrale.

Il explique également, à la note 12 de la page 85, les obligations liées à la mise hors service d'immobilisations en 2012 provenant de la centrale nucléaire de Gentilly-2 :

NOTE 12 Obligations liées à la mise hors service d'immobilisations

Les passifs au titre des obligations liées à la mise hors service d'immobilisations concernent les coûts à engager pour le démantèlement de la centrale nucléaire de Gentilly-2, pour l'évacuation du combustible nucléaire irradié généré par l'exploitation de cette centrale ainsi que pour le démantèlement des centrales thermiques et de certains réservoirs à carburant et postes de transport. Par suite de l'abandon du projet de réfection de la centrale de Gentilly-2 comme il est indiqué à la note 7, Activités abandonnées, les hypothèses clés sur lesquelles étaient fondés les paramètres de calcul et le montant estimé des obligations liées au démantèlement de la centrale à la fin de sa vie utile ont fait l'objet d'une révision qui a eu pour principal effet de devancer le début des travaux de 27 ans.

La valeur comptable globale des obligations liées à la mise hors service d'immobilisations s'établit comme suit :

	2012			
	Démantèlement de la centrale nucléaire[a]	Évacuation du combustible nucléaire irradié[a]	Démantèlement d'autres immobilisations	Total
Solde au début de l'exercice	208	201	131	**540**
Passifs engagés	–	12	–	**12**
Charge de désactualisation	15	18	4	**37**
Passifs réglés	–	(2)	(5)	**(7)**
Révision des flux de trésorerie estimatifs et de l'échéancier prévu des paiements	365	–	5	**370**
Solde à la fin de l'exercice	588	229	135	**952**
Moins				
Portion à court terme	122	3	53	**178**
	466	226	82	**774**

Demande :

3.1 La Régie note qu'Hydro-Québec a radié les actifs de la centrale nucléaire de Gentilly-2 au montant de 1 876 M$ en 2012, en vertu des PCGR. Veuillez expliquer de façon détaillée quel est le « *nouvel enjeu en IFRS, qui n'existe pas en US GAAP* », ni aux PCGR. Veuillez donner un aperçu de l'impact financier.

Réponse :

D'emblée, le Distributeur tient à rappeler que la décision d'adopter les US GAAP en est une d'entreprise. L'enjeu concernant la centrale Gentilly-2 est un enjeu du Producteur et non du Distributeur.

Sommairement, en vertu des PCGR, la juste valeur du passif au titre de l'obligation liée au démantèlement de la centrale et à l'évacuation du combustible irradié est établie en actualisant les flux estimatifs nécessaires pour régler l'obligation. Au cours des exercices suivants, le passif n'est pas réévalué suite à une modification du taux d'actualisation, alors qu'en vertu des IFRS, une variation du taux pourrait nécessiter une réévaluation du passif.

Rémunération des comptes d'écarts et de report (CER)

4. Références : (i) Pièce B-0012, p. 10;
(ii) Pièce B-0037, p. 6;
(iii) Pièce B-0070, p. 16;
(iv) Pièce B-0089, p. 7 et 8.

Préambule :

(i) « *À cet égard, l'AUC indique que le compte avait été créé pour être équitable autant pour le distributeur que pour ses clients sachant que les excédents/déficits pouvaient être remboursés/récupérés auprès des clients. <u>S'il y avait une probabilité égale de soldes positifs et négatifs, ATCO devrait théoriquement être indifférent entre l'utilisation des taux d'intérêt résultant de l'article 23 des règles de l'AUC régissant les paiements d'intérêts ou l'utilisation du coût moyen pondéré du capital</u> tel qu'approuvé dans les décisions antérieures de l'AUC. Toutefois, l'AUC note que depuis décembre 2010, le solde de ce compte s'était maintenu dans une position de compte à recevoir pour ATCO.* » [nous soulignons]

(ii) Le Tableau 1 présente l'évolution des comptes d'écarts et autres actifs.

(iii) Dans sa réponse à la question 5.2 le Distributeur affirme:
« *Si la Régie n'avait pas autorisé la création de ces comptes d'écarts, les coûts engagés dans une année donnée auraient été constatés aux résultats réels de l'année en cours, affectant ainsi le rendement du Distributeur présenté dans son rapport annuel.* »

(iv) Dans sa réponse à la question 1.10 Concentric affirme :
« *The risk to the utility is very much impacted by the existence of large deferral balances. The account is integral to the utility and the risk it creates, i.e. the lag between investment and recovery is factored into the required return by investors. <u>Deferral accounts impose greater risk on the utility</u> by introducing an uncertain recovery period which must be reflected in the WACC.* » [nous soulignons]

Dans sa réponse à la question 2.3 Concentric affirme :
« *In Hydro-Québec Distribution's present Application, the balance of deferral and variance accounts is around $ 359.3 million and rate base is $1 0,729.8 million, such that the DVA balance represents 3.3 % of rate base.* »

Demandes :

4.1 Veuillez indiquer si le Distributeur est d'accord avec l'affirmation de la référence (i) à l'effet que s'il y avait une probabilité égale de soldes positifs et négatifs, un distributeur devrait être indifférent au taux utilisé pour rémunérer un compte d'écart et de report. Veuillez commenter.

Réponse de Concentric :

For deferral balances that have the potential to be large, Concentric does not agree that utilities are indifferent to the rate of return used to remunerate them even though there may be an equal probability of positive and negative balances. Variability in cash flow, even though captured in a deferral, is less desirable, even if there were an equal opportunity for positive and negative balances.

4.2 Veuillez compléter le tableau 1 de la référence (ii) en fournissant, pour chacun des comptes d'écarts et autres actifs présentés, l'évolution du solde de ces comptes au 31 décembre de chaque année depuis leur création. Veuillez fournir le chiffrier Excel.

Réponse :

Le tableau R-4.2 présente, pour chacun des comptes d'écarts et autres actifs du tableau 1 de la référence (ii) du préambule, l'évolution du solde de ces comptes au 31 décembre de chaque année depuis leur création ainsi que le total de ces soldes en pourcentage de la base de tarification de chacune des années.

Tableau R-4.2 :
Soldes des comptes d'écarts et autres actifs au 31 décembre (M$)

Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Année de base 2014	Année témoin 2015
Inclus dans la base de tarification												
Contributions à des projets de raccordement	-	-	76,0	70,4	63,3	59,3	54,8	52,9	73,3	103,9	95,5	299,2
Compte de nivellement pour aléas climatiques	-	-	-	-	131,9	53,3	50,4	42,8	126,4	135,2	222,9	142,3
Compte de frais reportés de transport	-	-	355,4	285,4	101,6	-	-	-	-			
Total des comptes d'écarts inclus dans la base de tarification	**-**	**-**	**431,4**	**355,8**	**296,8**	**112,6**	**105,2**	**95,7**	**199,7**	**239,1**	**318,4**	**441,5**
Hors base de tarification												
Compte de nivellement pour aléas climatiques	-	-	122,4	128,9	8,8	22,6	162,0	188,1	192,9	94,7	(44,0)	-
Compte d'écarts - Charge locale de transport	-	-	-	58,9	2,8	(0,1)	16,8	(47,8)	(17,5)	(30,9)	(5,1)	-
Compte de *pass-on* pour l'achat d'électricité	-	33,3	(232,0)	(54,5)	(51,7)	9,9	51,6	25,1	10,3	19,0	380,0	407,1
Compte d'écarts - Combustibles	-	-	-	-	-	9,5	(3,4)	(13,1)	(2,5)	(4,7)	12,1	-
Compte d'écarts - Tarif de maintien de la charge	-	-	-	-	-	-	3,5	5,8	2,7	0,5	-	-
Compte d'écarts - Coût de retraite	-	-	-	-	-	-	-	(33,5)	1,3	45,9	(13,2)	-
Compte d'écarts - Pannes majeures	-	-	-	-	-	-	-	5,5	14,0	34,2	27,4	-
Compte d'écarts - BEIÉ	-	-	-	-	-	-	-	-	-	(4,0)	(28,7)	(22,2)
Compte d'écarts - Projets majeurs	-	-	-	-	-	-	4,6	4,0	-	-	34,2	-
Compte d'écarts - Montant à remettre à la clientèle suite à la modification de la base de tarification 2014	-	-	-	-	-	-	-	-	-	-	(1,9)	-
Total des comptes d'écarts hors base de tarification	**-**	**33,3**	**(109,6)**	**133,3**	**(40,2)**	**41,9**	**235,1**	**134,1**	**201,2**	**154,7**	**360,8**	**384,9**
TOTAL	**-**	**33,3**	**321,8**	**489,1**	**256,6**	**154,5**	**340,3**	**229,8**	**400,9**	**393,8**	**679,2**	**826,4**
Total de la base de tarification au 31 décembre	**8 467,3**	**8 617,5**	**9 507,4**	**9 580,8**	**10 174,2**	**10 124,1**	**10 275,0**	**10 539,6**	**10 004,4**	**10 385,5**	**10 819,1**	**11 088,4**
Solde en pourcentage de la base de tarification	**-**	**0,4%**	**3,4%**	**5,1%**	**2,5%**	**1,5%**	**3,3%**	**2,2%**	**4,0%**	**3,8%**	**6,3%**	**7,5%**

Le tableau R-4.2 permet de constater que l'année de base 2014 et l'année témoin 2015 constituent deux années exceptionnelles en ce qui a trait au solde total des comptes d'écarts et à la proportion par rapport à la base de tarification. Cette situation découle des soldes élevés pour ces deux années des comptes de *pass-on* et de nivellement pour aléas climatiques résultant des conditions climatiques rigoureuses au cours de l'hiver 2013-2014.

4.3 Veuillez fournir le solde annuel du total des comptes hors base et inclus dans la base de tarification présentés au tableau 1, depuis leur création. Veuillez fournir le solde en dollars ainsi qu'en pourcentage de la base de tarification, tel que présenté à la référence (iv).

Réponse :

Voir la réponse à la question 4.2.

4.4 Veuillez expliquer comment la création d'un compte permettant d'éviter que des coûts engagés n'affectent le rendement du Distributeur, tel qu'énoncé à la référence (iii), augmente le risque du Distributeur, tel qu'énoncé à la référence (iv).

Réponse de Concentric :

Mechanisms that mitigate earnings variability and promote timely recovery of capital serve to reduce the risk profile of the utility and accordingly its weighted average cost of capital (WACC). By extending the deferral account recovery period further into the future, regulatory lag increases as does the associated business risk. The shareholder must fund the resulting cash shortfall through the delayed period of recovery. Risk has increased due to the introduction of regulatory lag.

4.5 Veuillez identifier chacun des comptes présentés au tableau 1 qui, selon le Distributeur, lui impose un risque plus grand, tel qu'énoncé à la référence (iv), et veuillez justifier chaque cas identifié.

Réponse de Concentric :

Deferral account balances that grow beyond that which may be comfortably recovered from customers in one year, impose additional risk on the utility. The accounts in Table 1, whose recovery period has been deferred beyond that which was originally proposed when the account was established are the Stabilization Account for Climate Conditions (currently being amortized over a 5 year period) and the Pass-on Account for Electricity Purchases for 2014 and

2015 (proposed to be amortized over a 5 year period beginning 2016 due to an exceptionally high balance). This extension of the recovery period imposes greater risk on the utility by increasing regulatory lag in each case, and particularly when balances are large, could become a concern to investors.

4.6 Veuillez indiquer si, dans l'éventualité où certains CER augmentent le risque du Distributeur, ce dernier considère souhaitable l'élimination de ces CER. Dans l'affirmative, veuillez les identifier. Sinon, veuillez justifier.

Réponse de Concentric :

Removing the deferral variance accounts (DVAs) would remove the regulatory protection that they provide and would materially and negatively impact the risk profile of the utility. This shift in risk would have to be considered in the utility's next cost of capital proceeding. Arguably, such treatment would make the utility an outlier amongst its comparators and as a result, a higher equity ratio or equity return would be warranted. It is not the DVA itself that increases the risk to investors; it is the introduction of an extended recovery period associated with the DVA.

5. Références : (i) Pièce B-0012, p. 11;
(ii) Décision BCUC G-110-12, FortisBc inc 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, p.105;
(iii) Pièce B-0089, p. 6;
(iv) Pièce B-0070, p. 16.

Préambule :

(i) Le Distributeur fait référence à la décision G-110-12 de la BCUC.

(ii) « *Normally, a utility, whether a Crown corporation or shareholder-owned, <u>is not entitled to receive a return on operating costs</u> or current period charges but simply recovery of those amounts from its ratepayers, assuming recovery is otherwise justified. <u>Current period charges are not "investments" which attract a capital return, they are deferred operating costs/current period expenses</u> which, as noted above, in the Panel's view, should not attract rate base rate of return.* » [nous soulignons]

(iii) « *Rate of return regulation assumes that every dollar of capital investment is financed in accordance with the firm's capital structure at the associated weighted average costs.* »

(iv) Dans sa réponse à la question 5.2 le Distributeur affirme:

« *Si la Régie n'avait pas autorisé la création de ces comptes d'écarts, les coûts engagés dans une année donnée auraient été constatés aux résultats réels de l'année en cours, affectant ainsi le rendement du Distributeur présenté dans son rapport annuel.* »

Demandes :

5.1 Veuillez déposer la décision de la BCUC nommée en référence.

Réponse :

Le Distributeur dépose la décision G-110-12 en annexe A du présent document.

5.2 Veuillez indiquer si le Distributeur est d'accord ou non avec les énoncés soulignés à la référence (ii). Veuillez commenter.

Réponse de Concentric :

Concentric agrees that utilities do not earn a return on current period operating costs or current period charges. Those charges are recovered in the revenue requirement in the period they are incurred. However, if recovery of operating expenses is deferred to future periods, those costs cease to be current operating expenses and instead become regulatory assets of the utility. Concentric disagrees that the cash paid for operating expenses that are ultimately deferred and capitalized do not meet the definition of an investment. These assets must be financed exactly the same way that other assets are financed, i.e. such as computers or vehicles. Therefore, Concentric cannot agree that these types of assets are significantly different from other rate base investments that attract the WACC or that they do not qualify as investments themselves.

5.3 Veuillez traduire et définir ce que le Distributeur considère être, à la référence (iii), un « *capital investment* ». Veuillez préciser si une dépense d'opération peut-être considérée comme un « *capital investment* ». Dans l'affirmative, veuillez expliquer. Veuillez définir et distinguer ce que le Distributeur considère être une dépense en capital par opposition à une dépense d'opération.

Réponse de Concentric :

A capital expenditure is funds used to acquire or upgrade physical assets such as property, plant or equipment. It is usually tied to maintaining, reinforcing or expanding utility infrastructure as opposed to the expenses associated with the day to day operating of the utility, as is the case with operating expenses.

It is important to note that invested capital for ratemaking purposes typically includes both types of capital, physical assets and working capital.

As explained in Concentric's response to 5.2 above, an operating expense ceases to be an operating expense if it is deferred beyond one year. Once deferred, it becomes an investment in the business.

5.4 Veuillez préciser si les coûts engagés dans une année donnée, tels qu'énoncés à la référence (iv), mais recouvrés une année subséquente répondent automatiquement, selon le Distributeur, à la définition de « *capital investment* ». Veuillez expliquer.

Réponse de Concentric :

As indicated in responses to 5.2 and 5.3 above, if a cost that would have otherwise been considered an operating expense is capitalized and deferred, it ceases to be an operating expense and becomes a utility asset or capital investment for the remainder of its unamortized life.

6. Référence : Pièce B-0070, p. 20.

Préambule :

Le Distributeur indique que :

« *Hydro-Québec finance l'ensemble de ses activités, y incluant celles du Distributeur, sur une base globale. Ses emprunts sont effectués pour l'ensemble de ses activités et ne sont pas liés à un actif particulier, que ce dernier soit récupéré sur 3 ans ou sur 40 ans.*

Effectuer un financement, dont les conditions seraient fonction de la nature particulière d'un actif, impliquerait qu'une garantie particulière soit attachée à ce dernier au bénéfice des détenteurs de la dette spécifique qui serait émise.

Il est important de rappeler que les engagements contractuels d'Hydro-Québec découlant de ses conventions de financement font en sorte que l'octroi d'une garantie sur un actif, par exemple une hypothèque sur un immeuble pour garantir le remboursement d'un emprunt, causerait un cas de défaut sur la dette d'Hydro-Québec. »

Demandes :

6.1 Veuillez préciser si le fait de consolider les besoins de financement des différentes divisions sur une base globale élimine le besoin de tenir compte des particularités de chacune des entités ainsi que la nature des actifs à financer par chacune des entités. Veuillez expliquer.

Réponse :

Comme mentionné au préambule, les financements de l'entreprise sont effectués sur une base consolidée. Dans ses décisions d'emprunt, la trésorerie de l'entreprise ne tient pas de compte de l'identité du secteur d'activité qui génère les besoins de fonds. Elle travaille avec le budget de caisse consolidé de l'entreprise.

6.2 Veuillez préciser en quoi faire un appariement entre la durée (ou l'échéance) des comptes à l'actif et celle des sources de financement implique obligatoirement qu'une garantie particulière y soit attachée.

Réponse :

Les créanciers de l'entreprise ont accès à tous les actifs de la compagnie pour garantir le remboursement de leur prêt. Si on cherche à effectuer un appariement entre un actif et son financement et à déterminer quelles seraient les conditions exigées par les prêteurs pour financer un actif en particulier, il est nécessaire, entre autres, que le créancier puisse avoir accès en exclusivité en cas de défaut à cet actif pour rembourser son capital. La façon d'y arriver est de donner cet actif spécifique en garantie du prêt, ce que les modalités des emprunts de la compagnie ne permettent pas. L'appariement de la durée des flux monétaires du financement d'un actif avec les flux monétaires générés durant la durée de vie de l'actif sera, quant à lui, capté par le budget d'encaisse consolidé.

7. Références : (i) Pièce B-0070, p. 20 et 21;
(ii) Pièce B-0037, p. 6.

Préambule :

Le Distributeur indique que :

(i) « *Aussi, le risque financier est géré sur une base globale comprenant des actifs à court terme comme à long terme. Le service de la dette d'Hydro-Québec ne repose pas sur les flux monétaires spécifiques d'un actif, mais bien sur l'ensemble des flux monétaires générés par ses activités.* »

« *Par ces émissions, un arrimage est effectué entre la durée de vie utile de la grande majorité des actifs de l'entreprise et de l'échéance des divers financements. Ces émissions à long terme sont complétées par des émissions de 3 à 5 ans.* »

« *Les besoins de fonds d'Hydro-Québec à court et à moyen terme sont considérés dans l'élaboration d'un programme de financement optimal.* »

(ii) Le Distributeur présente au Tableau 1 l'évolution des comptes d'écarts et autres actifs.

Demandes :

7.1 Veuillez confirmer ou infirmer que les notions de risque et d'échéance, deux facteurs déterminants pour la fixation d'un taux de rendement, ne disparaissent pas par le fait que les besoins de financement sont agrégés et financés globalement. Veuillez commenter.

Réponse de Concentric :

Concentric confirms that risk is a primary factor in determining a return on debt or equity securities, and the maturity of the instrument will impact the risk. There is, however, no requirement under cost of service ratemaking to attribute specific assets to their individual financing instruments. It would indeed be highly impractical, if not impossible, to trace each asset, for any regulated utility, to its original financing.

7.2 Veuillez confirmer ou infirmer que la notion d'arrimage entre la durée des actifs à financer et l'échéance des sources de financement constitue un principe et une approche qui sont reconnus en finance. Veuillez commenter.

Réponse de Concentric :

Confirmed. Finance recognizes the matching principle for funding assets, but this is not the only consideration in determining the appropriate financing for an asset. Financial managers must consider how to place the debt, i.e. public or private placement, collateral, call features, fixed or floating rate, covenants, etc. It is not a requirement that long term assets are exclusively financed with long term debt, but to do otherwise would expose the firm to refinancing risk subjecting the firm's earnings to short-term interest rate volatility. Similarly, it is generally not advisable to use long-term debt to fund short-term assets, since prevailing market rates may vary significantly from the original long-term interest rate. These general principles are reflected in utility ratemaking concepts, where the invested capital of the utility is deemed to be funded with a mixture of debt and equity for all of the utility assets.

7.3 Veuillez confirmer que le compte de nivellement pour aléas climatiques et le compte de *pass-on*, si la Régie retenait la proposition du Distributeur, seraient les deux seuls CER amortis sur une période de 5 ans. Sinon, veuillez préciser.

Réponse :

Le Distributeur le confirme.

7.4 Veuillez confirmer que, pour tous les comptes du Tableau 1 de la référence (ii) désignés comme « Compte d'écarts », tout solde estimé pour l'année de base est constaté aux charges de l'année témoin. Sinon, veuillez expliquer en détaillant chaque cas.

Réponse :

En vertu des modalités de disposition actuelles, le Distributeur le confirme, à l'exception des comptes suivants :

- **Compte de nivellement pour aléas climatiques : Disposition de l'écart sur une période de cinq ans à compter du deuxième exercice subséquent [1];**
- **Compte d'écarts –Tarif de maintien de la charge : Disposition de l'écart dans les revenus requis de la demande tarifaire du deuxième exercice subséquent [2] ;**
- **Compte d'écarts – Pannes majeures : Disposition de l'écart dans les revenus requis de la demande tarifaire du deuxième exercice subséquent [3] ;**
- **Comptes d'écarts – BEIÉ : Disposition de l'écart dans les revenus requis du dossier déposé à la Régie après la date d'adoption du décret [4] ;**

Le Distributeur rappelle toutefois qu'il propose une mesure ponctuelle afin de disposer des soldes 2013 et 2014 du compte de *pass-on* sur une période de cinq ans à compter de 2016.

8. Références : (i) Pièce B-0070, p. 22;
(ii) Pièce B-0017, p. 9.

Préambule :

(i) « *Le coût moyen pondéré du capital (CMPC) intègre le coût historique de la dette ainsi que le coût des nouveaux financements prévus.* »

---

[1] D-2009-016, page 14
[2] D-2010-022 pages 44-45.
[3] D-2013-037 page 42.
[4] D-2014-037 pages 26-27.

(ii) Le Distributeur présente au tableau 2 l'évolution du coût de la dette, précisant le numérateur – frais financiers, ainsi que le dénominateur – valeur ajustée de la dette et des swaps, servant au calcul du coût moyen de la dette de 6,511 % en 2015.

Demande :

8.1 Veuillez préciser quel pourcentage des frais financiers, servant au calcul du coût moyen de la dette, provient de la valeur ajustée de la dette historique et quel pourcentage provient des nouveaux financements prévus. Veuillez fournir le détail des calculs.

Réponse :

Tel qu'il apparaît au tableau R-8.1, le pourcentage des frais financiers, servant au calcul du coût moyen de la dette, attribuable à la dette historique s'élève à 97 %, alors que le pourcentage relatif aux nouveaux financements prévus est de 3 %.

Tableau R-8.1 :
Numérateur - Frais financiers 2015

	Dette historique	Nouveaux financements prévus	Total
Numérateur - Frais financiers (en M $)	2 663	82	2 745
Pourcentage des frais financiers	97 %	3 %	100 %

Modification des modalités de disposition des soldes 2013 et 2014 du compte de *pass-on*

9. Références : (i) Pièce B-0081, p. 14 et 15;
(ii) Pièce B-0081, p. 80 à 82;
(iii) Pièce B-0070, p. 40.

Préambule :

(i) En réponse à une demande de renseignements de la Régie, le Distributeur présente au tableau R-5.1 la prévision du compte de *pass-on* 2014 sur la base de neuf mois réels et trois mois projetés (9/3), au montant de 309,2 M$ (débiteur).

(ii) En réponse à une demande de renseignements de la Régie, le Distributeur présente au tableau R-35.1 le compte de nivellement pour aléas climatiques pour la période de janvier à septembre 2014, au montant de 128,0 M$(créditeur), incluant des intérêts créditeurs de 4,7 M$.

(iii) En réponse à une demande de renseignements de la Régie, le Distributeur présente au tableau R-11.4, l'impact tarifaire des modalités de disposition du *pass-on* suivantes :

- Proposées par le Distributeur : Amortissement 5 ans dès 2016;
- Alternative : Amortissement 3 ans dès 2016.

Demandes :

9.1 Veuillez commenter la possibilité de verser dans les revenus requis 2015, à titre exceptionnel :

- le solde relié au compte de nivellement pour aléas climatiques au 30 septembre 2014 au montant de -128,0 M$;
- et une partie du solde débiteur relié au compte de *pass-on* 2014 pour un montant de +128,0 M$;

et de verser dans les revenus requis subséquents, le solde restant du compte de *pass-on* 2014 au montant de 181,2 M$ (309,2 M$-128,0M$) + intérêts, amorti dès 2016.

Réponse :

D'emblée, le Distributeur tient à préciser que les intérêts créditeurs de 4,7 M$ présentés au tableau R-35.1 de la pièce HQD-15, document 1.2 ne sont pas inclus dans le solde créditeur de 128,0 M$ du compte de nivellement pour aléas climatiques au 30 septembre 2014.

Le Distributeur ne s'opposerait pas, à titre exceptionnel, à verser dans ses revenus requis de 2015 d'une part, le solde du compte de nivellement pour aléas climatiques au 30 septembre 2014 de 128,0 M$ ainsi que les intérêts y afférents jusqu'au 31 décembre 2014 et, d'autre part, un montant équivalent pour le compte de *pass-on* 2014. Ce faisant, tout écart entre les montants réels constatés en 2014 et les montants versés aux revenus requis de 2015 serait pris en compte dans les exercices subséquents, selon des modalités à déterminer.

9.2 Veuillez présenter sous forme de tableau, selon le même niveau de détail que le tableau R-11.4 (référence (iii)), une comparaison des modalités de disposition proposées par le Distributeur du compte de *pass-on* 2013 (58,8 M$) et du compte de *pass-on* 2014

(309,2 M$ + intérêts) ainsi que les modalités en vigueur pour le compte de nivellement au 30 septembre 2014 (-128,0 M$), avec les alternatives suivantes :

- 58,8 M$ (2013) et le solde restant de 181,2 M$ + intérêts (2014), amortissement 5 ans dès 2016;
- 58,8 M$ (2013) et le solde restant de 181,2 M$ + intérêts (2014), amortissement 3 ans dès 2016.

Veuillez fournir le fichier excel.

Réponse :

Le tableau R-9.2 présente la comparaison des modalités de disposition proposées par le Distributeur des soldes du compte de *pass-on* 2013 et du compte de *pass-on* 2014 au 30 septembre conjuguées aux modalités actuelles du compte de nivellement pour aléas climatiques avec l'alternative décrite à la question 9.1 selon un amortissement de cinq ans ou de trois ans pour le solde restant du compte de *pass-on*.

Tableau R-9.2 :
Impact tarifaire des modalités de disposition des soldes des comptes de *pass-on* (2013 et 2014 au 30 septembre) et de nivellement au 30 septembre 2014 – Comparaison des modalités proposées par le Distributeur avec les modalités selon les alternatives proposées par la Régie (M$)

		Solde prévu au 31/12/2014	Solde prévu au 31/12/2015	Versé aux revenus requis						
				2015	2016	2017	2018	2019	2020	Total
Pass on 2013		54,9								
Pass on au 30 septembre 2014		309,2								
Nivellement 2014[1]		(135,0)								
Modalités proposées par le Distributeur										
Pass on 2013	Amortissement		58,8	-	11,8	11,8	11,8	11,8	11,8	58,8
	Rendement de la base de tarification			-	3,3	2,5	1,7	0,8	-	8,4
Pass on 2014	Amortissement		331,2	-	66,2	66,2	66,2	66,2	66,2	331,2
	Rendement de la base de tarification			-	18,8	14,1	9,4	4,7	-	47,0
Nivellement 2014[2]	Amortissement		(144,6)	-	(28,9)	(28,9)	(28,9)	(28,9)	(28,9)	(144,6)
	Rendement de la base de tarification			-	(8,2)	(6,2)	(4,1)	(2,1)	-	(20,5)
				-	63,0	59,5	56,0	52,6	49,1	280,2
Modalités proposées - amortissement 5 ans										
Pass on 2013	Amortissement		58,8	-	11,8	11,8	11,8	11,8	11,8	58,8
	Rendement de la base de tarification			-	3,3	2,5	1,7	0,8	-	8,4
Pass on 2014	Amortissement	309,2	186,5	135,0	37,3	37,3	37,3	37,3	37,3	321,6
	Rendement de la base de tarification			-	10,6	7,9	5,3	2,6	-	26,5
Nivellement 2014	Amortissement	(135,0)		(135,0)	-	-	-	-	-	(135,0)
				-	63,0	59,5	56,0	52,6	49,1	280,2
Modalités proposées - amortissement 3 ans										
Pass on 2013	Amortissement		58,8	-	19,6	19,6	19,6	-	-	58,8
	Rendement de la base de tarification			-	2,8	1,4	-	-	-	4,2
Pass on 2014	Amortissement	309,2	186,5	135,0	62,2	62,2	62,2	-	-	321,6
	Rendement de la base de tarification			-	8,8	4,4	-	-	-	13,2
Nivellement 2014	Amortissement	(135,0)		(135,0)	-	-	-	-	-	(135,0)
				-	93,4	87,6	81,8	-	-	262,8

[1] Solde de 128 M$ au 30 septembre 2014 auquel s'ajoutent des intérêts de 7 M$ pour l'ensemble de l'année 2014.
[2] Solde de 128 M$ au 30 septembre 2014 auquel s'ajoutent des intérêts de 16,6 M$ pour les années 2014 et 2015.

9.3 Veuillez indiquer le taux utilisé pour le calcul des intérêts inclus dans le compte de nivellement pour aléas climatiques au 30 septembre 2014, au montant de -4,7 M$ (référence (ii)).

Réponse :

Le taux utilisé pour le calcul des intérêts 2014 du compte de nivellement et de tout autre compte d'écarts est de 7,135 %, soit le taux de rendement de la base de tarification reconnu par la Régie pour l'année 2014 en vertu de la décision D-2014-037.

10. Références : (i) B-0070, p. 38;
(ii) B-0094, p. 26;
(iii) B-0085, p. 24 et 25.

Préambule :

(i) « *À titre indicatif et sujet aux modifications de certains paramètres et/ou hypothèses qui pourraient survenir au cours des prochaines années, les hausses tarifaires prévues, selon les modalités proposées de disposition du compte de pass-on, seraient de 3,9 % en 2015, de l'ordre de 3 % pour les années 2016 et 2017 et de l'ordre de 2 % pour les années 2018 à 2020.*

Selon les modalités actuelles de disposition du compte de pass-on, les hausses tarifaires prévues seraient de 7,6 % en 2015, de moins de 0,5 % pour les années 2016 et 2017 et de l'ordre de 2,5 % pour les années 2018 à 2020. » [nous soulignons]

(ii) « *L'écart entre les hausses tarifaires prévues pour la période 2016-2020, avec et sans l'impact des modalités de disposition du compte de pass-on proposées par le Distributeur, s'explique principalement par :*

- *l'impact tarifaire des modalités de disposition du compte de pass-on actuelles versus celles proposées comme présenté au tableau R-11.3 de la question 11.3 de la Régie à la pièce HQD-15, document 1 (B-0070)*;
- *l'impact sur les revenus des ventes avant hausse d'une année donnée en fonction de la hausse tarifaire de l'année précédente.* »

(iii) « *Le Distributeur tient à mentionner que lors de la préparation de son dossier tarifaire, les revenus requis sont établis selon ses meilleures prévisions et selon le cadre réglementaire en vigueur.*

Le Distributeur a proposé l'introduction d'une mesure ponctuelle afin de disposer du solde exceptionnel de 2013 et 2014 du compte de pass-on sur une période de cinq ans à compter de 2016, afin d'atténuer la hausse tarifaire demandée. De plus, comme mentionné en réponse à la question 32.3 de la demande de renseignements n°2 de la Régie à la pièce HQD-15, *document 1.2, le Distributeur ne s'oppose pas au versement, à titre exceptionnel, de l'écart créditeur 2014 relatif au BEIÉ, aux revenus requis de 2015.*

Par ailleurs, le Distributeur souligne que le solde du compte de nivellement pour aléas climatiques au 30 septembre 2014 représente 128 M$ à remettre à la clientèle. Cette information est déposée en réponse à la question 35.1 de la demande de renseignement no 2 de la Régie à la pièce HQD-15, document 1.2.

À l'instar du traitement proposé par la Régie quant au solde du compte d'écarts relatif au BEIÉ, le Distributeur ne s'opposerait pas, à titre exceptionnel, à verser en tout ou en partie dans ses revenus requis de 2015, le solde de ce compte qui pourrait aussi contribuer à la réduction de la hausse tarifaire, et ce dans la mesure où la Régie le jugerait approprié. » [nous soulignons]

Demandes :

10.1 Quel niveau de confiance accordez-vous à vos prévisions des hausses tarifaires pour les années 2016-2020, en particulier celle de 2016, dans l'un et l'autre des deux scénarios présentés à la référence (i)? Veuillez élaborer.

Réponse :

Le Distributeur s'assure d'établir ses prévisions de hausses tarifaires au meilleur de sa connaissance et sur la base de l'information disponible au moment de la préparation du dossier tarifaire. Plus précisément, dans ses prévisions de hausses tarifaires 2016 à 2020 au présent dossier, le Distributeur a tenu compte des revenus et des coûts reconnus et anticipés, établis en fonction des principaux paramètres et hypothèses suivants :

- **Prévision de la demande établie par catégories de consommateurs ;**
- **Coûts d'approvisionnement en lien avec la prévision des besoins ;**
- **Enveloppe de charges d'exploitation liées aux activités de base établie selon la formule paramétrique ayant comme point de départ les charges de l'année témoin 2015 ;**
- **Mise à jour des charges d'exploitation liées aux activités de base avec facteurs d'indexation particuliers et éléments spécifiques ;**
- **Charge de service de transport selon les prévisions à long terme du Transporteur ;**
- **Plan d'investissement à long terme incluant la prévision des mises en service et des amortissements ainsi que le rendement sur la base de tarification ;**

- **Disposition des comptes d'écarts antérieurs à 2015 selon les modalités de disposition reconnues ou proposées. Aucun nouvel écart n'a été considéré pour les années 2015 et suivantes.**

Par ailleurs, le Distributeur tient à rappeler que ses prévisions de hausses tarifaires sont sujettes aux modifications de ces paramètres et/ou hypothèses qui pourraient survenir au cours des prochaines années et que, comme pour toute autre prévision, l'incertitude quant aux hausses soumises croît avec l'horizon de prévision.

10.2 Veuillez indiquer quels sont les paramètres et hypothèses qui pourraient survenir au cours des prochaines années et qui ont été pris en compte dans les prévisions des hausses tarifaires 2016-2020 établies selon les modalités proposées de disposition du compte de *pass-on*.

Réponse :

Voir la réponse à la question 10.1.

10.3 Veuillez indiquer si tous les coûts connus et anticipés à ce jour (par exemple : approvisionnement) ont été considérés dans les prévisions des hausses tarifaires 2016-2020. Si non, veuillez expliquer et estimer.

Réponse :

Voir la réponse à la question 10.1.

10.4 Veuillez mettre à jour les hausses tarifaires 2015-2020 établies selon les modalités proposées de disposition du compte de *pass-on* (référence (i)), en considérant la possibilité de verser dans les revenus requis 2015, à titre exceptionnel, les soldes créditeurs des charges reliées au BEIÉ de l'année de base 2014 (-20,1 M$) et du compte de nivellement pour aléas climatiques au 30 septembre 2014 (-128,0 M$) (référence (iii)).

Réponse :

Considérant la possibilité de verser à titre exceptionnel dans les revenus requis de 2015, les soldes créditeurs de l'année de base 2014 des comptes d'écarts du BEIÉ et du nivellement pour aléas climatiques, estimés respectivement à 20,1 M$ et 128 M$, ainsi que les intérêts y afférents, les hausses tarifaires prévues seraient de 2,4 % en 2015 et de l'ordre de 4 % en 2016, 3,5 % en 2017 et 2 % pour les années 2018 à 2020.

PROJET LECTURE À DISTANCE (LAD)

11. Références : (i) Pièce B-0070, p. 10, tableau R-3.3-C;
(ii) Dossier R-3770-2011, pièce B-0016, p. 30, tableau R-10.3;
(iii) Dossier R-3863-2013, pièce B-0012, p.10, tableau 6;
(iv) Pièce B-0081, p. 13, tableau R-4.1;
(v) Pièce B-0035. p. 22, tableau A-4.

Préambule :

(i) En réponse à une demande de renseignements, le Distributeur présente au tableau R-3.3-C, l'amortissement accéléré au montant cumulatif de 10,1 M$ sur la période 2012-2016.

Tableau R-3.3-C :
Amortissement et radiation (M$)
et nombre d'appareils retirés du projet LAD - 2010-2016

	Année historique 2012	Année historique 2013	Année de base 2014	Année témoin 2015	Année 2016
Amortissement des appareils en service	21,2	21,4	20,6	19,9	18,6
Amortissement accéléré	2,6	11,1	3,5	3,7	(10,8)
Charges de radiation des appareils en service [1]	0,2	20,1	38,5	22,7	4,7
Total avant Compte d'écarts - Projets majeurs	**24,0**	**52,6**	**62,6**	**46,3**	**12,5**
Compte d'écarts - Projets majeurs			*(19,0)*	19,0	
Total après Compte d'écarts - Projets majeurs	**24,0**	**52,6**	**43,6**	**65,3**	**12,5**
Nombre d'appareils retirés (en milliers) [2]	2	1 021	1 471	1 000	355

[1] Les retraits pour l'année 2012 correspondent à une partie des compteurs des projets pilotes qui ont été retirés seulement au début de l'année 2012.

[2] Le nombre d'appareils retirés inclut les compteurs récupérés pour utilisation ultérieure dans les zones non déployées.

(ii) Dans le dossier R-3770-2011 relatif au projet d'investissement LAD, le Distributeur présente au tableau R-10.3, l'amortissement accéléré (ou amortissement additionnel) au montant cumulatif de -34,9 M$ sur la période 2012-2017.

Tableau R-10.3 : Amortissement, radiation et nombre d'appareils radiés

M$	2012	2013	2014	2015	2016	2017	TOTAL
Amortissement des appareils en service	19,5	18,9	18,5	18,3	17,4	16,7	109,3
Amortissement additionnel	7,4	3,6	-5,3	-12,8	-13,6	-14,2	-34,9
Charges de radiation des appareils en service	9,9	38,7	27,8	10,7	0,0	-1,4	85,7
	36,8	61,2	41,0	16,2	3,8	1,1	160,1
Nombre d'appareils radiés	330 391	1 339 931	1 097 369	647 488	207 233	202 818	3 825 231

(iii) Dans le dossier R-3863-2013 relatif au projet d'investissement LAD phases 2 et 3, le Distributeur présente au tableau 6, l'amortissement accéléré au montant cumulatif de -21,3 M$ sur la période 2012-2018.

TABLEAU 6 : AMORTISSEMENT, RADIATION ET NOMBRE D'APPAREILS RETIRÉS DU PROJET LAD 2012-2018

	2012	2013	2014	2015	2016	2017	2018	Total
Amortissement des appareils en service (en M$)	21,2	21,8	21,3	20,7	19,4	18,6	8,5	131,6
Amortissement accéléré (en M$)	2,6	11,1	4,5	(6,3)	(12,0)	(14,2)	(6,9)	(21,3)
Charges de radiation des appareils en service (en M$)[1]	0,2	20,1	36,6	20,4	3,3	0,6	(0,4)	80,8
Total	23,9	52,9	62,5	34,8	10,7	5,1	1,3	191,1
Nombre d'appareils retirés (en milliers) [2]	2	1 022	1 190	1 002	275	204	83	3 778

(iv)« *La dépense d'amortissement accéléré des anciens compteurs de 3,7 M$ de l'année témoin 2015 résulte de l'effet combiné d'un changement de la période d'amortissement des compteurs et d'une baisse de l'amortissement suite à un plus grand nombre de compteurs qui seront radiés en 2015. Lorsque comparée à un scénario de fin de projet en 2018, l'accélération du déploiement avec une fin de projet en 2016 entraîne donc une augmentation de 12,8 M$ de la dépense d'amortissement accéléré pour l'année 2015. Le tableau R-4.1 présente l'impact de l'accélération du déploiement sur la charge d'amortissement accéléré.* »

Tableau R-4.1 :
Impact en 2015 sur l'amortissement accéléré (M$)

		2015
	Année témoin - Fin de projet en 2016	3,7
Moins:	Scénario - Fin de projet en 2018	-9,1
Impact - Révision durée d'utilité		**12,8**

(v) Le Distributeur présente au tableau A-4, l'impact sur les revenus requis du projet LAD sur la période 2012-2015, dont les écarts entre les données des dossiers R-3905-

2014 et R-3770-2011 de la rubrique « Amortissement accéléré des anciens compteurs » :

Écart annuel 2015 : 16,5 M$;

Écart cumulatif 2015 : 27,9 M$.

Demandes :

11.1 Veuillez compléter le tableau R-3.3-C jusqu'à la fin du projet (référence (i)).

Réponse :

Le tableau R-11.1 compare la charge d'amortissement et de radiation des appareils en service du présent dossier avec celle prévue au dossier R-3770-2011.

Tableau R-11.1 : Comparaison amortissement et radiation (M$) et nombre d'appareils retirés du projet LAD 2012-2017

R-3905-2014

	Année historique 2012	Année historique 2013	Année de base 2014	Année témoin 2015	Année 2016	Année 2017	Total
Amortissement des appareils en service	21,2	21,4	20,6	19,9	18,6	16,9	118,6
Amortissement accéléré	2,6	11,1	3,5	3,7	(10,8)	(16,9)	(6,8)
Charges de radiation des appareils en service [1]	0,2	20,1	38,5	22,7	4,7	-	86,2
Total	**24,0**	**52,6**	**62,6**	**46,3**	**12,5**	**-**	**198,0**
Nombre d'appareils retirés (en milliers) [2]	2	1 021	1 471	1 000	355		3 849

[1] Les retraits pour l'année 2012 correspondent à une partie des compteurs des projets pilotes qui ont été retirés seulement au début de l'année 2012.

[2] Le nombre d'appareils retirés inclut les compteurs récupérés pour utilisation ultérieure dans les zones non déployées.

R-3770-2011

	2012	2013	2014	2015	2016	2017	Total
Amortissement des appareils en service	19,5	18,9	18,5	18,3	17,4	16,7	109,3
Amortissement accéléré	7,4	3,6	(5,3)	(12,8)	(13,6)	(14,2)	(34,9)
Charges de radiation des appareils en service	9,9	38,7	27,8	10,7	-	(1,4)	85,7
Total	**36,8**	**61,2**	**41,0**	**16,2**	**3,8**	**1,1**	**160,1**
Nombre d'appareils retirés (en milliers)	330	1 340	1 097	647	207	203	3 825

Écart R-3905-2014 vs R-3770-2011

	2012	2013	2014	2015	2016	2017	Total
Amortissement des appareils en service	1,7	2,5	2,1	1,6	1,2	0,2	9,3
Amortissement accéléré	(4,8)	7,5	8,8	16,5	2,8	(2,7)	28,1
Charges de radiation des appareils en service	(9,7)	(18,6)	10,7	12,0	4,7	1,4	0,5
Total	**(12,8)**	**(8,6)**	**21,6**	**30,1**	**8,7**	**(1,1)**	**37,9**
Nombre d'appareils retirés (en milliers)	(329)	(319)	374	352	148	(203)	24

La prévision de la charge d'amortissement et de radiation des appareils en service sur la période 2012-2017 augmente de 37,9 M$ par rapport à celle du dossier R-3770-2011 et s'explique par les investissements en compteurs de première génération de 2012 à 2014 qui se sont avérés nécessaires compte tenu du report du début du déploiement massif. Ces compteurs devront être amortis ou radiés d'ici la fin du projet en 2016.

Le Distributeur précise que tout ajustement au scénario de déploiement a un impact simultané sur la charge d'amortissement des appareils en service, sur l'amortissement accéléré et sur la charge de radiation des appareils en service. À titre d'exemple, une mise à jour du calendrier de déploiement a un impact sur la prévision des radiations de compteurs et sur l'amortissement évité suite à ces radiations. Il est donc plus approprié d'analyser globalement la dépense d'amortissement des appareils en service.

11.2 Veuillez concilier le montant de -9,1 M$ relié à l'amortissement accéléré pour la fin du projet en 2018 présenté à la référence (iv) et les montants de fin de projet présentés aux références (i), (ii) et (iii). Veuillez expliquer.

Réponse :

La réduction de l'amortissement de 9,1 M$ correspond à l'effet net, pour l'année 2015, de l'amortissement évité suite à la radiation des appareils en service et du changement de la période d'amortissement des compteurs, en fonction du scénario de déploiement avec une fin de projet en 2018 et déposé lors du dossier tarifaire 2014-2015 (R-3854-2013).

Le Distributeur tient à préciser que chacune des références (i), (ii) et (iii) correspond au scénario de déploiement en vigueur à une date donnée et que ce scénario évolue dans le temps en fonction de divers facteurs dont, entre autres, le rythme d'installation des compteurs et le niveau d'investissement nécessaire en compteurs de première génération. Ainsi, l'évolution des scénarios de déploiement explique l'écart en amortissement accéléré entre les différentes références.

11.3 Veuillez fournir le calcul de l'impact de 12,8 M$ de la dépense d'amortissement accéléré pour l'année 2015 découlant de la révision de la durée d'utilité des équipements de mesurage (projet LAD).

Réponse :

Le tableau R-11.3 présente le calcul de l'impact de la dépense d'amortissement accéléré pour l'année 2015 découlant de la révision de la durée d'utilité des équipements de mesurage en lien avec le projet LAD.

Tableau R-11.3 :
Impact de la dépense d'amortissement accéléré (M$)

	Année 2015		
	R-3905-2014	R-3854-2013	Écart
Révision de la période d'amortissement	36,0	11,4	24,6
Amortissement évité suite à la radiation des appareils en service	-32,3	-20,5	-11,8
Impact - Amortissement accéléré	**3,7**	**-9,1**	**12,8**

11.4 Veuillez expliquer les écarts entre les données des dossiers R-3905-2014 et R-3770-2011 de la rubrique « Amortissement accéléré des anciens compteurs » :

- Écart annuel 2015 : 16,5 M$;
- Écart cumulatif 2015 : 27,9 M$.

Réponse :

Tel qu'il est expliqué en réponse à la question 11.1, la dépense d'amortissement des appareils en service doit être analysée dans sa globalité. Ainsi, comme présenté au tableau R-11.1, l'augmentation annuelle et cumulative de la dépense d'amortissement de l'année 2015 s'explique principalement par les investissements en compteurs de première génération pour les années 2012 à 2014 qui doivent être amortis ou radiés d'ici la fin du projet en 2016.

De plus, le Distributeur souligne qu'au présent dossier, l'échéancier de la fin du projet est devancé d'une année seulement comparativement à la demande d'autorisation de la phase 1 du projet au dossier R-3770-2011 et que la dépense globale d'amortissement prévue en 2017 au dossier R-3770-2011 était de 1,1 M$.

COÛTS ÉVITÉS

Coûts évités de puissance dans les réseaux autonomes (RA)

12. Référence : Pièce B-0081, p. 29.

Préambule :

« De plus, compte tenu du critère de fiabilité, la puissance installée est toujours plus élevée que la puissance maximale appelée. L'utilisation de la puissance installée comme dénominateur dans le calcul des facteurs d'utilisation engendrerait une réduction de ces derniers et, par conséquent, une surestimation des coûts évités en puissance (exprimés en ¢/kWh) et, de ce fait, des coûts évités totaux. »

Demande :

12.1 Veuillez fournir pour chacun des réseaux autonomes le ratio entre la puissance installée et la puissance maximale appelée.

Réponse :

Les ratios entre la puissance installée et la puissance maximale appelée sont présentés dans le tableau R-12.1.

Tableau R-12.1
Ratios entre la puissance installée et la puissance maximale appelée

	2013 - 2014	2014 - 2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
Îles-de-la-Madeleine										
Cap-aux-Meules	1,6	1,6	1,6	1,6	1,6	1,6	1,5	1,5	1,5	1,5
L'Île-d'Entrée	4,2	4,2	4,1	4,1	4,1	4,1	4,0	4,0	4,0	4,0
Nunavik										
Akulivik	1,4	1,3	2,8	2,8	2,7	2,6	2,5	2,5	2,4	2,3
Aupaluk	2,3	2,1	2,1	2,0	1,9	1,9	1,8	1,7	1,7	1,6
Inukjuak	2,2	2,1	2,1	2,0	1,9	1,9	1,8	1,8	1,7	1,7
Ivujivik	2,1	2,1	2,1	2,0	1,9	1,9	1,8	1,8	1,7	1,7
Kangiqsualujjuaq	2,4	2,2	2,2	2,1	2,1	2,0	2,0	1,9	1,9	1,9
Kangiqsujuaq	1,8	1,8	1,7	1,7	1,6	1,6	1,5	1,5	1,5	1,4
Kangirsuk	2,2	2,1	2,0	2,0	2,0	1,9	1,9	1,8	1,8	1,8
Kuujjuaq	1,7	1,7	1,7	1,6	1,6	1,5	1,5	1,4	1,4	1,4
Kuujjuarapik	1,7	1,6	1,6	1,6	1,5	1,5	1,5	1,4	1,4	1,4
Puvirnituq	2,2	2,1	2,0	1,9	1,8	1,8	1,7	1,6	1,6	1,6
Quaqtaq	2,2	2,1	2,1	2,0	1,9	1,9	1,8	1,8	1,7	1,7
Salluit	2,0	1,9	1,9	1,8	1,8	1,7	1,7	1,6	1,6	1,6
Tasiujaq	1,9	1,7	1,7	1,6	1,6	1,6	1,5	1,5	1,5	1,5
Umiujaq	1,8	1,8	1,7	1,7	1,7	1,6	1,6	1,6	1,5	1,5
Basse Côte-Nord										
Lac Robertson	1,9	1,9	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8
La Romaine	1,6	1,6	1,6	1,6	1,6	1,5	1,5	1,5	1,5	1,5
Port-Menier	2,6	2,6	2,6	2,6	2,6	2,5	2,5	2,5	2,5	2,5
Schefferville										
Schefferville	1,6	1,6	1,5	1,5	1,4	1,4	1,4	1,3	1,3	1,3
Haute-Mauricie										
Opitciwan	1,6	1,6	1,6	1,5	1,5	1,5	1,5	1,4	1,4	1,4
Clova	2,5	2,5	2,5	2,5	2,5	2,5	2,5	2,4	2,4	2,4

Production décentralisée en RA

13. Références : (i) Pièce B-0081, p, 30;
(ii) D-2011-162, p, 98;
(iii) Dossier R-3864-2013, Pièce B-0009, p, 21.

Préambule :

(i) « *Tous les réseaux au Nunavik ont des installations de production ou de conservation de la glace dans les arénas ou les deux. Aupaluk, Salluit et Kuujjuarapik possèdent leur propre génératrice afin d'alimenter ces systèmes.*

[…]

Jusqu'à présent, ces installations n'ont pas été utilisées comme source de puissance interruptible. Le Distributeur évalue néanmoins, avant de procéder à un ajout de capacité, notamment dans les villages présentant un déficit de puissance à court terme, les différents moyens visant à réduire l'appel en puissance. »

(ii) « *[357] La Régie est d'avis que le Distributeur doit poursuivre ses efforts en vue de favoriser l'implication des communautés dans des projets locaux, y compris ceux de production d'électricité et de récupération de chaleur.* »

(iii) « *Dans le passé, les analyses de projet de chauffage urbain à Kuujjuag et à Kangiqsualujjuaq ont démontrées que l'application de cette technologie n'était pas rentable dans les réseaux autonomes. Plus récemment, les résultats de l'évaluation visant l'alimentation de l'école d'Akulivik ont aussi fait la démonstration que le coût de ce type d'énergie alternative est trop élevé dans les réseaux autonomes. Le Distributeur n'entend donc pas procéder à de nouvelles études de projets de récupération de chaleur dans les réseaux autonomes.* »

Demandes :

13.1 Veuillez élaborer sur la possibilité et les coûts d'intégrer les génératrices existantes dans le plan d'équipement uniquement dans le but de respecter le critère de puissance garantie dans les réseaux mentionnés en référence (i).

Réponse :

Le Distributeur n'écarte aucune option, incluant l'utilisation des génératrices aux fins de la puissance garantie, en autant qu'elle soit techniquement réalisable, économiquement rentable, acceptable d'un point de vue environnemental et accueillie favorablement par les communautés. Le Distributeur considère aussi d'autres moyens pour équilibrer son bilan, notamment la gestion de la demande en puissance et les options d'électricité interruptible disponibles en réseaux autonomes.

13.2 Veuillez élaborer sur la possibilité d'utiliser des installations décentralisées de production d'électricité là où il y aurait aussi des besoins de chaleur, plutôt que d'amener la chaleur des centrales du Distributeur vers les besoins d'utilisateurs comme des arénas, des piscines, des bâtisses institutionnelles, industrielles ou commerciales.

Réponse :

Le Distributeur précise qu'afin de récupérer la chaleur d'unités de production décentralisée d'électricité, les bâtiments à chauffer doivent être adaptés à cette fin. De plus, la chaleur excédentaire de la production d'électricité doit être suffisamment abondante.

1 **Voir également la réponse à la question 13.1.**

CHARGES D'EXPLOITATION

14. Références : (i) Pièce B-0023, p. 10 à 12;
(ii) Pièce B-0118, p. 3 et 4.

Préambule :

(i) Le Distributeur établit sa prévision du coût de retraite, à titre d'activité de base avec facteurs d'indexation particuliers, à 102,5 M$ pour l'année témoin 2015 et explique l'évolution du coût de retraite sur la période 2013 à 2015.

Il indique également :
« *Conformément à la décision D-2014-037 de la Régie, le Distributeur confirme qu'il poursuit ses efforts afin de contrôler les coûts associés aux régimes de retraite. Selon l'évaluation actuarielle de capitalisation la plus récente, soit celle du 31 décembre 2013, le surplus de capitalisation est de 2 451 M$ dégageant un ratio de capitalisation de 115,1 %. L'actif détenu par la Caisse de retraite est suffisant pour couvrir les rentes futures.* » [nous soulignons]

(ii) Dans un complément de réponse à la demande de renseignement n° 1 de la FCEI, le Distributeur indique que :
« *Conformément aux dispositions de la législation en vigueur, Hydro-Québec doit prévoir une cotisation afin d'amortir le déficit actuariel du régime relatif aux services passés. Cette cotisation est égale au maximum entre la cotisation d'amortissement du déficit actuariel de capitalisation (lequel peut être amorti sur une période de 15 ans) et la cotisation d'amortissement du déficit actuariel de solvabilité (lequel peut actuellement être amorti sur une période de 10 ans).*

En vertu de la dernière évaluation actuarielle de ces déficits, soit en date du 31 décembre 2013, le régime ne montre pas de déficit sur base de capitalisation et montre un déficit sur base de solvabilité de 579 M$ (soit un ratio de solvabilité de 97,0 %). La cotisation d'amortissement du déficit actuariel du régime pour Hydro-Québec est donc évaluée à 69 M$ pour l'année 2014 (soit le montant requis afin d'amortir le déficit de solvabilité de 579 M$ sur une période de 10 ans). » [nous soulignons]

Demandes :

14.1 Considérant le surplus de capitalisation, veuillez indiquer si Hydro-Québec envisage un congé de cotisations. Veuillez élaborer.

Réponse :

En vertu de l'article 146.3.4 de la *Loi sur les Régimes complémentaires de retraite* (Loi RCR), pour qu'Hydro-Québec ait droit à un congé partiel ou total de cotisation, il faut que le régime soit en situation de surplus suffisant sur base de capitalisation et de solvabilité et qu'il ait constitué une provision pour écarts défavorables telle que définie à la Section VI.1 du *Règlement sur les régimes complémentaires de retraite.*

En date du 31 décembre 2013, le régime est pleinement capitalisé, affichant un taux de capitalisation de 115 %, mais présente un ratio de solvabilité de 97 %. Dans ces conditions, la loi RCR ne permet aucun congé.

14.2 Veuillez expliquer la différence entre :

- le surplus de capitalisation de 2 451 M$, un ratio de capitalisation de 115,1 %;
- le déficit actuariel de solvabilité de 579 M$, soit un ratio de solvabilité de 97,0 %.

Réponse :

L'évaluation actuarielle sur base de capitalisation sert au provisionnement du régime et repose sur l'hypothèse de continuité de ce régime. Le surplus de capitalisation indique que le régime est adéquatement capitalisé et que l'actif détenu par la caisse de retraite est suffisant pour couvrir le coût des rentes futures.

L'évaluation de solvabilité est un indicateur prescrit par la Loi RCR. Elle repose sur l'hypothèse théorique de terminaison du régime. Ainsi cette évaluation est établie à partir d'un ensemble de méthodes et d'hypothèses prescrites par la Loi RCR, méthodes et hypothèses qui diffèrent de celles utilisées dans l'évaluation de capitalisation.

Le déficit de solvabilité indique que, dans l'hypothèse de terminaison du régime au 31 décembre 2013, les actifs du régime seraient légèrement inférieurs aux obligations payables.

15. Références : (i) Pièce B-0023, p. 14, tableau 5;
(ii) Pièce B-0023, p. 15, tableau 6.

Préambule :

(i) Le Distributeur présente au tableau 5, le détail de la dépense de mauvaises créances (DMC) sur la période 2013 À 2015.

Tableau 5 :
Dépense de mauvaises créances (M$)

	Année historique 2013	D-2014-037	Année de base 2014	Année témoin 2015
Activités de base avec facteurs d'indexation particuliers	**92,9**	**89,8**	**99,0**	**105,2**
Stratégie pour la clientèle à faible revenu (radiations)	14,6	14,6	19,4	22,7
Dépense de mauvaises créances	78,3	75,2	79,6	82,5
Clientèle régulière (résidentielle, commerciale et affaires)	76,1	73,0	80,6	80,2
Autres	2,2	2,2	(1,0)	2,3
Total de la dépense de mauvaises créances	**92,9**	**89,8**	**99,0**	**105,2**

(ii) Le Distributeur présente au tableau 6, la DMC et le taux de DMC sur la période 2009 à 2015.

Tableau 6 :
DMC et taux de la DMC sur les ventes 2009-2015

	Année historique					D-2014-037	Année de base	Année témoin
	2009	2010	2011	2012	2013		2014	2015
En (M$)								
Ventes clientèle résidentielle	4 484	4 287	4508	4451	4825	4 945	5 205	5 226
Ventes clientèle commerciale et affaires	3 203	3 184	3220	3208	3328	3 440	3 456	3 615
Ventes	**7 687**	**7 471**	**7728**	**7659**	**8153**	**8 385**	**8 661**	**8 841**
Dépense de mauvaises créances résidentielle	58,8	111,7	71,7	73,5	84,1	78,9	93,1	95,7
Dépense de mauvaises créances commerciale et affaire	10,4	7,8	11,9	8,2	6,6	8,7	6,9	7,2
Dépense de mauvaises créances	**69,2**	**119,5**	**83,6**	**81,7**	**90,7**	**87,6**	**100,0**	**102,9**
Taux de la dépense de mauvaises créances résidentielle (%)	1,3%	2,6%	1,6%	1,7%	1,7%	1,6%	1,8%	1,8%
Taux de la dépense de mauvaises créances commerciale et affaires (%)	0,3%	0,2%	0,4%	0,3%	0,2%	0,3%	0,2%	0,2%
Taux de la dépense de mauvaises créances (%)	**0,90%**	**1,60%**	**1,08%**	**1,07%**	**1,11%**	**1,04%**	**1,15%**	**1,16%**

Demande :

15.1 Veuillez compléter le tableau 5 en indiquant les données des années historiques 2009 à 2012. Veuillez expliquer les tendances constatées depuis 2009.

Réponse :

Le tableau R-15.1 présente l'évolution des composantes de la dépense de mauvaises créances (DMC) de 2009 à 2015.

Tableau R-15.1 :
Dépense de mauvaises créances 2009 – 2015 (M$)

	Année historique 2009	Année historique 2010	Année historique 2011	Année historique 2012	Année historique 2013	D-2014-037	Année de base 2014	Année témoin 2015
Activités de base avec facteurs d'indexation particuliers	**71,8**	**137,8**	**91,1**	**86,6**	**92,9**	**89,8**	**99,0**	**105,2**
Stratégie pour la clientèle à faible revenu (radiations)	1,1	3,7	2,7	8,8	14,6	14,6	19,4	22,7
Dépense de mauvaises créances	70,7	134,1	88,4	77,8	78,3	75,2	79,6	82,5
Clientèle régulière (résidentielle, commerciale et affaires)	68,1	115,8	80,9	72,9	76,1	73,0	80,6	80,2
Autres	2,6	18,3	7,5	4,9	2,2	2,2	(1,0)	2,3
Total de la dépense de mauvaises créances	**71,8**	**137,8**	**91,1**	**86,6**	**92,9**	**89,8**	**99,0**	**105,2**

Comme mentionné à la pièce HQD-7, document 4 (B-0028) du dossier R-3776-2011, la DMC de l'année 2010 est exceptionnellement élevée par rapport aux montants des autres années. En effet, celle-ci inclut un montant de 38 M$ de provision spéciale pour couvrir le risque associé aux comptes à recevoir des clients résidentiels auquel s'ajoutent 15 M$ de mauvaises créances relatives à des clients de grande puissance. Le contexte économique difficile de 2008 et 2009 a créé une pression à la hausse sur la DMC. Le Distributeur rappelle que celle-ci varie principalement en fonction des ventes, mais que certains facteurs, hors du contrôle du Distributeur, tels que le contexte économique, peuvent créer une pression à la hausse sur cette dépense.

Comme l'indique le tableau 6 de la référence (ii), le taux de DMC est relativement stable depuis 2011, soit à environ 1,1 % des ventes. L'augmentation de la DMC s'explique donc par la hausse des ventes au fil des années.

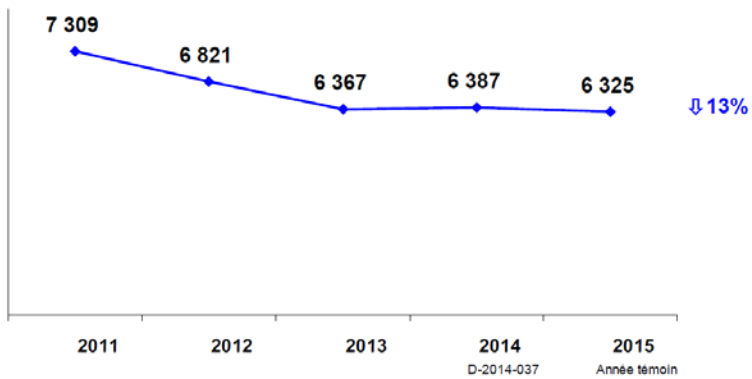
MASSE SALARIALE ET EFFECTIFS

16. Référence : Pièce B-0005, p. 8, figure 2.

Préambule :

Le Distributeur présente à la figure 2, l'évolution de l'effectif (équivalent temps complet) pour la période 2011 à 2015.

Figure 2 :
Évolution de l'effectif (équivalent temps complet)



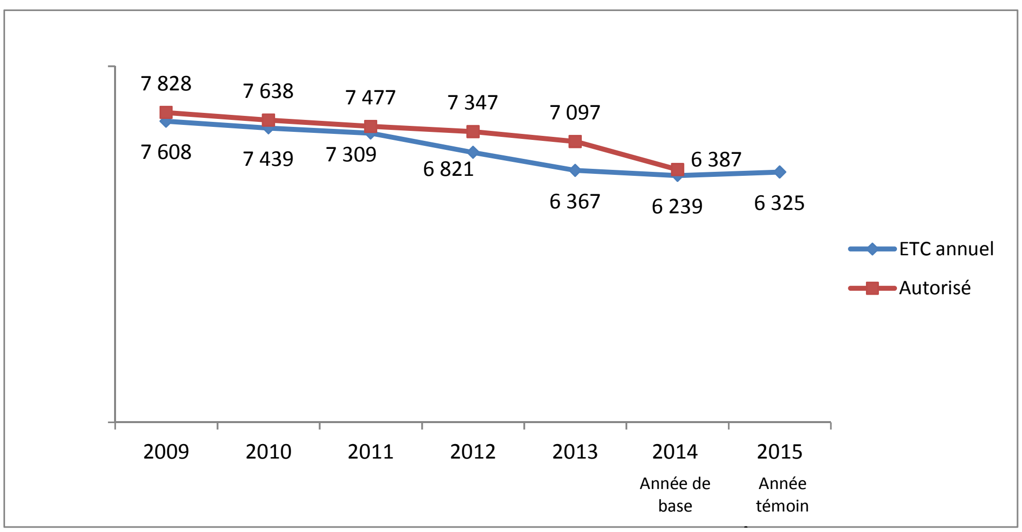
Demande :

16.1 Veuillez compléter la figure 2 en indiquant les données réelles 2009, 2010 et de l'année de base 2014. Veuillez fournir également à la figure 2 une comparaison avec les données autorisées 2009-2014.

Réponse :

La figure R-16.1 présente l'évolution de l'effectif (équivalent temps complet) de 2009 à 2014, année de base, ainsi que la comparaison avec les données autorisées 2009-2014.

Figure R-16.1 :
Évolution de l'effectif (équivalent temps complet)



17. Références : (i) Pièce B-0024, p. 8;

(ii) Dossier R-3854-2013, phase 1, pièce B-0162, p. 2 à 4.

Préambule :

(i) Le tableau suivant présente l'évolution des écarts d'ETC entre les données réelles et celles autorisées et ajustées pour les années 2010-2014.

Rapport annuel		Écart entre les données réelles et celles autorisées et ajustées	
2010	Éléments spécifiques Amélioration de la performance Total	-47 ETC -152 ETC -199 ETC	-5,5 M$ -10,0 M$ -15,5 M$
2011	Éléments spécifiques Amélioration de la performance Total	-17 ETC -151 ETC -168 ETC	-0,9 M$ -14,4 M$ -15,3 M$
2012	Éléments spécifiques Amélioration de la performance Total	-12 ETC -454 ETC -466 ETC	-1,6 M$ -40,3 M$ -41,9 M$
2013	Éléments spécifiques Activités de base FIP Amélioration de la performance Total	77 ETC -20 ETC -787 ETC -730 ETC	6,9 M$ -2,2 M$ -61,1 M$ -56,4 M$
Année de base 2014	Éléments spécifiques Activités de base FIP Amélioration de la performance Total	203 ETC -1 ETC -350 ETC -148 ETC	13,7 M$ -0,1 M$ -28,0 M$ -14,4 M$

Sources : Pièce B-0024, p. 8, tableau 3; Rapport annuel 2013, pièce HQD-10, document 1, p. 4; Dossier R-3854-2013, phase 1, pièce B-0088, p. 43, tableau R-20.1.

La Régie note une sous-évaluation systématique des ETC reliés à l'amélioration de la performance nette de croissance.

(ii) Dans le dossier tarifaire précédent, le Distributeur indique que :

« *En termes de ressources humaines, c'est avec 958 ETC de moins en 2014 par rapport à la fin de l'année 2011 que le Distributeur doit effectuer une prestation de service de qualité au moins équivalente à celle à laquelle les clients sont habitués, soit 13 % d'ETC de moins (NS, vol. 4, p. 15).*

[…]
Le Distributeur considère que des <u>coupures additionnelles seraient imprudentes</u> compte tenu de la réalité à laquelle il doit faire face en termes de stabilisation de l'organisation et des processus (NS, vol.4, pages 14 à 17).

Des efforts additionnels de 1 % d'efficience, c'est environ 150 ETC. <u>Or, le Distributeur a déjà substantiellement réduit ses ETC et 2014 est une année de stabilisation.</u>

Anticiper 1 % de plus sans actions précises <u>serait imprudent, cela mettrait à risque la qualité du service.</u> Au même effet, une réduction de 25 M$ de la masse salariale serait hasardeuse étant donné son impact sur les effectifs et sur la nécessité de maintenir la qualité du service.

Il y a maintenant une nécessité pour le Distributeur de consolider son organisation, de contrôler ses processus de travail et de permettre aux effectifs qui demeurent de s'approprier les nouvelles façons de faire. <u>Toute coupure supplémentaire dans le coût de service serait imprudente</u>. »
[nous soulignons]

Demandes :

17.1 La Régie note une sous-évaluation systématique des ETC reliés à l'amélioration de la performance nette de croissance. Veuillez indiquer pourquoi l'établissement des prévisions de la performance organisationnelle ne tient pas compte de l'historique des départs à la retraite et des pistes d'efficience. Veuillez indiquer comment le Distributeur peut améliorer l'établissement de ses prévisions.

Réponse :

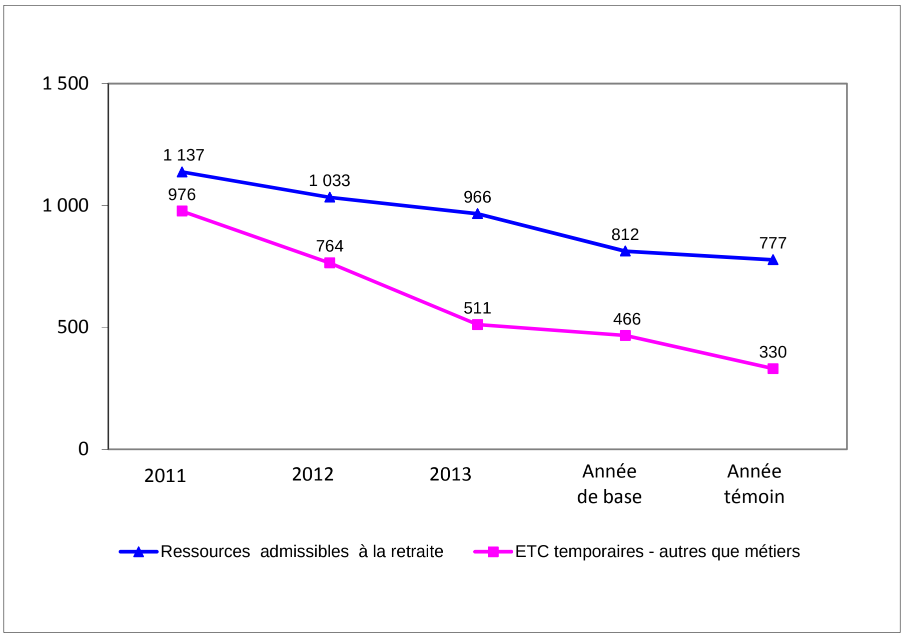
La mise en place de certaines pistes d'efficience organisationnelle affectant le niveau des effectifs est un processus dont le rythme de déploiement dépend de facteurs n'étant pas entièrement sous le contrôle du Distributeur. De même, la prise en compte des pistes d'efficience dans l'élaboration de ses prévisions se fait de façon prudente, afin de s'assurer, d'une part, que l'efficience identifiée est récurrente et, d'autre part, que son implantation se fait dans le respect des conventions collectives et en fonction des enjeux organisationnels. Ainsi, la prévision des départs à la retraite présentée au dossier tarifaire est la meilleure que le Distributeur puisse faire au moment de l'élaboration de celui-ci.

De plus, le Distributeur souligne qu'une part importante des écarts constatés au cours des dernières années entre les ETC reconnus et réels découlait, d'une part, du fait qu'il a saisi les opportunités que lui ont offertes les départs à la retraite qui ont été plus importantes qu'anticipées et, d'autre part, de la réduction de ses effectifs temporaires autres que métiers. En effet, le Distributeur a constaté que les changements structurants apportés aux

façons de faire ont pu contribuer à l'augmentation du nombre de départs à la retraite de même qu'à des départs à la retraite plus rapides qu'anticipés.

La figure R-17.1 présente l'évolution des effectifs éligibles à la retraite ainsi que les ETC temporaires autres que métiers sur la période 2011-2015.

Figure R-17.1 :
Évolution des effectifs éligibles à la retraite
et des ETC temporaires autres que métiers
2011-2015



Le Distributeur est d'avis que les opportunités offertes par les départs à la retraite et les emplois temporaires qui ont permis de concrétiser l'efficience additionnelle, seront plus limitées pour les années à venir.

Outre les départs à la retraite et les emplois temporaires qui ont permis historiquement de réaliser l'efficience additionnelle, des changements au processus de renouvellement de la main-d'œuvre ont amené en 2014 des écarts sur le nombre d'ETC prévu, écarts que le Distributeur ne pouvait anticiper au moment de la préparation du dossier tarifaire précédent. En effet, ces modifications qui consistent en la mise en place par Hydro-Québec d'un processus d'affichage à dates fixes et en l'approbation préalable du président de la division de tout comblement de postes, ont entrainé des opportunités d'efficience non planifiées et des mouvements sur le plan de main-d'œuvre qui ont eu des impacts à la baisse sur le nombre d'ETC en 2014.

Il est également important de rappeler que le Distributeur vise toujours à capter les réductions d'effectifs sans affecter la prestation de service rendu

aux clients et que ces réductions sont au bénéfice de l'ensemble de la clientèle, et ce, de façon récurrente.

17.2 Veuillez concilier les deux points suivants :

1. Lors de l'audience du dossier tarifaire 2014, le Distributeur avait indiqué à la Régie que « *des coupures additionnelles seraient imprudentes compte tenu de la réalité à laquelle il doit faire face en termes de stabilisation de l'organisation et des processus* » et « *cela mettrait à risque la qualité du service* ». (référence (ii))

2. Dans le présent dossier tarifaire, le Distributeur présente une amélioration de la performance nette de croissance de 350 ETC entre l'année de base 2014 et le nombre autorisé de ETC en 2014.

Réponse :

Le Distributeur considère que l'amélioration de la performance opérationnelle nette de la croissance totalise dans les faits 261 ETC. Cette efficience a été réalisée dans les activités de soutien puisque le Distributeur effectue une gestion prudente de ses activités opérationnelles en renouvelant la main-d'œuvre y étant afférente, afin d'assurer la pérennité de son réseau et le maintien de la qualité de son service.

L'écart résiduel de 89 ETC s'explique comme suit :

- **Diminution de 66 ETC découlant d'actions structurantes relatives aux phases 2 et 3 du projet LAD qui n'a pas été prise en compte dans le nombre d'ETC reconnu pour 2014, ces phases n'ayant pas encore été autorisés ;**
- **Diminution de 23 ETC métiers représentant un nombre de départs à la retraite plus fort qu'anticipé et qui sera par ailleurs comblé en 2015 puisque le Distributeur doit procéder au renouvellement de cette main-d'œuvre afin d'assurer la pérennité de son réseau et de maintenir la qualité de son service.**

La réduction de 261 ETC non anticipée en 2014, dont une réduction de 152 ETC s'est réalisée en 2013, découle des activités de soutien suivantes :

- **Diminution de 48 ETC découlant du projet SOGEM autorisé en septembre 2013. Cette diminution résulte du départ de commis distribution-ordonnancement qui anticipaient l'abolition de leur poste lors de la mise en œuvre prochaine du projet ;**
- **Diminution de 31 ETC bureau résultant de l'optimisation du processus d'ingénierie du réseau de distribution ;**

- **Diminution de 182 ETC attribuable à la gestion courante du Distributeur en lien avec les éléments expliqués en réponse à la question 17.1.**

18. Références : (i) Pièce B-0081, p. 50, tableau R-21.1;
(ii) Pièce B-0081, p. 54, tableau 3.

Préambule :

(i) Le Distributeur présente au tableau R-21.1, les gains associés au projet LAD en M$ et en ETC, sur la période 2012 à 2016.

**Tableau R-21.1 :
Gains associés au projet LAD 2012-2016 (M$)**

	Année historique 2012	Année historique 2013	D-2014-037	Année de base 2014	Année témoin 2015	Année 2016
Charges d'exploitation	-	(5,1)	(6,5)	(10,1)	(15,0)	(26,5)
Masse salariale	-	*(4,7)*	*(4,4)*	*(6,9)*	*(12,4)*	*(19,9)*
Autres charges	-	*(0,4)*	*(2,1)*	*(3,2)*	*(2,6)*	*(6,6)*
Revenus de mise en conformité	-	(0,8)	(0,5)	(1,2)	(0,6)	(1,8)
Total avant Compte d'écarts - Projets majeurs	-	(5,8)	(6,9)	(11,3)	(15,6)	(28,3)
Compte d'écarts - Projets majeurs				*5,7*	*(5,7)*	-
Total après Compte d'écarts - Projets majeurs	-	(5,8)	(6,9)	(5,6)	(21,3)	(28,3)
ETC avant compte d'écarts - Projets majeurs		(61)	(66)	(118)	(201)	(232)

(ii) Le Distributeur présente au tableau 3, les principales variations des ETC.

Tableau 3 :
Variation des ETC

VARIATION	Année de base 2014 vs D-2014-037		Année témoin 2015 vs Année de base 2014	
	ETC	M$	ETC	M$
Éléments spécifiques	+ 203	+ 13,7	+ 145	+ 11,8
Automatisation du réseau	- 13	- 1,3	-	-
Lecture à distance - Phase 1	+ 68	+ 3,8	- 134	- 9,3
Lecture à distance - Phases 2 et 3	+ 148	+ 11,2	+ 279	+ 21,1
Activités de base avec facteurs d'indexation particuliers	- 1	- 0,1	- 2	- 0,2
Stratégie pour la clientèle à faible revenu	-	-	-	-
Plan global en efficacité énergétique (PGEÉ)	-	-	- 2	- 0,2
Inspection et retraitement des poteaux de bois	- 1	- 0,1	-	-
Variation des effectifs découlant des « Éléments spécifiques » et des « Activités de base avec facteurs d'indexation particuliers »	+ 202	+ 13,6	+ 143	+ 11,6
Amélioration de la performance opérationnelle nette de la croissance	- 350	- 28,0	- 57	- 0,9
Gestion de la main-d'oeuvre opérationnelle	- 23	- 1,7	+ 110	+ 8,3
Amélioration de la performance opérationnelle	- 327	- 26,3	- 167	- 9,2
TOTAL	- 148	- 14,4	+ 86	+ 10,7

Demande :

18.1 Veuillez indiquer si les gains associés au projet LAD de -201 ETC en 2015 (référence (i)) sont inclus dans l'amélioration de la performance opérationnelle de -165 ETC en 2015 (référence (ii)). Si oui veuillez concilier les ETC. Si non, veuillez expliquer.

Réponse :

Le Distributeur confirme que les gains associés au projet LAD de -201 ETC en 2015 sont inclus dans l'amélioration de la performance opérationnelle de -167 ETC. Une augmentation de 34 ETC liée aux activités de base du Distributeur explique la différence.

AUTRES CHARGES

19. Références : (i) Décision D-2014-037, dossier R-3854-2013, phase 1, p. 92;
(ii) Pièce B-0029, p. 7 et 8;
(iii) Pièce B-0094, p. 16, tableau R-5.4;
(iv) Pièce B-0081, p. 66.

Préambule :

(i) Dans sa décision D-2014-037, la Régie a fait la demande suivante au Distributeur :

« [345] *Considérant une surestimation moyenne d'environ 18 M$ de la charge totale d'amortissement sur la période 2010-2013, la Régie est d'avis que cette surestimation du budget de cette rubrique est due principalement à des mises en service moindres qu'anticipées. Considérant également sa demande d'ajuster globalement la projection de la base de tarification en 2014, notamment pour les projets reportés ou non réalisés, la Régie juge que cela aura un impact à la baisse sur l'amortissement de l'année témoin 2014 (voir la section 11.1). En conséquence, la Régie réduit le budget de 20 M$ pour la charge totale d'amortissement pour l'année témoin 2014.* » [nous soulignons]

(ii) Dans le présent dossier, au sujet de la demande de la Régie citée en (i), le Distributeur écrit que :
« *Le Distributeur souligne que le montant reconnu de 804,9 M$ pour 2014 comprend la réallocation de la réduction globale de 20 M$ de la charge d'amortissement découlant de la décision de la Régie dont 12,7 M$ ont été alloué aux immobilisations en exploitation et 7,3 M$ aux actifs incorporels.* » [nous soulignons]

Plus loin dans la même référence, il écrit cependant :
« *Le Distributeur rappelle que l'amortissement de l'année de base découle des mises en service liées aux investissements déjà autorisés par la Régie dans des années antérieures. Ce faisant, le Distributeur évalue ne pas être en mesure de réaliser la portion de la diminution demandée par la Régie allouée aux immobilisations en exploitation.* » [nous soulignons]

(iii) En réponse à une demande de renseignements, le Distributeur présente au tableau R-5.4 le détail de la réduction globale de l'amortissement suite à décision D-2014-037. Voici un extrait du tableau.

• Amortissement et déclassement	0,0
Immobilisations en exploitation	-12,7
Actifs incorporels	-7,3
Plan global en efficacité énergétique	-1,8
Logiciels et autres actifs incorporels	-5,5
Réduction globale de l'amortissement	20,0

(iv)« *Le tableau R-30.1 présente l'historique des écarts entre l'amortissement reconnu et l'amortissement réel des immobilisations en exploitation pour les années 2010 à 2013.*

Tableau R-30.1 :
Amortissement des immobilisations en exploitation (M$)

	Amortissement reconnu	Amortissement réel	Écart réel / reconnu	Provenance des écarts	
				Révision des durées d'utilité	Mises en service
2013	460	470	11		11
2012	558	559	1		1
2011	553	552	(0)		(0)
2010	571	566	(6)	(4)	(2)

À la lumière de ce tableau, force est de constater qu'il n'y a pas eu de surestimation de la charge d'amortissement des immobilisations en exploitation dans les dernières années, à l'exception de 2010, année pour laquelle l'écart est essentiellement attribuable à la modification, en novembre 2010, de la durée d'utilité des poteaux qui est passée de 30 à 40 ans. Les révisions des durées d'utilité étant maintenant appliquées au 1er janvier de chaque année, celles-ci ne sont plus une source d'écart de la charge d'amortissement des immobilisations en exploitation. »

La Régie souligne que l'amortissement reconnu en 2012 des « Immobilisations en exploitation » est de 569 M$ plutôt que 558 M$ (tableau R-30.1). Par conséquent, l'écart est de -10 M$.

Demandes :

19.1 Veuillez justifier le choix du Distributeur d'allouer une partie importante de la réduction globale de 20 M$ pour l'année témoin 2014 de la rubrique « Amortissement et déclassement », soit une réduction de 12,7 M$ attribuée à la charge d'amortissement des immobilisations en exploitation, alors qu'il n'y a pas eu, selon le Distributeur, de surestimation de la charge d'amortissement des immobilisations en exploitation dans les dernières années et ce faisant, qu'il évalue ne pas être en mesure de réaliser la portion de la diminution allouée aux immobilisations en exploitation.

Réponse :

D'emblée, le Distributeur confirme que l'amortissement reconnu en 2012 pour les immobilisations en exploitation est de 558 M$ comme présenté au Rapport annuel 2012[5], après les reclassements relatifs au projet LAD de l'ordre de 10 M$ et demandés par la Régie dans sa décision D-2013-037[6].

Dans sa décision D-2014-037[7], la Régie justifie la réduction globale de la charge d'amortissement 2014 de 20 M$, principalement par des mises en service moindres qu'anticipées ainsi que des projets reportés ou non réalisés. Par

[5] Pièce HQD-2, document 3, page 7
[6] D-2013-037, paragraphe 184
[7] D-2014-037, paragraphe 345

conséquent, le Distributeur a alloué la réduction globale aux rubriques actifs incorporels et immobilisations en exploitation.

Afin de répartir cette réduction globale de 20 M$, le Distributeur a d'abord procédé à la prévision de la charge d'amortissement de l'année de base 2014 selon sa meilleure évaluation, comme présenté au tableau R-19.1.

Tableau R-19.1 :
Amortissement et déclassement 2014 (M$)

Description	2014	
	Reconnu avant réduction globale de 20 M$	Année de base
Amortissement et déclassement		
Immobilisations en exploitation	483,9	488,8
Contrat de location-financement	2,0	2,2
Actifs incorporels	242,3	235,8
Plan global en efficacité énergétique	*138,1*	*136,4*
Programmes et activités du BEIÉ	*15,4*	*15,4*
Logiciels et autres actifs incorporels	*88,8*	*84,0*
Autres actifs	4,0	3,8
Contributions à des projets de raccordement	*4,0*	*3,8*
TOTAL	**732,2**	**730,5**

L'amortissement des actifs incorporels étant plus bas que celui reconnu par la décision D-2014-037, une partie de la réduction globale, soit une réduction de l'ordre de 7,3 M$, leur a été allouée. Évaluant ne pas être en mesure de réaliser la diminution demandée par la Régie, le résiduel de 12,7 M$ a été alloué à l'amortissement des immobilisations en exploitation, qui représente la rubrique la plus importante de la charge d'amortissement.

Le Distributeur tient à rappeler que, comme expliqué en réponse à la question 30.2 de la demande de renseignements n° 2 de la Régie à la pièce HQD-15, document 1.2 (B-0082), la charge d'amortissement 2014 des immobilisations en exploitation est composée d'une part, de l'amortissement des immobilisations en exploitation au 31 décembre 2013 qui ne peut être réduit puisqu'il découle de calculs générés par le système comptable et, d'autre part, par des mises en service découlant d'investissements préalablement autorisés par la Régie.

19.2 Veuillez expliquer pourquoi le Distributeur, pour respecter la demande de la Régie, n'a pas effectué une allocation différente de la réduction globale de 20 M$ de la charge totale d'amortissement.

Réponse :

Voir la réponse à la question 19.1.

BASE DE TARIFICATION

20. Référence : Pièce B-0031, p. 7 et 13.

Préambule :

Base de tarification (moyenne des 13 soldes, K$)			
	2014 (D-2014-037)	*2015 (projeté)*	*Différence AT 2015 (D-2014-037)*
Immobilisations en exploitation	8 634 359	8 958 705	324 346

Demandes :

20.1 Veuillez expliquer, chiffres à l'appui, l'écart de 324 M$ entre les immobilisations en exploitation de l'année témoin 2015 et celles approuvées dans la décision D-2014-037.

Réponse :

Le tableau R-20.1 présente l'évolution de la base de tarification (moyenne 13 soldes) pour les années 2014 et 2015.

Tableau R-20.1 :
Évolution de la base de tarification (moyenne 13 soldes)
D-2014-037 vs R-3905-2014 (M$)

	Solde au 01/01/2014	Mises en service 2014	Amort. 2014	Régul./ Retraits	Solde au 31/12/2014	Moy. 13 soldes 2014	Mises en service 2015	Amort. 2015	Régul./ Retraits	Solde au 31/12/2015	Moy. 13 soldes 2015
Décision 2014-037	**8 564,4**	**701,2**	**471,2**	**39,0**	**8 755,4**	**8 634,4**					
Dont : LAD phase 1	155,1	123,1	20,7	19,5	238,0	221,4					
Année de base 2014	**8 566,3**	**852,3**	**488,8**	**55,4**	**8 874,4**	**8 673,0**					
Dont : LAD (total)	137,1	302,5	19,7	38,5	381,4	251,0					
Phase 1	137,1	107,9	16,6	19,5	208,9	199,5					
Phase 2	0,0	194,6	3,1	19,0	172,5	51,5					
Écart année 2014	**1,9**	**151,1**	**17,6**	**16,4**	**119,0**	**38,6**					
Année témoin 2015					**8 874,4**		**814,8**	**518,7**	**40,2**	**9 130,3**	**8 958,7**
Dont : LAD (total)							212,3	39,6	22,7	531,4	465,9

La base de tarification de l'année témoin 2015 étant établie à partir du solde au 31 décembre 2014 selon l'année de base, l'écart de 324,3 M$ entre la moyenne 13 soldes selon la décision D-2014-037 et celle de l'année 2015 s'explique comme suit :

- **Écart de 38,6 M$ entre la moyenne 13 soldes selon la décision D-2014-037 et l'année de base 2014 dont 29,6 M$ sont attribuables au projet LAD ;**
- **Écart de 285,7 M$ découlant des activités de 2015, soit des mises en service totalisant 814,8 M$, une charge d'amortissement annuel de 518,7 M$ et des retraits de 40,2 M$. Pour le projet LAD, l'ensemble des activités de 2015 représente 150 M$.**

20.2 Veuillez indiquer la part occupée par le projet LAD dans cet écart, de même que pour l'année témoin 2015 et dans le montant approuvé dans la décision D-2014-037.

Réponse :

Voir la réponse à la question 20.1.

ÉVOLUTION DES COMPTES D'ÉCARTS ET AUTRES ACTIFS

Contributions à des projets de raccordement

21. Références : (i) Pièce B-0037, p. 7;
(ii) Pièce B-0081, p. 79;
(iii) Dossier R-3903-2014, pièce B-0031, p. 11 à 13.

Préambule :

(i) Le Distributeur présente au tableau 2, l'évolution des contributions à des projets de raccordement sur la période 2013 à 2015, dont une mise en service de 217,9 M$ en 2015 reliée aux projets en croissance du Transporteur.

Tableau 2 :
Évolution des contributions à des projets de raccordement (M$)

	Solde au 01/01/2013	MES 2013	Amort. 2013	Solde au 31/12/2013	MES 2014	Amort. 2014	Solde au 31/12/2014	MES 2015	Amort. 2015	Solde au 31/12/2015
VILLAGE CRI WASKAGANISH	65,2		(2.2)	63,0		(2.2)	60,8		(2.2)	58,6
Coûts de raccordement	58,3		(1,7)	56,6		(1,7)	54,9		(1,7)	53,2
Charges d'entretien et d'exploitation	6,9		(0,5)	6,4		(0,5)	5,9		(0,5)	5,4
PREMIER APPELS D'OFFRES ÉOLIEN A/O 2003-02		31,4		31,4		(1,6)	29,8		(1,6)	28,2
Coûts de raccordement		27,3		27,3		(1,4)	25,9		(1,4)	24,5
Charges d'entretien et d'exploitation		4,1		4,1		(0,2)	3,9		(0,2)	3,7
PROJETS EN CROISSANCE DU TRANSPORTEUR								217,9	(4,8)	213,1
Coûts de raccordement								189,5	(3,8)	185,7
Charges d'entretien et d'exploitation								28,4	(1,0)	27,4
AUTRES CONTRIBUTIONS	8,1	1,5	(0,0)	9,5	(4,7)	(0,0)	4,9	(5,9)	0,3	(0,7)
Contributions internes	6,2	1,4	0,1	7,6	(4,1)	0,1	3,7	(5,1)	0,4	(1,0)
Frais d'entretien	3,9	0,2	(0,3)	3,8		(0,3)	3,5	0,6	(0,3)	3,8
Revenus d'entretien	(2,0)	(0,1)	0,2	(1,9)	(0,6)	0,2	(2,3)	(1,4)	0,2	(3,5)
TOTAL	73,3	32,9	(2.2)	103,9	(4,7)	(3.8)	95,5	212,0	(8,3)	299,2

(ii) En réponse à une demande de renseignements, le Distributeur présente au tableau R-34.1, les contributions du Distributeur à des projets de raccordement avec le Transporteur et le Producteur.

Tableau R-34.1 :
Contributions à des projets de raccordement (M$)

COMPOSANTES	Solde au 31/12/2013	Solde au 31/12/2014	Solde au 31/12/2015
Contributions avec le Transporteur			
Village cri Waskaganish	63,0	60,8	58,6
Premier appels d'offres éolien A/O 2003-02	31,4	29,8	28,2
Projets en croissance du Transporteur			213,1
Autres contributions	28,8	23,1	16,4
- Travaux sur le réseau et activités de mesurage	(4,5)	(8,9)	(19,0)
- Autres	33,3	32,0	35,4
Total des contributions avec le Transporteur	**123,2**	**113,7**	**316,3**
Contributions avec le Producteur			
Autres contributions	(19,3)	(18,2)	(17,1)
TOTAL	**103,9**	**95,5**	**299,2**

Il indique que la « *contribution annuelle du Distributeur aux projets d'investissement en croissance du Transporteur, laquelle est désignée par le Transporteur comme étant la contribution liée à l'agrégation annuelle des projets du Distributeur* ».

(iii) Dans le dossier R-3903-2014 : « *Le Transporteur présente dans les tableaux suivants l'évaluation demandée pour les années 2013, 2014 et 2015. Selon la présente évaluation, une contribution du Distributeur serait requise pour les années 2014 et 2015. Cependant, celles-ci ne seront confirmées qu'en début des années suivantes, soit respectivement au premier trimestre de 2015 et de 2016, avec les coûts réels des mises en services effectivement réalisées durant les années 2014 et 2015.* »

Le Transporteur présente aux tableaux 6 à 8, le détail de l'évaluation de la contribution requise du Distributeur pour les années suivantes :

Année 2013 : N/A
Année 2014 : 217,9 M$
Année 2015 : 71,4 M$

Demandes :

21.1 Veuillez expliquer pourquoi la contribution reliée aux projets en croissance du Transporteur passe de zéro en 2013 et en 2014 à 217,9 M$ en 2015.

Réponse :

Le détail des contributions reliées aux projets en croissance du Transporteur est présenté au dossier du Transporteur[8]. Ainsi, il n'y a eu aucune contribution requise du Distributeur en 2013, puisque l'ensemble des coûts

[8] R-3903-2014, HQT-12, document 2, pages 12 à 13

des projets en croissance mis en service en 2013 n'a pas excédé l'allocation maximum du Transporteur. En 2014 et 2015, le Transporteur évalue que l'ensemble des coûts des projets en croissance dépassera l'allocation maximale.

21.2 Veuillez commenter sur la possibilité de comptabiliser la contribution dans l'année concernée afin de s'assurer que les coûts soient imputés dans la bonne année (démarcation). Ainsi, le montant de la contribution de 217,9 M$ en 2014 soit comptabilisée dans l'année de base 2014 plutôt que dans l'année témoin 2015.

Réponse :

Comme expliqué par le Transporteur[9], le montant de la contribution 2014 ne sera confirmé qu'au début de l'année 2015, soit lorsque l'ensemble des mises en service réelles sera connu. Le Distributeur souligne par ailleurs que le traitement qu'il applique est identique à celui du Transporteur.

21.3 Veuillez commenter sur la possibilité de déposer dans les prochains dossiers tarifaires le détail de l'évaluation de la contribution du Distributeur reliée aux projets en croissance du Transporteur, pour l'année historique, l'année de base et l'année témoin (référence (iii)).

Réponse :

Le Distributeur n'y voit aucun inconvénient.

PLAN GLOBAL EN EFFICACITÉ ÉNERGÉTIQUE (PGEÉ)

Mesures de gestion de la demande de puissance à la pointe (GDP)

22. Référence : Pièce B-0081, p. 83 et 84.

Préambule :

« *Ainsi, le budget prévu pour la GDP, en 2015, a été augmenté substantiellement. Les nouvelles interventions expliquent l'ensemble des résultats des tests économiques.* »

Demandes :

[9] R-3903-2014, HQT-12, document 2, page 11

22.1 Dans les budgets prévus pour les nouvelles interventions en GDP en 2015, veuillez fournir séparément les sommes consacrées aux activités de R&D de celles consacrées au déploiement et à l'exploitation des mesures de GDP elles-mêmes.

Réponse :

Le budget demandé en 2015 pour les interventions en GDP, qui s'élève à 12 M$, n'intègre pas les activités en R&D. Les sommes consacrées aux activités de R&D en GDP, qui s'élèvent à environ 3 M$ et qui visent autant les marchés Résidentiel que Commercial, Institutionnel et Industriel, sont intégrées à l'activité Innovations technologiques et commerciales.

22.2 Veuillez élaborer sur les tests économiques des mesures de GDP en tenant compte de votre réponse à la question précédente.

Réponse :

Les tests économiques du tableau 6 de la pièce HQD-10, document 1 (B-0038), page 19, présentent spécifiquement les résultats des interventions en GDP, tandis que ceux touchant les activités de R&D en GDP sont inclus dans l'activité Innovations technologiques et commerciales.

CONDITIONS DE SERVICE D'ÉLECTRICITÉ (CDSÉ)

23. Référence : Pièce B-0045, p. 5.

Préambule :

Le Distributeur propose la modification suivante à l'article 1.1 des CDSÉ :

« ***1.1*** *Les dispositions du présent texte établissent les conditions de service d'électricité d'Hydro-Québec.* ~~*Toutefois, les dispositions des chapitres 14, 15, 16 et 17 des présentes conditions de service ne s'appliquent qu'au service en basse tension et au service en moyenne tension lorsque le courant maximum n'excède pas 260 A à une tension triphasée.*~~

Advenant que le demandeur requiert l'alimentation pour une installation au service d'électricité en moyenne tension lorsque le courant maximum excède 260 A à une tension triphasée ou en haute tension, les dispositions de la partie III des présentes conditions de service s'appliquent avec les ajustements nécessaires lorsque pertinents. Une entente entre le demandeur et Hydro-Québec doit alors consigner par écrit les conditions applicables ainsi que lesdits ajustements, avant le début des travaux, y compris les éléments suivants :

1º la date prévue de mise sous tension de l'installation électrique;
2º la description des travaux de l'offre de référence et des options qui seront réalisées par Hydro-Québec;
3º la contribution financière du demandeur au coût des travaux et les modalités de paiement;
4º l'engagement de puissance du demandeur;
5º les garanties financières à fournir par le demandeur;
6º les conditions relatives au report ou à l'abandon de la demande d'alimentation.

Les garanties financières exigées par Hydro-Québec doivent être suffisantes pour couvrir le montant de l'allocation accordée en contrepartie d'un engagement de consommation de la part du demandeur. » [nous soulignons]

Demandes :

23.1 La Régie doit-elle comprendre que l'ensemble des CDSÉ s'applique ou seulement la partie 3 s'appliquera avec les ajustements nécessaires.

Réponse :

L'ensemble des CDSÉ s'applique. Toutefois la partie III des CDSÉ est visée par de possibles ajustements pouvant s'avérer nécessaires.

23.2 Veuillez élaborer sur ce que le Distributeur entend par des « *ajustements nécessaires* » et préciser ce qu'il entend par l'expression « *lorsque pertinent* ». Veuillez fournir des exemples.

Réponse :

Le Distributeur propose d'utiliser la mention « avec les ajustements nécessaires lorsque pertinents » afin de pouvoir apporter les modifications qui seraient requises lorsque les principes prévus aux situations en basse tension ou en moyenne tension de 260 A et moins ne peuvent s'appliquer tels quels aux situations en haute tension ou en moyenne tension de plus de 260 A. Ceci évite d'alourdir considérablement le texte des CDSÉ tout en permettant d'appliquer les principes réglementaires aux particularités inhérentes à chaque situation en haute tension ou en moyenne tension de plus de 260 A par une gestion rigoureuse spécifique à chaque cas.

Certaines des dispositions de la partie III des CDSÉ nécessitent des adaptations, alors que d'autres ne sont pas pertinentes pour les situations en haute tension ou en moyenne tension de plus de 260 A.

Voici des exemples pour illustrer certaines de ces situations en haute tension ou en moyenne tension de plus de 260 A :

<u>Exemples - sans ajustements</u>

1) **L'article 14.9 des CDSÉ (limite pour l'alimentation) s'applique en haute tension ou en moyenne tension de plus de 260 A sans ajustements.**
2) **L'article 15.10 des CDSÉ (coût relatif à une ligne de relève) s'applique en haute tension ou en moyenne tension de plus de 260 A sans ajustements.**
3) **L'article 17.4 des CDSÉ (coût des travaux pour charges inférieures à 2 kW) n'est pas pertinent à l'alimentation en haute tension ou en moyenne tension de plus de 260 A et ne nécessite pas d'ajustements.**

<u>Exemples - avec ajustements</u>

1) **Les principes régissant une conversation de tension (article 14.11 des CDSÉ) sont identiques pour les deux niveaux de tension, mais nécessitent un ajustement relatif au délai pour aviser le client de la date prévue de la conversion de tension prévue en haute et moyenne tension de plus de 260 A. Au lieu de 24 mois, le Distributeur donne un préavis de 48 mois, car il s'agit de travaux et d'investissements plus importants qu'en basse ou en moyenne tension de 260 A et moins.**
2) **Lorsqu'il s'agit de conversion en haute tension, l'article 14.11 ne s'applique pas, mais les rubriques de compensation prévues aux annexes III et V des CDSÉ (valeur de remplacement dépréciée du poste du client, matériel et main-d'œuvre pour effectuer la mise sous tension et pour le démantèlement) s'appliquent.**
3) **Les règles prévues à l'article 15.2 des CDSÉ (type de branchement) ne peuvent s'appliquer telles quelles aux situations en haute tension ou en moyenne tension de plus de 260 A et nécessitent des ajustements pour ces situations, car le type de branchement est déterminé par l'offre de référence.**

La proposition du Distributeur permet de clarifier le champ d'application des CDSÉ en précisant, à l'article 1.1, l'exigence d'une entente écrite pour les cas en haute tension ou en moyenne tension de plus de 260 A. Cette exigence n'est actuellement indiquée qu'à l'article 10.6 des Tarifs d'électricité

24. Référence : Pièce B-0046, p. 16.

Préambule :

À la référence, le Distributeur présente l'article 6.5 actuellement en vigueur ainsi que la modification proposée.

L’article 6.5 en vigueur :

> « ***6.5*** *Le client doit présenter une nouvelle demande* <u>*s’il désire modifier son abonnement*</u>*. Si la nouvelle demande respecte les conditions de service, un nouvel abonnement remplace celui qui est en cours.* » [nous soulignons]

L’article 6.5 proposé ne traite que de l’ajout ou du retrait d’un responsable et d’un changement d’adresse.

> « ***6.5*** *L’ajout ou le retrait d’un responsable, ainsi que son changement d’adresse doit faire l’objet d’une nouvelle demande d’abonnement.* »

Demandes :

24.1 Veuillez indiquer si d’autres cas de modification d’abonnement étaient visés par l’article 6.5 actuellement en vigueur. Dans l’affirmative, veuillez les énumérer et veuillez expliquer pourquoi ils ne sont pas reconduits.

Réponse :

La modification de l'article 6.5 vise à préciser les seuls cas qui doivent générer un terme à l'abonnement actif du client qui sera remplacé par un nouveau contrat d'abonnement en vertu des nouveaux articles 5.1 et 5.2.

Le client peut en cours d'abonnement modifier plusieurs informations liées aux renseignements relatifs :

- **à l'utilisation de l'électricité, soit de l’usage résidentiel pour l’usage commercial ;**
- **aux caractéristiques techniques de son abonnement, par exemple la modification d’une entrée électrique de 100 A à 400 A ;**
- **au tarif, lors de son adhésion à la biénergie ;**
- **aux données nominatives de son abonnement, lors d’un changement de numéro de téléphone ;**

sans que le Distributeur ne mette un terme à l'abonnement du client pour en créer un autre. Dans ces cas, le Distributeur modifie les données du contrat d'abonnement et ne facture aucuns frais de gestion ou d'ouverture de dossier.

24.2 Veuillez préciser si des frais de gestion de dossier seront exigés pour l’ajout ou le retrait d’un responsable. Dans l’affirmative, veuillez justifier ces frais.

Réponse :

Oui, ces frais ont toujours été exigibles dans cette situation. En effet, l'ajout ou le retrait d'un responsable met un terme aux responsabilités liées à l'abonnement du ou des clients définis à l’article 6.1 des CDSÉ. De plus, une

obligation de solidarité est prévue en vertu de ce même article. Ce faisant, il n'est pas possible que le même abonnement se poursuive à l'occasion du retrait ou de l'ajout d'un responsable. Un nouvel abonnement doit donc être créé conformément à l'article 5.1 des CDSÉ et les frais appropriés s'appliquent alors.

25. Référence : Pièce B-0046, p. 28.

Préambule :

À la référence, le Distributeur présente l'article 11.2 modifié substantiellement. Cet article traite des modes de facturation, et le Distributeur propose des simplifications et des regroupements d'information :

« **11.2** *Hydro-Québec transmet une facture au client au moins tous les 90 jours dans le cas d'un abonnement pour lequel seule l'énergie est facturée.*

Lorsqu'elle ne peut relever le ou les compteurs du client, Hydro-Québec établit la facture en fonction d'une estimation et présente des rajustements sur une facture subséquente établie à la suite d'une relève du ou des compteurs.

À la fin d'un abonnement, Hydro-Québec envoie une facture finale au client dans les délais suivants :

- *60 jours dans le cas d'un abonnement pour lequel seule l'énergie est facturée;*
- *30 jours dans le cas d'un abonnement pour lequel l'énergie et la puissance sont facturées.*

Hydro-Québec peut établir la facture initiale et la facture finale du client en fonction d'une estimation. En l'absence d'un relevé d'Hydro-Québec à la date de fin de l'abonnement, le client peut fournir son propre relevé de compteur et Hydro-Québec établit la facture en conséquence. [nous soulignons]

Demande :

25.1 Veuillez expliquer pourquoi le Distributeur ne permet pas au client de fournir son propre relevé de compteur à la date de début de l'abonnement sur la base d'une estimation en l'absence d'un relevé du Distributeur.

Réponse :

Le Distributeur souligne qu'il continue d'accepter que les clients fournissent leur propre relevé lors du début de leur abonnement, et ce, uniquement pour les clients pour lesquels un compteur de nouvelle génération (CNG) n'a pas encore été installé.

Le Distributeur rappelle que la modification à l'article 11.2 des CDSÉ, proposée par le Distributeur dans le dossier R-3814-2012 et approuvée par la Régie dans sa décision D-2013-037, visait d'une part, à éviter une éventuelle confusion entre la relève du client et celle du Distributeur lorsqu'un CNG est installé. D'autre part, en acceptant à la fois la lecture du client lors de son déménagement et celle du nouveau client lors de son emménagement, il y aurait alors toujours eu un certain nombre de kilowattheures non facturés. Cela aurait créé une incohérence avec la date de terminaison du contrat d'abonnement.

26. Référence : Pièce B-0046, p. 30 et 31.

Préambule :

À la référence, le Distributeur propose des modifications substantielles à l'article 11.5 qui traite des modes de facturation. Le Distributeur propose des modalités de simplifications selon que la correction de la facture entraîne un débit ou un crédit.

La Régie souhaite examiner les modifications suivantes dans un souci de clarté des termes utilisés:

« **11.5** *Si la facture du client contient des erreurs, Hydro-Québec apporte les corrections appropriées selon les modalités suivantes :*

1º Lorsque la correction entraîne un crédit au compte du client, celui-ci s'applique à :

i) toutes les périodes touchées par un défaut lié au mesurage ou par une erreur quant au multiplicateur;

ii) un maximum de 36 mois dans tous les autres cas.

Les intérêts applicables au montant remboursé sont calculés au taux préférentiel de la Banque Nationale du Canada en vigueur le premier jour ouvrable du mois au cours duquel s'effectue le remboursement.

2º Lorsque la correction entraîne un débit au compte du client, celui-ci s'applique à :

[…] »

La Régie note que la notion de remboursement et de réclamation sont retirées du texte en vigueur.

La Régie comprend qu'un compte peut regrouper plusieurs abonnements ou factures.

Demande :

26.1 La Régie doit-elle comprendre que le Distributeur fera une mise à jour du compte client si les modalités de correction entraînent un remboursement ou une réclamation.

Réponse :

Oui, le Distributeur fera, le cas échéant, la mise à jour du compte client.

27. Références : (i) Décision D-2014-156, dossier R-3891-2014, p. 27;
(ii) Pièce A -0015.

Préambule :

(i) La Régie demandait un suivi sur les avenues possibles de participation des membres de l'AREQ aux options d'électricité interruptible.

« *[113] La Régie prend acte des engagements du Distributeur envers l'AREQ. Elle lui demande d'assurer un suivi, dans les meilleurs délais, de l'état des discussions avec l'AREQ quant à la possibilité de participation de ses membres aux options d'électricité interruptible. Cela pourrait, notamment, être fait dans le cadre du dossier tarifaire R-3905-2014, sous réserve d'une décision de la formation saisie de ce dernier dossier quant à la possibilité d'y traiter de ce sujet.* »

(ii) La Régie a inclus comme sujet à traiter dans le cadre du présent dossier le suivi demandé par la Régie au paragraphe 113 de la décision D-2014-056 (dossier R-3891 2014), relativement à l'état des discussions du Distributeur avec l'AREQ quant à la possibilité de participation des membres de cette dernière aux options d'électricité interruptible.

Demande :

27.1 Veuillez indiquer l'état des discussions avec les membres de l'AREQ.

Réponse :

Pour l'hiver 2014-2015, aucun membre de l'AREQ n'a fait de proposition de puissance interruptible au Distributeur.

Le Distributeur présentera les options d'électricité interruptible actuelles aux représentants de l'AREQ lors d'une rencontre prévue le 20 novembre 2014. Cette rencontre sera l'occasion pour le Distributeur d'expliquer ces options et leurs modalités d'application ainsi que d'identifier avec l'AREQ le potentiel d'effacement de ses membres, au-delà de l'effacement actuel aux fins de gestion de la pointe de leur réseau.

Si des quantités de puissance interruptible peuvent potentiellement être mises à la disposition du Distributeur et si des modifications aux modalités des options sont nécessaires pour tenir compte des particularités des

réseaux, le Distributeur présentera une proposition à la Régie dans le cadre d'un prochain dossier tarifaire.

TARIFS D'ÉLECTRICITÉ

Option d'électricité additionnelle

28. Références : (i) Rapport annuel du Distributeur 2013, HQD-3, document 2.2, p. 4 ;

(ii) Rapports annuels du Distributeur 2010-2012, HQD-3, document 2.2.

Préambule :

(i)

TABLEAU 1

BILAN DE L'OPTION D'ÉLECTRICITÉ ADDITIONNELLE POUR 2013

Mois	Volume mensuel additionnel (MWh)	Prix moyen de l'électricité additionnelle (¢/kWh)	Prix réel à la zone M + ajustements (¢/kWh)	Écart de prix (%)	Écart de revenu total ($)
Janvier	23 767	4,27	5,14	-20,4%	-207 374
Février	40 607	4,27	4,15	2,8%	50 742
Mars	50 647	4,27	4,44	-4,0%	-85 131
Avril	47 458	4,38	2,43	44,5%	924 400
Mai	20 959	4,38	2,52	42,5%	389 056
Juin	28 588	4,38	2,14	51,1%	638 987
Juillet	40 018	4,38	3,16	27,9%	489 626
Août	28 871	4,38	2,10	52,1%	657 760
Septembre	42 155	4,38	2,03	53,7%	991 070
Octobre	53 390	4,38	2,23	49,1%	1 149 907
Novembre	45 981	4,38	1,85	57,8%	1 164 974
Décembre	72 641	4,38	3,50	20,1%	638 340
Total	**495 082**	**4,35**	**2,98**	**31,5%**	**6 802 357**

(ii) Le Distributeur présente au Tableau 1 le bilan de l'option d'électricité additionnelle pour chacune des années de 2010 à 2012.

Demandes :

28.1 Pour chacune des années de 2010 à 2013, veuillez produire, sous la forme du tableau en référence, une simulation du prix qu'aurait donné la nouvelle formule proposée pour l'électricité additionnelle, en assumant que le Distributeur, à chaque année, planifiait procéder à des achats de court terme sur les marchés d'énergie durant 500 heures au cours de la période de décembre à mars et en assumant que les volumes mensuels additionnels auraient été les mêmes que ceux présentés aux rapports annuels. Veuillez expliquer tout écart important avec les données réelles présentées aux rapports annuels pour chacune des années.

Réponse :

À titre illustratif, le Distributeur présente au tableau 28.1-A l'impact de la nouvelle formule proposée pour les années 2010 à 2013, sur la base des coûts évités déposés dans le cadre de ses différents dossiers tarifaires de 2009 à 2012.

Le Distributeur souligne cependant que les coûts évités pour l'année 2010 ne lui permettent pas d'appliquer la nouvelle formule d'établissement du prix de l'électricité additionnelle pour la période d'hiver compte tenu du fait qu'avant 2010 il n'établissait pas de coûts évités distincts pour l'hiver et l'été.

Tableau 28.1-A :
Impact de la nouvelle formule
sur le prix de l'électricité additionnelle

Période	Prix plancher	Formule proposée	Références aux coûts évités utilisés
Été 2010	4,30 ¢/kWh	2,77 ¢/kWh	HQD-10, document 4, p.16 (R-3708-2009)
Hiver 2010-2011	4,30 ¢/kWh	3,22 ¢/kWh	HQD-2, document 4, page 5 (R-3740-2010) & HQD-10, document 3, p.16 (R-3708-2009)
Été 2011	4,30 ¢/kWh	2,77 ¢/kWh	HQD-10, document 3, p.16 (R-3740-2010)
Hiver 2011-2012	4,30 ¢/kWh	3,14 ¢/kWh	HQD-2, document 4, page 5 (R-3776-2011) & HQD-10, document 3, p.16 (R-3740-2010)
Été 2012	4,27 ¢/kWh	2,77 ¢/kWh	HQD-10, document 3, p.16 (R-3776-2011)
Hiver 2012-2013	4,27 ¢/kWh	3,14 ¢/kWh	HQD-2, document 4, page 5 (R-3814-2012) & HQD-10, document 3, p.16 (R-3776-2011)
Été 2013	4,38 ¢/kWh	2,77 ¢/kWh	HQD-10, document 3, p.16 (R-3814-2012)
Hiver 2013-2014	4,38 ¢/kWh	3,15 ¢/kWh	HQD-3, document 4, page 5 (R-3854-2013) & HQD-10, document 3, p.16 (R-3814-2012)

Les tableaux 28.1-B à 28.1-E présentent l'impact de la nouvelle formule proposée pour les années 2010 à 2013, sur une base mensuelle.

Tableau 28.1-B : Impact de la nouvelle formule sur le prix de l'électricité additionnelle - 2010

Mois	Volume mensuel additionnel (MWh)	Prix moyen de l'électricité additionnelle (¢/kWh)	Prix de l'électricité additionnelle (nouvelle formule) (¢/kWh)	Prix réel à la zone M + ajustements (¢/kWh)	Écart de prix (%)	Écart de revenu total ($)
Janvier	29 540	5,56	s.o.	5,06	s.o.	s.o.
Février	31 421	5,34	s.o.	4,34	s.o.	s.o.
Mars	40 257	4,30	s.o.	3,68	s.o.	s.o.
Avril	18 305	4,30	4,30	2,22	94,0%	381 334
Mai	14 271	4,30	4,30	2,92	47,4%	197 437
Juin	7 833	4,30	4,30	3,28	31,1%	79 926
Juillet	8 145	4,30	4,30	4,35	-1,2%	-4 254
Août	7 319	5,19	4,30	5,68	-24,3%	-101 184
Septembre	5 979	4,60	4,30	4,97	-13,5%	-40 127
Octobre	5 949	4,30	4,30	4,14	3,9%	9 628
Novembre	8 549	4,30	4,30	4,74	-9,4%	-37 987
Décembre	7 563	4,30	4,30	3,89	10,6%	31 133
Total	**185 133**	**4,59**	**4,30**	**4,11**	**4,7%**	**515 906**

Tableau 28.1-C : Impact de la nouvelle formule sur le prix de l'électricité additionnelle - 2011

Mois	Volume mensuel additionnel (MWh)	Prix moyen de l'électricité additionnelle (¢/kWh)	Prix de l'électricité additionnelle (nouvelle formule) (¢/kWh)	Prix réel à la zone M + ajustements (¢/kWh)	Écart de prix (%)	Écart de revenu total ($)
Janvier	6 905	5,48	4,30	5,74	-25,1%	-99 558
Février	9 528	4,74	4,30	4,50	-4,4%	-18 950
Mars	16 887	4,30	4,30	4,13	4,0%	28 220
Avril	11 174	4,34	4,30	4,05	6,3%	28 409
Mai	12 448	4,30	4,30	2,41	78,7%	235 767
Juin	8 494	4,30	4,30	2,68	60,6%	137 838
Juillet	5 822	4,30	4,30	3,20	34,4%	64 061
Août	6 971	4,30	4,30	2,77	55,3%	106 714
Septembre	5 119	4,30	4,30	2,43	76,9%	95 668
Octobre	11 216	4,30	4,30	2,66	61,7%	184 043
Novembre	12 998	4,48	4,30	4,06	5,9%	31 216
Décembre	15 154	4,53	4,30	3,75	14,7%	83 542
Total	**122 717**	**4,45**	**4,30**	**3,59**	**19,9%**	**876 972**

Tableau 28.1-D :
Impact de la nouvelle formule
sur le prix de l'électricité additionnelle - 2012

Mois	Volume mensuel additionnel (MWh)	Prix moyen de l'électricité additionnelle (¢/kWh)	Prix de l'électricité additionnelle (nouvelle formule) (¢/kWh)	Prix réel à la zone M + ajustements (¢/kWh)	Écart de prix (%)	Écart de revenu total ($)
Janvier	17 878	4,31	4,30	3,94	9,0%	63 516
Février	19 159	4,30	4,30	3,29	30,7%	193 474
Mars	17 596	4,30	4,30	1,23	250,0%	540 432
Avril	18 100	4,27	4,27	1,17	264,2%	560 674
Mai	16 216	4,27	4,27	0,83	414,2%	557 774
Juin	7 863	4,27	4,27	1,16	268,2%	244 545
Juillet	8 604	4,27	4,27	2,16	98,1%	181 895
Août	8 410	4,27	4,27	1,92	121,9%	197 248
Septembre	10 567	4,27	4,27	1,48	189,4%	295 320
Octobre	16 321	4,27	4,27	2,11	102,3%	352 356
Novembre	12 031	4,27	4,27	2,82	51,2%	174 040
Décembre	33 140	4,27	4,27	1,97	117,2%	763 532
Total	**185 885**	**4,28**	**4,28**	**2,06**	**107,7%**	**4 124 805**

Tableau 28.1-E :
Impact de la nouvelle formule
sur le prix de l'électricité additionnelle - 2013

Mois	Volume mensuel additionnel (MWh)	Prix moyen de l'électricité additionnelle (¢/kWh)	Prix de l'électricité additionnelle (nouvelle formule) (¢/kWh)	Prix réel à la zone M + ajustements (¢/kWh)	Écart de prix [1] (%)	Écart de revenu total ($)
Janvier	23 767	4,27	4,27	5,14	-17,0%	-207 374
Février	40 607	4,27	4,27	4,15	3,0%	50 742
Mars	50 647	4,27	4,27	4,44	-3,8%	-85 131
Avril	47 458	4,38	4,38	2,43	80,1%	924 400
Mai	20 959	4,38	4,38	2,52	73,6%	389 056
Juin	28 588	4,38	4,38	2,14	104,2%	638 987
Juillet	40 018	4,38	4,38	3,16	38,8%	489 626
Août	28 871	4,38	4,38	2,10	108,4%	657 760
Septembre	42 155	4,38	4,38	2,03	115,9%	991 070
Octobre	53 390	4,38	4,38	2,23	96,7%	1 149 907
Novembre	45 981	4,38	4,38	1,85	137,2%	1 164 974
Décembre	72 641	4,38	4,38	3,50	25,1%	638 340
Total	**495 082**	**4,35**	**4,35**	**2,98**	**46,1%**	**6 802 357**

[1] Constatant que les pourcentages d'écart de prix au tableau du préambule (i) étaient erronés, ils ont été rectifiés.

Sur l'ensemble des 45 prix mensuels de l'électricité additionnelle établis d'avril 2010 à décembre 2013 selon la formule actuellement en vigueur, 8 ont été supérieurs aux prix planchers. En supposant que le Distributeur planifiait chaque année procéder à des achats de court terme sur les marchés d'énergie durant 500 heures au cours de la période de décembre à mars, l'application de la formule proposée aurait amené le prix applicable pour ces 8 valeurs au prix plancher.

28.2 Veuillez fournir les données présentées au tableau en référence pour la période couvrant les mois de janvier à avril 2014.

Réponse :

L'information demandée pour les mois de janvier à avril 2014 est présentée au tableau R-28.2.

Tableau R-28.2 :
Bilan de l'option d'électricité additionnelle pour 2014

Mois	Volume mensuel additionnel (MWh)	Prix moyen de l'électricité additionnelle (¢/kWh)	Prix réel à la zone M + ajustements (¢/kWh)	Écart de prix (%)	Écart de revenu total ($)
Janvier	38 756	5,49	13,39	-59,0%	-3 063 237
Février	49 726	5,49	6,75	-18,7%	-629 013
Mars	50 268	5,49	7,81	-29,7%	-1 167 026
Avril	45 989	4,54	2,95	54,0%	732 297
Total	**138 750**	**5,49**	**8,99**	**-38,9%**	**-4 859 276**

La situation exceptionnelle des marchés de l'électricité (et du gaz naturel) observée au cours de l'hiver 2013-2014, tributaire des conditions climatiques très froides, s'est traduite par une hausse importante des prix de l'énergie.

Toutefois, les écarts de prix et de revenus présentés au tableau R-28.2 sont établis sur la base d'un indicateur de marché pour l'ensemble des heures du mois. En pratique, compte tenu de l'équilibre offre - demande, le Distributeur n'entrevoyait pas de volumes d'achats importants au moment d'établir le prix de l'électricité additionnelle des mois de janvier à avril 2014 (soit 7 jours ouvrables avant le début de chacun des mois visés).

Pour cette raison, et dans un souci de transmettre à sa clientèle un signal prévisible du coût d'approvisionnement à la marge, le Distributeur a reconduit le prix de l'électricité additionnelle du mois de janvier 2014 pour les mois de février et de mars.

Dans le cadre du présent dossier, le Distributeur demande à la Régie d'approuver une nouvelle formule d'établissement du prix de l'électricité additionnelle qui permet une meilleure prévisibilité et qui reflète plus fidèlement l'état de l'équilibre offre - demande du Distributeur et les conditions de marché.

29. Référence : Pièce B-0050, p. 128.

Préambule :

VERSION MODIFIÉE

HAP x CEE$_h$ + (1 – HAP) x CEP / H$_h$ ~~(a x NYISO Zone A Peak + (1 - a) x NYISO Zone A Off-Peak + MoyMo + FS Zone M) x TX~~	
où	
HAP~~a~~ =	le nombre d'heures pour lesquelles Hydro-Québec Distribution prévoit faire des achats de court terme sur les marchés durant la période d'hiver~~lequotient des heures de pointe par les heures totales du mois visé établi au calendrier de la North American Electric Reliability Corporation (NERC)~~ ;

Demande :

29.1 Veuillez démontrer la validité de la formule proposée.

Réponse :

Le Distributeur constate qu'une erreur s'est glissée dans la formule présentée à la pièce HQD-14, document 4 (B-0050). Elle devrait plutôt s'énoncer comme suit :

(HAP x CEE$_h$ + (H$_h$ - HAP) x CEP) / H$_h$

Pour un exemple d'application de la formule, voir la pièce HQD-14, document 2 (B-0049), page 13, lignes 13 à 19.

Service Signature

30. Référence : (i) Pièce B-0081, p. 95 et 96;
(ii) Dossier R-3644-2007, pièce HQD-12, document 7.1, p. 12;
(iii) Pièce B-0081, p. 96;
(iv) Dossier R-3644-2007, pièce HQD-12, document 7.1, p. 15 et 16.

Préambule :

(i) La Régie remarque, au Tableau R.43-2 de la pièce B-0081, p. 95, que les revenus totaux et les bénéfices (différence entre les revenus totaux et les coûts totaux) du Service Signature étaient de 491,8 K$ et de 245,7 K$ respectivement, en 2013. Au Tableau R-43.3-B, le Distributeur présente une analyse financière reflétant l'impact des modifications proposées aux frais annuels et au coût des nouveaux appareillages de mesure. Il y est prévu une perte de

110 K$ en 2015 et une augmentation des revenus requis en 2015 et 2016, laquelle ne sera pleinement compensée, sur une base cumulative, qu'en 2020.

Tableau R-43.3-B :
Analyse financière du service Signature

k$ courants	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Revenus	-45	175	363	489	615	756	558	372	246	120	27
Charges d'exploitation	43	75	183	293	313	322	205	88	78	68	60
Amortissement	19	98	131	153	176	183	139	107	85	62	35
Frais financiers	3	18	19	18	17	14	11	7	4	2	1
Dépenses totales	65	191	333	464	505	519	355	202	167	132	96
Bénéfice net	-110	-16	30	25	110	237	203	170	79	-12	-68
Rémunération de l'avoir de l'actionnaire	4	17	19	18	16	14	10	7	4	2	1
Revenus requis	**114**	**33**	**-11**	**-7**	**-94**	**-223**	**-193**	**-163**	**-75**	**14**	**69**

(ii) « *Le niveau du tarif du service de base du Service Signature a été fixé en considérant les aspects suivants :*

- *Le tarif doit permettre de couvrir tous les coûts à encourir pour la fourniture du service.*
- *Le tarif doit refléter la valeur du service d'autant plus qu'il nécessite une expertise pointue.*
- *Le tarif ne doit pas être trop élevé pour ne pas rebuter la clientèle à adhérer au Service*

Signature, particulièrement pour les points de mesure additionnels.

- *Le tarif doit refléter les économies de volume lorsqu'il y a plus d'un point de mesure pour un même client.* »

(iii) À la question 43.4 demandant de préciser si le Distributeur s'est référé aux paramètres énoncés à la référence (ii) aux fins de sa proposition, le Distributeur répond :
« *Oui. Les trois premiers paramètres ont été respectés dans leur intégralité. Ainsi, la tarification du service proposé permet de couvrir tous les coûts à encourir pour la fourniture du service et reflète la valeur du support offert par des spécialistes en qualité de l'onde dans le service de base. Le prix tient également compte de l'ouverture du Service aux clients de moyenne puissance pour lesquels le prix actuel n'est pas attrayant.* »

(iv) Lors de l'introduction du service en 2007, le Distributeur affirmait :
« *L'analyse financière montre que le projet amène une légère diminution des revenus requis du Distributeur dès la première année.* »

TABLEAU 3: ANALYSE FINANCIÈRE DU *SERVICE SIGNATURE*
EN MILLIERS DE DOLLARS

Signature	2008	2009	2010	2011	2012
k$ courants					
Revenus	260	305	400	485	540
Charges	141	148	177	193	218
Amortissement	2	6	11	18	23
Taxe sur le capital	0	0	0	0	0
Taxe sur les services publics	0	0	0	1	1
Frais financiers	1	2	4	6	7
Dépenses totales	144	157	193	218	248
Bénéfice net	116	148	207	267	292
Rémunération de l'avoir de l'actionnaire	1	2	3	4	5
Revenus requis	-115	-147	-205	-263	-287

Note: les totaux et les sous-totaux peuvent être différents de la somme des données en raison des arrondis.

»

Demandes :

30.1 Veuillez expliquer les revenus négatifs de 45 K$ prévus pour l'année 2015, tel qu'indiqué à la référence (i), en précisant les hypothèses et les composantes sous-jacentes.

Réponse :

Le Distributeur a considéré, aux fins de l'analyse économique, les revenus provenant de l'adhésion de nouveaux clients ainsi que l'écart de revenus associé aux clients du service actuel afin de tenir compte de la diminution du tarif.

Par ailleurs, puisque le nouveau service et la nouvelle tarification seront applicables à compter du 1er avril 2015, les revenus ne sont comptabilisés que pour une partie de l'année. De plus, le Distributeur fait l'hypothèse que les nouveaux clients adhéreront progressivement au service proposé.

Le Distributeur réitère que l'objectif recherché par le service Signature est d'offrir aux clients des outils et l'expertise leur permettant d'améliorer la qualité de l'onde à leurs installations ou de se prémunir contre certaines perturbations du réseau électrique. De plus, ce service favorise l'adoption de mesures contribuant à améliorer les caractéristiques du réseau. Pour ces raisons, le service Signature constitue un outil accessoire au même titre que ceux offerts à la clientèle résidentielle sur le site Internet du Distributeur tels le *Diagnostic résidentiel* ou *Comparez-vous*. Le Distributeur souligne que, par conséquent, l'analyse économique ne constitue pas un critère permettant de juger de la pertinence du service Signature, mais vise plutôt à s'assurer que le tarif de ce service est au bon niveau, sans pour autant limiter la participation de la clientèle.

Le détail du nombre de clients et des revenus par services considérés dans l'analyse pour l'année 2015 est présenté au tableau R-30.1.

Tableau R-30.1 :
Hypothèses d'analyse du service Signature pour 2015

	Nombre de clients fin 2015	Revenus (k$)
Nouveaux clients au service proposé		
Base	40	79
Points additionnels	0	0
Option Harmoniques	4	8
Option Bilan annuel	4	8
Option - Tableau de bord	4	1
Sous-total	**40**	**96**
Clients existants au service actuel		
Base	24	84
Points additionnels	8	28
Option Harmoniques	14	47
Option Bilan annuel	12	40
Option - Tableau de bord	5	2
Sous-total	**24**	**200**
Clients existants au service proposé		
Base	24	-240
Points additionnels	8	-53
Option Harmoniques	14	-47
Option Bilan annuel	12	0
Option - Tableau de bord	5	-2
Sous-total	**24**	**-342**
TOTAL	**64**	**-45**

30.2 Veuillez expliquer la chute des revenus de 491,8 K$ en 2013 à -45 K$ en 2015 en détaillant le nombre de clients desservis, les services offerts et les prix exigés pour chacun des services.

Réponse :

Voir la réponse à la question 30.1.

30.3 Veuillez démontrer comment les deux premiers paramètres de la référence (ii) sont respectés dans leur intégralité sur un horizon de 5 ans, horizon auquel le Distributeur faisait référence lors de l'introduction du service en 2007.

Réponse :

Aux fins de l'analyse, le Distributeur suppose que les clients resteront abonnés au nouveau service pour une durée de cinq ans. La période d'analyse retenue par le Distributeur permet d'inclure la totalité des revenus sur cinq ans associés à chacune des nouvelles adhésions.

L'analyse économique montre que le nouveau service proposé est rentable sur la période allant du 1er avril 2015 au 31 mars 2025, ainsi que sur une période de 5 ans débutant en avril 2015. Le tarif permet donc de couvrir les coûts à encourir pour la fourniture du service tout en reflétant la valeur du service, ce qui respecte les deux premiers paramètres de la référence (ii).

30.4 Veuillez estimer quels prix le Distributeur devrait charger pour ces services afin de couvrir ses frais, en moyenne pour les années 2015 et 2016? Veuillez commenter

Réponse :

Le Distributeur tient à préciser que ce service comporte un investissement initial, particulièrement au plan du développement informatique, qui sera amorti sur la durée de vie du service, ce qui est souvent le cas d'un programme commercial. Dans cette optique, il convient d'analyser la rentabilité du service sur sa durée de vie et non pas uniquement sur les premières années de sa mise en place. En fixant le prix uniquement sur les années 2015 et 2016, celui-ci serait élevé et devrait être rajusté à la baisse par la suite. De plus, un tel prix diminuerait l'intérêt pour ce service à court terme et, en conséquence, affecterait la participation de la clientèle ainsi que la rentabilité dans une perspective plus longue.

Dispositions tarifaires visant le développement économique

31. Références : (i) Pièce B-0078, p. 6;
(ii) Pièce B- B-0107, p. 8 et 9;
(iii) Pièce B-0112, p. 11;
(v) Pièce B-0112, p. 9.

Préambule :

(i) « *De plus, afin d'éviter que l'ajout de nouvelles charges ne se fasse au détriment de charges existantes au Québec, le potentiel d'ajout net de nouvelles charges sera considéré pour établir l'admissibilité au tarif. <u>Ce potentiel sera évalué par une combinaison de critères</u>, notamment l'intensité des échanges commerciaux, le niveau d'utilisation des capacités de production existantes et la croissance prévue de la* *demande du secteur concerné. L'évaluation de chaque projet, eu égard aux critères d'évaluation retenus, de même qu'à la valeur ajoutée et aux retombées économiques générées au Québec, sera faite par Hydro-Québec, en mettant à profit les connaissances et l'expertise des instances gouvernementales relatives aux secteurs d'activité porteurs de développement économique.* » [nous soulignons]

(ii) « *Comme mentionné en réponse à la question 4.1, le Distributeur cherche avant tout à attirer des entreprises oeuvrant dans de nouveaux secteurs d'activité au Québec plutôt que d'en ajouter aux secteurs à maturité. Ainsi, de prime abord, les projets pouvant bénéficier du tarif ne devraient pas provenir d'un transfert de production entre deux entités au Québec.*

Un client désirant s'implanter au Québec, devra fournir au Distributeur, en vertu de l'article 6.42 du tarif, les renseignements pertinents, notamment une description de son projet, les produits qui seront fabriqués et les procédés et technologies utilisés. De plus, l'expertise du Distributeur ainsi que celle des instances gouvernementales serviront à dresser un portrait d'ensemble du secteur visé. À partir de cette information, le Distributeur pourra vérifier si ce secteur réalise une part importante de ses ventes à l'extérieur du Québec (intensité des échanges commerciaux), si ce secteur est en croissance à l'échelle mondiale et si les clients de ce secteur, déjà présents au Québec, sous-utilisent leurs capacités de production.

Par ailleurs, un client déjà établi au Québec devra également démontrer, au soutien de sa demande, l'impact que sa nouvelle installation pourrait avoir sur le niveau de la production de ses installations existantes. Cette information fera partie de l'entente à conclure avec le Distributeur.

Enfin, <u>le Distributeur n'allouera pas le tarif de développement économique à un projet comportant un risque significatif sur ses ventes d'électricité actuelles</u>. » [nous soulignons]

(iii) « *Comment gérez-vous le risque que cette mesure puisse donner lieu à de l'arbitraire ?*

Réponse : *<u>L'arbitraire se produit lorsqu'une décision n'est pas prise en observant des règles ou sur la base d'informations pertinentes</u>. Le Distributeur a expliqué comment il entend analyser les demandes en réponse aux questions 4.1 et 5.1 de la demande de renseignements no°3 de la Régie à la pièce HQD-15, document 1.4.*

En offrant ce tarif à des entreprises qui oeuvrent dans de nouveaux secteurs et <u>en limitant l'offre aux entreprises actives dans des secteurs à maturité</u>, le Distributeur s'assure de réduire le risque de cannibalisation au maximum. » [nous soulignons]

(iv) « *Le tarif de développement économique est soumis à la juridiction de la Régie. Ainsi, comme pour l'application des autres tarifs, un client d'Hydro-Québec pourra adresser, dans une première étape, une plainte à Hydro-Québec qui pourra alors revoir le dossier* *et confirmer, ou non, sa décision en regard des arguments du client. Si cette démarche ne reçoit pas un accueil favorable, le client pourra alors référer sa plainte à la Régie où la preuve des deux parties sera entendue et les arguments et informations, incluant celles provenant des instances gouvernementales, seront partagées.*»

Demandes :

31.1 Veuillez préciser si les trois critères d'évaluation mentionnés à la référence (i) constituent des critères de base qui s'appliqueront à l'ensemble des projets. Sinon, veuillez préciser dans quelles circonstances ils ne s'appliqueront pas.

Réponse :

Les trois critères cités en référence (i) seront utilisés dans l'évaluation de tous les projets. Toutefois cette liste de critères n'est pas exhaustive et le Distributeur devra l'utiliser conjointement avec toute autre information pertinente pouvant servir à dresser un portrait complet du secteur d'activité concerné.

Compte tenu du critère d'intensité électrique, le Distributeur n'envisage pas recevoir un nombre élevé de demandes d'adhésion et encore moins, dans des secteurs existants. Par ailleurs, les projets pouvant bénéficier du tarif ne devraient pas se réaliser au détriment de charges existantes au Québec puisque le Distributeur cherche avant tout à attirer des entreprises œuvrant dans de nouveaux secteurs d'activité.

Quant aux nouveaux projets susceptibles d'avoir un impact sur les ventes actuelles du Distributeur, ils nécessiteront une analyse plus approfondie. Le Distributeur, avec l'aide du gouvernement, devra alors considérer tous les aspects pertinents pour faire la meilleure évaluation possible du risque de cannibalisation des ventes afin de déterminer l'admissibilité du projet au tarif de développement économique. Pour ce faire, l'expertise disponible tant chez le Distributeur qu'au gouvernement sera mise à contribution pour dresser un bilan d'ensemble du secteur et de l'ensemble des enjeux.

La diversité et la complexité des projets ainsi que l'aspect novateur des technologies visées ne permettent pas de fonder la décision uniquement sur des seuils rattachés aux critères considérés, ni de limiter l'analyse à ces trois critères. La décision devra également reposer sur des facteurs comme le type de procédés utilisés et l'évolution des technologies et de la réglementation. Ainsi, la décision ne peut être prise en considérant le résultat découlant d'une formule, mais plutôt sur la base d'une analyse de marché plus complète.

31.2 Veuillez expliquer selon quels critères, à partir de quels seuils et comment le Distributeur déterminera si un risque sur ses ventes d'électricité actuelles, tel que mentionné à la référence (ii), constitue un risque significatif pouvant entraîner le rejet d'un projet.

Réponse :

Voir la réponse à la question 31.1.

Les critères mentionnés en référence (i) peuvent être développés de la façon suivante :

- **l'intensité des échanges commerciaux permettra d'évaluer si le marché ciblé par le secteur est davantage intérieur ou international. Plus le projet visera les exportations ou le remplacement des importations, moins il y aura de risque de cannibalisation des ventes ;**
- **plus le niveau d'utilisation des capacités de production existantes au Québec sera élevé, plus faible sera le risque de cannibalisation des ventes ;**
- **plus la croissance prévue de la demande pour les produits du secteur visé sera forte, plus le risque de cannibalisation des ventes sera faible.**

Ces critères devront être analysés de façon combinée afin de bien évaluer le risque de cannibalisation des ventes.

L'analyse ne peut reposer sur des seuils rattachés à ces critères principalement dans les situations jugées intermédiaires. À titre d'exemple, dans le cas où le marché cible est essentiellement intérieur, le risque de cannibalisation des ventes sera toujours élevé sauf si les capacités de production existantes sont pleinement utilisées et que le marché est en croissance. Dans le cas où le marché cible est essentiellement international, le risque de cannibalisation des ventes sera davantage influencé par le positionnement des usines existantes au Québec par rapport aux nouvelles installations, qu'elles s'implantent au Québec ou ailleurs.

31.3 Afin d'éviter l'arbitraire, tel que mentionné à la référence (iii), et afin de préciser les règles d'admissibilité, veuillez expliquer pourquoi le Distributeur ne mentionne pas, à l'article *6.41 Conditions d'admissibilité* du tarif de développement économique, certains des critères qu'il entend utiliser afin de juger de l'admissibilité d'un client au tarif.

Réponse :

Selon le Distributeur, l'alinéa d) de l'article 6.41 du tarif indique les principes lui permettant de considérer un ensemble de facteurs nécessaires et suffisants à la prise de décision. L'analyse sur la base de principes met en lumière l'importance de travailler avec les autorités compétentes.

Étant donné la diversité des cas qui pourraient se présenter, fixer des critères très précis pour juger du potentiel d'ajout net de nouvelles charges limiterait

la latitude requise pour considérer l'ensemble des facteurs pertinents au cas à l'étude et conséquemment, limiterait son évaluation.

31.4 Veuillez indiquer si les critères d'évaluation peuvent varier d'un projet à l'autre. Veuillez développer.

Réponse :

Non. Toutefois, le Distributeur devra tenir compte de tous les facteurs pertinents à l'analyse de l'ajout net de nouvelles charges dont les critères mentionnés au préambule. Selon les différents cas, certains facteurs peuvent être plus pertinents que d'autres. Voici des exemples de situations qui pourraient rendre l'analyse d'un projet plus complexe et qui illustrent le risque de baser une décision sur une liste de critères pré-établis :

- **nouveau joueur qui répond à une demande en croissance à l'extérieur du Québec et dont la production n'affecterait pas le niveau de production des capacités existantes répondant essentiellement à une demande intérieure ;**
- **nouveau joueur qui utilise de nouveaux procédés ou de nouvelles technologies rendant ses installations plus compétitives à l'échelle mondiale ainsi que par rapport aux joueurs existants au Québec ;**
- **nouveau joueur qui a le choix d'installer son projet au Québec ou dans une juridiction voisine et qui affecterait, dans ces deux cas, la compétitivité des joueurs existants au Québec.**

Tout projet présentant des caractéristiques s'apparentant à celles mentionnées ci-dessus devra faire l'objet d'une analyse exhaustive mettant à contribution l'expertise du Distributeur et du gouvernement.

31.5 Veuillez indiquer si, afin de limiter le nombre de plaintes éventuelles, comme il est mentionné à la référence (iv), les critères d'évaluation utilisés afin de juger de l'admissibilité d'un projet seront précisés et communiqués au client potentiel qui se voit refuser le tarif. Si oui, veuillez spécifier à quel moment et sous quelle forme cette information sera communiquée au client. Sinon, veuillez justifier.

Réponse :

Comme il l'a indiqué en réponse à la question 31.1, le Distributeur n'envisage pas recevoir un nombre élevé de demandes d'adhésion étant donné les critères d'admissibilité. Le tarif ne s'adresse pas à une clientèle de masse et l'analyse des projets devra être faite au cas le cas, selon les particularités des projets ainsi que celles du secteur dans lequel ils s'implanteront.

Tout client qui implante un projet nécessitant une alimentation électrique est déjà accompagné par le Distributeur tout au long de son processus de raccordement. En outre, dès qu'un client montrera de l'intérêt pour installer un projet au Québec, il sera accompagné par le Distributeur et le gouvernement dans ses démarches. Des échanges auront lieu afin de déterminer son admissibilité au tarif, le résultat de l'évaluation lui sera communiqué et les raisons d'un refus, le cas échéant, seront discutées avec lui.

ANNEXE A

RÉPONSE
D'HYDRO-QUÉBEC DISTRIBUTION
À LA QUESTION 5.1
DE LA DEMANDE DE RENSEIGNEMENTS NO 4
DE LA RÉGIE

BRITISH COLUMBIA
UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

ORDER
NUMBER G-110-12

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of 2012-2013 Revenue Requirements and
Review of 2012 Integrated System Plan

BEFORE: D.A. Cote, Commissioner
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

August 15, 2012

O R D E R

WHEREAS:

A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed an application pursuant to sections 44.1, 44.2, 56 and 59 to 61 of the *Utilities Commission Act* (the Act) for approval of its 2012-2013 Revenue Requirements and the review of its 2012 Integrated System Plan (collectively referred to as the Application);

B. The Application contains two parts:

1) FortisBC's 2012-2013 Revenue Requirements (including the Company's 2012-2013 Capital Expenditure Plan filed pursuant to section 44.2(1) of the Act),

2) FortisBC's 2012 Integrated System Plan filed pursuant to section 44.1 of the Act, comprising its 2012 Long Term Capital Expenditure Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan;

C. FortisBC sought, among other things, approval of interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. FortisBC also sought a permanent rate increase of 6.9 percent effective January 1, 2013;

D. The Company requests a determination from the British Columbia Utilities Commission (the Commission) on whether the 2012-2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3)(a) and satisfies the requirements of section 45(6) of the Act;

E. The Company also requested a Commission determination on whether the 2012 Integrated System Plan, which is comprised of three components (the 2012-2013 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand-Side Management Plan), is in the public interest pursuant to section 44.1 (6);

F. A Workshop to review the Application was held in Kelowna on July 22, 2011;

…/2

G. The Company filed an Evidentiary Update to the Application on November 4, 2011, which reduced the rate increase sought to 1.5 percent in 2012 and a 6.5 percent increase in 2013;

H. The 2011 Annual Review was held in Kelowna on November 22, 2011, to review the Company's performance for the 2011 year, followed by a Procedural Conference to hear submissions on procedural matters regarding the current Application;

I. By Order G-199-11, the Commission approved a 1.5 percent interim rate increase for FortisBC, effective January 1, 2012;

J. Pursuant to Order G-214-11, the Oral Public Hearing to review the Application took place between March 5 and March 9, 2012 in Kelowna;

K. Between April 5 and April 23, 2012, FortisBC and Interveners filed their Final Submissions. FortisBC filed its Reply Submission on May 3, 2012;

L. The Commission has considered the Application, the evidence and all the submissions as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. Pursuant to sections 59 to 61 of the *Act*:

   a. The requested permanent rate increase of 1.5 percent in 2012 and 6.5 percent in 2013 is not approved, as filed.

   b. Cross charges between FortisBC and its affiliates regulated by the Commission are approved to be based on fully loaded costs, not including overhead.

   c. The proposed Deferral Account for Power Purchase Expense variances from forecast is approved and is to be amortized into rates in 2014. The proposed Revenue Variance Deferral Account is also approved and is to be amortized into rates in 2014.

   d. Determinations for the new proposed Deferral Accounts and treatment for existing Deferral Accounts are set out in Section 5.4.4 of the Decision.

   e. Costs of Removal of $4.7 million for 2011, $5.4 million for 2012 and $4.0 million for 2013 are approved to be included in Rate Base as set out in Section 5.4.2 of the Decision.

2. Pursuant to section 44.2(3) of the *Act*, FortisBC's 2012-2013 Capital Expenditure Plan is approved subject to the determinations and reductions set out in Section 5.4.3 of the Decision.

3. The Commission Panel accepts FortisBC's Long Term Capital Plan is in the public interest and the Long Term Resource Plan meets the requirements of the Act except for the Planning Reserve Margin as set out in Section 7.0 of the Decision.

…/3

4. FortisBC is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 30 days of this Order.

5. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision. FortisBC is to provide all customers, by way of an information notice, of the change in rates.

6. If the 2012 permanent rates are less than the interim rates, FortisBC is to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which FortisBC conducts its business. If the 2012 permanent rates exceed the interim rates, FortisBC is to reflect this difference in customer rates over the balance of 2012.

7. FortisBC is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

BY ORDER

Original signed by:

D.A.Cote
Commissioner

IN THE MATTER OF

FORTISBC INC.

2012-2013 REVENUE REQUIREMENTS
AND
REVIEW OF 2012 INTEGRATED SYSTEM PLAN

DECISION

August 15, 2012

Before:

D.A. Cote, Commissioner/Panel Chair
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

TABLE OF CONTENTS

Page No.

1.0 EXECUTIVE SUMMARY 1

2.0 INTRODUCTION 7

2.1 The Application and Approvals Sought 7

2.2 Legislative Framework 8

2.3 Regulatory Process 14

2.4 Approach to this Application 16

3.0 OVERRIDING ISSUES 18

3.1 Magnitude of Rate Increase 18

3.2 Relevance of BC Hydro/FortisBC Inc. Rate Disparity 20

3.3 Importance of Productivity Improvements 21

4.0 ISSUES OF IMPORTANCE 23

4.1 Load and Customer Forecast 23

4.2 Capital Structure and ROE 25

5.0 2012-2013 REVENUE REQUIREMENTS APPLICATION 32

5.1 Power Purchase Management 32

5.1.1 Power Purchase Expense 32

5.1.2 Power Purchase Management Expense 35

5.1.3 Planning Reserve Margin 38

5.1.4 Water Fees 41

5.2 Operations and Maintenance Expenses 42

5.2.1 Overriding Issues 42

5.2.1.1 Demographic Challenges 42

5.2.1.2 Productivity Factor 44

5.2.1.3 Integration of FortisBC and FortisBC Energy Utilities 46

5.2.1.4 Cost Allocations 48

5.2.2 Review of Operating and Maintenance Costs and Issues 49

5.2.2.1 Introduction 49

5.2.2.2 Labour Related costs 51

5.2.2.3 Non-Labour Costs 64

TABLE OF CONTENTS

Page No.

5.2.2.4 Summary of Operating and Maintenance Cost Changes 70
5.2.2.5 Other Revenue Requirement Issues 71
5.3 Financing Costs 79
5.4 Rate Base 82
5.4.1 Plant In Service 84
5.4.2 Accumulated Depreciation and Cost of Removal 84
5.4.3 2012/2013 Capital Expenditure Plan 86
5.4.4 Deferral Accounts 103
5.4.4.1 Existing Deferral Accounts 107
5.4.4.2 Proposed Deferral Accounts 112
5.4.4.3 Existing Deferral Accounts with Proposed Change in Treatment . 125

6.0 DEMAND-SIDE MANAGEMENT 126

6.1 Long-Term Demand-Side Management Plan 126
6.2 Monitoring and Evaluation Plan 127
6.2.1 The Commission's Review of the Long-Term DSM Plan 128
6.2.1.1 Adequacy and Cost Effectiveness 128
6.2.1.2 The Public Interest 129
6.2.1.2.1 Monitoring and Evaluation Plan 131
6.3 FortisBC's Expenditure Request for 2012-2013 134
6.3.1 The Commission's Review of the DSM Expenditure Request 135
6.3.1.1 Sufficiency of DSM Spending Level 136
6.3.1.2 FortisBC Industrial Incentives 137
6.3.1.3 Transfers of DSM Funding Among Programs 140
6.3.1.4 Integration of DSM Programs Among BC Utilities 141

7.0 INTEGRATED SYSTEM PLAN 142

7.1 Long-Term Capital Plan 142
7.2 Long-Term Resource Plan 143
7.2.1 2012 Long-Term Resource Plan Summary 144
7.2.2 Requirements under the Utilities Commission Act 147
7.2.3 Filing of the Next LTRP 149

TABLE OF CONTENTS

Page No.

8.0 SUMMARY OF DIRECTIVES 150

COMMISSION ORDER G-110-12

APPENDICES

APPENDIX A Sections 59 through 61 Utilities Commission Act

APPENDIX B Section 44.2 Utilities Commission Act

APPENDIX C Section 2, Clean Energy Act

APPENDIX D List of Acronyms

APPENDIX E List of Appearances

APPENDIX F List of Exhibits

1.0 EXECUTIVE SUMMARY

On June 30, 2011, FortisBC Inc. filed its 2012-2013 Revenue Requirements (Application) and its 2012 Integrated System Plan for approval.

FortisBC sought across-the-board interim and permanent rate increases of 4.0 percent and 6.9 percent respectively for 2012 and 2013, pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (*Act, UCA*). This was revised with the filing of its Evidentiary Update on November 4, 2011, and FortisBC now seeks a rate increase of 1.5 percent for 2012 and 6.5 percent for 2013. Pursuant to subsection 44.2 (1) of the *Act*, the Company has also filed its 2012-2013 Capital Expenditure Plan with proposed gross expenditures over the test period of $162.467 million as part of the Application.

A second part of the Application is the 2012 Integrated System Plan, which is made up of the 2012 Long Term Capital Plan, the 2012 Resource Plan and the 2012 Long Term Demand-Side Management Plan. FortisBC is seeking Commission acceptance that this is in the public interest pursuant to subsection 44.1(6) of the *Act*.

In reviewing this Application, the Commission Panel identified a number of overriding issues which have a direct impact on this proceeding and must be considered. These issues are as follows:

- The Magnitude of Rate Increase

  The rate increases being sought in this Application and the expected future rate increases through 2016 indicate a trend that is well in excess of inflation. Given the economic challenges faced by all British Columbians including those within the FortisBC service area, the Commission Panel will review this Application with a view to minimizing current and potential future rate increases.

- Relevance of BC Hydro/FortisBC Inc. Rate Disparity

  Considerable concern was raised in this proceeding with respect to the disparity in rates and practices of BC Hydro and FortisBC. The Commission Panel's notes that the two companies operate with a different set of supply resources and a different customer base in terms of geography, population density and the residential/commercial/industrial mix. Therefore the Panel is of the view that there is no mandate nor would it be appropriate to expect FortisBC to have programs and rates that mirror those of BC Hydro.

- Importance of Productivity Improvements

The Commission Panel places considerable importance on the need for creating what it has described as a "productivity improvement culture" within utilities and, in the absence of evidence supporting its existence, to impose some form of productivity factor. The question facing the Panel is whether FortisBC has taken appropriate steps to demonstrate that it has processes in place to ensure productivity opportunities are explored.

These issues were not determinative in nature but did provide the Panel with a context to deal with specific issues as they arose within the proceeding.

Other key issue areas included:

- Power Purchase Management
- Departmental Operations and Maintenance (O&M) Expenses
- 2012-2013 Capital Expenditure Plan
- Deferral Accounts
- Demand-Side Management
- The Integrated System Plan

The Commission Panel has considered the views of all of the parties in making its determinations. We have not approved all of the FortisBC proposals nor have we agreed with all of the positions taken by the different Interveners. In the view of the Panel, the determinations made in this Decision are in the public interest and the resulting rates are just and reasonable as required under sections 59 and 60 of the *Act*.

A discussion of some of the highlights and key issues related to the Decision follows:

Power Purchase Management

A key function within FortisBC is the handling of power purchases through power purchase management. This Decision has examined a number of issues related to this function:

- A request for approval of increased power purchase expenses over the test period and a proposal to capture power purchase variances (both positive and negative) in a deferral account and flow them to customers in subsequent years.
- A proposal to increase power purchase management expenses (PPME) by 30 percent and include them as part of the estimate for power purchase expense.
- A proposal to implement a Planning Reserve Margin (PRM) late in the test period at an initial cost of $310,000.

The Commission Panel made the following determinations:

- Approval of the deferral account to capture power purchase expense variances was granted, however, the Panel directed FortisBC to reduce its Power Purchase Expense Forecasts by $1.5 million in consideration of previous forecast variances.
- PPME expenses were approved in a reduced amount and the proposal to move PPME from Operations and Maintenance and include it as part of power purchase expense was rejected.
- The proposal to implement a PRM and related expenses as part of the power purchase expense in this test period was rejected.

Departmental Operations and Maintenance Expenses

FortisBC has applied for O&M expenses of $55.4 million in 2012 and $56.8 million in 2013 (including PPME). A major consideration of the Commission Panel was whether FortisBC in this Application has demonstrated it has processes in place to ensure productivity opportunities are explored and implemented. The Commission Panel, while noting some concerns in specific departments, was not of the view that imposing an overall productivity factor as proposed by some of the Interveners was appropriate given the size of proposed increases and the evidence on this matter.

The Commission Panel directs FortisBC to reduce O&M expenditures for labour by $250,000 noting specific concerns in the Generation, Utility Operations and Community and Aboriginal Affairs departments. The Panel has made further determinations with respect to a reduction of proposed expenditures for the asset management program and non-labour related expenses in Customer Service and Community and Aboriginal Affairs.

2012-2013 Capital Expenditure Plan

FortisBC proposed capital expenditures totalling $162,467 million. The Interveners that commented on the 2012-2013 Capital Expenditure Plan were unanimous in calling for a reduction in expenditures. BCPSO notes that there has been a significant build-out in recent years resulting in increased reliability, safety and quality of service to ratepayers. The Industrial Customers Group (ICG) argues that capital expenditures being made on the basis of reliability improvements should not form part of the Plan.

The Commission Panel is of the view that safety, reliability and quality of service to ratepayers are at an acceptable level and a focus on identified problem areas is considered most appropriate at this time. The Panel has made specific determinations on projects which are inadequately supported or require additional work and has also made observations with regard to specific projects or project amounts we consider questionable given the evidence provided by the Company. The Commission Panel has rejected two projects totalling $10.5 million. While the Panel has identified possible overall reductions of $17.4 million, it has reduced that amount to $ 10.5 million to allow FortisBC to achieve the level of service it requires and have sufficient flexibility to manage its projects and workforce. The Commission Panel has accepted capital expenditures of $140,218 for the 2012-2013 test period.

Deferral Accounts

Important issues related to deferral account financing charges and the appropriate time period over which deferral accounts should be amortized have been examined. The Commission Panel has outlined the following guiding principles in making its determinations:

- A rate base rate of return applies only when a deferral balance has been transferred to become part of a capital project. Prior to this an interest rate of return based on the Weighted Average Cost of Debt (WACD) will apply.
- Deferred operating costs/current expenses are to attract an interest rate of return which varies based on the length of time they are deferred and the size of the amounts deferred.
- The length of amortization periods depends on a number of factors including the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on the ratepayer.

These have been applied to the determinations on new and existing deferral accounts.

Demand-Side Management

FortisBC seeks approval of its 2012 Integrated System Plan which includes its 2012 Long-Term Demand-Side Management (DSM) Plan. In addition the Company has sought approval of DSM program expenditures of $7.73 million in 2012 and $7.88 million in 2013.

The Commission Panel has found that the 2012 Long-Term DSM Plan is adequate and cost effective. Citing the evidence of BCSEA's expert witness, Mr. Plunkett, that FortisBC has achieved a ranking placing it in his second tier of jurisdictions with successful DSM programs, the Commission Panel approves the Company's DSM expenditures as requested.

Integrated System Plan

In addition to the 2012 DSM Plan the 2012 ISP includes the 2012 Long Term Capital Plan (LTCP) and the 2012 Long Term Resource Plan (LTRP). Both of these plans address the medium and the long term and cover requirements through 2031 in the case of the 2012 LTCP and 2040 in the 2012 LTRP. Based on our review of the evidence, the Commission Panel finds that the 2012 LTCP to be in the public interest and the 2012 LTRP as meeting the requirements of the *Act with the* exception of the Planning Reserve Margin which was rejected. FortisBC has been directed to file its next Long Term Resource Plan no later than June 30, 2016.

2.0 INTRODUCTION

2.1 The Application and Approvals Sought

FortisBC Inc. is a vertically integrated electric utility operating in British Columbia and is regulated by the British Columbia Utilities Commission (Commission).

This is an application by FortisBC Inc. (FortisBC or the Company) for approval of its Revenue Requirements of $287.4 million for 2012 and $310.4 million for 2013 which, if approved, will result in general rate increases for its approximately 161,000 direct and indirect customers of 1.5 percent effective January 1, 2012 and 6.5 percent effective January 1, 2013. (Exhibit B-12, Table 1.0) This approval is sought pursuant to sections 59 to 61 of the *Utilities Commission Act* (the *Act*) RSBC 1996 c. 473.

FortisBC also applies for Commission acceptance of proposed capital expenditures in the gross amounts of $105.86 million for 2012 and $129.08 million in 2013 as being in the public interest under subsection 44.2(3) of the *Act*. These amounts include previously-approved capital expenditures of $7.92 million for 2012. They also include planned expenditures in the amounts of $10.52 million and $42.13 million for 2012 and 2013, respectively, for which the Company expects to file separate detailed applications for Certificates of Public Convenience and Necessity (CPCNs). (Exhibit B-1, Tab 6, p. 6, Table 1.1)

FortisBC has also filed its 2012 Integrated System Plan (ISP) which provides the long-term context for its 2012-2013 Revenue Requirements Application and 2012-2013 Capital Expenditure Plan. The Integrated System Plan outlines the long-term strategic direction of the Company in terms of capital, resource and energy conservation. The Integrated System Plan is made up of FortisBC's 2012 Long Term Capital Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan. FortisBC is seeking Commission acceptance that the Integrated System Plan is in the public interest pursuant to subsection 44.1(6) of the *Act*. (Exhibit B-1-1, Volume 1, pp. 1-2)

2.2 Legislative Framework

FortisBC is seeking approval of its proposed rate increases pursuant to sections 59 to 61 of the *Act.* Those sections basically require the Commission to have due regard to setting a rate that is not unjust or unreasonable in respect of the service provided by the utility. Subsection 59(5) provides that a rate is "unjust" or "unreasonable" if it is:

> "(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
>
> (c) unjust and unreasonable for any other reason".

The utility is required to file rate schedules with the Commission setting out its approved rates.

Sections 59 to 61 are set out in their entirety in Appendix A.

As noted above, the Company is seeking Commission acceptance of proposed capital expenditures for the 2012-2013 test period pursuant to subsection 44.2(3) of the *Act*. Section 44.2 deals with expenditure schedules and is set out in its entirety in Appendix B.

Subsection 44.2(1) provides that:

> "A public utility may file with the commission an expenditure schedule containing one or more of the following:
>
> (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
>
> (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
>
> (c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

Subsection 44.2(3), pursuant to which approval of the proposed capital expenditures for 2012-2013 is sought, states:

> ”After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6) must
>
> > (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
> >
> > (b) reject the schedule”.

By subsection 44.2(4), the Commission may also accept or reject a part of a schedule.

Subsection 44.2(5) provides the factors which the Commission is required to consider in its review of an expenditure schedule filed by a public utility (other than the British Columbia Hydro and Power Authority) stating:

> (5) “In considering whether to accept an expenditure schedule...the commission must consider
>
> > (a) the applicable of British Columbia’s energy objectives,
> >
> > (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
> >
> > (c) the extent to which the [expenditure] schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act,*
> >
> > > [only section 6 of the *Clean Energy Act* is relevant to subsection 44.2(5)(c) and requires the public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* [which deals with long-term resource plans] to consider British Columbia’s energy objective to achieve electricity self-sufficiency in planning for the construction or extension of generation facilities and energy purchases, (by subsection 6(4))].
> >
> > (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any,
> >
> > > [Demand-Side Measures Regulation BC Reg 326/2008 as amended by BC Reg. 228/2011 is applicable]
> >
> > and

> (e) the interests of persons in British Columbia who receive or may receive service from the public utility".

Subsection 44.2(5.1) is not relevant to the Commission's review of the proposed capital expenditures in this case as that subsection applies only to British Columbia Hydro and Power Authority (BC Hydro).

Subsection 44.2(6) provides that:

> "[i]f the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1(6),
>
> (a) subsection 5 [which sets out the considerations for the commission's acceptance of an expenditure schedule as set out above] does not apply with respect to that expenditure, and
>
> (b) the commission must accept under subsection (3) the expenditure in the expenditure schedule".

British Columbia's energy objectives, the applicable of which the Commission is required to consider in its review of an expenditure schedule, exceed fifteen in number and are listed in section 2 of the *Clean Energy Act (CEA).* They relate in large measure to the use of clean or renewable resources, promotion of energy conservation and efficiency and the reduction of greenhouse gas emissions. Section 2 of the *CEA* is set out in Appendix C.

Also as noted above, FortisBC is seeking approval of its Integrated System Plan under section 44.1 of the *Act*, which relates to long-term resource and conservation planning.

Subsection 44.1(2) requires public utilities to file a long-term resource plan with the commission (in the form and at the times required by the commission) including all of:

> (a) an estimate of the demand for energy the utility would expect to serve absent new demand-side measures taken during the period addressed by the long-term resource plan;

(b) a plan of how to reduce that demand through cost-effective demand-side measures;

(c) the resulting net demand, after cost-effective demand-side measures are taken;

(d) a description of the facilities needed to be constructed or extended to serve the resulting net demand;

(e) information on energy purchases necessary to serve the resulting net demand;

(f) an explanation of why the resulting net demand which is to be served by the new facilities and energy purchases is not planned to be replaced by demand-side measures; and

(g) any other information that the commission requires.

By subsection 44.1(6), once the Commission has reviewed the long-term resource plan, it must either accept it, if it determines that carrying out the plan would be in the public interest, or reject it. The commission may also accept or reject part of a long-term resource plan pursuant to subsection 44.1(7).

Subsection 44.1(8) sets out the factors which the Commission is required to consider in determining whether to accept or reject a public utility's long-term resource plan. These factors are consistent with those the commission is required to consider when considering a public utility's expenditure schedule and comprise:

(a) the applicable of British Columbia's energy objectives;

(b) the extent to which the [long-term resource] plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;

> [Again, only subsection 6(4) of the *Clean Energy Act* is relevant. As noted earlier, this subsection requires the public utility, in planning for the construction or extension of generation facilities and energy purchases in accordance with its long-term resource planning under section 44.1 of the *Act*, to consider British Columbia's energy objective to achieve electricity self-sufficiency.]

(c) whether the [long-term resource] plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility.

The Demand-Side Measures Regulation

As noted above, BC Reg. 228/2011 amended the Demand-Side Measures Regulation, BC Reg. 326/2008.

The Demand-Side Measures Regulation applies to demand-side measures proposed in long-term resource plans filed under section 44.1 of the *Act* as well as those proposed in expenditure schedules filed under section 44.2 of the *Act*.

Among other things, the Demand-Side Measures Regulation defines the class composed of all demand-side measures proposed by a public utility in a long-term resource plan submitted under section 44.1 of the *Act* as a "plan portfolio". It defines the class composed of all demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the *Act* as an "expenditure portfolio".

Section 3 of the Demand-Side Measures Regulation sets out the criteria, all of which must be met (as long as the plan portfolio is submitted after June 1, 2009), for a utility's plan portfolio to be "adequate" for the purposes of subsection 44.1(8) (c) of the *Act*. To be adequate, the plan portfolio must include:

(a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

(b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools within the public utility's service area;

(d) an education program for students enrolled in post-secondary institutions in the public utility's service area.

Section 4 of the Demand-Side Measures Regulation provides for the calculation of the cost effectiveness of demand-side measures. It also prescribes how the "cost-effectiveness" of a demand-side measure is to be determined for a demand-side measure proposed in an expenditure portfolio.

The calculation prescribed by the Regulation has been called the modified TRC (mTRC) to distinguish it from the more traditional Total Resource Cost test (TRC).

In essence, for any demand-side measure proposed in an expenditure portfolio (i.e. filed pursuant to section 44.2 of the *Act*) which is not directed at residents of low income households, and for which the benefit amount to be used in the TRC test has not already been increased in accordance with the utility's request, the Commission is required to increase the benefit of the demand-side measure by an amount that:

- increases the benefits of the entire expenditure portfolio of which the demand-side measure is a part by 15 percent, and
- is equal to the increase made for all other demand-side measures making up the expenditure portfolio.

Thus, each individual demand-side measure in an expenditure portfolio is subject to a minimum increase of 15 percent.

However, other than for "specified demand-side measures" (which are defined) and "public awareness programs" (which are also defined) there is basically a 10 percent cap on demand-side measures which need the 15 percent adder to be cost-effective, in the case of electric utilities. (Demand-SideMeasures Regulation, subsection 4(1.5))

The Commission also has the ability, in certain circumstances, to include other demand-side measures not included in the expenditure portfolio when determining cost-effectiveness and may, again in certain circumstances, and for certain demand-side measures, apply the utility cost test, as opposed to the modified Total Resource Cost test discussed above. (Demand-Side Measures Regulation, subsections 4(1.7), 4(1.8))

Demand-side measures which are required for a plan portfolio to be adequate, as set out above, are also subject to the Total Resource Cost test, but receive a 30 percent adder. (Demand-Side Measures Regulation, subsection 4(2))

2.3 Regulatory Process

FortisBC filed its Application on June 30, 2011. By Order G-111-11 of the same date, the Commission, among other things, established an Initial Regulatory Timetable and determined that the Company's Load Forecast would be reviewed by a Load Forecast Technical Committee, outside the Information Request (IR) process.

Ten Parties registered as Interveners, although not all participated in the regulatory hearing process. The Registered Interveners were:

- The British Columbia Municipal Electrical Utilities (BCMEU)
- British Columbia Hydro and Power Authority
- Mr. Alan Wait
- Mr. Norman Gabana
- British Columbia Pensioners' and Seniors' Organization *et al.* (BCPSO)
  (The British Columbia Old Age Pensioners' Organization *et al.* filed a Notice of Name Change on July 23, 2012.)
- The BC Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA)
- The Regional District of Okanagan Similkameen
- Ms. Buryl Slack
- The Industrial Customers' Group (comprising: Zellstoff Celgar Limited Partnership, ATCO Wood Products Ltd. International Forest Products Limited, Kalesnikoff Lumber Co. Ltd., Porcupine Wood Products, Springer Creek Forest Products)
- The Irrigation Ratepayers Group.

Five other parties registered as "Interested Parties".

The review of the Application included two rounds of Information Requests.

On September 16, 2011, FortisBC provided a summary of required changes to its Application including, among other things, an expected reduction to its Power Purchase Expense resulting from the Provincial Government's review of BC Hydro's proposed rate increases and BC Hydro's announced intention to amend its Revenue Requirements Application to seek lower rate increases. The Company proposed to recalculate its Revenue Requirements and resulting rate impacts following the report of the Load Forecast Technical Committee which was at that time expected on October 28, 2011. (Exhibit B-6)

On September 28, 2011 FortisBC submitted responses to Information Requests from the Commission and from the BCPSO on system losses. (Exhibit B-7)

On October 4, 2011 the Commission issued Order G-167-11 which, among other things, established a Revised Preliminary Regulatory Timetable and set the date of November 22, 2011 for a Procedural Conference. (Exhibit A-7)

BCSEA filed Intervener evidence on October 31, 2011 on the issue of demand-side management. One round of Information Requests was held on that evidence.

On November 4, 2011, FortisBC filed an Evidentiary Update to its Application. The Evidentiary Update amended the Application to, among other things, incorporate actual results to September 30, 2011, expected reductions to BC Hydro's F2012-2014 rates and updated forecast market rates for electricity, as well as to make certain corrections. The net impact of the changes set out in the Evidentiary Update was to reduce the Revenue Requirements in each year of the test period, resulting in a revised rate increase request for 2012 from 4.0 percent to 1.5 percent and a revised rate increase request for 2013 from 6.9 percent to 6.5 percent. (Exhibit B-12)

A Procedural Conference was held in Kelowna, British Columbia on November 22, 2011.

On November 25, 2011, FortisBC filed its Load Forecast Technical Committee Report.

On November 30, 2011, by Order G-199-11, the Commission Panel determined that FortisBC's Revenue Requirements Application would be reviewed through an Oral Public Hearing process to be held in Kelowna, British Columbia, commencing on January 24, 2012. The Commission Panel also ordered that FortisBC's interim rates for 2011 were to be made permanent, and a deferral account to capture any difference as between the impact of BC Hydro's interim and final rates was approved. The Commission Panel also approved an increase to FortisBC's interim rates, effective January 1, 2012, in the amount of 1.5 percent. (Exhibit A-13)

On December 7, 2011, FortisBC requested an amendment to the Regulatory Timetable to reschedule the Oral Public Hearing from January 24, 2012 to March 5, 2012, or later, in part because key FortisBC personnel were unable to devote the time required to prepare for a hearing commencing in January.

On December 15, 2011, the Commission issued Order G-214-11 amending the Regulatory Timetable and establishing the date of March 5, 2012 for the commencement of the Oral Public Hearing.

The Oral Public Hearing proceeded for five days commencing on March 5, 2012. FortisBC filed its Final Submissions on April 5, 2012. Final Submissions were received from participating Interveners by April 23, 2012. FortisBC filed its Reply on May 3, 2012.

2.4 Approach to this Application

The Commission Panel is of the view that there are a number of broader issues raised in this Application, which are important. These include: the magnitude of rate increases for the current test period and beyond, the relevance of the rate disparity between BC Hydro and FortisBC, and the importance of establishing a productivity improvement culture. These issues are introduced in Section 3 and, while not determinative, provide the Commission Panel with context to deal with specific issues as they arise. This will be followed in Section 4 with a discussion of a number of specific issues of importance, some of which require Commission Panel determinations. Section 5 is a review of the 2012-2013 Application, its related issues and concerns and includes a discussion of operating and maintenance costs and various rate base issues in addition to the 2012-2013 capital plan. Following this is a review of Demand-Side Management in Section 6 and the Integrated System Plan in Section 7.

3.0 OVERRIDING ISSUES

3.1 Magnitude of Rate Increase

Prior to the Evidentiary Update filed on November 4, 2011, FortisBC was seeking rate increases of 4.0 percent and 6.9 percent for 2012 and 2013, respectively. As noted previously, the net impact of the changes set out in the Evidentiary Update resulted in a reduction in the requested rate increase to 1.5 percent in 2012 and 6.5 percent in 2013.

FortisBC attributes the need for rate increases primarily to:

(a) a growing rate base;

(b) an increase in the cost of financing the rate base;

(c) increased power purchase costs; and

(d) taxes.

(Exhibit B-1, Tab 1, p. 6)

A number of Interveners took issue with the proposed rate increases.

The ICG asserts that FortisBC "needs to make immediate changes to reduce costs" and that that will not happen "as long as the Commission continues to approve rate increases..." (ICG Final Submission, p. 47)

The BCPSO argues that "[t]he present economic climate requires the Commission to carefully examine any cost increases that exceed inflation and are not essential to providing service as significant increases will only exacerbate the problems of struggling families during difficult economic times." It submits that FortisBC's capital build-out has been aggressive and agrees that this has resulted in increased reliability, safety and quality of service but argues that "a balance needs to be struck between appropriate levels of safety, reliability, quality of service and reasonable customer rates." (BCPSO Final Submission, p. 3)

Similarly, the BCMEU, which represents the interests of FortisBC's five wholesale electricity customers which are municipal electrical utilities, encourages the Commission "to direct FortisBC to do better in terms of minimizing rate impacts on customers in this test period and beyond." The BCMEU adopts the position taken by the City of Penticton in its letter of comment (Exhibit D-4):

> "The last three years have been very tough at the City of Penticton. The City has had to take drastic steps. The road was not easy. The City faced organizational restructuring, staff layoffs and terminations, elimination of bonuses and no or very low salary increases. In addition, efficiencies were also found. In short, the City of Penticton has worked very hard to reign in expenses so that costs for our customers do not have to increase. In fact, for 2011 the Penticton residential tax rate was reduced by 0.5%.
>
> ...
>
> In closing I would ask that BCUC challenge FortisBC to also look internally to see what steps they can take to streamline their organization, increase efficiency and reduce costs in order that the proposed 2012 and 2013 rate increase can be reduced or eliminated."

(BCMEU Final Submission, pp. 2-3)

Mr. Norman Gabana also references the letter of comment from the City of Penticton as "what is happening in the real world" and asks the Commission to require FortisBC to produce operations plans that require no rate increases for 2012 and 2013. (Gabana Final Submission, pp. 1-2 referencing in part T2:84)

The Commission Panel acknowledges the position taken by the Interveners and agrees that the size of the proposed rate increases is significant, particularly in relation to inflation generally, and is therefore a very significant issue in these proceedings. The Commission Panel also views the main driver of this proposed increase as flowing from the increase in the size of rate base, as the other factors noted by FortisBC seem to be at or near historic lows. The Commission Panel also notes that rates are forecast to increase by a further 5.4 percent, 10.6 percent and 4.3 percent in 2014, 2015 and 2016, respectively. In the Commission Panel's view, these increases are also significant and likely to exceed inflationary increases for those years. (Exhibit B-12, Tab 7, p. 1) The Commission Panel acknowledges that electricity is a necessity and, while customers are encouraged to reduce their consumption somewhat, it will take time for Energy Efficiency and Conservation (EEC) measures to take hold and consumption is unlikely to be significantly reduced during the test period, or in the near future. The Commission Panel, bearing in mind the requirements of subsection 59(5) of the *Act*, is sensitive to the comments of Interveners and will therefore make its determinations in this proceeding with a view to minimizing the proposed current and potential future rate increases, where possible.

3.2 Relevance of BC Hydro/FortisBC Inc. Rate Disparity

A number of interveners expressed concern about the disparity between FortisBC rates and BC Hydro rates. FortisBC acknowledges the disparity and the resulting customer concern. The "Fortis Group of Companies of BC Communications & Public Affairs Plan 2010/2011" states: "FortisBC rates are currently considerably higher than BC Hydro's (approximately 20 percent). Although the spread is anticipated to diminish within the next five years, having higher rates remains a concern as they impact customer satisfaction and the company's competitive position." (Exhibit C1-7, p. 26)

As was demonstrated in evidence, FortisBC has gone through a period of significant capital expenditures over the last number of years in order to upgrade its generation and transmission infrastructure to provide greater safety and reliability. The bulk of this investment has now been made. In BC Hydro's case, FortisBC testified that significant costs will be incurred by BC Hydro in the areas of new generation and refurbishment of existing plants that, when reflected in rates, will lower the disparity between FortisBC and BC Hydro rates. (Exhibit B-1, p. 6-7; T2:116, 221)

FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC's responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia's energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result in rates that are greater than those of BC Hydro and potentially times when they are less.

3.3 Importance of Productivity Improvements

A considerable number of submissions were made with respect to the need for productivity improvements and the need to impose a productivity factor. The Commission Panel believes there is value in addressing this at the outset by stating our position with respect to productivity improvements and outlining our expectations as to how a utility should address this issue within its day-to-day operations. In doing so, we would hope to provide greater clarity and insight into relevant parts of the Decision which follow.

The Commission Panel is of the view that there is an ongoing need for utilities to manage their business in a manner that actively seeks out and creates efficiencies resulting in what might be described as a "productivity improvement culture". We believe this is in the interests of both the ratepayer and the shareholder. Put most simply, a productivity improvement culture is one where there is a demonstrated capability of a company to regularly undertake a review of the organization from both a macro and a micro point of view to examine what is being done, how it is being done and, where warranted, to make decisions to do things differently, or in some cases, not at all. When the Panel refers to the need for productivity measures we are not speaking of "cost cutting" but rather, "cost management". It is not a difficult task to cut costs in order to achieve a desired result over a short term period. It is however, a difficult task to manage costs downward on a sustained basis with greater or no loss of efficiency over the longer term. It is this latter result that the Commission Panel believes needs to be addressed more comprehensively within utilities and best describes what can be achieved in a productivity improvement culture.

FortisBC notes that in the recent FortisBC Energy Utilities 2012 Revenue Requirements and Rates Decision which was issued on April 12, 2012, the Commission made a cut to FEU's O&M budget and submits that such a reduction would not be appropriate in the context of the current proceeding. FortisBC states that imposing a percentage reduction as advocated by the BCMEU and BCPSO in this proceeding would not further the objective of subsection 60(1)(b)(iii) of the *Act* (which requires the

Commission to have due regard to setting a rate that encourages public utilities to increase efficiency, reduce costs and enhance performance) as the revenues as applied for by the utility accurately reflect the cost of service. The Company states that imposing a reduction would:

- Harm performance in the short term by denying access to necessary revenues it has forecast.
- Create an incentive for utilities to inflate revenues in a cost of service application in anticipation of such cuts; and
- Create regulatory inefficiency by undermining the process of review of the O&M part of a cost of service application.

(FortisBC Reply, pp. 24-25)

The Commission Panel agrees that imposing some form of productivity factor is not a decision to be taken lightly. However, there may be cases where a utility has been unable to satisfy the Commission that it has taken the necessary steps to ensure productivity and efficiency levels within the organization have been optimized. In these instances, some form of productivity adjustment to the O&M budgets of a utility are warranted. One purpose of examining productivity in greater detail in recent proceedings has been to encourage utilities to formalize processes to help create a productivity improvement culture and, where appropriate, to make the sometimes difficult decision to bring about change. These are difficult times for many ratepayers and the Commission Panel believes this is the least they can expect.

4.0 ISSUES OF IMPORTANCE

4.1 Load and Customer Forecast

FortisBC prepared a load forecast which was reviewed in detail by the Load Forecast Technical Committee (the Committee). This group was established by Order G-111-11. Members include representatives of FortisBC, BCUC staff, BCMEU, BC Hydro, and BCPSO and Ms. Buryl Slack Goodman.

The Committee met on various occasions and reviewed the load forecast, including the methodologies behind the forecast, for the 2012 and 2013 Revenue Requirements and for the Integrated System Plan. The review excluded assessment of the forecast of Demand-Side Management (DSM) savings, savings from rate structures or estimated system losses.

Committee members have accepted the load forecast and methodologies as put forward by FortisBC. Details of the forecast and the methodologies behind the forecast were filed by FortisBC on November 25, 2011. (Exhibit B-16)

The 2012 and 2013 Load Forecasts are summarized below:

Table 1

	2012 (GWh)	**2013 (Gwh)**
Residential	1,264	1,276
Commercial	696	709
Wholesale	926	935
Industrial	250	255
Lighting	14	14
Irrigation	44	43
Net	3,193	3,233
Loss	309	310
Gross	3,502	3,543
Winter Peak (MW)	721	731
Summer Peak (MW)	567	575

Source: Exhibit B-16, Appendix A, Attachment 1, Slide 5.

The customer count summary for 2012 and 2013 is summarized below:

Table 2

	2012		2013	
	Number	**% Change**	**Number**	**% Change**
Residential	101,320	1.9%	103,279	1.9%
General Service	11,837	2.3%	12,130	2.5%
Wholesale	7	0.0%	7	0.0%
Industrial	36	0.0%	36	0.0%
Lighting	1,830	0.0%	1,830	0.0%
Irrigation	1,075	0.0%	1,075	0.0%
Total Direct	116,105	1.9%	118,357	1.9%

Source: Exhibit B-16, Appendix A, Attachment 1, Slide 30.

One issue that was raised by interveners with respect to the forecasting process was the use of a 1 in 20 peak forecast. Under this methodology, seasonal peaks are recorded from actual demand in the previous twenty years. Net energy growth is calculated from actual sales over the same time period. The maximum peaks of the past twenty years are then projected forward using the historical net energy growth calculation.(Exhibit B-16, Appendix A, Attachment 1, Slide 28) For the current 1 in 20 year forecast, the base year winter peak was 1990 and the base year summer peak was 1998. (Exhibit B-10, BCUC 2.3.1 (Losses))

BCMEU is concerned with this methodology and submits that the more commonly used 1 in 10 peak forecast would be more appropriate. (Exhibit B-10, BCUC 2 3.3; BCMEU Final Submission, p. 9)

FortisBC responded to these concerns by pointing out that the 1 in 20 forecast is not used for the purpose of determining the need for power purchases or directly for capital planning. It is used for benchmarking against the existing distribution planning forecast to confirm that it can accommodate load increases that result from extreme weather variations. (Exhibit B-10, BCUC 2.3.1 (losses), p. 9) FortisBC states that all capital projects were driven by the distribution planning forecast and that no changes were made in terms of projects or timing as a result of the 1 in 20 forecast. (Exhibit B-10, BCUC 2.3.3)

Commission Panel Determination

The Commission Panel notes that in spite of the concerns raised by BCMEU concerning the use of a 1 in 20 peak forecast, all of the Committee members have accepted the Load Forecast. **The Panel further notes there was no evidence to suggest there were difficulties with the forecast or methodologies and therefore accepts the Load Forecast for the current test period.**

With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relevant merits of each as a planning tool.

4.2 Capital Structure and ROE

In the Procedural Conference held in Kelowna on November 22, 2011, ICG questioned whether there was sufficient evidence for the Commission Panel to make a determination on FortisBC's capital structure and rate of return. ICG argued that the allowed capital structure of 60 percent debt and 40 percent equity and a risk premium of 40 basis points above the "benchmark" rate of return as approved by Order G-58-06 (Decision on an Application by FortisBC Inc. for Approval of its F2006 Revenue Requirement Application and Establishment of a Multi-Year Performance Based Regulation Mechanism (FBC 2006 RRA Decision)) could not be applied in this proceeding. In particular, ICG disputed the application of the benchmark rate of 9.5 percent as approved by Order G-158-09 (Decision on the Application by Terasen Gas Utilities for Return on Equity and Capital Structure (2009 ROE Decision)) considering its relationship to the automatic adjustment mechanism (AAM) which was eliminated by the same Order. (T1:27-38)

In the Reasons for Decision accompanying Order G-199-11 dated November 30, 2011, the Commission Panel addressed, among other things, the ICG's position on ROE and capital structure. The Panel noted that subsequent to the Procedural Conference on November 28, 2011, the Commission had issued a letter expressing its intent to conduct a Generic Cost of Capital (GCOC) Hearing designed to deal with capital structure and ROE with application to all utilities. In view of this, the Commission Panel concluded that there was little to be gained in terms of value or efficiency by considering the issue of capital structure and return on equity as part of this proceeding. The Panel's determination was as follows:

> "Accordingly, the Commission Panel has determined there is no need to expand this hearing to include a comprehensive review of FortisBC's capital structure and ROE. Therefore, the Commission Panel has determined that given the Commission announcement regarding a generic hearing process, it would be appropriate to maintain the current ROE and capital structure pending determinations made in the Generic Cost of Capital Hearing."

In its Final Submission, ICG argues that the cost of capital is "a significant component of a regulated utility's revenue requirements, and there should be no doubt that before rates are set the Commission Panel must determine the cost of capital for each year of the test period by applying the fair return standard". (ICG Final Submission, p. 45)

ICG refers to its submissions at the November 22, 2011 Procedural Conference where it argued that the Commission has never accepted any evidence other than expert evidence regarding the cost of capital and in the absence of such evidence, the Commission should not approve the rates applied for. (ICG Final Submission, pp. 45-46)

ICG submits that Recital D of Order G-20-12 in the GCOC proceeding, which includes a statement that there have been changes in the financial markets since the 2009 ROE Decision, prevents the Commission from relying upon the cost of capital as determined by the 2009 ROE Decision to determine fair and reasonable rates. (ICG Final Submission, p. 46)

ICG also submits that the elimination of the ROE AAM upon which the Commission had been able to rely to ensure the fair return standard is met, now means the Commission Panel must determine the fair return standard before it approves rates for the first year of a test period. (ICG Final Submission, p. 46)

ICG continues by noting that, for the period between the 2009 ROE Decision and the test period for this proceeding, the Commission relied upon negotiated settlements to ensure the fair return standard was met. ICG submits that, given Order G-47-12 dated April 18, 2012 in the GCOC proceeding, which states that the determination of the equity ratio and specific risk premiums for utilities will be no earlier than January 1, 2013, the Commission Panel has no other proceeding to rely on to ensure the fair return standard has been met for year one of the test period in this proceeding. (ICG Final Submission, p. 46)

ICG argues that subsection 58(1) of the *Act* requires a hearing before rates are set. It further submits that the onus is on the utility to justify all elements of its revenue requirement before the Commission sets rates. It submits there was no onus on the Interveners in this proceeding to file expert evidence on the cost of capital for the test period and, without expert evidence from the Company, the Application is deficient and cannot be approved. (ICG Final Submission, pp. 46-47)

ICG further submits that considerations of fairness require that there be an opportunity for the parties to challenge in a hearing, assertions of fact or opinion in dispute in order for a decision having an effect on rates to be made. Given Orders G-199-11 and G-47-12, it submits there will be no adjudicative process to determine FortisBC's cost of capital for the first year of the test period in this Application. ICG submits that this is a requirement before the Panel "can increase rates based on a return on equity of 9.9% and an equity ratio of 40%." (ICG Final Submission, p. 47)

The only other Interveners who comment on capital structure and ROE in their final submissions are the BCMEU and BCPSO. The BCMEU accepts that this issue will be addressed in the GCOC proceeding and, in particular, looks forward to the impact of the Commission's review on the Company's risk premium. BCMEU questions whether the existing risk premium is appropriate given FortisBC's proposal to further mitigate risks through the use of deferral accounts. (BCMEU Final Submission, p. 10)

BCPSO submits that it "will be seeking through the GCOC [proceeding], to reduce the Company's approved ROE to reflect current economic conditions." (BCPSO Final Submission, p. 4)

FortisBC notes that the ICG arguments to make a return on equity an issue in this proceeding have been made several times and are contrary to the determinations of the Commission in the November 30, 2011 Reasons for Decision for Order G-199-11 in this proceeding and the Commission's Reasons for Decision dated April 18, 2012 in the GCOC proceeding. Specifically, the Company notes that in the April 18, 2012 Reasons for Decision, the Commission reaffirmed that the current capital structure and ROE will be maintained pending GCOC proceeding determinations with specific determinations related to FortisBC to be made at a future proceeding following the generic hearing. (FortisBC Reply, p. 10)

Commission Panel Determination

The Commission Panel has reviewed the arguments of the parties and remains of the view that an examination of the ROE and capital structure for FortisBC is not a requirement in this proceeding and finds that the revenue requirements of FortisBC and resultant rate impacts can be adjudicated. Our reasons for this conclusion are as follows:

- FortisBC is not seeking a change to its capital structure or to its ROE in this proceeding. ICG submits that the onus was on FortisBC to file expert evidence on cost of capital in any event. FortisBC provided evidence that there had been no material change in its 40 point risk premium since the 2006 RRA Decision. In response to BCUC IR 2.31.1, FortisBC provides evidence with respect to maintaining the current ROE with a risk premium of 40 points over the benchmark in light of the Company's improved credit metrics. In its response, FortisBC states that it bases its business risk profile on the long-term perspective and continues to support a risk premium over the benchmark. The Company refers to the Moody's September 6, 2011 credit opinion which, among other things, states:

  > "financial metrics remain weak compared to Baa-rate peers" and

FortisBC submits that any reduction in ROE would challenge the Company's credit metrics as well as available liquidity which could potentially result in a credit downgrade and cost of debt increase. In addition, FortisBC refers to the October 6, 2011 DBRS credit opinion which commented upon challenges related to relatively large anticipated capital expenditures and their contribution to large free cash flow deficits as well as challenges related to the execution of the capital expenditure program. In response to BCUC IR 1.31.1, the Company noted that a credit rating upgrade is not the sole determinant of a business risk premium and listed a significant number of other risk factors that it faced. Included among these were the relative size of the utility, major businesses served by FortisBC, population and economic growth, competition and technological changes which the Company asserts has influence on an entity's long-term risk profile and collectively do not support a reduction to the Company's risk premium. The Commission Panel agrees as the FortisBC evidence supports the view that there has not been a substantive change in risk. As noted below, none of the parties challenged this evidence. (Exhibit B-8, BCUC 2.31.1; Exhibit B-8, Appendix 31.2)

- While paragraph 9 of Order G-158-09 issued concurrently with the 2009 ROE Decision eliminates the AAM, paragraph 8 of that Order approves the continued use by FortisBC of the benchmark return on equity of 9.5 percent which was determined as appropriate for Terasen Gas Inc. for rate setting purposes. Paragraph 8 of that Order provides that: "The TGI ROE approved in paragraph 3 of this order can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates." In the view of the Commission Panel, this paragraph clearly establishes the Benchmark ROE for FortisBC for the purposes of this proceeding. In the Panel's further view, this approach is not substantially different in effect from what has been done in the recent past. In other words, in recent years, expert testimony on the cost of capital in a revenue requirements hearing has in fact been the exception, rather than the rule.

- The position of ICG is that for the period between the 2009 ROE Decision and the test period for this proceeding, the Commission could rely upon negotiated settlements to ensure the fair return standard was met. The last FortisBC RRA was completed on December 9, 2010 utilizing a negotiated settlement process (NSP) and resulted in a Commission approved Negotiated Settlement Agreement (NSA). The Commission Panel notes that the NSA which forms Appendix A to Order G-184-10 includes a list of issues and resolutions from the NSP. Neither ROE nor capital structure are referred to in the list of issues. Contrary to ICG's submission, the Panel's examination of the evidentiary record for that proceeding discloses that no expert evidence on capital structure or return on equity was filed by FortisBC or another party. Further, none of the parties raised this issue during the Information Request process. In their letters of support for the proposed NSA, none of the parties expressed any concern with the Commission approving the proposed NSA in the absence of expert evidence on capital structure or return on equity. While ICG was not a party to the NSA, Zellstoff-Celgar (a principal member of ICG) was a party, as were a number of the Interveners in this proceeding.

- The Revised Regulatory Timetable attached to Order G-167-11 provided for the filing of Intervener Evidence by October 31, 2011, after two completed rounds of information requests. Neither ICG nor any other Intervener filed evidence which challenged the FortisBC evidence that there had been no material change by that date or prior to the November 22, 2011 Procedural Conference. Consistent with the Commission Panel's determination in the Reasons for Decision accompanying Order G-199-11, no party sought to file such evidence after November 30, 2011.
- The ICG argues that the Commission must apply the "fair return standard" before it approves rates for the first year of the test period and that it is not able to do so in the absence of expert evidence, given the automatic adjustment mechanism was eliminated by Order G-158-09.

The Commission Panel disagrees.

The Utilities Commission Act governs the rate-setting jurisdiction of the Commission. By subsection 59(1), a utility is prohibited from making, demanding or receiving a rate that is "unjust, unreasonable, unduly discriminatory or unduly preferential" or a rate that otherwise contravenes the Utilities Commission Act, its regulations, Commission orders or any other law.

By subsection 59(5), a rate is "unjust" or "unreasonable" if it is:

(a) more than a fair or reasonable charge for service of the nature and quality provided by the utility, or
(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
(c) unjust or unreasonable for any other reason."

The fair return standard has been articulated in various regulatory decisions across North America including the Commission's August 26, 1999, Decision entitled "In the Matter of Return on Equity for a Benchmark Utility". The standard provides the regulated utility the opportunity to:

- Earn a return on investment which is commensurate with that of comparable risk enterprises.
- Maintain its financial integrity; and
- Attract capital on reasonable terms.

In the Commission Panel's view, the "fair return standard" is therefore intended to protect the utility. This is also apparent from the wording of subsection 59 (5)(b) that a rate is "unjust" or "unreasonable" if it is *insufficient* to yield a fair and reasonable compensation for the service provided by the utility or a fair and reasonable return on the appraised value of its property.

In the Panel's view, the rate for the first year of the test period is not insufficient to yield a fair and reasonable compensation to the utility for its service. This conclusion flows from the following:

- FortisBC has not sought to challenge the existing capital structure or ROE as yielding an insufficient return,
- The NSA for the previous test period arrived at rates which were approved by the Commission as not being "unjust" or "unreasonable". The rates for the first year of this test period are basically the same, when inflation is considered, and there has been no degradation in the nature and quality of the service provided as is indicated by the SAIDI and SAIFI statistics.

- The GCOC proceeding has been initiated to deal with the issues of ROE and capital structure for all utilities at the same time. This will ensure all of the utilities taking part in the GCOC proceeding are treated in a consistent manner. The Commission Panel considers this to be just and reasonable for both the utilities and the ratepayers.
- Reviewing cost of capital in a single process is an efficient and cost effective approach. The Commission Panel is of the view that holding a separate hearing process to examine cost of capital issues for FortisBC alone, for only one year in the test period, would result in significant additional costs which would be borne by FortisBC's ratepayers.

For these reasons **the Commission Panel reaffirms its Decision of November 30, 2011, to maintain the current ROE and capital structure pending determinations made in the GCOC proceeding.**

5.0 2012-2013 REVENUE REQUIREMENTS APPLICATION

5.1 Power Purchase Management

A key function within FortisBC is power purchase management. FortisBC has proposed a number of significant changes with respect to power purchase expense and the overall management of this important function. Additionally, the Company has proposed that the concept of a PRM be explored and put in place during the latter stages of this test period. In this section, the proposals put forth by FortisBC will be reviewed beginning with the handling of the Power Purchase Management group and related expenses, followed by a review of power purchase expense requirements and proposed changes in how these are handled and end with consideration of the PRM proposal.

5.1.1 Power Purchase Expense

FortisBC submits that the purpose of its resource acquisition policy is to allow customer load requirements to be met at the lowest reasonable cost with a minimum of environmental impacts. The Company can supply over 98 percent of its annual energy requirements from long-term, firm resources. In meeting its energy requirements, FortisBC uses a combination of Company-owned generation entitlements and firm supply which has been contracted, augmented by spot market purchases to deal with any capacity or energy deficits. FortisBC-owned generation entitlements include the Canal Plant Agreement (CPA) entitlements while examples of contracted firm supply include the Brilliant Power Purchase Agreement (BPPA) and the BC Hydro Rate Schedule (RS) 3808 Power Purchase Agreement (PPA). Other purchases include Independent Power Producers and market purchases made in advance, as well as those on the spot market. (Exhibit B-1, Tab 4, pp. 3-10)

FortisBC seeks approval for a power purchase expense forecast of $89.0 million in 2012 and $94.6 million in 2013 (Exhibit B-12).

As outlined in Table 3, FortisBC has consistently reported a power purchase expense under-expenditure variance. Over the period from 2007 through 2011 (actuals through 2010) the under-expenditure is expected to total in excess of $26 million:

Table 3

	2007	2008	2009	2010	2011A	Total
	Over / (Under) Approved					
Sales Load Variance (Gwh)	13	0	50	(153)	25*	
Power Purchase Expense Variance ($000s)	(5,631)	(2,528)	(168)	(8,444)	(9,693)	**(26,464)**

* 2011 is forecast

(Calculated from Exhibit B-1, Table 4.1.5-1 and Transcript 5, p. 849)

The Company explains that these power expense variances could result from a number of factors, including:

- Load variances related to variances in customer growth, usage or weather;
- Unit price variances from forecast (an example being BC Hydro rates which were not known at the time of application and were not finalized at the close of the evidentiary record);
- FortisBC's ability to displace contracted purchase with lower-cost market purchases;
- True-up of BPPA costs; and
- CPA operational factors affecting the Company's usage or timing of entitlements.

(Exhibit B-1, Tab 4, p. 23)

A Performance Based Regulation (PBR) Plan was in place over this period which allowed these variances to be shared equally between customers and shareholders through the ROE sharing mechanism.

In this Application, FortisBC has proposed a deferral account to capture variances in forecast and actual Power Purchase Expense. This is in part in response to a request from stakeholders in the 2011 Negotiated Settlement Agreement. FortisBC has requested that firm rates be set for the 2012-2013 test period and any accumulated variances be applied to rates in 2014. Thereafter, the Company proposes to flow through any variance in the Power Purchase Expense Variance Deferral Account to customers in the subsequent year. (Exhibit B-1, Tab 4, pp. 23-24)

None of the Interveners made specific submissions with respect to the proposed Power Purchase Expense Variance Deferral Account although it can be assumed that they support it given their request at the last NSP.

Commission Panel Determination

The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC. The Panel understands the complexity of managing the number of variables affecting the power purchase process and is in agreement that any positive or negative variances are most appropriately borne by the customer. The establishment of a Power Purchase Expense Variance Deferral Account is the most effective way to manage this process with variances being handled in customer rates in subsequent periods.

Of concern to the Commission Panel however, is the level of accuracy of FortisBC's forecasts for power purchases over the past five years. As noted previously, the under-expenditure to forecast over this period has totalled more than $26 million or more than $5 million per year. Moreover, in only one of those five years has the under-expenditure been less than $2.5 million. This matter was pursued by Commission Counsel at the oral hearing phase of the proceeding. FortisBC, using 2010 as an example, pointed out that much of the under-expenditure was driven by a load variance. (T5:831-832) The Commission Panel accepts this reasoning for 2010 but notes that, based on the information presented in the above table, the favourable sales load variances in 2007 and 2009 also resulted in significant over-forecasting of the power purchase expense in those years.

The Commission Panel finds that based on the past five years, FortisBC has been overly conservative with its power purchase expense forecasts. As discussed in Section 3.1, there have been significant concerns raised with respect to the continued increase in rates given the economic challenges faced by all customer groups. The Commission Panel is of the view that reducing the power purchase forecast is both justified and will provide some relief to customer groups. The Panel understands that much of the customer risk associated with an under-expenditure has been eliminated by the approval of the Power Purchase Expense Variance Deferral Account but is of the view that this does not justify setting rates on the basis of overly conservative forecasts. **The Commission Panel directs FortisBC to reduce its Power Purchase Expense forecasts by $1.5 million in 2012 and 2013.** The Commission Panel notes that FortisBC forecasts its rate increases on the assumption that BC Hydro's rate increase, effective April 1, 2012, is 3.9 percent with a further 3.9 percent effective April 1, 2013. The Commission Panel notes that BC Hydro has recently adjusted its permanent rates for April 1, 2013 to 1.44 percent plus a 5 percent Deferral Account Rate Rider. **FortisBC is directed to adjust its power purchase expense forecast to reflect this change.**

5.1.2 Power Purchase Management Expense

FortisBC proposes a budget of $1.2 million in 2012 and $1.3 million in 2013 for PPME to be included in its Power Purchase Expense forecast. This represents an increase of $284,000 or 30 percent over the 2011 Forecast for this function which is primarily responsible for planning and securing power from a variety of sources (company-owned generating units, power supply contracts and market transactions) on a short, medium and long-term basis. The Company submits that its Power Supply group is facing a need to secure an increasing future load while dealing with a regional environment which is becoming more constrained and more tightly regulated. FortisBC further submits that the Application includes funding for incremental staff and funding for power supply which it believes to be necessary to manage the growing complexity of efficiently meeting an increasing load. The incremental costs for 2012 over the previous test period are made up of the following:

- $0.022 million for labour cost escalation.
- $0.143 million for the addition of one Full Time Equivalent (FTE) employee.

- $0.068 million for additional consulting resources.
- $0.050 million for inter company transfers from FortisBC Energy Inc. for services provided.

Costs in 2013 are planned to increase by $0.055 million reflecting inflationary changes affecting labour and some non-labour costs. Some examples of additional work requirements driving the increased costs over the test period include:

- The need for more in-depth analysis of power supply options
- The need to participate in outside organizations to cooperatively deal with common problems.
- Additional resource requirements with business continuity skills at the System Control Centre
- Requirement for more active management with dispatchers monitoring real-time resource load.

(Exhibit B-1, Tab 4, pp. 13-15; Exhibit B-8, BCUC 2.8.2)

A significant change that FortisBC has proposed for this test period is that the PPME be included in the estimate of Power Purchase Expense rather than maintaining it within the O&M budget as in the past. FortisBC submits that linking PPME directly to the Power Purchase Expense will help to ensure that there are sufficient resources to plan, implement and mitigate Power Purchase Expense. (Exhibit B-1, Tab 4, p. 13)

BCMEU is not supportive of increased staffing in order to purchase power supply. BCMEU expresses concern with the increase in PPME, given the longer term agreements being executed which it submits should provide stability in power purchase management. Additionally, BCMEU expresses concern that there is the potential for further efficiencies to be gained through the management of power purchase matters on a shared basis (i.e., with FortisBC Energy Inc.), which is not being pursued. BCMEU make no submission with regards to moving the PPME out of O&M. (BCMEU Final Submission, p. 17)

BCPSO expresses concerns similar to the BCMEU and points to the company's success in reducing power purchase costs over the PBR period. BCPSO suggests the Commission may wish to consider whether the additional power purchase costs are necessary and whether the benefits justify the additional cost. Like BCMEU, BCPSO makes no submission regarding the movement of the PPME out of O&M. (BCPSO Final Submission, p. 9)

FortisBC acknowledges the concerns of BCMEU and BCPSO and agrees that the current lower price environment has allowed it to realize power purchase cost savings against forecast through displacement of purchases under the BC Hydro RS 3808 PPA. However, FortisBC further notes that market conditions continue to change and submit that the Company must be proactive and responsive to these changes in order to maximize savings. FortisBC underlines this point with respect to the BCMEU comments regarding the apparent stability offered by long-term agreements. FortisBC notes that savings would be lost if it relied on existing agreements and did not take full advantage of opportunities to displace those purchases. In addition, FortisBC argues that the nature of long-term agreements continues to change and the yet-to-be negotiated BC Hydro RS 3808 PPA and the addition of Waneta Expansion capacity will not result in reduced workload. (FortisBC Reply, pp. 43-44)

Commission Panel Determination

The Commission Panel is in agreement with BCMEU and BCPSO with respect to the additional expenditures being proposed by FortisBC for PPME and is concerned as to whether there is a need for an increase of 30 percent of existing resources.

FortisBC has acknowledged that it has integrated its gas and power supply teams and has requested additional PPME funding for the services provided by the gas supply side as a means of creating greater efficiencies and leveraging off the experience of the two groups. (FortisBC Final Submission, p. 17) While the Commission Panel is disappointed that this integration has not led to some immediate savings, we do accept that there is potential benefit to utilizing some of the gas resources to maximize the productivity of existing PPME resources. However, we are not convinced that there has been a sufficient case made to justify the further FTE position that is proposed by FortisBC. As noted by

BCMEU in reference to the sizable under-forecast in power supply expense, favourable market transactions should continue to be achievable with existing staffing levels. (BCMEU Final Submission, p. 17) **The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of $142,000 in each of 2012 and 2013.**

The Commission Panel has an additional concern with the proposal to move PPME from O&M to become part of the estimate of Power Purchase expense. We are somewhat confused by how this movement will help ensure there are sufficient resources for planning, implementation and mitigation of power purchases as submitted by FortisBC. (FortisBC Final Submission, p. 77) The proposed move will result in no cost savings, nor will it have any impact on rates so it is difficult to determine where the benefits attached to this move actually lie. While there is a potential for less scrutiny of the activities, this will only serve to reduce transparency rather than increase efficiency and will only muddy the waters with respect to direct annual comparisons of metrics based on O&M expenditures. **Accordingly, the Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses.**

5.1.3 Planning Reserve Margin

Following the Western Electricity Coordinating Council (WECC) recommendations, FortisBC is proposing to implement a PRM within the test period. FortisBC has included $310,000 in its Power Purchase Expense which is the forecast cost of holding an additional resource for the fourth quarter of 2013. FortisBC asserts that it is common practice to consider the level of capacity reserves required to handle long-term requirements and most neighbouring utilities carry PRM as a means to meet uncertain load requirements, provide operating flexibility and manage uncertainty in resource delivery. FortisBC states that while it is not mandatory, it believes it is prudent to carry an appropriate level of PRM. (T5:747, 748,763; T4:765; Exhibit B-8, BCUC 2.7.2)

FortisBC states there are three circumstances which have the potential to drive the need for PRM:

- Unavailability of supply due to unplanned generating unit or transmission outage,
- Unexpectedly high loads, typically due to extreme weather events, and
- A period of accelerated growth that outpaces the installation of new power supply resources. (Exhibit B-1-2, pp. 53-54)

FortisBC asserts that looking forward, a failure to carry a PRM will force the Company to rely on market purchases in order to meet future capacity shortfalls which, depending on the market, could become increasingly risky. Risk factors identified by FortisBC's consultant, Midgard Consulting, include increasing installed intermittent generation, decreasing regional capacity margins and the re-introduction of industrial load following an economic recovery, among others. (Exhibit B-1-2, Appendix D) FortisBC concludes that, given these risk factors, a failure to include PRM as part of its resource adequacy requirements exposes ratepayers to an unacceptable level of risk. (Exhibit B-8, BCUC 2.7.2)

With respect to quantification of the PRM requirement, FortisBC indicated that it has been doing further assessment. In testimony during the oral phase of the proceeding, Ms. Des Brisay, FortisBC Vice President of Energy Supply and Resource Development, stated that the formula-driven approach to determining PRM proposed in the Application may overstate PRM requirements. Ms. Des Brisay further stated that a detailed assessment is being undertaken and the Company is now taking a probabilistic approach to PRM and hopes to have an analysis completed by the end of the third quarter of the current year. (T5:766) Earlier, Ms. Des Brisay commented on that analysis by stating that "what is very clear is that it's not clear." In her testimony she continued by stating that there is a bit of art and science in determining an appropriate PRM and that it is very utility-specific. (T4:741)

ICG notes FortisBC's acknowledgement that its initial approach to PRM was not supported by evidence. ICG submits that the new approach to Planning Reserve Margin is not acceptable because it has not been sufficiently developed to where it can be relied upon by the Commission to determine fair and reasonable rates. ICG also points out that one of the underlying concerns leading to a need for PRM is risk associated with capacity shortfalls. ICG questions the submissions of FortisBC with regard to capacity constraints and submits that before the Commission Panel can approve PRM for ratemaking purposes, it needs to agree that this region has become tight from a capacity perspective. In addition, ICG points out that FortisBC's RS 3808 PPA contract negotiations with BC Hydro have not been completed and FortisBC does not know whether it will include excess capacity provisions to allow the forecast load requirement to be met without a PRM. Accordingly, ICG concludes that a PRM should not be approved at this time as the RS 3808 PPA contract negotiations with BC Hydro have yet to be concluded and further development of the methodology to identify the appropriate PRM is required. (ICG Final Submission, pp. 29-34)

BCPSO submits that a key factor in FortisBC's need for PRM is capacity constraints. BCPSO agrees with ICG that FortisBC may not be facing the capacity constraints which it has predicted. BCPSO concludes that the Commission should be satisfied that capacity constraints actually exist before allowing PRM requirements into rates. (BCPSO Final Submission, p. 16)

FortisBC notes that the Midgard Planning Reserve Margin Report identifies six factors which are aligned with a potential increase in capacity resource market costs within the WECC-Canada and WECC –Northwest Regions. Each of these is described by the Midgard Report as a risk factor and none is a justification in itself. FortisBC points out that the Midgard Report lists three potential circumstances which drive the need for PRM (listed above in this Section). FortisBC argues that there is, therefore, no basis for the ICG assertion that the Commission needs to agree that the region is becoming increasingly tight for capacity before approving rates based on PRM requirements.

FortisBC acknowledges that it is adopting a different approach to assessing PRM than was originally proposed but argues that consideration of PRM in assessing the adequacy of its resource portfolio is prudent and should be accepted by the Commission. The Company proposes to complete its PRM study and recommendations by the end of the third quarter of 2012 and file these with the Commission at that time for review and approval of related power purchase costs required to meet the appropriate resource adequacy standard. (FortisBC Reply, pp. 64-68)

Commission Panel Determination

It is clear from the evidence that there is a significant amount of work to be completed with respect to development of a methodology to determine an appropriate PRM, a point with which neither the Applicant nor the Interveners seem to disagree. **The Commission Panel also agrees with this assessment and therefore denies the proposal to implement a PRM at this time and the proposed additional $310,000 in planned Power Purchase Expense for 2013.**

The Commission Panel agrees with FortisBC's suggestion to complete its PRM methodology study and file it with the Commission along with its proposed recommendations later in 2012. Hopefully, by that time, the Company will have completed its BC Hydro RS 3808 PPA negotiations and any implications of the new agreement can be taken into consideration when reviewing the new proposal. The approval of the Power Purchase Expense Variance Deferral Account (PPEVDA) will allow any approved expenses incurred during the test period to be deferred to 2014.

5.1.4 Water Fees

FortisBC's power supply costs include not only power purchases but also water fees. (Exhibit B-1, Tab 1, p. 7) Water fees are assessed by the Province based on FortisBC's generation in the previous year and the rate is indexed to the BC Consumer Price Index (CPI). (Exhibit B-1, Tab 4, p. 28) Variance in water fees could be a result of either volume variances in FortisBC's generation in the prior year or from rate variances due to differences in water rental rates.

Water fees were $9.3 million in 2010 and $9.0 million forecast in 2011. FortisBC forecasts water fees to increase to $9.7 million in 2012 and to $9.8 million in 2013 due to increased plant entitlement use in 2011 and 2012, respectively, as well as the increase in water fee rates from 2011 levels based on the Company's forecast of BC CPI. (Exhibit B-1, Tab 4, p. 28; Exhibit B-12)

Although FortisBC has not proposed to include variances in water fees in the PPEVDA (Exhibit B-8, BCUC 1.22.1), during the oral hearing phase of the proceeding, Ms. Des Brisay stated that doing so would be consistent with the intent of the deferral account. (T5: 850)

Commission Panel Determination

The Panel agrees that water fees are solely related to the cost of generation. Given the intent of the Power Purchase Expense Variance Deferral Account, **the Panel directs FortisBC to include any variances related to water fees in that deferral account.**

5.2 Operations and Maintenance Expenses

5.2.1 Overriding Issues

The overriding issues pertaining to FortisBC's O&M budget are discussed in the following sections.

5.2.1.1 Demographic Challenges

FortisBC faces the challenge of having approximately half of its workforce eligible to retire in the next few years. Of these, 28 percent are eligible to retire with an unreduced pension. The Company states that it is difficult to predetermine the number of eligible employees that will retire but indicates that over a five year period beginning in 2006, 24 percent of those eligible to retire with an unreduced pension actually did so. Based on this past experience, this would indicate that roughly a quarter of those eligible to retire with unreduced benefits are likely to do so. FortisBC states that the biggest challenge departmentally is with Transmission and Distribution (T&D) with 33 of 72 employees eligible to retire in 2011 with an unreduced pension. Positions requiring focus are Power Line Technicians (PLTs) where there is a market shortage, Meter Technicians, Communication, Protection and Control Technicians and Power System Dispatchers. In addition, FortisBC notes that 30 percent of the management group in T&D are eligible to retire with unreduced pensions. (Exhibit B-1, pp. 35-39)

In addition to the retirement challenge is the risk of employee turnover. FortisBC states that voluntary turnover (not including retirements) was approximately 4.5 percent from 2008 through 2010. When viewed in relation to other companies, this turnover seems to compare favourably within the Transportation and Utilities sector and is well below the average of other comparable sectors. FortisBC has reported that 181 new employees were recruited from 2008 to 2010. It seems that many of these were not actually new employees but FortisBC employees moving to new positions within the organization. Such backfills often result in a cascading effect when filled with internal candidates. (Exhibit B-1, pp. 39-40)

Within the Application, FortisBC outlined a number of initiatives it has been undertaking as part of its workforce strategy to offset the combined effects of retirements and other turnover. Included among these are the following:

- A PLT apprentice program
- Sponsorship of the “Bright Futures” program to create interest in the industry within schools.
- Development and Execution of succession and workforce plans.
- Investment in Education.
- Offering Scholarships and participating in Co-op programs in conjunction with schools.
- Development of a Supervisory Skills program.

(Exhibit B-1, pp. 40-41)

Commission Panel Determination

The Commission Panel acknowledges the challenges faced by FortisBC with respect to planning for and dealing with the potential retirement of a significant number of employees in the near future. The Panel also acknowledges the work the Company has put into developing initiatives to mitigate or at least soften the impact of a large number of retirements if they were to occur. However, of concern to the Panel is the lack of clarity with respect to this problem beyond the current test period. During the oral phase of the proceeding, Ms. Drope, FortisBC's Chief Human Resources Officer, was asked to comment upon whether FortisBC, looking beyond the current test period, had forecasted the size of the problem, the costs, and when an end can be expected to the "bubble" of retirements moving through the system. Ms. Drope replied that an analysis had not been completed because of the number of variables at play but estimated that 10 years is a likely time horizon. Further, when asked whether a detailed plan or cost estimates for that 10 year period had been developed, Ms. Drope failed to confirm that a plan had been completed and was unable to respond to the cost implications "off the top of [her] head." (T3:581-582)

The Commission Panel is of the view that this issue is sufficiently important to warrant further analysis, including a comprehensive plan outlining the implications, activities and costs of dealing with this workforce challenge. **Therefore, FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.**

5.2.1.2 Productivity Factor

As noted previously in Section 3.3, there were a number of submissions regarding the need for productivity improvement. The BCMEU in its submissions expressed concern that FortisBC had not included a productivity factor in the preparation of the O&M budgets and urged the Commission to impose a productivity target of 1.5 percent for both 2012 and 2013. BCPSO agreed with BCMEU with both the concept of a productivity factor and the amount. For purposes of clarification, the Commission Panel interprets these submissions to mean that both parties are in agreement that an overall reduction of 1.5 percent of O&M budgets should be imposed by the Commission as a means of driving productivity improvement.

FortisBC advanced the position that productivity improvement factors are not appropriate if applied outside of PBR. The Commission Panel has addressed the need for productivity improvement factors in Section 3.3 of this Decision. The Panel will now address the issue of productivity improvement from the following perspectives:

- whether FortisBC has demonstrated that it has adequately addressed productivity improvement in this proceeding.
- whether there is evidence to justify imposing a productivity factor as suggested by BCMEU and BCPSO.

FortisBC states that it has achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors during the PBR period. The Company acknowledges that there have been increases in O&M expenditures forecast for both 2012 and 2013 but submits that an increase in O&M expenditures is not inconsistent with performance during the PBR period. FortisBC further submits that there are factors other than a lack of productivity which could result in an increase in O&M costs regardless of how efficient the Company has been. These include items such as inflation, but also could involve the need to undertake new expenditures in certain areas or the need to reclassify an expense from capital to operating. In support of its management of O&M costs and resultant productivity, FortisBC states that "[a]fter factoring out the $3.78 million that was transferred from capital to O&M expense in 2011 as directed by Order G-195-10, concerning the Company's 2011 Capital Expenditure Plan, and those items referred to under the PBR mechanism as extraordinary O&M expense, the O&M expense per customer, on a real basis, has declined over the period 2007 to 2010". (FortisBC Reply, pp. 26-27)

Commission Panel Determination

The Commission Panel acknowledges that growth in O&M or O&M per customer are factors in determining whether an organization can be described as being efficient and productive. In the Panel's view the forecasted growth of O&M for the test period is not unreasonable (2.8 percent in 2012 and 2.6 percent in 2013), as it is generally in line with inflation. (Exhibit B-1, Tab 4, p. 31; Exhibit B-12, Tab 7, p. 1) We also accept that there are factors beyond the control of the Company which can affect growth of O&M and related measures. However, while O&M metrics must be considered, they do not directly address the question of whether FortisBC has demonstrated that it has addressed the issue of productivity improvement within this proceeding.

In his testimony, Mr. Walker, FortisBC's President and CEO, spoke to the issue of productivity and stated that he believed that a continuous focus of the Company was on productivity and how to be more efficient and that this commitment to finding efficiencies was well demonstrated within the Application. (T2:118-119) Moreover, throughout the O&M departmental review (Exhibit B-1, Tab 4), the Company outlined steps which had been recently undertaken or were planned to be undertaken in each of the departmental workgroups in a subsection entitled "Management of Cost Efficiency." Many of the initiatives undertaken were in recognition of the need to do things differently as a means of controlling costs and creating efficiencies and, in the view of the Commission Panel, provide an excellent example of the types of practices required to keep rates from rising unnecessarily. Further evidence of the Company's commitment to improving productivity is illustrated in answer to BCUC IR 1.28.2 which summarizes productivity improvement measures taken over the PBR period. The Panel notes that these examples would be more instructive if they were measured and quantified in dollar savings.

Given the evidence and the fact that the increases in O&M expenditures are within a reasonable range, the Commission Panel is not in agreement with BCMEU and BCPSO with regard to imposing a productivity improvement factor. However, this should not be interpreted to mean that the Commission Panel is satisfied with the need for all of the expenditures within the O&M area. O&M expenditures will be addressed in greater detail in Section 5.2.2.

5.2.1.3 Integration of FortisBC and FortisBC Energy Utilities

The level and speed of integration of common functions among the FortisBC group of companies was very much at issue in this proceeding. FortisBC states that the process is at an early stage as a number of key foundational elements (among these is the proposed amalgamation of the gas utilities) must be put in place. To date, the senior management teams of both organizations have been combined with the result that total executive costs in 2013 are projected to be only $13,000 higher than in 2007. Additionally, a Board of Directors has been shared by both organizations since in 2010, resulting in significant savings. FortisBC indicates that it is now about to start the process of looking for efficiencies through alignment of operational elements of the business. As noted by Mr. Walker under cross examination, the Company expects to see additional benefits by the latter part of 2013 and expects there to be filings to deal with integrated activities in 2014 and 2015. Further, Mr. Swanson, FortisBC's Director of Regulatory Affairs, noted that the process is just starting and there will be a period of time required for investigation and trying to determine whether there are potential savings. (Exhibit B-1, pp. 95, 100; FortisBC Final Submission, pp.16-17; T2:135, 267)

While acknowledging that some progress has been made, BCMEU expresses scepticism with the level of effort that FortisBC has applied in pursuing opportunities for integration to the benefit of ratepayers. BCMEU believes that additional savings can be attained (presumably in the short term) and states that it is frustrated that opportunities may not be identified earlier. (BCMEU Final Submission, p. 7)

FortisBC states that it is unrealistic to expect benefits beyond those embedded in the Application to be achieved before the end of the test period and argues that it would not be reasonable to reduce FortisBC's revenue requirements. FortisBC points out that while savings may be achieved at the higher level within the companies, this does not necessarily apply to lower levels of the two organizations. The reasons for this relate to the differences in commodities sold, different customers (in most cases) and embedded systems that work well for each organization. FortisBC concludes by stating that further synergies may be achieved following the Company's filing of a shared services model, which is unlikely to occur before the 2014 RRA application. (FortisBC Reply, pp. 16-18)

Commission Panel Determination

The Commission Panel, like BCMEU, would like to see the process of integration of common functions move forward more quickly. However, we accept that proceeding in this direction may not be a simple matter and must be done only after careful consideration. **Because of this, the Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.**

5.2.1.4 Cost Allocations

FortisBC has stated that costs related to the Board of Directors' compensation and other expenses are shared amongst FortisBC and FEI utilizing a Massachusetts Formula which is applied to revenue, payroll and net tangible assets with a forecast allocation of 23.35 percent to FortisBC. The method for allocating the expenses of senior management between FortisBC and FEU differs significantly from this. In the case of senior management, FortisBC is charging FEI for those FortisBC executives who have responsibilities in FEI and is receiving charges for those FEI executives who have responsibilities at FortisBC based on estimated time spent.

ICG disagrees with the method of cost allocation for executives. ICG submits that the costs of executive officers should also be allocated to FortisBC on the basis of the Massachusetts Formula. (ICG Final Submission, p. 17) ICG provided no reasons as to why this was appropriate.

BCMEU concurs with the position of ICG and submits that, relative to other members of the FortisBC group of companies, FortisBC is potentially being overcharged by not using the Massachusetts Formula. (BCMEU Final Submission, p. 15)

FortisBC submits that the allocation of executive costs based on executive estimates of where time is spent is appropriate and there is no cross-subsidization between gas and electric customers. FortisBC continues by stating that the use of the Massachusetts Formula to allocate costs is currently being considered and once it has completed an examination of optional methodologies, the Company expects to bring the results before the Commission for review and approval. (FortisBC Reply, pp. 40-41)

On a related matter, FortisBC seeks to streamline the cross charges for executives to and from FortisBC Energy Inc. and base it on a fully loaded wage (excluding the current overhead charge) thereby mirroring the process approved in the 2012-2013 FortisBC Energy Utilities Revenue Requirements Decision. (Exhibit B-1, Tab 4, p. 100)

Commission Panel Determination

The Commission Panel concurs with the position which has been taken by FortisBC. There is value in exploring a variety of options for cost allocation and considering the implications of each. In the meantime, the Panel is satisfied that the allocation based on time estimates is reasonable and does not result in a significant variance from an appropriate amount. **The Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant. The Commission Panel also approves the proposed handling of cross charges for executives based on a fully loaded wage only.**

5.2.2 Review of Operating and Maintenance Costs and Issues

5.2.2.1 Introduction

FortisBC's proposed O&M expenditures are approximately $55.4 million in 2012 and $56.8 million in 2013 which includes PPME as previously determined. This represents a 2.8 percent increase in 2012 and 2.6 percent increase in 2013. (Exhibit B-1, Tab 4, pp. 31-32; Exhibit B-12)

FortisBC submits that its 2012 and 2013 O&M Expense forecasts have been developed in support of the Company's business objectives, ensuring that O&M funding is appropriate and prioritized to meet the needs of customers. FortisBC states that its annual departmental O&M budgets are prepared by the department managers and incorporate both a trended and zero-based approach where appropriate. The budgets then go through a cycle of reviews and updates, and are eventually approved by the Company's Executive and Board of Directors. (Exhibit B-1, Tab 4, pp. 28-29)

FortisBC states that the costs for PPME have been excluded from these budgets but, if inclusion of the PPME costs in Power Purchase Expense is not approved by the Commission, the costs will be reclassified to O&M Expense. (Exhibit B-1, Tab 4, p. 29) A summary of the O&M expenses by department sought in this Application is provided in the table below:

Table 4

DEPARTMENTS	**2012 Forecast**	**2013 Forecast**
	($000s)	
Generation	2,287	2,497
Utility Operations	18,503	18,964
Mandatory Reliability Standards	1,179	1,187
Cominco Facility Charge	46	46
Brilliant Terminal Station	3,160	3,192
Internal Audit	396	393
Legal & Regulatory	1,520	1,548
Customer Service	6,737	6,806
Community & Aboriginal Affairs	674	689
Communications	923	952
Human Resources	1,840	1,874
Information Technology	2,841	2,846
Health, Safety & Environment	925	953
Facilities Management	3,685	3,466
Finance & Accounting	3,275	3,360
Transportation Services	573	593
Supply Chain Management	498	505
Corporate & Executive Management	5,112	5,674
TOTAL O&M EXPENDITURE	54,174	55,544
Power Purchase Management Expense	1,211	1,266
TOTAL O&M EXPENDITURES incl. PPME	55,383	56,810

(adapted from Exhibit B-1, Table 4.3.1 and Exhibit B-12, Tab 7, p. 1)

The Commission Panel has reviewed the relevant material pertaining to O&M. In what follows, we will separate the O&M budgets into Labour related costs and Non-Labour related costs and address the issues related to each in turn. Following this, the Panel will address any remaining issues not specifically related to either of these categories.

5.2.2.2 Labour Related costs

Based on the information in Table 4.3.4 of the Application (Exhibit B-1-6, Tab 4, p. 45), the number of FTEs has remained relatively stable over time. This trend continues into the current test period with 3 additional FTEs planned for 2012 and an additional 1 FTE planned for 2013. Labour costs are projected to increase by 1.5 percent in 2012 and 2 percent in 2013 which is a positive outcome given the size of labour adjustments contemplated in Table 4.3.2.1 which is discussed below.

i. Labour Inflation

FortisBC identifies the Company's three employee groups as unionized, exempt and executive employees. The Company states that its unionized employees are represented by either the Canadian Office and Professional Employees Union (COPE) or the International Brotherhood of Electrical Workers Union (IBEW).

FortisBC states that for each employee group, it targets a total compensation package which is at the median level of its peer group of companies and asserts that labour and benefits inflation are primarily non-discretionary cost increases. The Company affirms that given the demographic challenges, it must continually monitor and assess its total rewards framework and find a balance, allowing talented people to be attracted and retained. FortisBC states that the guiding principle is to have a total compensation program which is prudent, competitive, understandable and efficient to administer. Table 5 below outlines the labour adjustments which have been made from 2007 through to the present.

Table 5 – Labour Inflation (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
2.0	**Pay Increases**							
2.1	COPE[(1)]	2.5%	2.5%	2.5%	3.5%	*	*	*
2.2	IBEW[(2)]	1.5%	3.0%	3.0%	3.0%	4.0%	5.0%	*
2.3	Exempt	3.0%	4.0%	3.5%	4.0%	3.0%	3.0%	3.0%

(Exhibit B-1, Tab 4, p. 34)

FortisBC states that for the unionized staff and, consistent with past practice, length of service-related step increases have been included in labour inflation. Presumably, we can infer from this data that this is not the case for Exempt employees. Wage increases for IBEW total 4 percent and 5 percent for 2011 and 2012, respectively. Increases for COPE over this period remain subject to negotiations.
(Exhibit B-1, Tab 4, pp. 32-34)

FortisBC submits that a key consideration with respect to the IBEW contract is that it covers PLTs. The Company states that it has had difficulty in finding and retaining PLTs due to the high demand for this workforce. FortisBC further submits that over the last number of years, 15 percent of PLTs have left the organization (a slightly higher number than have retired) to seek employment elsewhere. (FortisBC Final Submission, p. 39; Exhibit B-1, Tab 4, p. 51; T6:1023-1028)

During the oral phase of the proceeding, Counsel for FortisBC had Ms. Drope provide information concerning collective bargaining agreements in re-examining certain evidence provided by Mr. Walker in his testimony. Ms. Drope's evidence included the following:

- Recent research published by the Canadian Electricity Association in 2011 states that 45,000 workers will need to be recruited by utilities by the end of 2016 and utilities have gone on record stating that they intend to poach employees for many critical positions.
- The base hourly rate for FortisBC PLTs is $39.91.
- The Line Contractor Association base hourly rate is $44.97.
- BC Hydro's comparative rate is $37.96 for PLTs.
- The base rate for PLTs at Altalink in Alberta is $45.12.
- BC Hydro's compensation package for PLTs includes specific provisions not offered by FortisBC that make the rates comparable. These include 17 additional days off.
- FortisBC was able to negotiate some productivity offsets as part of the package.

(T3: 286-292, 294-295)

ICG asserts that the IBEW contract illustrates the FortisBC approach to cost control and prudent management which sends a message "...that FortisBC does not yet appreciate the need for fiscal restraint." ICG states that this is in sharp contrast to the provincial government message of restraint regarding wage increases. ICG further states that if FortisBC had focused on reducing costs with respect to the IBEW contract, the Company would have followed the 2010 Zero mandate or the more recent 2012 Cooperative Gains mandate.

The position taken by ICG is that FortisBC negotiated a contract with the IBEW that included percentage increases which were well beyond the norm and were not reflective of the downward pressure on wages which existed in 2010 (when the contract was negotiated). ICG has relied on information from:

- the BC Bargaining database (Exhibit C 9-9) which reported BC Hydro signed an agreement with the International Brotherhood of Electrical Workers, Local 258 for 0 percent for the period April 1, 2010 to May 31, 2012;
- the 2012/13 to 2014/15 Budget and Fiscal Plan (Exhibit C-9-10), outlining the British Columbia Government's public sector compensation mandate; and
- a MMK Consulting Report (Exhibit B-4, BCUC 1.179.1), which provided statements in support of a downward trend in contract settlements since 2008 as putting pressure on 2010 negotiations to settle at lower rates.

ICG argues that Ms. Drope was unable to answer tough questions with respect to the IBEW contract especially in support of "her conclusion that there has not been a downward trend in contract negotiations since 2008." ICG states that, in response to queries looking for particulars, her evidence amounted to vague references to newspaper articles and a memorandum of understanding. Further, ICG asserts that the affirmative response of Ms. Drope to a question posed by the Panel Chair as to whether FortisBC has a turnover problem puts an end to suggestions that turnover is a justification for the increases within the IBEW contract. (ICG Final Submission, pp. 14-16)

BCMEU expresses concern that ratepayers are paying a significant rate increase to extract "productivity gains" over the test period which may reduce O&M to the benefit of shareholders. BCMEU submits that the solution to ensure the ratepayer receives a share of the benefits for this investment is for the Commission to impose a productivity target. (BCMEU Final Submission, pp. 11-12)

BCPSO made no submissions with respect to this issue.

FortisBC argues that the position taken by ICG has no basis and is not supported by the evidence. The Company submits the following:

- with regard to ICG alleging that Ms. Drope was unable to comment on whether BC Hydro's PLTs would have settled for 0 percent over 2012 and 2013, FortisBC asserts that when the question was rephrased to ask whether BC Hydro PLTs settled for 0 percent over the two years, she answered "no."
- The part of the MMK Consulting Report focused on by ICG was construction labour which the Company argues is not at issue in this instance. Further, the report in question was prepared in May 2010 which was over a year past the conclusion of the IBEW negotiations.
- ICG's reliance on the statement that there was no turnover problem, while applicable to the company as a whole, did not apply to PLTs which were identified as a particular problem.
- Even if there was no percentage increase for BC Hydro PLTs over the test period, the differences in other aspects of the BC Hydro and FortisBC contracts result in greater absolute payments by BC Hydro.

FortisBC argues there is no basis to the BCMEU assertion that the contract may reduce O&M during the test period to the benefit of the shareholder only. The Company submits the contract negotiations were conducted several years ago and any implications of the contract can be readily forecast. (FortisBC Reply, pp. 31-34)

Commission Panel Determination

The Commission Panel agrees that on the surface the percentage increase offered to IBEW seems to be on the higher side of what might have been expected over the past few years. Moreover, the information provided through the BC Bargaining database suggests that in the time frame of the negotiations, other comparable negotiations in the Transportation, Communication and Other Utilities areas resulted in settlements which were significantly lower on a percentage basis than that reached by FortisBC. (Exhibit C9-11) However, what is not known are the issues and circumstances that were at play in the comparable negotiations and whether they are actually comparable. Because of this, the Panel believes the information in Exhibit C9-11 should be given only limited weight.

What is known with respect to the FortisBC settlement is that a significant number of employees in the bargaining group, the PLTs, were and are in high demand and short supply. Moreover, the role played by PLTs is an important one and their contribution to the operations of the company cannot be ignored. Finally, in the view of the Commission Panel, FortisBC has made the case that the risk of retirement and turnover with regard to PLTs is significant.

Nonetheless, the question remains as to whether these circumstances justify the size of wage increase which was awarded in the recent IBEW contract. In the view of the Panel, the evidence provided by Ms. Drope with respect to comparative salaries was most informative. As described, the base rate for PLTs is slightly higher with FortisBC than it is with BC Hydro. However, when the additional benefits that BC Hydro PLT employees receive are considered, the total compensation between the two companies becomes more comparable. When a comparison is made with Altalink in Alberta the base rate very much favours employees of Altalink. While perhaps not directly comparable, the fact remains that both companies compete for people in the same market. **For these reasons, the Commission Panel has determined that acceptance of the IBEW contract as it applies to rates is reasonable.** In making this determination, the Commission Panel understands that there is a significant part of the IBEW bargaining unit that is not in a PLT position. However, there was little evidence to suggest that the wages negotiated for the other employees were unreasonable.

ii. Executive Compensation

FortisBC's executive compensation program involves four main elements – base pay, short term incentives, long-term incentives and benefits. Collectively, these comprise what the Company describes as the "Total Rewards" package which, FortisBC asserts, supports customer needs and contributes to the support of both long and short term corporate objectives. FortisBC states that the compensation program is designed to provide competitive compensation and further its ability to attract and retain qualified and experienced executives. As a general policy, FortisBC has established its base program and related initiatives target for its executives to be compensated at the median level of a broad reference group of companies as established by Hay Management Consultants. This reference group is not weighted in favour of utilities. FortisBC submits that this is in keeping with its practice of hiring from a variety of other industries as well as energy and utilities. (Exhibit B-1, p. 44; Exhibit B-4, BCUC 1.34.4)

With respect to base salaries, FortisBC submits the normal range is between 80 and 110 percent, with the target amount being 100 percent. The Company further submits that an individual's placement within this range is determined after consideration of work experience and job performance. Short term incentives are related to the achievement of short term objectives and focus on key areas such as cost control, customer service, and safety and reliability and are tied to the achievement of specific targets. Long term incentives are intended to focus executives on sustained customer value creation through long-term strategies which provide a balance between long and short term company and customer interests. FortisBC has chosen to furnish its long-term incentives through participation in its stock option plan, the cost of which is funded by the shareholder. The Company submits that this would also be included in regulated expense but for Order G-52-05. To round out the executive compensation, the Company offers a Supplemental Employee Retirement Program (SERP) funded by the ratepayer which provides an accrual of 13 percent of all earnings in excess of the Canada Revenue Agency's RRSP limit. FortisBC states its consultant, Hay Management Consultants, advised that this is industry standard and the amount is reasonable and within the norm in Canada. (Exhibit B-8, BCUC 2.10.2; Exhibit B-4, BCUC 1.34.1, 1.34.5; T2:121; T3:439-440; FortisBC Final Submission, p. 48)

FortisBC argues the incentive portion of executive compensation is levered off of four broad categories, which make up the "scorecard", only one of which is earnings and directly benefits the shareholder. Additionally, the scorecard itself accounts for only 50 percent of the incentive pay with the remaining 50 percent being related to personal performance. FortisBC therefore concludes that Company earnings make up only a small component of the overall incentive plan. (FortisBC Final Submission, pp. 48-49)

BCMEU notes that over the test period, BC Hydro has a 0 percent increase in executive compensation. Further, BCMEU notes that in the oral phase of the hearing it was identified that FortisBC executive compensation was equal to or greater than that of the reference group. BCMEU submits that because the expansion of deferral accounts lowers the risk of operating a utility, it does not seem appropriate that FortisBC's executive compensation is so high and questions how this may affect the ability to negotiate settlements with the bargaining unit. Specifically, BCMEU also raises the following concerns:

- Executive base salaries are above the 100 percent target amount and the average compensation is above the average target median.
- Short term incentives are not sufficient to promote productivity improvements within the organization.
- The appearance is that FortisBC executives are getting the best of both worlds through base pay equal to or better than the reference group and further compensation through stock options.

BCMEU concludes by stating it would endorse an approach that would separate bonus elements of executive compensation from pensionable benefits. (BCMEU Final Submission, pp. 12-14)

BCPSO points out there is a need for benchmark information on FortisBC's executive long-term incentive plan (stock options) and submits the cost of these stock options should continue to be borne by the shareholder. (BCPSO Final Submission, pp. 6-7)

None of the other Interveners commented on this issue.

With respect to executive salaries, FortisBC states that prior to the job scope change in 2010, salaries were held flat and increases reflected the change in scope of executive positions and the roles executives play. Concerning a reduced level of risk for an executive operating a utility due to the expansion of deferral accounts, FortisBC responds that there is no basis to suggest reduced risk for the utility or the members of the executive and points out that Ms. Drope testified that if there was less risk, executive compensation would not necessarily be lower. Finally, with respect to concerns raised with regard to the ability to negotiate a reasonable settlement with the bargaining unit, the Company points out that the scope changes with respect to executive roles are not occurring at the bargaining unit level.

FortisBC responds to the remaining BCMEU concerns as follows:

- On the matter of incentives to find productivity improvements, FortisBC submits that the evidence is that the Company has cost control incentives through its incentive program for non-union employees.
- Base salary and short term incentives do not exhaust the total compensation paid at other companies. FortisBC points to Ms. Drope's testimony that a stock option program is common and market competitive.
- Excluding executive bonuses from pension benefits would depart from how the pension contribution is arrived at. FortisBC points to Ms. Drope's testimony that the pension contribution is derived from both base and incentive pay which is consistent for both the gas and electric non-union groups.

(FortisBC Reply, pp. 34-36)

Commission Panel Determination

While having some concerns, which are commented on below, the Commission Panel is of the view there is no need to change the FortisBC Executive Management base pay or the incentive program at this time. The Panel considers that there is a need for both a competitive base pay and an incentive package to attract and retain quality executives. Relying upon statements attributed to Hay Management Consultants by FortisBC, the Panel is satisfied that the compensation program offered by the Company is in the range of those in the reference group of companies and therefore competitive. However, like the BCPSO, we are of the view that the entire compensation package must be reviewed to determine whether it is appropriate. **Therefore, the Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.** On a related matter, the Commission Panel would also like further information on the SERP program. Specifically, the Panel would like the benchmark study to address the following:

- whether the SERP is incentive-based or handled as a benefit; and
- how the 13 percent for SERP compares to amounts offered by comparable companies.

With respect to whether the incentive program should be included among pensionable benefits, the Commission Panel accepts that the incentive program is not levered solely off an earnings measure and therefore, there is some justification for the current practice of charging incentives in part to the ratepayer. What is less clear is the current practice in the labour marketplace with respect to allowing incentives to be included in pensionable benefits. We would like to see a more complete record on this matter in the future. **Accordingly, the Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.**

iii. Departmental Labour Expense Issues

In spite of the lack of significant growth in FTEs and overall labour costs, the Commission Panel has with specific areas of concern with a number of O&M departments.

a) Generation

Labour costs in the Generation department are forecast to increase from $1.248 million in 2011 to $1.374 million in 2012 and $1.535 million in 2013 which represents an increase in excess of 10 percent in both years. FortisBC states that with the Upgrade and Life Extension program coming to a conclusion, the fluctuations in maintenance activities and costs of the past five years are expected to stabilize. The Company has explained that while it has managed to reduce planned routine repetitive maintenance costs, this has not fully offset the costs associated with the increase in working hours due to changes in legislation such as those relating to working alone and working in confined spaces. As a result, the Generation area is faced with an increase in planned maintenance costs of $0.24 million (Exhibit B-4, BCUC 1.38.1; Exhibit B-1-6, p. 48)

FortisBC states that it will continue to refine its maintenance program in 2012 and 2013 through development of a more condition-based maintenance approach which, over time, will allow the Company to conduct equipment maintenance based on actual need as opposed to a time-based interval. FortisBC submits that the expected benefits of this approach are increased intervals between shutdowns for maintenance and an increased capability to perform operations and plant diagnostics remotely.

Presumably the benefits of moving to a more condition-based maintenance approach as described by FortisBC will also result in cost savings. Given the size of increase in maintenance costs over the test period the Commission Panel has concerns with the speed with which the Company is refining its maintenance program. Because of this and the fact that monitoring equipment has begun to be installed, the Commission Panel is of the view that an opportunity exists for some savings to be realized over the 2012-2013 time period. (Exhibit B-1, p. 50)

b) Utility Operations

Forecast labour costs in Utility Operations have increased from $10.617 million in 2011 to $11.587 million (an increase of 9.1 percent) in 2012 and $11.974 M. (an increase of 3.3 percent) in 2013. This represents a corresponding increase of 11 FTEs in 2012 and a further 2 FTEs in 2013. FortisBC notes that it has had difficulty attracting and retaining skilled journeymen PLTs and system controllers because of the high demand for these positions. FortisBC reports there were 12 vacancies for PLT positions at the end of 2012. Given the demographic challenges outlined in Section 5.2.1.1 of this Decision, FortisBC states it will continue to actively recruit these positions and operational budgets will increase marginally over time.

FortisBC states that in response to the Commission's decision on the 2011 Capital Expenditure Plan, (Order G-195-10) capital expenditures for right-of-way reclamation, pine tree beetle hazard tree removal and hot tap connector replacements totalling $3.78 million were reclassified as operating expenditures. The Company advises that these have been included in the 2012-2013 budgets for this department.

FortisBC states that infrastructure expansion occurs at an average growth rate of 1.1 percent per year and submits that budget forecasts for 2012-2013 reflect this increase in line kilometres. FortisBC also states that right-of-way maintenance costs will also increase in 2011. Additionally, maintenance expenditures for substations are forecast to increase based on historical load and a task driven budget through the Computerized Maintenance Management System. (Exhibit B-1, pp. 52-54)

When questioned as to the size of increase from 2011 to 2012 for the whole department at the oral phase of the hearing, Mr. Sam, FortisBC's Vice President of Engineering and Generation, responded that the $1.1 million increase was made up of the following components:

- $500,000 for salary increases.
- $255,000 in incremental substation work.
- $230,000 for four additional PLT apprentices. Two of the existing apprentices will "top out" this year.
- The remaining $100,000 for various costs including the additional day in February and some additional training requirements.

(T6:1027-1029)

Of concern to the Commission Panel is whether there is sufficient justification for all of the additional expenses which have been forecast for 2012 and 2013. The Commission Panel accepts that the Company has faced challenges with respect to recruiting and retaining PLTs and acknowledges that steps have been taken to respond to this by establishing an apprentice program where there are currently four employees. The Company seeks to double the size of the program by hiring an additional four FTEs to this program during the current test period at an incremental cost of $230,000. While the Panel remains supportive of the efforts to develop future PLT resources in-house, we are not persuaded that there is a need to double the size of the program at this time. Increasing the program to 5 or 6 FTEs from the current 4 employees, in the view of the Commission Panel, would still allow the Company to continue to grow the program as it assesses the performance impact of those employees that have "topped out" or completed the program.

c) Community and Aboriginal Affairs

Overall labour costs for Community and Aboriginal Affairs have risen dramatically since 2010. FortisBC attributes the growth in budgeted costs to the increased complexity of relationships with local governments and consultation requirements for First Nations. Staffing levels were increased from 1 FTE to 3 FTEs in 2011. In addition to these labour costs, the Company has included a provision for external contractors at a cost of $36,000 for both 2012 and 2013.

FortisBC states it has worked to establish open and consultative relationships with First Nations and their communities which are important to enable decision making that incorporates the interests of the Company and its customers as well as those of First Nations. The Company submits that the development and maintenance of First Nation relationships is directly related to its ability to move initiatives forward in a timely fashion. FortisBC advises that increases in the departmental budget in recent years are a reflection of the increased cost of meeting First Nation consultation requirements due to the increasing complexity of these relationships. (Exhibit B-1, Tab 4, pp. 65-66; Exhibit B-9, Celgar 2.16.3.5)

FortisBC also argues that "under present case law FortisBC regards the Commission as having a duty to assess consultation...[so it has]... been doing its own consultation and summarizing that consultation to facilitate the Commission's ...[assessment]". (FortisBC Final Submission, pp. 51-52)

ICG maintains that while the complexity of First Nation relationships may have changed over the past 20 years, there has been no change with regard to there being a need to notify and consult with Aboriginal communities regarding facilities. The ICG notes that FortisBC has always had facilities located on First Nation lands, as it does today. Further, ICG argues the growth of costs in the past few years does not equate to the change in complexity of such relationships. (ICG Final Submission, p. 44-45)

The Commission Panel acknowledges the importance of the work that has been done with respect to building relationships with First Nations and Aboriginal communities. However, the point raised by ICG merits consideration. While building relationships and consulting with all stakeholders is undoubtedly a necessary part of doing business, and always has been, the formal “duty to consult” discussed in recent case law relates to a formal duty imposed upon the government and its agents and is grounded in the “honour of the Crown”. The formal duty to consult is not a duty imposed by law upon FortisBC.

The Commission Panel notes that FortisBC is nearing the end of an aggressive capital build out and is moving toward greater emphasis on sustaining capital. (FortisBC Final Submission, p. 100) The Panel is of the view that while there will still be a need for consultation, it will be less intensive as the Facilities already exist. Therefore, we question whether there is a need for the proposed level of labour resources.

Given this and the fact that costs have risen dramatically and further increases continue to be forecast in the current test period, the Commission Panel is of the view there is an opportunity for cost reductions within the Community and Aboriginal Affairs area.

Commission Panel Determination

Taking these departmental labour expense concerns into consideration and, in addition the concerns raised as to whether there will be a need for all of the forecast requirements for Mandatory Reliability Standards discussed later in Section 5.2.2.4, the Commission Panel is of the view that a reduction in O&M expenditures for labour is warranted**. As a result, the Commission Panel directs FortisBC to reduce O&M expenditures for labour for each of 2012 and 2013 by $250,000. The Panel believes this reduction should be applied to the specific areas where concerns have been raised but will leave the decision as to where these costs are applied to the discretion of FortisBC.**

5.2.2.3 Non-Labour Costs

The following non-labour expenses in FortisBC's proposed O&M budgets are of concern to the Commission Panel and are individually addressed in the following sections. **Items not specifically addressed are approved by the Commission Panel.**

a) Asset Management Program

FortisBC proposes a staged approach to the development of an Asset Management strategy which it submits will require total expenditures of $0.8 million in 2012 and 2013. These expenditures are to accommodate the development of a project team made up of internal and external resources to examine current processes and map out an implementation plan for submission in a future capital expenditures plan application. (Exhibit B-1, Tab 5, p. 34; FortisBC Final Submission, p. 110) The project team will examine FortisBC's existing asset management process, review approved asset management models and strategies used by other utilities, investigate and evaluate available software, and provide a comprehensive report and project cost estimates with recommendations for changes.

FortisBC submits that this development work is incremental to the Company's existing workload. Without this project, FortisBC argues that it will continue to do a form of asset management, relying on professional judgment, which is consistent with other utilities. (T6:994-995)

The costs for the initial development phase of asset management are proposed to be captured in a rate base deferral account and to be dealt with in a future application. FortisBC submits that the asset management strategy would result in the development of processes and implementation of software that would provide benefits in subsequent years and, therefore, the project should be capitalized. (FortisBC Final Submission, pp. 111-112)

BCMEU argues that the expenditure on such a program may not be prudent if preliminary investigations have not been completed. (BCMEU Final Submission, p. 5) BCMEU sees no justification for the proposal and further urges the Commission to direct FortisBC to find more cost effective ways to come up with asset management processes. (BCMEU Final Submission, p. 19)

The Commission Panel notes that in 2010, FortisBC undertook a maintenance rationalization project in the Generation department which resulted in reducing routine maintenance by 10 percent and savings in labour costs of $110,000 per year. (Exhibit B-1, Tab 4, p. 50; Exhibit B-4, BCUC 1.39.4) The Panel expects these efforts and benefits from that project to continue into the test period. The Panel also notes that in 2011, additional monitoring equipment was installed at South Slocan which will assist in data collection and monitoring of equipment installed during the Upgrade and Life Extension (ULE) program. Over time, FortisBC claims that this monitoring will permit the company to further rationalize its maintenance activities by allowing maintenance on equipment to be conducted based on actual need rather than on a time based interval. The Panel notes that FortisBC's expected benefits of this approach are increased intervals between maintenance shutdowns and increased capability to perform remote operations and diagnosis of issues in the plants. (Exhibit B-1, Tab 4, p. 50) In light of the above, the Commission Panel acknowledges that FortisBC has made strides in improving asset maintenance activities and has realized benefits from these efforts.

The Commission Panel also notes the various systems that FortisBC currently has to review asset health and schedule maintenance such as GenJO, CMMS, Cascade, ArcFM and questions whether the full benefits of these existing systems have been exhausted. (Exhibit B-8, BCUC 2.15.1, 2.30.3)

Commission Panel Determination

The Panel understands that an asset management plan could provide system streamlining but the cost and benefits of such an undertaking have not been clearly presented in this proceeding. The Panel notes that there have been various asset management pursuits in the past so it is unknown whether this new proposal will create further additional cost savings or efficiencies to justify the incremental development costs. In addition, the Panel finds that, given the Company's adequate reliability performance, one of the goals of an asset management plan should be to identify and reduce non-essential maintenance to help control costs.

For these reasons, **the Panel denies the $0.8 million deferral account treatment sought by FortisBC in pursuit of the Asset Management Program.** The Panel believes that improving efficiencies and finding strategic solutions are a responsibility of corporate management and therefore should not be allowed as a deferred capital expense. **The Panel approves funds in the amount of $150,000 which may be required for external assistance over the test period. These funds may be included in the O&M budget.**

b) Community Investment (Corporate Sponsorships and Donations)

FortisBC states that expenses for Community Investment relate to the actual costs of donations and sponsorships the Company has undertaken to connect with customers and contribute to the communities that FortisBC serves. (Exhibit B-4, BCUC 1.52.3, 1.52.4) FortisBC indicates that some of these donations were made to political parties as well. (T3:315-316)

The amount of the non-labour expenses budgeted for event sponsorship and charitable donations for 2012 is $270,000 and for 2013 is $282,000. (T3:313-314)

FortisBC states that much of its work activities, including the siting of infrastructure, has an impact on communities and maintains that it is critical that the Company has a good relationship with the communities in which it operates. It argues that sponsorships and donations provided through the community investment program build such relationships and can reduce the expenses of these work activities. The Company argues that community investment is a requirement for successfully operating the utility for the benefit of ratepayers and should continue to be borne by ratepayers. (FortisBC Final Submission, pp. 52-53)

In taking the position that the cost of sponsorship and donations should be fully recovered from the ratepayer, FortisBC argues that the trend in British Columbia has been in the direction of allowing full recovery of donations made in rates if sufficient justification of customer benefit is provided. The Company further notes that this is a move away from an earlier pattern of sharing costs evenly between the ratepayer and the shareholder. The Company cites examples from recent decisions where the Commission allowed the utility to recover 100 percent of community expenditures in rates. In these cases, the Commission, in approving the expenditures, laid out expectations for further justification in future proceedings if the utility expected to continue with this practice. FortisBC argues that it has provided the justification required to support full recovery. (FortisBC Final Submission, pp. 54-56)

The Commission Panel notes the different treatment of these expenses in other jurisdictions in Canada, namely Alberta and Ontario, where donations and sponsorship costs are completely disallowed in revenue requirement applications. As noted previously, the treatment of donations and sponsorship costs in the recent past has been a 100 percent ratepayer expense until the 2012 FortisBC Energy Utilities RRA Decision (2012 FEU RRA Decision) in which community involvement spending was directed to be shared equally between the ratepayer and the shareholder. (Exhibits A2-7, A2-8, A2-9, A2-10, A2-11, A2-14; FEU 2012-2013 RRA Decision, p. 73)

ICG takes the position that all corporate sponsorships and donations should be borne 100 percent by the shareholder and not the ratepayer. ICG notes the testimony of Mr. Walker where he acknowledges that FortisBC determines the recipients of its corporate largesse and that its customers, whom FortisBC believes should continue to be responsible to pay 100 percent of these costs, may not share FortisBC's opinion as to the appropriate beneficiaries. (T2:181-182)

ICG argues that the line of reasoning set out in the March 17, 2006 decision of the Alberta Energy and Utilities Board (AEUB) in ATCO Electric Ltd.'s 2005-2006 General Tariff Application (ATCO Electric) on the issue of corporate donations, sponsorships and community relations expenses should be considered and followed. (ICG Final Submission, p. 43, citing excerpt from Decision-Exhibit A2-9) The ICG cites a quote from Decision 2004-067 of the Alberta Board which was noted and followed in the ATCO Electric:

> ...the Board considers that ***neither sponsorships nor donations*** (charitable or political) **should be included in a utility's revenue requirement.** The Board recognizes that ratepayers may not desire to support the same organizations that utility management or shareholders would support. **Therefore, the Board considers**

> **it inappropriate for ratepayers to bear such costs and *considers that all donations or sponsorships should remain as a shareholder expense.*** (Emphasis in original)

In ATCO Electric, the AEUB went on to determine that donations and sponsorships should not be included in ATCO's revenue requirement. The Board noted that "[c]ustomers have the right to support whichever charitable organizations or functions they choose through their own donation dollars and should not be expected to provide the funds to support the causes chosen by [ATCO] and for which [ATCO] receives the acknowledgement." (Exhibit A2-9, ATCO Decision, p. 68)

Furthermore, the Commission Panel notes that the Ontario Energy Board's current filing requirements clearly state that "[t]he recovery of charitable donations will not be allowed for the purpose of setting rates except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers" because "these expenses are not related to the provision of electricity distribution services and therefore do not appropriately form part of the revenue requirement." (Exhibits A2-10, A2-11)

BCMEU supports the sharing of expenditures on community and Aboriginal affairs on a 50/50 basis between the ratepayer and the shareholder, as being consistent with prior Commission decisions including the 2012 FEU RRA Decision. (BCMEU Final Submission, p. 14)

BCPSO submits that, at a minimum, the shareholder should pay 50 percent of the cost of sponsorships and donations, but urges the Commission to order the shareholder to pay 100 percent of such costs. BCPSO submits that the shareholder realizes significant benefits from these expenditures. (BCPSO Final Submission, p. 7)

In reply, FortisBC reiterates its interpretation of the 2012 FEU RRA Decision in that it did not exclude the possibility that ratepayers pay for donations and sponsorships in full in the appropriate circumstances. (FortisBC Reply, p. 38)

Commission Panel Determination

The Commission Panel is of the view that there are significant benefits that accrue to the shareholder from the Company's community sponsorship and donations spending. These include recognition of FortisBC as a good corporate citizen supporting the brand and improving goodwill. The Commission is also concerned that when all of the costs of Community Investment spending are borne by the ratepayer, the incentive for the Company to clearly focus on those activities that will help achieve its objectives is diminished. The Commission Panel agrees that customers may not wish to support the same causes as the Company and is also of the view that greater discipline will occur if the shareholder bears some of the community investment costs. **The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder. Consistent with the 2012 FEU RRA Decision, the remaining budgeted amounts are to be shared equally between the shareholder and the ratepayer.**

c) Customer Service

FortisBC is forecasting customer growth of 1.8 percent and 1.9 percent in 2012 and 2013, respectively. However, there does not appear to be any evidence of the linkage between customer growth and the need for increased customer service. The Commission Panel is not persuaded that an incremental customer addition would necessarily result in a need for increased incremental customer service expenses.

FortisBC indicates that customer growth has created the need for customer service to find more efficient ways to handle current business while creating room to take on more customers. (Exhibit B-4, BCUC 1.29.3) When describing some of the efficiencies the Company has embarked on during the PBR period, FortisBC identifies numerous activities where Customer Service has mitigated potential cost increases through improving efficiencies. FortisBC provided a list of specific actions which have created efficiencies and states that "[t]hese efficiencies have created more time for existing staff to absorb the continual customer growth." (Exhibit B-1, Tab 4, p. 63; Exhibit B-4, BCUC 1.28.2)

The Panel commends FortisBC for its efficiencies gained in this area and expects these efficiencies to continue into the test period. Given that FortisBC indicates that there are "no significant changes in cost drivers" (Exhibit B-1, Tab 4, p. 63) the Panel is not persuaded that the non-labour costs increases of 9 percent in 2011 and an additional 8 percent increase in 2012 are needed. **As such, the Commission Panel will only approve an increase equal to the forecast BC CPI of 2.2 percent in 2012 and another 1.9 percent in 2013. (Exhibit B-1, Tab 4, p. 43) FortisBC is directed to reduce its non-labour expense forecast for this department by $113,000 in 2012 and $100,000 in 2013.**

5.2.2.4 Summary of Operating and Maintenance Cost Changes

In light of the above discussions, the Commission Panel summarizes the following reductions to O&M:

Table 6 – Adjustments to Operation and Maintenance Budgets

	Commission Panel Determinations:
Asset Management Program	$785,000 proposed in a rate base deferral account is denied. $150,000 for external consultant is allowed in O&M for the test period.
Community Investment (Event / Community Sponsorships and Donations)	Expenses shared 50/50 between ratepayer and shareholder: 2012 reduce by $135,000 2013 reduce by $141,000 Political contributions are 100% disallowed
Customer Service	2012 reduce by $113,000 2013 reduce by $100,000
Labour Related Expense Adjustment	2012 reduce by $250,000 2013 reduce by $250,000

5.2.2.5 Other Revenue Requirement Issues

i. Capitalized Overhead

FortisBC states that in its 2006 Revenue Requirements Application, it introduced a new mechanism for allocating overhead costs to capital expenditures which suggested that 25.2 percent of Gross O&M Expense should be allocated to capitalized overhead. As part of the 2006 NSA, the parties agreed that a capitalized overhead of 20 percent would be set for the term of the PBR. The Company states that this methodology was further updated based on 2010 actual results and suggests that a 23.9 percent capitalized overhead would be appropriate. In this Application, FortisBC submits that the 20 percent rate currently in place should be maintained for 2012 and 2013, noting that this will serve to mitigate variances to Net O&M Expense and related fluctuations in revenue requirements. (Exhibit B-1, Tab 4, pp. 101-103)

BCMEU submits that there is insufficient evidence on the record to support a change from that which has been proposed by FortisBC. BCMEU submits that FortisBC should be ordered to update its overhead capitalization survey in recognition of the Company's move away from capital intensive activity. (BCMEU Final Submission, pp. 18-19)

BCPSO takes no position on the capitalization rate but does suggest there is a need to distinguish between the capitalization rate of 20 percent and direct loading which is meant to capture T&D supervisory and administrative costs. (BCPSO Final Submission, pp. 12-13)

FortisBC submits that it has included an updated capitalization study in this Application and Ms. Leeners, FortisBC's Vice President of Finance and CFO, testified that this was a detailed analysis and she was not sure what more work could be done in addition to that provided. (FortisBC Reply, pp. 48-49)

Commission Panel Determination

The methodology employed by FortisBC to determine capitalized overhead is consistent with what has been used in recent revenue requirements and the 20 percent rate is also consistent with past NSAs. Further, as noted by BCMEU, there is no evidence on the record in this proceeding that would suggest a better methodology or capitalized overhead rate. While the Commission Panel does not fully agree with BCMEU, as stated below, we are of the view that further work is required in the future. **Therefore, the Commission Panel approves the requested capitalized overhead rate of 20 percent for the test period. For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time.** The Panel also acknowledges the concerns raised by BCPSO with respect to the need to differentiate between capitalized and direct loadings which will be addressed in the next section.

ii. Department and Corporate Overhead Loadings

A number of issues related to departmental and corporate overhead loadings were raised by the participants in this proceeding. Some of these issues were examined in detail and were the subject of IRs and questions during the oral phase of the proceeding. In some cases these questions resulted in FortisBC Undertakings which were completed following or during the oral hearing. The issues raised involve departmental and corporate overhead directly related to the following:

- the significant increase in overhead loading rates from 2008 to 2012; and
- whether direct overhead loading, as currently applied, is appropriate.

The Commission Panel will now address these issues separately.

- Increase in Overhead Loading Rates

FortisBC states that for several operating business units, where an activity supports multiple projects, costs are estimated during the budgeting process and a direct overhead loading rate is used to distribute those costs among the projects. These are in addition to the capitalized overhead costs discussed above and both are applied to capital projects. (Exhibit B-1, Tab 4, p. 102)

A concern of the Commission Panel is the significant growth in the percentage of both capitalized and direct overhead loading being applied to the various projects. Table 7 below summarizes the growth of overhead as a percentage of capital expenditures for 2008, 2010 and the forecast for 2012 for T&D projects. The Okanagan Transmission Reinforcement Project (OTR) (CPCN Application for the Okanagan Transmission Reinforcement Project) has been excluded from the calculations as it was subject to a separate loading rate pursuant to the Reasons for Decision for the OTR project. As outlined in response to Undertaking #20, the total overhead percentage applied to T&D projects is only slightly more than that applied to Generation projects. Although the gross dollars for direct overhead have remained relatively stable during the period of 2008 to 2012, the total overhead loadings for T&D have increased from 16 percent to 26 percent, as shown in the table below.

Table 7 - Capital and Direct Loading Summaries

		2008 Actual	2010 Actual	2012 Forecast
Unloaded Capital Expenditure Excluding OTR	A	93,883	77,339	74,369
Capitalized OH Excluding OTR	B	8,691	5,604	11,512
Capitalized OH (Excluding OTR) Percentage	C=B/A	9%	7%	15%
Unloaded T&D Capital Expenditure Excluding OTR	D	67,268	47,004	46,695
Direct OH	E	4,720	5,157	5,000
Direct OH (Excluding OTR) Percentage	F=E/D	7%	11%	11%
Total Loadings Applicable to T&D Sustaining Projects	G=C+F	**16%**	**18%**	**26%**

(Source: Exhibit B-8, BCUC 2.51.2)

FortisBC states that loading percentages are a function of four parameters which include, in addition to overheads, other adjustments and the Company's unloaded capital expenditure plan. By way of explanation, the Company advises that the loading rate is a calculation of the overhead amounts to be recovered, divided by the total unloaded capital expenditures. In this case, the numerator (or overhead to be capitalized) has continued to increase over the four year period while the capital expenditures have decreased. As a result, the overhead rate for both direct and capitalized overhead as a percentage of capital expenditures has increased. (Exhibit B-8, BCUC 2.51.2)

Of concern to the Commission Panel is that where capital expenditures may be reduced in any test period, the amounts being charged to capital through the capitalized overhead allocation continue to rise in both dollars and as a percentage. This appears to be counter-intuitive and indicates there may be a need to more closely align the capitalized overhead rate to the changing capital expenditures rather than to simply rely upon a percentage of operating costs as is currently the case.

An additional concern of the Commission Panel is the 2012 Forecast as outlined in FortisBC's response to BCUC IR 2.51.2. While we have been able to reconcile the figures shown in the above IR response for 2008 and 2010 to comparative figures shown in FortisBC's financial schedules and to its annual reports, the figures shown for forecast 2012 appear irreconcilable. The capitalized overhead figure of $10.834 million in Table 8 below, (which is 20 percent of gross O&M), is inconsistent with the figure of $11.512 million in the preceding table (an amount which excludes approximately $155 thousand for overhead attached to the OTR project). We can find no explanation for this discrepancy.

Table 8 – E-Operating and Maintenance Expense

	Actual 2010	**Forecast 2011**	**Forecast 2012**	**Forecast 2013**
	($000s)			
Total Operating and Maintenance Expense	46,148	53,885	54,172	55,794
Capitalized Overhead	(9,529)	(10,777)	(10,834)	(11,159)
Net Operating and Maintenance Expense	36,619	43,108	43,338	44,635

(Source: Exhibit B-1, Tab 7)

Commission Panel Determination

One of the concerns with using a point-in-time study to determine a capitalized overhead rate is that the amount of capital expenditures varies from year-to-year. Therefore, what may be appropriate at one point-in-time, may be above or below what should be considered appropriate in any given year. Therefore, the failure to consider the amount of capital being expended over a given period of time leads to the potential for inaccurate capitalized overhead estimates where a capitalized overhead study has not been prepared for that period. Because of this, the Commission Panel is of the view that some consideration as to the amount of forecast or actual capital expenditure is an important variable in determining an appropriate level of capitalized overhead. This may well become increasingly important as FortisBC enters a period which BCMEU describes as a move away from "the capital intense activity of Fortis in recent years to a sustaining capital approach." (BCMEU Final Submission, p. 19) **Accordingly, the Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.** This will reduce the need to complete a comprehensive capitalized overhead study for each revenue requirement and allow capitalized overhead rates to vary annually in accordance with capital expenditure requirements.

The Commission Panel is also concerned with regard to the differing amounts of capitalized overhead reflected in Tables 7 and 8 above**. FortisBC is directed to prepare and file a report with the Commission by September 30, 2012, explaining this apparent inconsistency. If an amount greater than the 20 percent approved for capitalized overhead has been used in the calculation of rates, FortisBC is directed to adjust the capitalized overhead rates downward to reflect the approved amount for capitalized overhead.**

- Application of Direct Overhead

A second concern of the Commission Panel is whether FortisBC's current practice of charging a direct overhead loading to capital projects is appropriate. FortisBC distinguishes this from the 20 percent capitalized overhead rate applicable as well as from those cases where a person is working directly on a specific project and the time is charged directly to that project. According to FortisBC, direct overhead refers to the recovery of Transmission and Distribution supervisory and administrative costs that are not directly charged to specific projects. As noted in Table 7, the Direct Overhead is $5 million which, when added to the capitalized overhead of $10.834 million, totals $15.834 million or 29 percent of total forecast operations and maintenance costs. (Exhibit B-8, BCUC 2.25.4) This does not appear to include the Absorption Overhead applied to Generation projects, as shown in the table below, an Undertaking provided by FortisBC.

Table 9 - Overhead Loading By Category of Asset

Category of Assets		Approximate Overhead Load % by Asset Category							
		Absorption Overhead [1]		Capitalized Overhead [2]		Direct Overhead		AFUDC [3] (if applicable)	
		2012	2013	2012	2013	2012	2013	2012	2013
1	Generation	9%	9%	16%	15%	*Not applicable*		7%	7%
2	Transmission	*Not applicable*		16%	15%	11%	11%	7%	7%
3	Distribution			16%	15%	11%	11%	7%	7%
4	General Plant			16%	15%	*Not applicable*		7%	7%

Note-1: *Absorption Overhead for Generation is the equivalent of Direct Overhead for Transmission and Distribution*

Note-2: *Capitalized Overhead % also includes the ISP amortization of $677,000 per year.*

Note-3: *AFUDC is only applicable to specific projects that meet the AFUDC applicable criteria of >$100k and over 3 months in duration.*

(Source: Exhibit B-25, Undertaking #20)

Commission Panel Determination

The concerns of the Commission Panel are related to the lack of clarity as to how the amounts charged to direct overhead are calculated and whether there are some cases where costs which already form part of capitalized overhead are also charged as direct overhead, leading to duplication.

The Panel questions whether managerial and supervisory costs which are part of overall O&M expenses should be charged to capital projects. The Panel also notes that, in response to Undertaking 19, FortisBC has provided a list of departments that charge time to direct overhead loading. Among these are three Departments (Health and Safety, Finance and Procurement & Material) which are also included among those departments charged out through the capitalized overhead allocation. As noted above, our concern is that there is potential duplication in that the costs allocated through capitalized overhead are also being charged through direct overhead loading.

Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification. In preparing the material, the Company is encouraged to study the allocation methods of other comparable utilities and report on those findings.

iii. Mandatory Reliability Standards

On June 4, 2009, the Commission issued Order G-67-09 adopting certain Mandatory Reliability Standards (MRS). These standards are very similar to those developed by the North America Electric Reliability Corporation and the Western Electricity Coordinating Council and require affected BC entities to bring themselves into compliance with those standards that are applicable to them. Accordingly, FortisBC is responsible to ensure the Company is and remains compliant with all applicable standards. FortisBC states that it has reviewed the standards, filed mitigation plans to become compliant and submits that continued effort will be required to maintain compliance with all relevant standards and deal with changes to existing and new standards.

FortisBC has requested approval of O&M funds totalling $1.179 million in 2012 and $1.187 million in 2013 for Mandatory Reliability Standards in this Application. In addition, the Company seeks to amortize accumulated costs estimated at $0.7 million for this program over five years starting in 2012. The Company states that effort and costs going forward will focus on transitioning from capital expenditures to operating costs to maintain compliance. FortisBC states it has moved from 100 percent of the effort being directed to capital in 2010 to 100 percent of the effort being directed to operating in 2012 and 2013. This has resulted in an increase of $0.224 million in budget for 2012, with little additional requirements for 2013. (Exhibit B-1, Tab 4, pp. 54-55)

BCMEU has expressed concern with the program noting that the expenditures when compared to BC Hydro seem to be high.

FortisBC in response noted that in the oral phase of the proceeding, Mr. Chernikhowsky, FortisBC's Director of Engineering Services, testified that because BC Hydro has traditionally done business with the United States it has already implemented a number of the systems that support MRS. These standards had not been previously applicable to FortisBC because it was not trading across the border, nor did it have interconnections with other utilities. Given this context, FortisBC notes that its costs would understandably be proportionately higher than those of BC Hydro. (FortisBC Reply, p. 40)

Commission Panel Determination

The Commission Panel notes that the Company has built its forecast budget to cover the possibility that there will be changes to existing and the addition of new standards and there is no evidence to suggest that this is likely to occur in the future. However, the Panel acknowledges that the Mandatory Reliability Standards Program is an important program required by legislation. In addition, the Mandatory Reliability Standards program is still in the early stages of implementation and it is difficult to determine the exact costs which will be required to maintain compliance with all applicable standards. **Because of this, the Commission Panel is reluctant to take issue with the forecasts that have been prepared by FortisBC and approves the forecast expenditures, as requested.**

5.3 Financing Costs

FortisBC's financing costs are made up the cost of debt and the cost of equity. The Company's financing costs for cost of debt and cost of equity for the purposes of the Application are based on a deemed capital structure of 60 percent debt and 40 percent equity. The cost of debt is determined by the percentage of debt assumed to be included in the capital structure and the interest rate on that debt. The total percentage of debt discussed in the capital structure is determined by the Commission and the interest rate on the debt, by the banks, capital markets and the Company's credit ratings. The cost of equity is a function of the investment in rate base, the equity component in the capital structure and the rate of return on equity (ROE). (FortisBC Final Submission, p. 95)

Regarding the short-term and long-term interest rates, FortisBC submitted different forecasts at different points in time during the Proceeding. Tables 10 and 11 below summarize the Company's forecasts for short-term and long-term interest rates for the two-year test period. The first series of forecasts were used at the time of the Application, on June 30, 2011; the second, for the Evidentiary Update in early November 2011 and the third was presented during the oral phase of the proceeding, in March 2012.

Table 10 - Short-Term Interest Rate Forecasts for 2012 and 2013

			2012F[1]	2012F[2]	2012F[3]	2013F[1]	2013F[2]	2013F[3]
	A	Average Forecast Rate for Bankers' Acceptance Rates (3-month T-bill)	2.33%	1.13%		3.80%	1.95%	1.90%
+	B	Spread	0.30%	0.30%		0.10%	0.30%	0.30%
=	C	Sub Total Before Stamping Fee[4]	2.63%	1.43%		3.90%	2.25%	2.20%
	D	Rounded Up to Nearest 0.10%[5]	2.70%	1.50%		3.90%	2.30%	2.20%
+	E	Acceptance Fee Rate	1.25%	1.25%		1.25%	1.25%	1.25%
=	**F**	**Bankers' Acceptance Rate[6]**	**3.95%**	**2.75%**	**2.85%**	**5.15%**	**3.55%**	**3.45%**

[1] Exhibit B-4, Table BCUC 1.85.2a; Exhibit B-1, Table 4.7.1.2-1 p. 124

[2] Exhibit B-8, Table BCUC 2.35.2a; Exhibit B-8, Table BCUC 2.35.1

[3] T4:536

[4] Line C = Line A + Spread Line B

[5] Line D is Line C rounded up to the nearest 0.10 percent

[6] Bankers' Acceptance Rate (Line F) = Line D + Line E

Table 11 - Long-Term Interest Rate Forecast for 2013 Debt Issuance

	2013F[1]	**2013F[2]**	**2013F[3]**
Date of issuance	2013	2013	2013
Term (Years)	30	30	30
Average Forecast Rate for 30-year Government of Canada Bond	4.45%	3.55%	3.20%
Long-Term Debt Rate Spread	1.45%	1.70%	1.55%
All-in Borrowing Rate	5.90%	5.25%	4.75%

[1] Exhibit B-1, p. 122

[2] Exhibit B-8, BCUC 2.33.1.1

[3] T4:535

During the oral phase of the proceeding, FortisBC confirmed the Company's intention to use the interest rate forecasts presented in the Evidentiary Update, dated November 4, 2011. (T4:529-530) With respect to short-term debt, FortisBC argues that, because the Bankers' Acceptance Rate went up by 10 basis points in 2012 while it went down by 10 basis points in 2013, there is an offset that reduces the issue to a fairly immaterial impact on the revenue requirement model. (T4:536-537) With respect to long-term debt, FortisBC submits the impact of the change to the all-in borrowing rate from 5.25 percent to 4.75 percent on the revenue requirement model would be $100,000, in part because it is budgeted for the last part of 2013.

However, the BCMEU and BCPSO both support using the most current forecasts. The BCMEU submits that FortisBC has slightly overstated its financing costs and there should be an adjustment to recognize the lower interest rate environment that the entity is operating in. While the impacts are small and deferral accounts have been proposed, the BCMEU submits that the most current forecast should be used for financing costs in setting rates for the test period. (BCMEU Final Submission, p. 18) BCPSO also notes that the variances are small, but states that the use of more recent forecasts more accurately reflects current financial conditions. (BCPSO Final Submission, p. 11) Other Interveners did not take issue with the interest rate forecasts proposed by the Company.

In its Reply, FortisBC acknowledges the BCMEU and BCPSO's positions but emphasizes the need for a temporal cut-off point in establishing information for the test period. FortisBC also stresses that the difference is not material and the magnitude of the impact is not sufficient to depart from the need to have a temporal cut-off in preparing a revenue requirement application for a test period. In any case, the Company argues that any variances will go through a variance account for financing costs so that customers would only pay the actual costs. (FortisBC Reply, pp. 47-48)

Commission Panel Determination

The Panel agrees with the BCMEU and BCPSO that the use of more recent forecasts more accurately reflects current financial conditions. It also concurs with the BCMEU that FortisBC has slightly overstated its financing costs. For instance, the 2012 short-term principal that is financed at the

Banker's Acceptance rate is, on average, $44.702 million whereas the 2013 short-term principal that is financed at that rate is, on average, $69.442 million. (Exhibit B-8, Table, BCUC 2.35.1.1a) Therefore, when the Banker's Acceptance rate goes up by 10 basis points in 2012 (from 2.75 percent to 2.85 percent), the forecast interest expense should go up by $45,000. However, when the Banker's Acceptance rate goes down by 10 basis points in 2013 (from 3.55 percent to 3.45 percent), the forecast interest expense should go down by $69,000, which more than offsets the increase in interest expense the previous year. Even if the numbers are small, ratepayers benefit from using the most recent forecasts.

Regarding the 2013 long-term debt, the revised forecast saw a decrease in the all-in borrowing rate from 5.25 percent to 4.75 percent. The Panel notes that FortisBC has acknowledged this means a decrease in the revenue requirement for 2013 of about $100,000. Even if this variance is small, ratepayers again benefit from using the most recent forecasts. In addition, FortisBC indicated during the oral phase of the proceeding: "... we do agree at this point in time, based on future forecasts on 30-year underlying long Canada's that the rate likely will go down, based on today's information, in 2013." (T4:530) In light of this evidence, the Panel believes it is even more important to use the most up-to-date forecast long-term interest rates. This is particularly important given our determination not to approve FortisBC's proposed deferral account for financing costs, which is addressed in Section 5.4.3.

Therefore, the Panel directs FortisBC to use the most recent interest rate forecasts available at the time of the oral phase of the proceeding of 2.85 percent for short-term and 3.45 percent for long-term debt.

5.4 Rate Base

Rate Base is generally described as a utility's net investment in the assets it needs to provide service to its customers. The primary components of FortisBC's rate base are:

- Plant in Service
- Construction Work in Progress not subject to Allowance for Funds Used During Construction (AFUDC)
- Plant Acquisition Adjustment
- Deferred and Preliminary Charges
- Accumulated Depreciation and Amortization
- Contributions in Aid of Construction
- Allowance for Working Capital
- Adjustment for Capital Additions

(Exhibit B-1, Tab 5, p. 1)

FortisBC's mid-year Rate Base for 2010 to 2013 is set out below (in thousands of dollars):

Table 12

2010 (actual)	**2011 (forecast)**	**2012 (forecast)**	**2013 (forecast)**
$945,637	$1,070,756	$1,145,910	$1,215,357

(Exhibit B-12, Schedule 1)

As outlined in Table 12, Rate Base is forecast to increase 13 percent between 2010 and 2011, 7 percent between 2011 and 2012, and 6 percent between 2012 and 2013, representing an average increase of approximately 9 percent over the three year period.

As noted earlier in Section 3.1 of this Decision, the main driver of FortisBC' requested rate increases is the growth of its rate base. (Exhibit B-1, Tab 1, p. 6)

ICG argues that FortisBC's rate base has increased 142 percent since 2004 and that "this dramatic increase in rate base provides a very large benefit to shareholders." (ICG Final Submission, p. 4)

ICG further notes that FortisBC's sales in 2004 were 2,874 GWh with an associated revenue requirement in the neighbourhood of $170 million (or a revenue requirement of approximately $60,000 per GWh) as compared to forecast sales of 3,233 GWh for 2013 (an increase of approximately 13 percent) with an associated revenue requirement of $310 million, or $96,000 per GWh, an increase in the order of 60 percent, (37 percent on an inflation-adjusted basis). (ICG Final Submission, p. 10)

ICG further argues that the "distortion in rate base relative to sale [sic] growth needs to be addressed by the Commission Panel in this proceeding". (ICG Final Submission, p. 12)

The Commission Panel is of the view that the increase in the size of FortisBC's rate base is an issue given that it is the main driver of rate increases which have been and are predicted to be well in excess of inflation. However, as noted by FortisBC, many of its capital expenditures and rate base additions are the result of past approvals by the Commission. (FortisBC Reply, p. 2) As noted earlier, however, the Commission Panel is concerned with the magnitude of rate increases, which are forecast to continue beyond the test period, and is of the view that capital expenditures must be scrutinized carefully.

5.4.1 Plant In Service

Plant In Service makes up by far the largest component of rate base. It is made up of Property, Plant and Equipment used in the generation, transmission and distribution of electricity. Capital additions increase Property, Plant and Equipment while Retirements reduce the account. Rate Base is reduced by accumulated depreciation and amortization of capital expenditures.

5.4.2 Accumulated Depreciation and Cost of Removal

For 2010 to 2011, FortisBC was using a composite depreciation rate of 3.2 percent. FortisBC filed an updated depreciation study prepared by the depreciation consultancy firm Gannett Fleming (2011 Depreciation Study) as part of the Application. (Exhibit B-1, Appendix J as corrected in Exhibit B-12, Appendix J) FortisBC is requesting Commission approval to apply new depreciation rates flowing from the updated study, commencing in 2012. The combined updated depreciation schedules result in a virtually equivalent overall composite depreciation rate of approximately 3.2 percent. (Exhibit B-1, Tab 4, pp. 128, 131)

FortisBC is also seeking Commission approval to add $4.7 million into rate base for the net cost of asset removal for 2011, and $5.4 million and $4.0 million for removal costs for 2012 and 2013, respectively. (Exhibit B-1, Tab 5, p. 9)

In addition, FortisBC has requested Commission approval to continue its current accounting treatment of asset removal costs, which it charges against accumulated depreciation as they are incurred, as opposed to what has been referred to as the "traditional method" of pre-collecting estimated net negative salvage during the asset's estimated useful life.

Mr. Kennedy of the firm Gannett Fleming testified that both treatments of asset retirement costs are acceptable and "widely used." (T3:499-500) Ms. Leeners testified that adoption of the traditional method of collecting net negative salvage in advance would result in a rate increase of five percent. (T3:499)

In its Reply, FortisBC notes that should the Company adopt the traditional method of collecting net negative salvage in advance, "current and future customers will be paying for both the historical actual costs of removal already incurred, as well as the future costs of removal for existing assets." FortisBC suggests that if it were to adopt the traditional method for collection of net negative salvage, a transition period might be appropriate, given the otherwise immediate impact on customer rates. (FortisBC Reply, p. 43)

Commission Panel Determination

The Commission Panel notes the comments of Mr. Alan Wait concerning the erratic depreciation rates for certain particular classes of assets. However, as noted by the BCPSO, the overall effect on the composite depreciation rate for all classes is "relatively minor." The Commission Panel appreciates that establishing ongoing depreciation rates for various asset classes is not an exact science. The

Commission Panel finds that the variances in the depreciation rates were adequately explained during the oral phase of the proceeding and therefore approves the depreciation rates from the updated Depreciation Study and the corrected information provided in the Evidentiary Update of November 4, 2011.

The Panel also approves the inclusion of asset removal costs for 2011, 2012 and 2013 in rate base as requested in the Application. The Panel notes, however, that the inclusion of asset removal costs in rate base does increase the value of plant in service rate base by an amount that is actually being removed from plant in service. This concept may need to be reviewed in the future.

In any event, the Commission Panel approves FortisBC's continued use of recognizing actual asset removal costs as incurred, as requested. The Commission Panel acknowledges the view of the ICG that FortisBC "should not be permitted to delay the need to reduce costs by managing rates through accounting practices that do not follow the recommendations of the depreciation consultant", and we agree with the general premise. (ICG Final Submission, p. 43) However, the Panel finds that the evidence tendered at the oral phase of the proceeding, as noted above, supports FortisBC's current practice as being "widely used" and "acceptable." The Panel further notes the significant rate increase which would result from a change from the current method of accounting for asset removal costs to the traditional method of recognizing negative salvage value at the asset acquisition stage and is not prepared to direct a change in this accounting method at this time.

5.4.3 2012/2013 Capital Expenditure Plan

FortisBC seeks Commission acceptance under subsection 44.2(3) of the *Act* that the 2012-2013 Capital Expenditure Plan (2012-13 CEP) is in the public interest. FortisBC also requests the Commission to find that the 2012-13 CEP satisfies subsection 45(6) of the *Act* which requires a public utility to file with the Commission, at least once each year, a statement of the extensions to its facilities that it plans to construct. In considering whether to accept an expenditure schedule, the Commission Panel is required to consider subsection 44.2(5) of the *Act*. Section 44.2 is set out in its entirety in Appendix B of this Decision.

Table 13

Table 5.3.3.1 - Proposed 2012-13 Capital Expenditure Plan										
		2012	2013	Total	2012	2013	2012	2013	2012	2013
		Requested			Previously Approved		CPCN Application		Total	
		($000s)								
1	Generation	4,496	2,939	7,435	5,636	8	0	0	10,132	2,947
2	Transmission and Stations	33,028	29,036	62,064	2,219	0	0	3,720	35,247	32,756
3	Distribution	29,249	25,888	55,137	0	0	0	0	29,249	25,888
4	Telecom SCADA Protection and Control	2,329	3,682	6,011	0	0	0	0	2,329	3,682
5	General Plant	12,503	19,317	31,820	69	75	10,521	38,408	23,093	57,800
6	Total Plant and Equipment	81,605	80,862	162,467	7,924	83	10,521	42,128	100,050	123,073

(Exhibit B-1, Tab 6, p. 2, Table 1.1; Exhibit B-1-6, Errata 2, updated page 60, Table 3.3.2)

The amounts requested in this Application total $162.467 million in the current test period. In addition, FortisBC intends to submit applications for CPCNs in 2012 and 2013 for the following projects (Exhibit B-1, Tab 6, p. 6):

- Kelowna Bulk Transformer Capacity Addition project estimated at $25.6 million (exceeds the cost threshold);
- Advanced Metering Infrastructure (AMI) project estimated at $47.18 million (exceeds the cost threshold); and
- Kootenay Long Term Facilities Strategy estimated at $16.5 million (the project planning process falls between capital expenditure plan applications).

(Exhibit B-1, Tab 6, p. 6)

FortisBC has identified a number of key considerations that underpin the 2012-13 CEP, several of which are as follows:

- It has invested approximately $700 million in new or upgraded generation, transmission/distribution and general plant infrastructure since 2005 and is starting to move more into sustaining capital programs,
- It aims to level its annual capital spending where possible,
- It is not delaying expenditures for certain condition-based projects,

- The Company is making efforts to improve forecasting by narrowing the variance between approved and actual capital expenditures while increasing the accuracy of estimates by striving for, where possible, a Class 3 (Definition Phase) level of accuracy, and
- While committed to safety and reliability, FortisBC does not have the objective of attaining a gold “standard”.

(FortisBC Final Submission, pp. 100-106)

FortisBC states that for certain portions of the 2012-13 CEP where there is minimal forward looking information (such as unforeseen projects or new connects), the estimates tend to be based on historical information because the recent trend is the best information that FortisBC has available. However, the Company acknowledges that improvements could possibly be made and suggests asset management as a potential candidate. (FortisBC Final Submission, pp. 112-115)

BCPSO observes that FortisBC's capital program build-out since 2005 has been aggressive, and has resulted in increased reliability, safety and quality of service to ratepayers. It submits a balance needs to be struck between appropriate levels of safety, reliability, quality of service and customer rates. BCPSO further observes that while the costs of proposed transmission-related capital projects are declining, the costs for generation projects are not, which is a concern because of the rate impact to residential customers. In addition, it notes the Commission comments from the 2011 Capital Expenditure Plan Decision to the effect that estimates based primarily on historical average spending may not accurately address what is actually required in a given time period. BCPSO concludes by stating that in spite of having concerns with respect to specific capital projects, it requests the Commission Panel direct FortisBC to reduce the 2012-13 CEP by 15 percent, and leave FortisBC to determine which projects to cancel or postpone during the test period. (BCPSO Final Submission, pp. 3, 12-14)

BCMEU expresses concern as to whether FortisBC is implementing capital plans in the most prudent and cost effective manner and points to the Kettle Valley Project’s cost overruns as an example. BCMEU also expresses concern with the use of historical rolling averages for budgeting purposes and encourages a more active use of zero based budgeting for capital as an alternative. With respect to specific capital projects, BCMEU states it has ongoing concerns that the investments in fibre optic communications to service customers are above and beyond the necessary communication requirements for the area. Further, while not taking exception to any individual capital project, BCMEU recommends that a 10 percent reduction in capital expenditures is appropriate to implement discipline in the test period. (BCMEU Final Submission, pp. 9, 19-22)

ICG states that FortisBC has acknowledged that it is “approaching diminishing returns” from capital expenditures and submits that no capital expenditures which have been justified on the basis of reliability improvements should form part of the 2012-13 CEP. Furthermore, ICG recommends that until FortisBC develops alternate scenarios based on delaying capital expenditures as directed in the 2005 RRA Decision, only capital expenditures with ratings of 275 or higher (as shown on the project ranking scale submitted in Exhibit B-27, Undertaking 40), should be accepted. ICG has identified a few exceptions to this 275 threshold which include: Transmission Line Condition Assessment, Transmission Line Urgent Repairs, Transmission Line Right-of-Way Easements, Station Urgent Repairs, and Transmission Line Rehabilitation expenditures which it argues can be based on the average of the past five years of actual expenditures. (ICG Final Submission, pp. 40-42)

Mr. Gabana, in addition to comments concerning specific capital expenditures, recommends that the Commission Panel reject the Grand Forks Transformer Addition Project and that FortisBC confirm the estimates for all capital projects are accurate to within 3 percent. (Gabana Final Submission)

BCSEA and Mr. Wait had no comments with respect to the expenditures detailed in the 2012-13 CEP.

In reply, FortisBC states that any reduction to the capital expenditures would be arbitrary in light of the evidence it presented. FortisBC observes that in comparison to BCMEU and BCPSO’s proposed capital expenditure reductions of 10 percent and 15 percent respectively, the reductions ordered by the Commission in the 2011 Capital Expenditure Plan Decision amounted to 5.4 percent of the proposed expenditures in 2011 and 2012.

In response to ICG’s assertion that the Company should approve capital expenditures with a rating of 275 or greater, FortisBC argues that setting an arbitrary cut-off based on project rating, as suggested by ICG, would mean that capital investment would be reduced to a level where projects which are necessary are not undertaken. In the view of FortisBC, the ICG proposal seeks to reduce expenditures to unsustainable levels. FortisBC argues the proposed reduction is not supported by evidence.

FortisBC states it has also addressed the concerns raised by the Commission in the 2011 Capital Expenditure Plan Decision regarding the use of historical average expenditures for budgeting purposes by canvassing other utilities and finding similar examples of rolling averages being used for those purposes. In support of continuing to use this approach, FortisBC notes that, despite the concerns regarding the use of historical average expenditures for budgeting purposes, no party has suggested "a specific, reliable alternate solution." (FortisBC Reply, pp. 49-52)

Commission Panel Discussion

The Commission Panel notes that among the Interveners that commented on the 2012-13 CEP, the recommendations were unanimous for a reduction in expenditures. BCMEU and BCPSO call for general reductions of 10 percent and 15 percent respectively, while ICG is far more aggressive, calling for, by the Commission Panel's estimate, a reduction of approximately 55 percent spread across generation, transmission, stations, distribution and telecommunications, Supervisory Control and Data Acquisition (SCADA) and protection and control related expenditures.

In response to whether a slow-down in the capital building program should be anticipated as FortisBC shifts toward a sustaining program, Mr. Walker stated that this has been reflected in the capital plan. (T2:221) The Commission Panel observes the slow-down is not apparent when comparing the proposed 2012 /2013 capital expenditures with the 2011 Capital Expenditure Plan. Specifically, the approved 2011 Capital Expenditure Plan was for an expenditure of $103.3 million. (Decision accompanying Order G-195-10, p. 1) The current Application proposes additional expenditures (which include previously approved expenditures and expected CPCN applications) which bring the total capital expenditures to $100.0 million in 2012 and $129.1 million in 2013. (Exhibit B-1-6, Errata 2, Table 3.3.2)

A consideration in reviewing the 2012-13 CEP, is the level of reliability, safety and quality of service to ratepayers which is related to the recent capital expenditure program. The Commission Panel agrees with the comments of the BCPSO that it is important to strike a balance between safety, reliability, quality of service and achieving reasonable customer rates. The Commission Panel notes that System Average Interruption Frequency (SAIFI) and System Average Interruption Duration (SAIDI) are similar to or below Canadian Electricity Association average performance indexes. (Exhibit B-1-1, pp. 83-85) Within the oral hearing the issue was raised with Mr. Sam, the Vice President of Engineering and Generation, who was asked whether there was a need for further improvement in the SAIFI and SAIDI numbers with emphasis on the word "need". Mr. Sam replied that the Company did not see that there was a need to improve these numbers on average and agreed that the desire was to maintain them. (T6:1200) Taking this into consideration, the Commission Panel is of the view that safety, reliability and quality of service to ratepayers are at an acceptable level and a focus on identified problem areas is considered most appropriate at this time.

As noted above, subsection 44.2 (5) of the *Act* requires the Commission to consider certain matters in considering whether to accept an expenditure schedule.

Subsection 44.2(5) (a) of the *Act* requires the Commission to consider the applicable of British Columbia's energy objectives. With reference to this requirement, the Commission Panel is of the view that the following are the most relevant to this Application:

(a) To achieve electricity self sufficiency;
(b) To take demand-side measures and to conserve energy including the objective for the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;
(c) To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;... and
(d) To encourage communities to reduce greenhouse gas emissions and use energy efficiently.

The Commission Panel finds that the 2012-13 CEP is generally consistent with these objectives as the proposed expenditures will assist the province to achieve energy self sufficiency by prolonging the life of hydro-electric generation and transmission assets.

Subsections 44.2 (5)(b) and (d) also require the Commission Panel to consider the most recent long term resource plan filed by the utility under section441 and the cost effectiveness of any demand-side measures included in the expenditure schedule within the meaning prescribed by the Demand-Side Measures Regulation. Both of these have been filed with this Application. Demand-Side Measures are examined in Section 6 and the Long-Term Resource Plan is examined in Section 7 of this Decision.

Section 44.2 (5)(c) of the *Act* requires the Commission to consider the extent to which an expenditure is consistent with the applicable requirements under sections 6 and 19 of the CEA. Sections 6 and 19 of the *CEA* are primarily related to BC Hydro although section 6 does require a utility planning in accordance with section 44.1 of the *Act* to consider British Columbia's energy objective to achieve electricity self-sufficiency. Neither section applies to an expenditure schedule filed under section 44.2 of the *Act.*

The Commission Panel is also required under subsection 44.2 (5)(e) of the *Act* to consider the interests of persons in British Columbia who receive or may receive service from FortisBC. The Commission Panel finds that, except where an expenditure is reduced or rejected, the 2012-13 CEP is consistent with the interests of FortisBC's existing and potential customers.

The Commission Panel has reviewed the individual projects in the 2012-13 CEP in detail and in what follows will make specific determinations with respect to some projects which we have determined are inadequately supported or require additional work. In addition, the Commission Panel will make observations with regard to specific projects we consider to be questionable or program amounts which we consider to be unjustifiably high given the evidence provided by the Company. With this latter group of projects, the Commission Panel will not make specific determinations on individual programs, but will provide a determination directing FortisBC to reduce its overall expenditures by an amount we consider to be appropriate. The Panel will leave the final allocation of the approved capital expenditures for FortisBC to determine based on its objectives of providing reliable service and ensuring public and employee safety.

Generation

In the generation group of projects, the Commission Panel makes the following observations:

- Of the $1.2 million in expenditures in 2012 and 2013 for the "All Plants Concrete and Structural Rehabilitation" project, only $671,000 is related to public and worker safety which FortisBC has stated is a priority. (Exhibit B-4, BCUC 1.114.2)
- FortisBC has not sufficiently explained why all the windows in the Upper Bonnington, South Slocan and Corra Linn Powerhouses need to be opened on a daily or seasonal basis, especially with no noted ventilation deficiencies and the recent and proposed facility lighting upgrades. (Exhibit B-4, BCUC 1.115.3) The "Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows" project estimate is $430,000. (Exhibit B-1, Tab 6, pp.12-13)
- With regard to the Corra Linn Unit 3 Completion project, FortisBC proposed expenditures related to the transformer and the acquisition of spare generator stator coils. However, FortisBC considers the risk of a transformer failure to be low and stated that individual stator winding coil failures could be bypassed to allow continued operation of the generation unit. This suggests that the need for both expenditures, estimated at $460,000 from a project total of $722,000, may be overstated. (Exhibit B-4, BCUC 1.116.2, 1.117.5)
- In the 2011 Capital Expenditure Plan Application, FortisBC stated that the "potential for refurbishment of the remaining four old units at Upper Bonnington is under review and will be addressed at a later date." (2011 Capital Expenditure Plan Application, Exhibit B-1, p. 13) The Panel finds that the proposed expenditures of $1.31 million (Exhibit B-1, Tab 6, Section 2.2.5, pp. 14-16) for the "Upper Bonnington Old Plant Various Unit Upgrades" project demonstrate a piecemeal approach to the disposition of the Upper Bonnington Old Plant units. The Panel considers that these may be better addressed as either maintenance expenditures or as part of a comprehensive project to address either overall rehabilitation or retirement.
- The incremental personnel safety that FortisBC claims as the driver for the $509,000 "Fire Panels at Lower Bonnington, Upper Bonnington and Corra Linn" project may be better addressed by improving personnel egress. (Exhibit B-1, Tab 6, pp. 16-17)
- Many of the projects in the category of "Generation All Plants Minor Sustainment Capital Projects" appear to be discretionary in nature, with no reliability or safety impacts associated with deferral of the proposed expenditures. For instance, the "All Plants Air System Upgrade" (Exhibit B-1, Tab 6, pp. 19-20) and the "All Plants Upgrade Telephone Communications" projects (Exhibit B-4, BCUC 1.122.1) are intended to upgrade systems that, although not modern, have not been shown to be under-performing or failing. Similarly, the need for upgrading the spillway gate hoists and controls and removing old wiring at Lower Bonnington, Upper Bonnington and Corra Linn is not supported by either

recent control system failures, electrical code requirements or reliability indicators. (Exhibit B-4, BCUC 1.123.1 to 1.123.6, inclusive) In total, these projects account for $1.034 million in the test period.

Overall, the Commission Panel observes the proposed spending in the 2011 Capital Expenditure Plan for generation projects was $2.513 million (December 17, 2010 Decision, Order G-195-10, p. 5, Table 1.1) compared with the request for approval of new expenditures in 2012 and 2013 of $4.495 million and $2.939 million respectively. This does not demonstrate a shift from a capital-intensive growth and rehabilitation oriented program to a sustainment oriented program. **From the preceding analysis, the Commission Panel is of the view that reductions of approximately $4 million in the proposed generation portfolio over the test period are possible.**

Transmission Growth

The Transmission Growth portfolio consists of four large projects that are individually discussed the section below.

1) The Okanagan Transmission Reinforcement Project, which was previously approved by Order C-5-08.

2) The Kelowna Bulk Transformer Capacity Addition Project, forecast at $3.72 million in 2013, and driven by the requirement to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions, will be subject of a CPCN application in 2012. FortisBC states that this CPCN application will contain a detailed option analysis, information on the recommended solution and a revised project cost estimate and expenditure schedule. (Exhibit B-1, Tab 6, pp. 38-42)

3) Ellison to Sexsmith Transmission Tie project. FortisBC describes the Ellison to Sexsmith Transmission Tie project estimate as the equivalent of an “AACE Class 4” estimate. (Exhibit B-4, BCUC 1.126.2) FortisBC has updated this estimate to a class 3 estimate and notes that the remaining forecast costs are reduced by $0.283 million. (Exhibit B-28, Undertaking 51) The Commission Panel approves the project with the expectation that the capital request will be reduced by the amount stated.

4) The Grand Forks Transformer Addition project is forecasted to cost $7.205 million in 2013. FortisBC states that this project addresses two deficiencies in that it is intended to address transmission system reliability issues for the Grand Forks area as well as the gap between the Okanagan and Kootenay communications systems. (FortisBC Final Submission, p. 132) The project

> economics are aided by revenues with an NPV of approximately $2.5 million from a fibre leasing agreement (Exhibit B-4, BCUC 1.127.10), a redacted copy of which was provided by FortisBC. (Exhibit B-5, BCMEU 1.19, Appendix Q19) The proposed project has the highest NPV cost of the three options FortisBC analyzed for the project, one of which was the continued use of the existing 9L and 10L transmission lines. (Exhibit B-4, BCUC 1.127.1)

The Commission Panel notes that FortisBC was specifically directed to apply for a separate CPCN if it intended to proceed with the fibre installation portion of this project. (2011 CEP Decision) The filing of a CPCN application would allow the concerns expressed by the BCMEU regarding investments in fibre optic communications to be fully vetted. The Commission Panel notes the redacted fibre lease agreement contains a clause that requires the parties to negotiate in good faith to extend the agreement if the fibre is not in place by September 15, 2014. The Panel believes this to be more than sufficient time to accommodate a CPCN application and review.

In response to Mr. Gabana's comments regarding this project, FortisBC confirms that the transformer addition is not driven by capacity requirements, but is to maintain supply reliability in the Grand Forks area. (FortisBC Reply, p. 58) The Commission Panel notes that the customers served by the existing Grand Forks Terminal T1 have experienced better than average reliability in recent years. (Exhibit B-8, BCUC 2.46.2) Furthermore, the options reviewed by FortisBC, which include the continued use of 9L and 10L between Rossland and Christina Lake, have a lower NPV cost than the proposed project. (Exhibit B-4, BCUC 1.127.1) The removal of both the 9L and 10L transmission lines between Rossland and Christina Lake does not appear to be warranted at this time. **While the Commission Panel endorses the relocation of a spare transformer to the Grand Forks Terminal to reduce the downtime associated with a failure of the current transformer, we reject the proposed expenditure of $7.205 million for the Grand Forks Transformer Addition Project because the need for increased reliability is not apparent. In addition, the Panel notes that FortisBC was previously directed to apply for a CPCN for certain elements of the proposed project and failed to do so. If FortisBC intends to proceed with advancing either the fibre optic communications portion of the proposed project or the installation of the spare transformer at Grand Forks Terminal, it is directed to apply for a separate CPCN. In pursuing a CPCN for fibre optic communications, FortisBC is expected to diligently pursue the extension of the fibre leasing agreement to preserve the potential benefit to ratepayers.**

Transmission Sustainment

Approximately half of the capital expenditures proposed for Transmission Sustainment projects are driven by historical averages, and the other half are driven by specific transmission line condition issues. Rather than continuing to rely on simple rolling averages of historical expenditures, FortisBC was previously directed in the 2011 FortisBC Capital Plan Decision to investigate alternative means of developing capital budgets. As referenced earlier, this was also an issue of concern for some Interveners. FortisBC acknowledged that it has addressed the matter but it continues to use this method when there is a lack of better information. (T6:1124) FortisBC is encouraged to continue to investigate alternative methods of developing budgets for those project categories that were previously based on rolling averages of historical expenditures, with the caveat that the evaluation strategies and procedures be supported by direct linkage to fundamental objectives of reliability and safety. Absent direct linkage to direct reliability and safety effects, the Commission Panel is concerned that the cost of projects driven by specific condition issues may be inflated because the condition threshold may be set too high.

Furthermore, the Commission Panel notes that the true increase in the expenditures that underpin those budgets that are based on historic spending is made more difficult to determine because of the additive effects of both capitalized overhead loading rates and departmental direct overhead loading rates, both of which vary with the amount of overall capital expenditures. This will be considered in the discussion that follows. For transmission sustainment projects, the Commission Panel makes the following observations:

- For the "Transmission Line Condition Assessment" budget, the average of the last five years' expenditures is approximately $403,000. (Exhibit B-1-1, p. 129) The test period expenditures are proposed to be $522,000 and $485,000 in 2012 and 2013 respectively. The Commission Panel notes that even with the increases of 6 percent in capitalized overhead and 4 percent in direct overhead in 2012 compared with 2008 (Exhibit B-8, BCUC 2.51.2), for a total 10 percent increase in overhead, and an additional 8 percent for inflation over the same period, the proposed average expenditures over the test period are more than 5 percent, or over $50,000, greater than the historical average.

- FortisBC states that the "Transmission Line Rehabilitation" budget is based on previous years' transmission line condition assessment and explains the budget is also partially based on historical cost per pole expenditures because there is a delay in incorporating the condition assessment data from a given year into the next year's rehabilitation budget. (Exhibit B-1-1, p. 129; Exhibit B-1, Tab 6, p. 45) The Commission Panel notes that forecast amounts have increased substantially over the test period for the "Transmission Line Rehabilitation" budget. The average of the last five years' expenditures is approximately $1.466 million, while over the test period expenditures are proposed to be $3.372 million and $2.621 million in 2012 and 2013 respectively. (Exhibit B-1-1, p. 129) As above, considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 70 percent, or over $2.5 million greater than the historical average. FortisBC confirmed that the work required involved the rehabilitation of 2,191 poles in 2012 and 1,565 poles in 2013 which represents approximately 25 percent of the total number of transmission poles. (Exhibit B-4, BCUC 1.131.3) When asked about the causes for the large increase over the previous years during the oral hearing, Mr. Chernikhowsky indicated that there was some work that was rescheduled over the 2007 to 2011 period creating some backlog as well as work coming due on its cycle. (T6:1174-1175)

  The need for increased sustaining capital expenditures based on the current condition assessment is not immediately apparent given the level of reliability as indicated by SAIFI and SAIDI performance results. The Commission Panel is not suggesting delaying expenditures until reliability is seen to suffer but notes that large increases in sustaining capital expenditures over historical averages when reliability has been continually improving suggests that FortisBC's methodology of identifying condition based expenditures may be too over-reaching. Therefore, the Panel is not persuaded that the amounts forecasted are actually required.

- For the "Transmission Line Urgent Repairs" budget, the average of the last five years' expenditures is approximately $476,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be $594,000 and $620,000 in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 8 percent, or about $90,000, greater than the historical average.

- For the "Transmission Line Right of Way Easements" budget, the average of the last five years' expenditures is approximately $215,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be $400,000 in both 2012 and 2013. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 50 percent, or almost $300,000, greater than the historical average. The Commission Panel notes that FortisBC provided justification for the increase in the rolling average based on the combination of transmission and distribution easements rather than solely for transmission. (Exhibit B-4, BCUC 1.133.4) With this proposed shift of distribution easement costs into the transmission category, the corresponding reduction in the distribution sustaining capital budget is not apparent.

A number of the remaining Transmission Line Sustainment projects are driven by the line condition assessments where the lines themselves have experienced relatively good reliability performance. The Commission Panel has previously commented on the relationship between increasing reliability and increasing sustaining capital expenditures, and questions whether the condition threshold has been set too high for the following projects:

- The “21-24 Line Rebuild” project with proposed expenditures of $2.219 million in 2012 does not appear to be driven by rapidly deteriorating line condition. Emergency expenditures in 2010 were less than 1 percent of the proposed capital project (Exhibit B-8, BCUC 1.55.2) and there is significant redundancy in the lines whereby no generation is lost for any single contingency (Exhibit B-4, BCUC 1.136.7)
- The “20 line Rebuild” project with proposed expenditures of $4.664 million in 2013 is required to maintain service reliability and alleviate safety concerns. (Exhibit B-1, Tab 6, Section 3.2.9, p. 53) These concerns are in two major areas, one being structural integrity of the poles and another being inadequate circuit-to-circuit spacing resulting in transmission to distribution contacts. (Exhibit B-4, BCUC 1.138.2) The Commission Panel notes that FortisBC stated that there were no transmission to distribution contacts on 27 line since 2007 (Exhibit B-8, BCUC 2.57.1) and although FortisBC does not provide the same information for 20 Line, the installation of station class arrestors is being considered to prevent overvoltage caused by transmission to distribution contacts from affecting customers. (Exhibit B-4, BCUC 1.138.3)

Overall, there appears to be some opportunity for reduction in the Transmission Line Sustainment capital budget. The review above suggests that a reduction of as much as $9.5 million over the test period is possible. FortisBC acknowledges that if approval is not granted for the these projects, it would still endeavour to mitigate risks associated with line failures. (T6:1048)

Station Sustainment

FortisBC has several station sustainment projects which involve the rehabilitation and ongoing upgrades to substation system. The Panel makes the following observations:

- The PCB Mitigation project, with $22.822 million in capital expenditures in the test period represent over three-quarters of the proposed capital expenditure of $28.395 million for Station Sustainment projects. (Exhibit B-1, Tab 6, p. 54, Table 3.3) The Commission Panel is concerned that the project estimate is an "AACE Class 4" estimate (where typical end usage is for study or feasibility) despite FortisBC's objective of submitting "AACE Class 3" estimates (where typical end usage is for budget authorization or control) for acceptance or approval. (Exhibit B-4, BCUC 1.140.1) Because of this, **the Commission Panel is concerned about the estimate quality and control of actual costs associated with the PCB Mitigation project, and directs FortisBC to file a comprehensive scope and schedule for this project by October 1, 2012 and semi-annual progress reports thereafter.**

- For the "Station Urgent Repairs" budget, the average of the last five years' expenditures is approximately $622,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be $818,000 and $907,000 in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are about 11 percent, or over $150,000, greater than the historical average.

- Although FortisBC does not endorse the approach (FortisBC Final Submission, p. 153), the Commission Panel notes the "Addition of Arc Flash Detection To Legacy Metal-Clad Switchgear" project goes beyond typical current practice in other utilities where mitigating procedures are used in place of switchgear modification. (Exhibit B-4, BCUC 1.143.3) This project is budgeted at $1.083 million in the test period.

- In the "Huth Low Voltage Breaker Replacement" project, scope creep is expanding the scope of the project beyond the strict current need. (Exhibit B-4, BCUC 1.144.3; Exhibit B-8, BCUC 2.60.1) In an environment where the capital program is moving away from growth and towards sustainment, discipline must be reinforced to avoid the temptation of adding scope simply because a project is being proposed at a certain time or location. This project is budgeted at $0.07 million in the test period.

Overall, the Commission Panel estimates there are possible reductions of $1.3 million in the Station Sustainment portfolio.

<u>Distribution</u>

The Commission Panel makes the following observations with respect to the Distribution Projects Portfolio:

- For those budgets that continue to be based on historic rolling averages ("New Connects System Wide", "Distribution Unplanned Growth", "Distribution Urgent Repairs", and "Forced Upgrades and Line Moves"), (Exhibit B-4, BCUC 1.145.2; Exhibit B-4, BCUC 1.149.2) the aggregate of FortisBC's proposed budgets are more than $2 million less than the average of the last five years' expenditures. Additionally, a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012 is applied to the five year historical average. (Exhibit B-1-1, p. 160; Exhibit B-1-1, p. 161; Exhibit B-1-1, pp. 171-172; Exhibit B-1-1, pp. 172-173) The Commission Panel notes spending in these categories is largely non-discretionary as it is driven by third parties, and if the proposed test period spending is under-forecast, the true size of the capital budget may be understated.

- For the "Distribution Line Condition Assessment" budget, which is based on a historical average of the cost per pole times the number of poles being assessed, the average of the last five years' expenditures is approximately $777,000. (Exhibit B-1-1, p. 170) The test period expenditures are proposed to be $1.410 million and $1.398 million in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 50 percent or almost $1 million greater than the historical average.

- For the "Distribution Line Rehabilitation" budget, FortisBC acknowledges that at the time of the filing of the 2012-13 CEP, pole test results and condition reports were not available. Therefore, the Company has based its forecast expenditures on actual costs of previous years combined with the knowledge of the areas being assessed and equipment condition expectations. The Commission Panel notes that the average of the last five years' expenditures is approximately $2.757 million. (Exhibit B-1-1, pp. 170-171) The test period expenditures are proposed to be $5.298 million and $3.517 million in 2012 and 2013 respectively. As before, considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are about 35 percent, or about $2.3 million, greater than the historical average.

- For the "Distribution Line Rebuilds" budget, the average of the last five years' expenditures is approximately $1.504 million. (Exhibit B-1-1, p. 171) The test period expenditures are proposed to be $1.679 million and $1.660 million in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are less than the historical average by more than $200,000.

- For the "Distribution Line Small Planned Capital" budget, the average of the last five years' expenditures is approximately $793,000. (Exhibit B-1-1, p. 173) The test period expenditures are proposed to be $726,000 and $826,000 in 2012 and 2013, respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are over the test period are less than the historical average by more than $300,000.

Given the review of the Distribution Projects portfolio, the Commission Panel is of the view that reductions of $2.5 million of proposed capital expenditures are possible. This is an amount which is lower than the combined potential savings of $3.3 million and is reflective of there being a number of projects where FortisBC has forecasted budgeted amounts to be lower than the five year average.

Telecommunications, SCADA Protection and Control

The "Kelowna 138 kV Loop Fibre Installation" project ($3.761 million for both 2012 and 2013) accounts for more than half of the expenditures in the Telecommunications, SCADA, Protection and Control portfolio. The Commission Panel notes that FortisBC has filed this project for acceptance with a Class 4 estimate rather than the required Class 3 estimate. In addition, the Panel is not persuaded that there is sufficient justification to support moving forward with the most expensive Option F as proposed. Accordingly, **the Commission Panel rejects the expenditures for the Kelowna 138 kV Loop Fibre Installation project. FortisBC may provide Class 3 estimates for both Option E and Option F and additional justification for its recommendation in a future filing.**

The balance of the proposed 2012 and 2013 expenditures in the Telecommunications, SCADA, Protection and Control portfolio ($2.25 million) are for Communications Upgrades and SCADA Systems Sustainment, a portion of which address MRS issues. (Exhibit B-8, BCUC 2.64.1) Specifically, the Commission Panel questions the need for the "JungleMUX Laser Upgrade" expenditures ($144,000). FortisBC stated the JungleMUX equipment has been extremely reliable and it maintains a stock of spare equipment in both Trail and Kelowna. (Exhibit B-4, BCUC 1.157.3) The Commission Panel also questions the assignment of $163,000 of "MRS System Sustainment Internal Labour" cost as a capital expenditure and suggests such sustainment costs should be part of O&M expenditures. (Exhibit B-8, BCUC 2.64.1)

For the remaining projects, the Commission Panel estimates possible capital expenditure reductions of $300,000 in the Telecommunications, SCADA, Protection and Control portfolio.

General Plant

In the category of General Plant capital expenditures, the Commission Panel notes that the CPCN application for the Kootenay Long Term Facilities Strategy (Exhibit B-1, Tab 6, pp. 98-99) will be filed later this year and the Advanced Metering Infrastructure CPCN has been submitted to the Commission on July 26, 2012. Pursuant to the 2011 Revenue Requirements NSA, AMI costs are being collected in a non-rate base deferral account attracting AFUDC. FortisBC requests that the investigative funds be moved to a Rate Base deferral account in 2012 and, subject to the approval of the CPCN application, subsequently transfer the funds into the AMI capital project in 2012. (Exhibit B-1, Tab 5, p. 14) A determination on this issue is provided in Section 5.4.4.3 of this Decision.

Commission Panel Determination

The Commission Panel has rejected two projects, the Grand Forks Transformer Addition/High Capacity Communications Project and the Kelowna 138kV Fibre Loop Installation Project which result in a total reduction of $10.966 million in capital expenditures. These projects may be resubmitted over the current test period.

In addition, the Commission Panel has identified a number of areas where further reductions are possible. These total $17.6 million distributed as follows:

• Generation	$4 million
• Transmission Sustainment	$9.5 million
• Station Sustainment	$1.3 million
• Distribution Projects	$2.5 million
• Telecom/SCADA	$0.3 million
Total	**$17.6 million**

As outlined earlier in this Section, it is not the intention of the Commission Panel to make specific determinations on individual projects but to make an overall reduction to the capital expenditures portfolio and allow FortisBC to allocate the cost reductions as it deems appropriate. **Based on our review of the 2012-13 CEP the Commission Panel is of the view that an overall reduction to the CEP of $17.6 million over the test period is possible. However, the Panel believes imposing all of the reductions related to the $17.6 million may not provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion. By reducing the amount of $17.6 million to $10.5 million (which is approximately 60 percent), the Panel can be reasonably assured that FortisBC can achieve the level of service it requires and will still have sufficient flexibility to manage its projects and workforce. Accordingly, the Commission Panel directs FortisBC to reduce its capital expenditure budget by $10.5 million in addition to the two projects which have been specifically rejected above.** Collectively, these reductions and projects rejected result in a total reduction of $21.466 million from the $162.467 in additional capital expenditures requested over this test period. In addition to this there is a further reduction of $0.283 million as outlined in the undertaking on the Ellison to Sexsmith Transmission Tie Project. **Taking all of these reductions into account, the Commission Panel accepts additional capital expenditures totalling $140.218 million for the 2012-2013 test period.**

The Commission Panel confirms that FortisBC's 2012-13 CEP satisfies section 45(6) of the *Act*, which requires the utility to file a statement of the extensions to its facilities it plans to construct at least once each year.

5.4.4 Deferral Accounts

FortisBC is seeking a number of approvals relating to its existing and proposed new deferral accounts. These are summarized in Exhibit B-1, Tab 5, pp. 10-37.

In the view of the Commission Panel there are two important issues which must be considered in reaching a determination on whether to approve the deferral accounts as proposed by FortisBC. They are as follows:

1. Deferral Account Financing Costs

   This refers to the financing cost appropriate for various deferral accounts.

2. Determining an Appropriate Amortization Period

   This refers to the most appropriate time period over which specific deferral account groups should be amortized.

The Commission Panel believes that establishing principles to deal with these issues will be instrumental in helping provide a context for the determinations which follow. Accordingly, the Panel will address these two issues before undertaking to examine the specific deferral account approvals which are sought by FortisBC.

I. Deferral Account Financing Costs

FortisBC takes the position that all deferred expenditures or credits, other than notional or non-cash assets or liabilities should be included in rate base, which is financed at the Weighted Average Cost of Capital (WACC). It further submits that if a deferred expenditure is not included in rate base, then it should attract AFUDC. (FortisBC Final Submission, p. 81) The Commission Panel notes that these two rates are similar if not virtually the same.

The ICG argues that FortisBC's deferral accounts should be financed in the same way as those of BC Hydro, which is at the weighted average cost of debt, as opposed to the weighted average cost of debt and equity, as proposed by FortisBC.

In the alternative, the ICG argues that should the Commission Panel determine that some deferral accounts should attract the weighted average cost of debt and equity, then those should be limited to accounts where the balance is to be made part of a capital expenditure. (ICG Final Submission, pp. 39-40)

FortisBC argues in reply that BC Hydro is a Crown corporation with different access to resources. It argues that FortisBC, as an investor-owned utility, should properly earn an equity return on its rate base deferral balance to allow the shareholder an opportunity to earn a fair return on its invested capital. It argues that FortisBC's rate base, including deferral accounts, is financed as part of the total financing of the Company, and represents the actual cost being incurred by the Company. (FortisBC Reply, p. 47)

Commission Panel Determination

The Commission Panel agrees with the ICG that deferred expenditures or credits ought not to be included in rate base or attract a rate base rate of return. The Panel notes that deferral accounts are regulatory assets, not true capital assets. Capital assets which are recognized as such under standard accounting rules such as US GAAP do not require deferral account treatment. It is only amounts which would otherwise be required to be expensed under standard accounting principles for which deferral account treatment is needed. However, in the Panel's view, amounts which represent operating costs or other costs which would commonly be expensed as current period charges but which are deferred for rate-smoothing purposes do not become capital investments, simply by the fact of the deferral. Normally, a utility, whether a Crown corporation or shareholder-owned, is not entitled to receive a return on operating costs or current period charges but simply recovery of those amounts from its ratepayers, assuming recovery is otherwise justified. Current period charges are not "investments" which attract a capital return, they are deferred operating costs/current period expenses which, as noted above, in the Panel's view, should not attract rate base rate of return. **The Panel finds that a more appropriate financing cost is an interest return.** For expenditures which are amortized beyond one year, the Panel finds that the appropriate return is FortisBC's WACD. The Panel further finds that for true-up deferral accounts which are, by their very nature, a short term deferral, the appropriate interest return is FortisBC's short term interest cost.

The Commission Panel is also concerned about the proposed proliferation of smaller deferral accounts, all of which, as noted above, are proposed to be placed into rate base. The Commission Panel notes that deferral of current period expenses reduce the level of O&M expense recorded in a given period and, therefore, has the potential to distort true operating costs. We also note the dramatic forecast increase in rate base over the test period and are of the view that care must be taken to ensure that rate base items are properly so categorized.

II. Amortization Period

The Commission Panel also notes that deferral of expenses only serves to increase their ultimate cost by the amount of the financing charge and is of the view that amortization periods should be as short as possible, while continuing to serve the rate-smoothing function. The Commission Panel further notes that deferral of expenses only serves to increase their ultimate cost by the amount of the financing charge and is of the view that amortization periods should be as short as possible, while continuing to serve the rate-smoothing function. The length of amortization periods for a specific account depends on a number of factors including the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on the ratepayer.

In the same vein, deferral accounts which continue for long periods without being amortized into rates also increase the eventual cost to the ratepayer. The Commission Panel is of the view that decisions as to whether to proceed with a particular project where there is an associated deferral account for preliminary and investigative charges ought generally to be made within three years. This time period should be more than sufficient to complete preparatory work for a project and placing a limit of three years ensures that preliminary and investigative charges are not deferred indefinitely. **The Commission Panel therefore directs that such deferral accounts, with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates.** The amortization period to be used will depend upon the balance in the account. The amounts in these accounts, unless otherwise ordered, are to attract a return at FortisBC's WACD until such time as they are properly added to an approved capital project. For greater clarity, costs incurred in relation to projects for which a CPCN is eventually sought, or an expenditure schedule filed, will become part of the capital project upon approval or acceptance as the case may be.

5.4.4.1 Existing Deferral Accounts

A. Preliminary and Investigative Charges – Pumped Storage Hydro

FortisBC accumulates costs to investigate potential capital projects in the "Preliminary and Investigative Charges" category of deferral account. The current treatment is that if a capital project in fact proceeds, the costs are transferred to the project. In the event a project does not proceed, costs are expensed at that time.

FortisBC has identified "pumped storage hydro" as a potential resource to meet its future capacity requirements. FortisBC advises that the lead times associated with development of facilities for this resource are lengthy. FortisBC's preliminary investigations have identified two possible sites at a cost of $0.227 million. FortisBC does not seek disposition of this account during the test period.

Commission Panel Determination

The pump storage account is an example of a deferral account for amounts which do not meet the capitalization criteria required by standard accounting principles and would be required to be expensed. In the Panel's view, this account should attract an interest return at FortisBC's WACD, and is not to be included in rate base. **FortisBC is directed to commence the amortization of this deferral account into rates in the next test period if the associated project has not commenced by that time.**

B. Deferred Regulatory Expenses

Expenses related to regulatory proceedings are deferred until approved by the Commission, at which time they are amortized into rates. Incentive amounts are also deferred and used to adjust rates in subsequent years. FortisBC has a number of this type of regulatory expense deferral account, some of which are being sought to be amortized into rates during the test period.

Commission Panel Determination

The Commission Panel approves the amortization in 2012, as requested, of the following regulatory expense deferral accounts into rates:

- **Implementation of new rate structures**
- **Residential Inclining Block Rate and Industrial Stepped Rate Applications**
- **2011 Revenue Requirements Application**

However, the Commission Panel takes issue with the proposed disposition of other regulatory deferral accounts sought in the Application and makes the following determinations.

- Shaw Application for Transmission Facility Access

FortisBC is requesting approval to amortize costs relating to Shaw's application to the Commission to continue to have access to FortisBC's transmission infrastructure in the amount of $0.2 million, ($0.3 million before tax) into rates in 2012. These costs were deferred pursuant to Commission Order G-184-10. These costs include:

- the cost of FortisBC disputing the Commission's jurisdiction to hear Shaw's application, which was addressed in Order G-24-10,
- subsequently seeking a Reconsideration of that Order, which was addressed in Order G-63-10, both with Reasons, and
- unsuccessfully appealing the Commission's ruling on its jurisdiction to hear Shaw's application to the British Columbia Court of Appeal, which loss resulted in an award of costs against FortisBC (FortisBC Inc. v. Shaw Cablesystems Limited, 2010 BCCA 552).

Commission Panel Determination

The Commission Panel rejects FortisBC's proposal to amortize this deferral account into rates. As noted by the Court of Appeal (at para. 60), "[a] plain reading of s. 70 reveals that the legislation enables the BCUC to make decisions regarding electricity transmission facilities. That power is not limited to particular uses. The BCUC properly took jurisdiction over the matter..."

In the Panel's view, FortisBC's continued pursuit of this issue, without success, was not reasonable. Shaw was at all times seeking to continue to use FortisBC's transmission infrastructure for a fee, which was the result obtained at the end of the day. In the Panel's view these costs were entirely avoidable and ought not to be borne by ratepayers.

FortisBC is seeking to amortize the following regulatory expense deferral account into rates in 2013:

- Irrigation Rate Payer Group Consultation and Load Research

FortisBC is seeking approval to fully amortize costs in the amount of $0.07 million ($0.1 million before tax) which relate to segmenting the irrigation class customers into sub-groups and installing interval metering for a sample of each sub-group in 2013.

Commission Panel Determination

The Commission Panel approves the full amortization of the research costs relating to Irrigation rate payers in 2013, as requested. However, any ongoing balances for 2012 are to attract a short term interest financing charge only and will be carried as a non-rate base deferral account.

FortisBC is seeking to amortize the following deferral accounts over a longer period.

- Renewal of BC Hydro Power Purchase Agreement

FortisBC advises that it has been in negotiations with BC Hydro over renewal of its Power Purchase Agreement which expires in 2013, since 2005. FortisBC seeks Commission approval to begin amortizing its expected costs of negotiations in the amount of $0.2 million ($0. 3 million before tax) over five years, commencing in 2012.

Commission Panel Determination

The Commission Panel is of the view that the costs relating to FortisBC's negotiations with BC Hydro, ongoing for a number of years, are more properly considered operating costs. **The Commission Panel approves amortization of these amounts over a shorter, two year period to reduce carrying costs.** This deferral account is to be removed from rate-base and is to attract a financing charge at FortisBC's WACD.

C. Other Deferred Charges and Credits

- Revenue Protection

FortisBC forecasts expenditures of $0.17 million ($0.23 million before tax) in 2011 on its revenue protection program, which it proposes to amortize into rates in 2012. Revenue protection includes conducting inspections to detect and remedy illegal power diversion activities and also involves rental of poles and possibly other electrical infrastructure to third parties. FortisBC will be including the costs of its revenue protection program in Operating and Maintenance Expenses-Customer Service department commencing in 2012.

Commission Panel Determination

The Commission Panel approves the amortization of 2011 Revenue Protection expenses into rates in 2012, as requested.

- Right-of-Way Encroachment Litigation

FortisBC expects to defer approximately \$0.09 million (\$0.12 million before tax) of legal costs incurred to the end of 2011 related to its ongoing litigation with a land developer who is encroaching on one of its Right–of-Ways in Kelowna. FortisBC advises that it will include any recovered costs following resolution of the dispute in the deferral account and amortize the balance in rates, in accordance with Commission Order G-193-08. This residual will not be available for amortization until 2014 as the dispute has not been settled.

Commission Panel Determination

The Commission Panel approves the continuation of the Right–of-Way litigation deferral account, with the inclusion of any recovered costs following resolution of the dispute, as a non-rate base deferral account, attracting an interest financing charge at FortisBC's WACD.

- US GAAP

FortisBC seeks approval to amortize its costs for conversion to US GAAP in the forecast amount of \$0.6 million (\$0.8 million before tax) over a two year period commencing in 2012. These costs relate to audit, legal, advisory, and actuarial fees.

Commission Panel Determination

The Commission Panel approves the amortization of costs relating to conversion to US GAAP over the test period. Any future costs are to be carried as a non-rate base account attracting interest at FortisBC's WACD.

- Mandatory Reliability Standards Project

FortisBC has deferred set up costs estimated at $0.7 million ($1.0 million before tax) by the end of 2011 to become and remain compliant with the new Mandatory Reliability Standards. FortisBC seeks approval to amortize these costs over 5 years commencing in 2012.

Commission Panel Determination

The Commission Panel approves deferral of the set up costs relating to Mandatory Reliability Standards in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD. However, in the Panel's view, the amortization period requested is too long. Therefore, the Commission Panel directs that these costs be amortized into rates over a three year period, as opposed to the five year period sought, to reduce the associated carrying costs.

5.4.4.2 Proposed Deferral Accounts

(i) <u>Preliminary and Investigative Charges</u>

The Commission Panel notes that "Preliminary and Investigative Charges" are not properly considered to be capital expenditures under US GAAP, which is why Commission approval is sought for deferral account treatment. The Commission Panel further notes that FortisBC charges operating costs associated with capital projects directly to those projects, in addition to charging a percentage of operating costs to capital projects as capitalized overhead. In the Panel's view, Preliminary and Investigative Charges can be separated into two groups:

- Those costs which at a future time may become capital projects.
- Those that contribute to the development of Plans which are a regulatory requirement but are not actual capital projects.

Those projects which may in the future become capital projects are more properly considered operating expenses as they are not yet part of an approved capital project. Therefore, **the Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC's WACD until such time as they become part of a specific capital project.** As noted previously, the decision to proceed with a capital project should generally be made within three years.

For those costs which contribute to the development of a required regulatory plan, the Panel is of the view that they are most appropriately handled as regulatory expenses and amortized over the period of time the plan is intended to cover. As a regulatory expense any deferral amounts will attract a financing charge at FortisBC's WACD.

- 2012 Integrated System Plan

FortisBC forecasts that it will have spent $3.4 million on the development of its Integrated System Plan which was filed contemporaneously with its 2012-2013 Revenue Requirements Application. The Integrated System Plan includes the Long-Term Capital, Resource and DSM Plans. FortisBC proposes to transfer these costs to approved capital projects over the five year period from 2012 to 2016.

Commission Panel Determination

The Integrated System Plan was prepared for regulatory purposes to cover a five year period commencing in 2012. **The Commission Panel considers this item to be a regulatory expense not a capital expense related to any specific project and therefore, directs that this account attract an interest financing charge at FortisBC's WACD and be amortized into rates over a five year period.**

- Plants 1-4 Capital Sustainment

This account is for investigative spending for project planning and engineering and includes "development of more investigation and development of detailed project scopes and cost estimates." FortisBC expects to spend $0.03 million in each of 2012 and 2013, which amounts it proposes will then be transferred to the associated projects, once construction begins. (Exhibit B-1, Tab 5, p. 13)

FortisBC argues that amounts in this account are not annual recurring O&M charges because the work relates to determining what capital programs are required in future years and the specific projects are different. (Exhibit B-8, BCUC 2.26.1)

Commission Panel Determination

The Commission Panel is of the view that the amounts at issue in this deferral account are small, in the order of $30,000 per year, and finds deferral to be unnecessary. The Commission Panel also finds that these costs are not sufficiently associated with a capital project to be considered capital in nature. Rather these costs are more properly considered current operating costs and should be expensed as incurred. **The Commission Panel therefore directs that these costs be expensed during the test period.**

- Kelowna Bulk Transformer Capacity Addition

FortisBC expects to spend $0.3 million in 2011 and 2012 for preliminary engineering involved in the preparation of an application for a CPCN for the Kelowna Bulk Transformer Capacity Addition. FortisBC plans to obtain approval for this project in 2013 and will transfer costs to the capital project at that time.

Commission Panel Determination

As discussed above in Section 5.4.4.1, the Commission Panel directs that any amount in this deferral account should be treated as a non-rate base item and attract a financing charge at FortisBC's WACD until such time as they are transferred to the capital project. As discussed above, this amount should be expensed if the project does not proceed within a three year period.

- 2014-2015 Capital Expenditure Plan

FortisBC expects to spend $0.8 million on preliminary investigation and engineering costs for its 2014-2015 Capital Plan. FortisBC proposes to include these costs in the capital projects for those years.

Commission Panel Determination

Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD.

(ii) <u>Non-Controllable Items Variances</u>

FortisBC is proposing to create a number of variance deferral accounts for expenditures which it suggests are either beyond its control or it has limited ability to control and which it views as for the account of the customer. FortisBC advises that many of these items have been approved in the past as flow through or "Z-Factor" items eligible for deferral.

The forecast balances for 2012 and 2013 are nil.

Commission Panel Determination

The Commission Panel notes that these accounts for the most part represent variances in current period expenses which are proposed to be trued up in the short-term. In the Panel's view, the creation of these deferral accounts represents a reasonable attempt to manage the uncertainty and unpredictability associated with accounts which are largely uncontrollable in nature. **The Commission Panel therefore approves the following variance deferral accounts as non rate base deferral accounts attracting a short term interest financing charge.**

- **Power Purchase Expense Variance Deferral Account**
  - **any variance in this account is to be amortized in 2014**
- **Revenue Variance Deferral Account**
  - **any variance in this account is to be amortized in 2014**
- **HST Removal or Reform Variance Deferral Account**
- **Property Tax Asset Variance Deferral Account**
- **Pension and Other Post-Employment Expense Variance**

The Commission Panel declines to approve the following proposed non-controllable expense variance deferral accounts:

- Income Tax Variance Deferral Account

FortisBC is proposing to add a deferral account to capture and accumulate variances from forecast taxes, including federal and provincial income tax, sales tax and any other taxes. FortisBC proposes that the amortization period for this deferral account can be reviewed as part of its 2014 RRA.

FortisBC argues that it can face uncontrollable changes in tax laws or accepted assessing practices "at any time." FortisBC proposes to include as well any required compliance costs, including changes to information systems which are required in this account. FortisBC advises that income tax variances qualified as "Z factors" in the prior PBR period and so were treated in a similar manner for rate-setting purposes.

FortisBC considers this account to be "Primarily Non-controllable" as it may have some control over the costs to adapt information systems for new tax laws. (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel is of the view that it is not necessary to create a deferral account for possible variances in income taxes payable from those forecast. Taxes are a reality faced by all businesses and in the Panel's view are predictable with some certainty. Approval for this proposed deferral account is therefore denied. In the event that there is a significant change in the tax landscape it is always open to FortisBC to apply to the Commission for relief on an as-needed basis.

- Interest Expense Variance Deferral Account

FortisBC is proposing a new deferral account to capture any variances between actual and forecast interest expense – both long and short term, as well as financing fees. FortisBC proposes to address the amortization period for this account as part of its 2014 RRA.

FortisBC considers this account to be "Somewhat Controllable." (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel agrees with FortisBC that interest expense is at least "somewhat controllable" and also finds it to be somewhat predictable, in that numerous agencies publish opinions on future interest rates on a regular basis. Approval for this deferral account is denied on the basis that FortisBC should make its best effort to forecast and manage this cost as part of its day to day business operations.

- Insurance Expense Variance Deferral Account

FortisBC also proposes to capture the difference between forecast and actual insurance expenses in a new deferral account. FortisBC argues that global events can influence insurance costs and that such impacts cannot reasonably be incorporated into forecast expenses. FortisBC proposes to review the amortization period for this account as part of its 2014 RRA.

FortisBC considers this account to be "Somewhat Controllable." (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel is of the view that the need for the Insurance Expense Variance Deferral Account has not been established and denies it. The Commission Panel notes the evidence of FortisBC's Vice President of Finance and CFO, Ms. Leeners, that FortisBC has in fact been able to manage its insurance premiums to a large extent, in spite of extraordinary catastrophic events affecting the world such as Hurricane Katrina, and that FortisBC's geographical diversification, claims history and affiliation with a large company contribute to this ability. (T4:575-577)

- Extraordinary Costs (Z Factor) Variance Deferral Account

FortisBC proposes a further deferral account to capture variances from "steady state" operations due to unplanned events. FortisBC cites Commission directives and decisions, legislation, changes to GAAP and Force Majeure as examples of extraordinary events. FortisBC proposes to review the amortization period for this account as part of its 2014 RRA.

Commission Panel Determination

The Panel declines to approve this deferral account. As noted above, the Panel is concerned with the proliferation of proposed deferral accounts. The Panel agrees with the ICG that it is open to FortisBC to apply for a deferral account on a case by case basis for extraordinary events.

(iii) <u>Deferred Regulatory Expenses</u>

FortisBC is seeking deferral account treatment for certain regulatory expenses as set out below.

- 2014 Revenue Requirements Application

FortisBC is seeking approval to defer what it expects to be costs in the amount of $0.08 million ($0.1 million before tax) for its 2014 Revenue Requirements Application in 2013. FortisBC proposes to apply for disposition of these costs in a future application.

Commission Panel Determination

The Commission Panel is of the view that these regulatory expenses are operating costs and should be capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes. This deferral account is to attract a financing charge at FortisBC's WACD.

- 2014-2015 Capital Expenditure Plan Regulatory Costs

FortisBC is seeking approval to defer costs related to the regulatory review of a 2014-2015 Capital Expenditure Plan which it expects to file, in the estimated amount of $0.08 million ($0.1 million before tax) in 2013. FortisBC intends to apply for disposition of these costs in a future application.

Commission Panel Determination

The Commission Panel is of the view that these regulatory expenses are operating costs and are capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is also prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes. This deferral account is to attract a financing charge at FortisBC's WACD.

- 2012 Integrated System Plan and 2012-2013 Revenue Requirements Application

FortisBC is seeking approval to amortize the costs of the 2012 -2013 Revenue Requirements Application and Integrated System plan which it expects to be approximately $2.4 million ($3.3 million before tax) in 2011 over a five year period, commencing in 2012.

Commission Panel Determination

The Commission Panel is of the view that the amortization period requested for these regulatory expenses is too long and that FortisBC's ratepayers will suffer from the associated increased carrying charges. The Commission Panel approves a non-rate base deferral account attracting interest at FortisBC's WACD, to be amortized over a period of two, as opposed to five years.

(iv) Other Deferred Charges and Credits

- Prepaid Pension Costs

FortisBC has recorded the difference between the actuarial valuation of the pension net benefit cost and the forecast Company contributions on a net of tax basis in a "prepaid pension deferral account" for 2011. This treatment accords with pre-changeover Canadian GAAP (which no longer exists), was approved by Commission Order G-184-10 and is consistent with prior years' treatment in revenue requirement applications over the PBR term. This treatment is also similar to that allowed by US GAAP.

FortisBC has now been approved to use US GAAP, which, unlike current IFRS, permits deferral accounting. (Exhibit B-1, Tab 5, p. 23)

The 2012 and 2013 prepaid pension cost consists of the net benefit cost, relating to the following pensions:

- IBEW (defined benefit) Pension Plan
- COPE (defined benefit) Pension Plan
- FortisBC (defined benefit) Retirement Income Plan
- Supplemental pension arrangements for current and former executives.

FortisBC is requesting approval to recognize total Prepaid Pension Costs as a Rate Base deferral account, on a net of tax basis, for 2012 and 2013. FortisBC forecasts a $0.7 million ($1.0 million before tax) and a $2.7 million ($3.6 million before tax) increase in this deferral account in 2012 and 2013, respectively.

Commission Panel Determination

In keeping with its earlier determinations, the Commission Panel approves this deferral account as a non-rate base deferral account attracting interest at FortisBC's WACD.

- US GAAP Pension Transitional Obligation Deferral Account

FortisBC also seeks approval to establish a "Pension Transitional Obligation Deferral Account" as a Rate Base deferral account, with an equal offset to the Prepaid Pension Costs Deferral Account, to separate these proposed rate base items. The Pension Transitional Obligation Deferral Account will recognize the difference between pension net benefit costs calculated under Canadian GAAP and US GAAP, as required by US GAAP. This amount is forecast to be $2.2 million as of January 01, 2012. It consists of unamortized net transition obligations determined pursuant to Canadian GAAP, which are required to be fully amortized under US GAAP, and the net benefit cost for a three month period resulting from the change in measurement date from September 30th to December 31st, as required by US GAAP.

FortisBC proposes that the balance in the US GAAP Transitional Obligation Deferral Account be amortized over an approximate twelve year period, to accord with the expected average remaining service life of the Company's pension plans. FortisBC forecasts a further addition of $1.6 million ($2.2 million before tax) to this account for 2012.

Commission Panel Determination

The Commission Panel approves the creation of this deferral account as a non-rate base deferral account attracting interest at FortisBC's WACD.

- Accumulated Other Comprehensive Income

FortisBC is also requesting regulatory recognition and acknowledgment of a non-rate base deferral account to record amounts representing accumulated unrecognized losses/gains and unrecognized prior service costs/credits which would otherwise be required to be recognized as "Accumulated Other Comprehensive Income" and offset against prepaid pension costs for external financial reporting purposes. (Exhibit B-1, Tab 5, p. 26, Appendix E)

Commission Panel Determination

The Commission Panel approves the creation of this non-rate base deferral account, attracting interest at FortisBC's WACD.

- Other Post-Employment Benefits Deferral Accounts

FortisBC also records the difference between the actuarially determined OPEB net benefit cost and actual payments to retirees in an OPEB Deferral Account on a net of tax basis. FortisBC forecasts a $2.1 million ($2.8 million before tax) addition to the OPEB Deferral Account for 2011. The 2011 accounting treatment is consistent with pre-changeover Canadian GAAP and was approved by Commission Order G-184-10. As of January 1, 2012, the Company has been relying on US GAAP.

FortisBC therefore now requests approval to recognize US GAAP OPEB Liability as a rate base deferral account, to which it expects to add $5.7 million ($7.7 million net of tax) in 2012 with a further $1.7 million ($2.2 million before tax) in 2013.

Commission Panel Determination

The Commission Panel approves the creation of a non rate-base deferral account attracting interest at FortisBC's WACD for Other Post-Employment Benefits.

- US GAAP OPEB Transitional Obligation Deferral Account

FortisBC is also requesting a further US GAAP OPEB Transitional Obligation Rate Base Deferral Account to record differences resulting from the calculation methodology for Other Post-Employment Benefits required under Canadian as opposed to US GAAP. (US GAAP would require all remaining unamortized net transition obligations determined under Canadian GAAP to be fully amortized). The proposed US GAAP OPEB Transitional Obligation Deferral Account would also include the net benefit cost for three months resulting from the change in the measurement date from September 30th to December 31st, which is required by US GAAP. These amounts are forecast to be $2.0 million, as of January 1, 2012. FortisBC proposes to recover this amount over 12 years.

FortisBC also proposes that a remaining transitional obligation in the amount of $3.5 million which resulted from a change from cash to accrual accounting for OPEB under Canadian GAPP in 2005 be recognized in the US GAAP OPEB Transitional Obligation Rate Base Deferral Account. It has been tracked to this time in a Non-Rate Base deferral account.

An amount equal to the US GAAP OPEB Transitional Obligation Deferral Account is proposed to be offset against the US GAAP OPEB Liability Deferral Account. FortisBC forecasts a $4.1 million ($5.5 million before tax) increase to this account in 2012.

As requested for the pension accounting treatment, FortisBC is also requesting regulatory recognition and acknowledgement of a Non Rate Base Deferral Account to accumulate unamortized gains (losses) and unrecognized prior service costs (credits) rather than flowing such amounts through Accumulated Other Comprehensive Income and back into OPEB.

Commission Panel Determination

The Commission Panel approves the creation of a US GAAP OPEB Transitional Obligation Deferral Account as a Non Rate Base Deferral account, attracting interest at FortisBC's WACD. The Commission

Panel also approves the inclusion of the remaining transitional obligation in this Non-Rate Base Deferral Account.

The Commission Panel approves the offset account and agrees to the deferral of unamortized gains (losses) and unrecognized prior service costs, again in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD.

- Asset Management

This proposed Deferral Account is rejected, as discussed in subsection 5.2.2.3 (a).

- Joint Pole Use Audit 2013

FortisBC advises that its various joint pole use agreements require that an audit be performed on the joint use pole contacts every five years. The last audit was in 2008. FortisBC is seeking approval "to defer funds of $0.2 million ($0.3 million before tax) and to begin amortization in 2013 over a five year period."

Commission Panel Determination

The Commission Panel approves the deferral of costs of audits for joint pole use contacts in a Non-Rate Base Deferral account attracting interest at FortisBC's WACD. In the Panel's view, these expenses should be recovered over a shorter period than five years, to reduce carrying charges. The Commission Panel therefore directs that these costs be recovered over a two year period.

- Deferred Debt Issue Costs

FortisBC advises that it expects to issue $120 million in unsecured debentures with a term of 30 years in 2013. FortisBC estimates that the total issue costs for the debt will be approximately $1.6 million.

FortisBC seeks approval to defer the issuance costs and to amortize them over the term of the debt, subject to approval of the debt issuance itself, which will be sought in a separate application.

Commission Panel Determination

The Commission Panel approves deferral of the debt issuance costs as a Non-Rate Base Deferral account to be amortized over the term of the debt and attracting interest at the same rate as the debt issuance. In the event that the debt issuance does not proceed, and subject to further Commission order, the related costs are to be expensed at that time.

5.4.4.3 Existing Deferral Accounts with Proposed Change in Treatment

- Advanced Metering Infrastructure

FortisBC advises that the forecast amount of $1.8 million is for the preparation of an application for a CPCN for advanced metering infrastructure which was to be filed in 2011. This amount is being held in a non-rate base deferral account, and includes AFUDC in the amount of $0.121 million. FortisBC is seeking to transfer these funds to a rate base deferral account, pending transfer to the AMI capital project in 2012. FortisBC advises that, although AFUDC is not generally applied to balances in Preliminary Investigative Deferral Accounts, AFUDC was accrued pursuant to a specific agreement made in the 2011 RRA NSA, which was approved by Commission Order G-184-10 on a without prejudice basis. (Exhibit B-1, Tab 5, p. 14; Exhibit B-8, BCUC 2.27.1)

Commission Panel Determination

As noted in Section 5.4.4.1, the Commission Panel is of the view that the costs incurred in respect of a CPCN Application should not form part of rate base until such time as the capital project is approved. Accordingly, FortisBC' request to make this a rate base deferral account is denied. This account is to attract an interest financing charge at FortisBC's WACD going forward, until such time as a determination on the CPCN Application is made.

6.0 DEMAND-SIDE MANAGEMENT

FortisBC is seeking two approvals regarding its Demand-Side Management (DSM) programming. The first is approval under subsection 44.1(6) of the *Act* that its 2012 ISP is in the public interest. FortisBC's ISP includes its 2012 Long-Term DSM Plan. The second approval sought is to spend \$7.73 million in 2012 and \$7.88 million in 2013 on demand-side measures, pursuant to section 44.2 of the *Act*. These two requests are addressed below.

6.1 Long-Term Demand-Side Management Plan

FortisBC's Long-Term DSM Plan includes the years 2012-2030. The Plan sets out the expected DSM programming, energy savings and spending for 2012-2016 as an extension of the spending and savings levels from the 2011 DSM Plan previously approved by the Commission. For the years 2017-2030, FortisBC has included a constant proxy figure of 28 GWh/year in energy savings. Overall, the Plan was designed to achieve electricity savings to offset 50 percent of FortisBC's load growth until 2030. (Exhibit B-1-2, Volume 2, p. 1)

The expected energy savings for the 2012 DSM Plan are shown in the table below.

Table 15 – Savings Targets

Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.4	13.5	1.1	-
2012	16.1	12.2	1.7	-
2013	16.9	12.3	1.8	-
2014	19.5	11.9	1.8	-
2015	21.1	11.9	1.8	-
2016	22.6	9.9	1.9	-
2017-30	-	-	-	28

(Exhibit B-1-2, Volume 2, p. 15)

FortisBC plans to update its DSM Plan and the contributing studies (end-use studies and a Conservation Potential study) that are used in the development of the DSM Plan, every 5 years. (Exhibit B-1-2, Volume 2, p. 17)

6.2 Monitoring and Evaluation Plan

Included in the 2012 DSM Plan is FortisBC's Monitoring and Evaluation Plan (M&E Plan) for 2012-2014. The M&E Plan sets out the principles FortisBC will follow in evaluating its DSM programs and a schedule of programs that will be evaluated in 2012-2014.

As background on DSM evaluation, there are four major types of evaluation studies of DSM programs:

i. Process Studies

   These studies review how efficiently and effectively a program is run and are typically done 6-18 months after a program is launched;

ii. Market Studies

   These studies review how effective a DSM program is at increasing the market share of energy efficient technologies and are typically done 24-36 months after program launch and then every 2-3 years afterwards;

iii. Impact Studies

   These studies review and determine the energy savings that are directly attributable to a DSM program and are typically done 24-36 months after program launch and then, every 2-3 years afterwards;

iv. Pilot Studies

   These studies typically involve using a process study with some measurement and verification of energy savings and are usually completed during or immediately following a pilot program.

(Exhibit B-1-2, Volume 2, Appendix D, pp. 4-5, 7)

The M&E Plan proposes that each year FortisBC will conduct a Process, Market and Impact Study (what FortisBC terms a "Comprehensive Review") on two of its DSM programs and a Process Study and some M&E activities (what FortisBC terms a "Mini Review") on three of its programs. The Plan establishes a threshold to trigger evaluation, that is, when a DSM program is estimated to have achieved 10 GWh in energy savings, evaluation studies will be conducted. (Exhibit B-1-2, Volume 2, Appendix D, p. 11)

The proposed M&E plan would cost $385,000/year to implement which is approximately 5 percent of FortisBC's total requested annual DSM expenditure. (Exhibit B-1-2, Volume 2, Appendix D, p. 4)

6.2.1 The Commission's Review of the Long-Term DSM Plan

As discussed in Section 2.2 of this Decision, subsection 44.1(8) of the *Act* applies to the Commission's review of the ISP as a whole. The Long-Term DSM Plan, which is filed as part of the larger ISP, is appropriately assessed under subsection 44.1(8)(c) and (d) for adequacy, cost-effectiveness, and the public interest.

6.2.1.1 Adequacy and Cost Effectiveness

FortisBC currently runs and plans to continue running the four programs required for adequacy under the Demand-Side Measures Regulation which are:

Required DSM program for adequacy	**Current or planned FortisBC program(s)**
A program for low-income households	• Residential Energy Savings Kits • Residential Energy Conservation Assistance Program • First Nations Residential Households Program
A program for rental accommodation	• "Whole Home" financial incentives for landlords, property managers and rental agencies
An education program for students enrolled in schools in the utility's service area	• Financial sponsorship of educational events and programs • Designed Grade 11 curriculum-based course on energy and conservation
An education program for students enrolled in post-secondary institutions in the utility's service area	• Okanagan College "Home for Learning" energy efficiency training opportunities • Provide guest lecturers • Sponsorships and training for trades • Support energy management training workshops

(Exhibit B-1-2, Volume 2, pp. 24, 28-29)

FortisBC submits that the result of its mTRC test for its 2012-2013 DSM expenditure portfolio is 1.4 and that over the 2012 Long-Term DSM Plan the costs (avoided costs and measure costs) will change but that FortisBC will ensure the cost effectiveness of the portfolio will remain above one. (Exhibit B-27, Undertaking 31; Exhibit B-1-2, Volume 2, p. 14)

Commission Panel Determination

The Commission Panel finds that FortisBC's 2012 Long-Term DSM Plan is adequate and cost-effective as per subsection 44.1(8)(c) of the *Act*. No evidence was raised in the hearing to dispute FortisBC's position. The Commission Panel assesses the cost-effectiveness of FortisBC's DSM Plan on a portfolio basis and accepts FortisBC's calculation.

6.2.1.2 The Public Interest

Various issues were raised about FortisBC's Long-Term DSM Plan during the proceeding.

The first issue is whether the Plan is in fact a long-term plan or, more accurately, a five-year plan because a placeholder for energy savings has been used for 2017-2030. FortisBC's position is that detailed planning data is only valid for 5 years due to rapidly changing DSM technology and costs. (Exhibit B-8, BCUC 2.94.1.1)

The second issue is whether an increase in DSM spending is needed over the next five years, rather than FortisBC's Plan which proposes fairly flat DSM savings targets (and by extension, spending) for this period. FortisBC argues that it has increased DSM spending by almost 500 percent since 2000 and that further increased spending is not warranted at this time. (Exhibit B-8, BCUC 2.94.2)

The third issue is whether FortisBC's planning criteria of targeting 50 percent of load growth is appropriate. BCSEA argues that targeting DSM as a percentage of load growth does not aim to achieve all available energy savings and points out the following disadvantages of FortisBC's methodology: where there is no load growth, no DSM programs would be run; and when there is significant large load growth, all available energy savings may not be achieved. (T4: 620) BCSEA advocates the approach of targeting energy savings as a percentage of energy sales which FortisBC acknowledges is used in other jurisdictions. (T4: 621) In part as a result of consultation with its customers, FortisBC chose a “medium” DSM plan portfolio over a more costly “high” plan portfolio. BCSEA submits that FortisBC’s choice of a “medium” DSM scenario over a “high” scenario was flawed because FortisBC exaggerated the risk of DSM relative to new supply, failed to apply the same ranking criteria to DSM as new supply, and inappropriately considered rate impacts in its decision not to pursue more DSM activities. (BCSEA Final Submission, p. 14)

The issue of the rate impact of DSM programs and whether the rate impact should be used as a Plan selection criterion was also well-canvassed during the proceeding. BCSEA submits that rate impacts must be assessed in conjunction with bill impacts and that even if a higher level of DSM spending causes a rate increase, “the increase in average rates must be compared against the decrease in average bills.” (emphasis in original) (Exhibit C6-5, pp. 32-33) In other words, because DSM activities can help customers use less energy, their energy bills will decrease even if FortisBC’s increased spending on DSM causes an overall rate increase.

FortisBC cross-examined BCSEA’s expert witness, Mr. Plunkett, on his focus on bill impact versus rate impact suggesting that if only 10 percent or less of FortisBC’s customers participate in DSM programs, only that 10 percent will see bill savings from DSM, while the remainder of FortisBC ratepayers will see a rate (and bill) increase from the Company’s DSM activities. (T5: 941-944)

Mr. Plunkett agreed that, in the short term, bill savings will only be seen by ratepayers participating in DSM programs but postulated that bill savings will be obtained by most ratepayers over time. Mr. Plunkett testified that is “exactly how it works” because over time the Company will be in a position to avoid high cost new energy which will lower the total cost of service for everyone. (T5: 944)

BCSEA requests the Commission find that FortisBC’s Long-Term DSM Plan is not in the public interest because it does not show the utility’s intent to pursue all cost-effective demand-side measures. (BCSEA Final Submission, p. 28) It cites the evidence of Mr. Plunkett who recommends the Commission direct FortisBC to implement DSM programming by 2016 to target roughly 2 percent of annual sales, an increase from the current plan which targets approximately 0.85 percent of annual energy sales. BCSEA notes Mr. Plunkett's estimate that it would cost FortisBC approximately $33 million/year to achieve energy savings of 2 percent of energy sales. This yearly spending translates to roughly 5.5 cents/kWh which is less than the 10 cents/kWh FortisBC uses to estimate its avoided supply cost in its Long-Term DSM Plan. (BCSEA Final Submission, pp. 6-7)

BCSEA further recommends the Commission direct FortisBC to, among other things,

- Apply the same ranking criteria to DSM alternatives as it applies to generation alternatives;
- Take into account the ability to shape efficiency acquisitions to match energy and capacity requirements, in comparing DSM to generation alternatives;
- Address the timing of an updated Conservation Potential Review in its 2014 DSM expenditure schedule; and
- Revise its Long-Term Resource Plan if natural gas fired generation is added.

(BCSEA Final Submission, pp. 28-29)

6.2.1.2.1 Monitoring and Evaluation Plan

During the proceeding, FortisBC was questioned on the adequacy of its M&E Plan, especially given that the current plan and its 10 GWh savings threshold results in some DSM programs never being evaluated and others being evaluated very infrequently. (Exhibit B-4, BCUC 1.298.2) As noted, the proposed M&E Plan would cost FortisBC $385,000 per year to implement, which equates to 5 percent of its overall DSM budget. The 2004 California Evaluation Framework, a seminal document for DSM evaluation, references a spending range of 2-10 percent of overall DSM budget spending on DSM evaluation among utilities in North America, with the average spending being 4 percent. (Exhibit B-8, BCUC 2.98.7; Exhibit B-4, BCUC 1.297.1)

During the oral hearing, FortisBC referenced an evaluation study conducted by BC Hydro of the Energy Savings Kits program that FortisBC and BC Hydro both run. The study showed that of 700 kWh of possible energy savings in the kits, only 203 kWh in savings were realized if the kits were self-installed by the customer, whereas 350 kWh of savings were realized if maintenance personnel installed the kits. (T4:707-8)

FortisBC also testified as to the importance of conducting monitoring and evaluation studies on a regular basis to confirm that expected savings from a program are actually realized in the field. (T4:721-2) FortisBC agreed that administrative cost savings may be found when process studies are conducted on DSM programs and also stated that it intended to use M&E data from other utilities to supplement FortisBC studies. (T5: 873; FortisBC Final Submission, p. 215)

FortisBC outlined a possible alternative evaluation plan where every program undergoes evaluation according to the typical timing for the various evaluations described in Section 6.1.2 above. FortisBC estimates the alternative M&E plan would cost an additional $100,000 per year to implement. (Exhibit B-8, BCUC 2.98.7) This would represent just over 6 percent of the Company's total DSM budget.

FortisBC submits that its M&E plan, as proposed, is "robust." BCSEA submits it is generally satisfied with FortisBC's M&E plan for the 2012- 2014 period but notes that it is not best practice to never evaluate a program because "you'd eventually want to do some kind of evaluation of a program unless you had an awfully good reason not to." (T5: 884, 965; BCSEA Final Submission, p. 28)

Commission Panel Determination

The Commission Panel finds FortisBC's 2012 Long-Term DSM Plan to be in the interests of persons in British Columbia who receive or may receive service from FortisBC in accordance with subsection 44.1(8) (d) of the *Act.* Subject to the further findings relating to the M&E Plan and in accordance with subsection 44.1(7) of the *Act*, the Panel accepts the Plan under subsection 44.1(6) of the *Act*.

The Commission Panel recognizes that this acceptance means that FortisBC may simply maintain current levels of DSM spending over the next five years, subject to future DSM expenditure schedules filed for approval with the Commission. However, as discussed in relation to FortisBC's section 44.2 expenditure schedule request (below), FortisBC received approval to spend approximately twice the amount on DSM in 2011 over 2010 and was unable to spend to the higher approved level. As well, the Commission Panel acknowledges that the Company is implementing new programs that will take time to gain participants. The Panel is also persuaded that FortisBC can employ other best practises to achieve additional savings without adding to its budgeted spend.

The Commission Panel accepts FortisBC's proposal to submit a revised Plan and to update the contributing studies every 5 years.

The Commission Panel is also of the view that the rate impact from DSM spending is a relevant consideration for the public interest, at least in the short term, as increased participation in DSM programs may take some time.

With respect to BCSEA's proposals for the Company's next Long-Term DSM Plan, the Commission accepts that FortisBC may wish to apply the same ranking criteria to DSM as it applies to generation alternatives but does not accept that FortisBC should necessarily change its DSM target from one based on load growth to energy sales at this time. The Commission Panel is satisfied that FortisBC is taking a reasonable approach to setting targets for energy savings in the current environment.

Regarding FortisBC's proposed M&E Plan, the Commission Panel sees FortisBC's testimony concerning the Energy Savings Kits evaluation as highlighting the importance of the evaluation process. It would appear that if BC Hydro had not evaluated the kits, the utilities might assume savings of 700 kWh of energy savings per kit when in fact, the kits are producing savings of less than half of this amount. As stated by Mr. Warren, FortisBC's Director of Customer Service, M&E studies are done to ensure the savings claimed are actually occurring in the field. The Commission Panel expects that the energy savings estimates FortisBC puts before the Commission will actually occur because this represents the value of DSM to all ratepayers. An accurate account of energy savings cannot occur without M&E

studies conducted on programs. **The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.** Given that FortisBC's alternative M&E plan costs $100,000 more per year and that amount remains within the California Evaluation Framework range of common budget allocations to M&E**,** the Commission Panel recommends that FortisBC resubmit an alternative M&E schedule, such as that submitted in response to BCUC IR 2.98.7, that does not apply a 10 Gwh threshold to trigger evaluation and that follows the typical sequence of evaluations as laid out in the M&E Plan for acceptance by the Commission. Any additional funds for this alternative schedule should come from the currently proposed expenditure schedule and no additional funds above the requested amounts are approved. The Commission Panel encourages FortisBC to supplement its own studies with data from other utilities wherever appropriate and to conduct shared evaluations on integrated programs.

6.3 FortisBC's Expenditure Request for 2012-2013

As part of this Revenue Requirement Application, under section 44.2 of the *Act*, FortisBC is requesting approval to spend $7.73 m in 2012 and $7.88 m in 2013. The 2012-2013 DSM expenditure schedule is an extension of its previously approved 2011 DSM plan.

As background, in 2011 FortisBC was approved to spend $7.842m which is almost double the amount it was approved for in 2010. In 2011, FortisBC spent $5.917 million of the total $7.842 million approved. (Exhibit B-29, Undertaking 32)

The 2012-2013 proposed DSM expenditure schedule comprises DSM programs in the Residential, Commercial (or General Service) and Industrial sectors as well as funding for Supporting Initiatives and Planning and Evaluation.

Table 16

1		2011		2012		2013		TRC incl
2		Approved		Plan		Plan		MTRC
3		Savings	Cost	Savings	Cost	Savings	Cost	B/C
4	**Programs**	*MWh*	$(000s)	*MWh*	$(000s)	*MWh*	$(000s)	ratio
5	Residential	16,422	3,636	16,101	3,717	16,946	3,944	1.6
6	General Service	13,940	2,118	13,380	2,199	11,980	2,085	1.5
7	Industrial	9,360	613	2,480	350	2,580	364	3.3
8	**Sub-total Programs:**	**39,722**	**6,367**	**31,961**	**6,266**	**31,506**	**6,393**	**1.6**
9	Supporting Initiatives		725		725		$ 725	
10	Planning & Evaluation		750		740		760	
11	**Total (incl. Portfolio spend):**		7,842		7,731		7,878	**1.4**
12	Income Tax Impact		-2,078		-1,933		-1,969	
13	**Total deferred (net of tax)**		5,764		5,798		5,908	

(Exhibit B-27, Undertaking 31)

As shown in Table 16 above, FortisBC calculates that its proposed DSM portfolio has an mTRC of 1.4 and is thus cost effective.

6.3.1 The Commission's Review of the DSM Expenditure Request

As noted in Section 2.2 of this Decision, in considering whether to approve an expenditure schedule, the Commission must consider the following under subsection 44.2(5) of the *Act*:

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

The Commission has considered the applicable of British Columbia's energy objectives in the context of FortisBC's proposed Capital Expenditure Plan. FortisBC's long-term resource plan is considered in Section 7 of this Decision. Sections 6 and 19 of the *CEA* are not applicable to DSM expenditures.

Regarding the cost effectiveness of the DSM programs, the Commission has previously assessed FortisBC's DSM programming at a portfolio level and will continue to do so in this case. The Commission Panel accepts the cost effectiveness calculations put forward by FortisBC and thus **finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335).**

Given the assessment of the above items, the issue remaining for the Commission to consider is whether acceptance of the expenditure schedule is in the interests of persons in British Columbia who receive or may receive service from FortisBC. Of relevance to this issue is whether FortisBC's proposed spend is sufficient.

6.3.1.1 Sufficiency of DSM Spending Level

FortisBC is requesting approval to spend $7.73 million in 2012 and $7.88 million in 2013 on its DSM portfolio. As previously discussed in relation to FortisBC's Long-Term DSM Plan, BCSEA's position is that FortisBC is under spending on DSM and should ramp up spending to approximately $33 million per year.

FortisBC disagrees with BCSEA's position and counters that in 2011 they were approved for double the spend over 2010, that they have not yet been able to implement the increase, and that spending $33 million/year would result in a 6.4 percent rate increase between 2012 and 2016 which is significant. (T5: 869-70; Exhibit B-27, Undertaking 33, p. 26)

BCSEA's expert witness, Mr. Plunkett, provided testimony explaining his analysis of DSM programs in various jurisdictions across North America. Mr. Plunkett advised that he grouped the jurisdictions he reviewed into four tiers, based on energy sales avoided through DSM, with the first tier being the best. In Mr. Plunkett's analysis, only three jurisdictions were in Tier 1, California, Vermont and Connecticut. These jurisdictions were able to achieve one and one half per cent or more of energy sales being avoided through DSM. Mr. Plunkett placed FortisBC squarely in Tier 2, along with nine other jurisdictions which succeeded in achieving approximately one percent of energy sales being avoided through DSM. (T5:926-929)

Commission Panel Determination

Many of the issues related to FortisBC's 2012 Long-Term DSM Plan are the same as the issues related to the section 44.2 expenditure schedule request including spending level, rate impact and value for money.

Based on the conclusions the Panel has reached in relation to these issues for the Long-Term DSM Plan, and considering the testimony of Mr. Plunkett that FortisBC has achieved a ranking placing it in his second tier of jurisdictions with successful DSM programs, **the Commission Panel approves FortisBC's section 44.2 expenditure request for DSM in the amounts of $7.73 million in 2012 and $7.88 million in 2013**. The recovery of these expenditures is to continue in the manner previously approved for FortisBC.

6.3.1.2 FortisBC Industrial Incentives

An issue raised primarily by the Industrial Consumers Group is the difference in DSM incentive levels offered by BC Hydro and FortisBC and whether FortisBC's industrial incentives are sufficient. ICG requests the Commission direct FortisBC to enhance its industrial DSM programs to match BC Hydro's incentives and to implement an energy manager program, similar to that offered by BC Hydro to its industrial customers. (ICG Final Submission, p. 38)

FortisBC indicates a concern as to the persistence of savings from funding an energy manager position. (Exhibit B-5, Celgar 1.10.4)

BC Hydro’s industrial DSM program offers incentives of 30.9 cents/kWh with no payback period limit and with 100 percent of the project cost being eligible for rebate for projects costing up to $1 million and 75 percent being eligible for projects costing more than $1 million. (Exhibit B-9, Celgar 2.12.1, 2.12.3)

FortisBC offers 10 cents/kWh with a two year payback period limit on the incentive amount. FortisBC compared the incentive it would offer an industrial customer under its DSM program to that which would be available to a BC Hydro customer. In the comparison, FortisBC would pay the industrial customer $1.5 million in incentives while BC Hydro would pay $4.635 million in incentives for the same project. (T4:732; T5:795)

FortisBC recognizes that there is significant difference in incentives offered by FortisBC and BC Hydro but takes the position that it does not have to offer the same programs as BC Hydro, although FortisBC does try to match BC Hydro’s residential DSM incentives. (Exhibit B-9, Celgar 2.5.5, 2.10.3, 2.11.1; T5:801)

FortisBC was questioned during the oral phase of the proceeding about the difference in incentive levels, to which its witness responded:

> MR. WARREN: In this case I would have -- with a 1.0 benefit/cost ratio TRC, I would have -- I have some difficulty justifying paying the kind of numbers that B.C. Hydro pays, which is effectively 58 percent of the TRC value. For example, our air source heat pump customers, measured on the same benefit/cost ratio basis, have about a 1.0 TRC as well at $85, and we pay about 12 percent of the total cost of those upgrades.
>
> So it would be difficult to justify.
>
> (T5: 795-6)

ICG’s position is that there is “simply no explanation” for the differences in BC Hydro and FortisBC industrial DSM programs and that at FortisBC’s incentive levels, it is no surprise that Celgar, one of FortisBC’s industrial customers, did not proceed with a planned DSM project. (ICG Final Submission, pp. 35-36)

BCSEA submits that the fact that FortisBC's commercial and industrial program incentives are capped at 10 percent of annual kWh savings with a two-year payback period limit discourages cost-effective energy savings. (BCSEA Final Submission, p. 12)

BCSEA advocates for consistent DSM programs across the province and requests the Commission to direct FortisBC to revise its DSM incentives to be better aligned with those offered by BC Hydro and to increase, wherever possible, standardization of common DSM program features across the Province, including marketing, financial incentives, and eligibility requirements. (BCSEA Final Submission, pp. 28-29)

FortisBC replies that increasing industrial incentives to match those of BC Hydro could result in millions of dollars in additional expenditures and argues that ICG did not file any evidence to explain why Celgar did not proceed with its planned DSM project. (FortisBC Reply, pp. 73-74) FortisBC also submits that the FortisBC and BC Hydro DSM programs which ICG references are comparable and that FortisBC takes a reasoned approach by preferring to have customer co-investment. (FortisBC Reply, pp. 75-77)

Commission Panel Determination

The Commission Panel does not accept ICG's request to direct FortisBC to match BC Hydro's industrial incentives or to implement an energy manager program. The Commission Panel acknowledges that BC Hydro does offer larger incentives to its industrial customers. However, we are not persuaded that BC Hydro's level of incentive is necessarily optimal and that FortisBC should move to that level.

As noted earlier, in the Panel's view, BC Hydro and FortisBC are different utilities, operating in different contexts. The Commission Panel is not prepared to direct FortisBC to implement the same DSM programs as BC Hydro, particularly in the industrial sector where the customer base is very different.

The Commission Panel also reiterates its view that FortisBC's DSM Program, as advanced, is reasonable.

6.3.1.3 Transfers of DSM Funding Among Programs

Currently FortisBC has no official policy in place for the transfer of funds between sectors such as residential and industrial but rather makes a judgment call to determine when transfers are appropriate. FortisBC agrees that customers might be concerned about a large transfer between sectors. FortisBC submits that it will seek concurrence of its DSM Advisory group in some cases prior to transferring funds. (Exhibit B-9, Celgar 2.2.2; T5:888-9)

FortisBC indicated in the oral phase of the Hearing that it was amenable to gaining Stakeholder Group approval and informing the Commission prior to making a transfer of funds between sectors where the proposed transfer would exceed a threshold of 30 percent of a sector's budget. (T5: 890-1)

Commission Panel Determination

The Commission Panel is of the view that a more formal policy regarding fund transfers among sectors/program areas is appropriate at this time, given the substantial increase in the budget for DSM programs. The Commission Panel is also of the view that a threshold of 25 percent is most appropriate. **The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission**. In cases where a proposed transfer into or out of an approved Sector is greater than 25 percent of that sector, prior Commission approval is required. The Commission Panel recommends that funding transfers of 25 percent or more requiring prior Commission approval, should, where feasible, be presented to FortisBC's DSM Advisory Committee for feedback before the approval request is made to the Commission.

6.3.1.4 Integration of DSM Programs Among BC Utilities

In its Final Submission BCSEA also recommends the Commission direct FortisBC to “provide evidence of concrete progress in terms of coordinating, integrating and standardizing DSM program design and delivery among FortisBC, BC Hydro and the FEU in FortisBC’s next DSM expenditure schedule filing.” (BCSEA Final Submission, pp. 28-29)

BCMEU requests the Commission direct FortisBC to “work more closely with Fortis Gas as well as BC Hydro to find efficiencies for investment in DSM which provides opportunities to ratepayers while reducing costs to ratepayers.” (BCMEU Final Submission, p. 90)

FortisBC submits that it has always collaborated with other BC utilities on DSM and that a direction in this regard is not necessary. (FortisBC Final Submission, p. 208; FortisBC Reply, pp. 72-73)

Commission Panel Determination

The Commission Panel agrees that every effort should be taken to integrate and collaborate among BC utilities to maximize the effectiveness and efficiency of DSM programs and minimize cost to ratepayers. **The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.**

7.0 INTEGRATED SYSTEM PLAN

7.1 Long-Term Capital Plan

FortisBC's Long-Term Capital Plan is the component of its Integrated System Plan that lays out the long-term strategic direction the company intends to follow to meet its infrastructure and asset needs. The overall capital plan has three components – the short term (2012-2013), dealt elsewhere in this Decision, the medium term (2014-2016) and the long term (2017 onwards). The Long-Term Capital Plan sets out projects that are expected to be developed over the next 20 years and, in the case of bulk transmission assets, projects expected over the next 30 years are also included.

The Company is not seeking approvals for any specific projects in its 2012 Long-Term Capital Plan, but does request Commission acceptance of its ISP, of which the LTCP is a component, as being in the public interest. (Exhibit B-1-1, p. 1)

The planning process to prepare a long-term capital plan has a number of key inputs, including load forecasts, cost estimation and capital-related accounting practices. FortisBC filed a detailed description of the processes utilized in developing the 2012 Long-Term Capital Plan. The filing includes details by types of projects (e.g. transmission infrastructure, generation infrastructure) and by region. Estimates for the medium term (2014 to 2016) are provided on an annual basis. For the longer term (2017-31) a single estimate is provided for the entire period. (Exhibit B-1-1, pp. 9-209)

While there was considerable focus on the 2012 -2013 capital expenditures in both the filed evidence and in information requests and cross-examination, parties to the proceeding generally did not express concerns with respect to details of the capital plan outside of the 2012-2013 period. A general concern explored in this proceeding was that, having gone through a major period of infrastructure renewal, FortisBC should be in a sustainment mode where its focus should be on cost containment. (ICG Final Submission, p. 5; BCMEU Final Submission, p. 2; BCPSO Final Submission, p. 3)

Commission Panel Determination

While the focus in this proceeding was largely on cost containment in the short term, the Commission Panel believes that the economic pressures many of FortisBC's customers are now facing and are likely to face in the foreseeable future, make this a long-term issue as well. The Commission Panel encourages FortisBC to pursue vigorously means to minimize costs in the long run while maintaining safe, reliable service. **The Commission Panel accepts the Long-Term Capital Plan (2014-2031) as being in the public interest.** Given the lack of detail in the long-term part (2017-31) and the limited information in the medium term part (2014-16) of the capital plan, the Commission Panel wishes to make it clear that acceptance of the LTCP for 2014-2031 is on that basis. In other words, capital programs based on limited information that may appear acceptable at a high level a number of years out, may be found not to be acceptable following a detailed review at a future time, when there is more detailed information and costs are carefully scrutinized or the context has changed significantly.

7.2 Long-Term Resource Plan

The Commission's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives. The Commission's Resource Planning Guidelines set out a comprehensive process to assist utilities in the development of their resource plans and provide a basis upon which to assess the LTRP. The Commission requires that any plan submitted under subsection 44.1(2) of the *Act* be prepared in accordance with these guidelines.

Under the guidelines, the utility is to prepare a range of gross (pre-DSM) demand forecasts structured in such a way that savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast. The plans should identify feasible supply and demand resources and measure each supply and demand resource against the objectives set out for the plan. The objectives include:

- provision of adequate and reliable service,

- economic efficiency,
- preservation of the financial integrity of the utility,
- equal consideration of DSM and supply resources,
- minimization of risks,
- compliance with government regulations and stated policies, and
- consideration of social and environmental impacts.

For each of the gross demand forecasts the utility should develop several plausible resource portfolios, each consisting of a combination of supply and demand resources needed to meet the gross demand forecasts. The process should lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts. Out of this process should come an action plan setting out the detailed acquisition steps which would need to be initiated over the next four years in order to meet the most likely gross demand forecast.

On June 30, 2011 FortisBC filed its 2012 Long Term Resource Plan (2012 LTRP) as Volume 2 of its 2012 ISP. FortisBC states that its plan is consistent with the requirements under section 44.1 of the *Act* and with the Commission's Resource Planning Guidelines. (Exhibit B-1-2, p. 1) The Company states that it has also prepared its 2012 LTRP to be consistent with the objectives set out in the *CEA* which are believed to be relevant to the FortisBC resource planning process. (Exhibit B-1-2, p. 2)

7.2.1 <u>2012 Long-Term Resource Plan Summary</u>

The FortisBC LTRP sets out FortisBC's demand forecasts and supply requirements for the period 2012 to 2040. It summarizes FortisBC's objectives as: (1) providing cost-effective reliable power over the forecast term; (2) assessing the uncertainty and risks in its market purchase strategy and, over time, achieving 100 percent self sufficiency; and (3) balancing the provision of cost effective power against the applicable of British Columbia's energy objectives. (Exhibit B-1-2, p. 1) There are 16 energy objectives set out in Part 1, section 2, of the *CEA.* The objectives which FortisBC argues are applicable to it and which are addressed in the LTRP are:

- To achieve electricity self sufficiency;
- To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build infrastructure necessary to transmit that electricity;
- To ensure that BC Hydro's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract* continue to accrue to the authority's ratepayers;
- To reduce BC greenhouse gas emissions;
- To reduce waste by encouraging the use of waste heat, biogas and biomass;
- To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia; and
- To take demand-side measures and to conserve energy.

(*Clean Energy Act,* Section 2; Exhibit B-1-2, p. 2)

The Company has prepared high, low and expected forecasts of demand before DSM through to the year 2040. The Company is targeting to meet 50 percent of its load growth through DSM and sets out an expected forecast on this basis. Due to the uncertainties inherent in DSM resources, FortisBC treats DSM as contributing to a range of outcomes, rather than as a single pre-determined percentage component meeting the gross demand needs. (Exhibit B-1-2, p. 3)

As discussed earlier, FortisBC owns four hydroelectric generating plants providing about 30 percent of its current capacity needs and 45 percent of its current energy requirements. It also has long-term power purchase agreements with BC Hydro and with the Brilliant Power Corporation, and a five year capacity agreement with Powerex. These resources provide a total winter peak capacity of about 710 MW and a summer peak capacity of 524 MW. (Exhibit B-1-2, pp. 2-3)

Subsequent to this Hearing, FortisBC received approval to purchase capacity from the Waneta Expansion Project. This capacity purchase agreement (WAX CAPA) is expected to come into effect in early 2015 and will both replace the Powerex capacity agreement and meet FortisBC's forecast capacity needs through the period of the 2012 LTRP. FortisBC is currently negotiating to extend its

RS 3808 PPA with BC Hydro. In the LTRP, it is assumed the RS 3808 PPA will be renewed in 2013 with the same right to the capacity and all associated energy that FortisBC currently has under the existing agreement. Although existing resource arrangements are expected to meet most of FortisBC's energy requirements, the Company expects that, in the near term, there will be some energy gaps during the winter period due to the shape of the load. (Exhibit B-1-2, p. 7)

To address capacity and energy requirements in the near and longer term FortisBC looked at resource options characterized as "New Resources" (Build strategy), "Wholesale Market" (Buy Strategy) and a "Combined Strategy" incorporating elements of build and buy. These potential resource solutions were looked at from a short term (2011-2015), medium term (2016-2020) and long term (2021-2040) perspective. Potential resources in the build category were evaluated based on their ability to meet capacity gaps, their environmental impact and their relative economics. Detailed evaluation of a number of resource options was provided by Midgard Consulting Inc. in its "FortisBC – 2010 Resource Options Report." (Exhibit B-1-2, Appendix C) For the buy strategy, FortisBC assessed future market risk (price and availability) based on a further study (2011 FortisBC Electricity Market Assessment) provided by Midgard Consulting Inc. (Exhibit B-1-2, Appendix B)

With respect to capacity requirements, FortisBC's proposed solution is to rely on wholesale market purchases in the short and medium term (2012 to 2020) with the possibility of accelerating construction of new resources in the medium term (2016-2020), if necessary. For the longer term (2021-2040), new capacity resources are anticipated to be built by the mid-to-late 2020s, with additional resources in the 2030s. To meet energy needs FortisBC intends to rely on wholesale market purchases in the short and medium term (2012-2020) while continuing to assess new clean energy resources. No energy gap is anticipated until 2018. By 2020, an energy gap of 13 GWh is predicted. In the long-term (2021-2040), this gap is expected to increase by about 14 GWh/year, reaching 287 GWh by 2040. (Exhibit B-1-2, pp. 64, 86)

No planned capital expenditures for capacity resources are included in the LTRP. To meet energy needs, new clean energy resources and the Similkameen Hydroelectric Project are expected in the 2021 – 2040 period, but further evaluation will be required before any specific projects are selected.

FortisBC states that it cannot prioritize the preferred resource options that have been identified at this time. (Exhibit B-5, BCSEA 1.15.1)

ICG takes the position that the Commission should reject the Integrated System Plan (containing FortisBC's LTRP) on the basis that the ISP does not meet the requirements of the Commission's Resource Planning Guidelines. Specifically, ICG is concerned that FortisBC failed to include a portfolio analysis of resource options as set out in Guidelines 5 and 6. ICG quoted from the Commission's Decision on the BC Hydro 2006 Integrated Electricity Plan (IEP): "[t]he Commission Panel also agrees with BC Hydro that a portfolio analysis is a best practice for IEP or IRP analysis" (2006 IEP and LTAP Decision dated May 11, 2007, pp. 89-90) FortisBC testified that because its forecast energy gaps are small and its capacity gaps are being met for some time into the future, it did not do a full portfolio analysis for its LTRP. The Company characterized its resource plan work as a supply/demand resource gap analysis. (T5: 789-791; ICG Final Submission, pp. 17-26)

Commission Panel Determination

The Commission Panel agrees that portfolio analysis is a "best practice" for resource plan analysis. However, the Resource Planning Guidelines do not state that portfolio analysis "must" be done, but that it "should" be done. **The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP.**

7.2.2 Requirements under the Utilities Commission Act

As noted earlier, under section 44.1 of the *Act*, in determining whether to accept or reject a long-term resource plan (or a part thereof), the Commission must consider:

- The applicable of British Columbia's energy objectives;
- The extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;
- Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and
- The interests of persons in British Columbia who receive or may receive service from the public utility.

Section 7.2.1 of this Decision outlines those British Columbia energy objectives which FortisBC argue apply to its Long Term Resource Plan. Within the 2012 LTRP the Company has addressed these objectives and assert that these objectives have played an important role in shaping its analysis and decision-making. Specifically, FortisBC has identified resource options and related strategies to handle forecast capacity and energy deficits over the short, medium and longer term. The Commission Panel finds that the LTRP is generally consistent with the applicable British Columbia energy objectives as they are a key input in the evaluation of capacity and energy alternatives.

As noted in Section 5.4.3 of this Decision, sections 6 and 19 of the *CEA* are primarily related to BC Hydro. However, section 6 does have application when a public utility is planning in accordance with section 44.1 of the *Act*. The Commission Panel is of the view that the steps taken by FortisBC to identify and evaluate resource options and related strategies to handle forecast capacity and energy deficits as described in the 2012 LTRP, address the British Columbia energy objective to achieve self-sufficiency.

In Sections 6.2.1.1 and 6.2.1.2 of this Decision, the Commission Panel has found that the FortisBC 2012 Long Term DSM Plan is adequate and cost effective and in the public interest under subsection 44.1(8) of the *Act*.

The Commission Panel considers acceptance of the 2012 LTRP to be in the interests of British Columbians who receive or may receive service from FortisBC. In our view the 2012 LTRP has adequately met the provisions for considerations laid out in subsection 44.1 (8) of the *Act.*

Therefore, based on the Commission's Panel's review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the *Act* with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected.

In reaching this conclusion, the Commission Panel notes that acceptance of the 2012 LTRP does not constitute approval of any of the potential initiatives addressed within this plan. The resource planning process by its nature is a high level exercise. Because of this, the Commission Panel would like to point out that in "accepting" the LTRP, the programs and initiatives outlined in the plan are not sufficiently "fleshed out" to finally determine whether they will pass careful scrutiny when a more detailed application is put forward.

7.2.3 Filing of the Next LTRP

FortisBC stated that its intention is to file its next long-term resource plan five years from the date the last plan was filed (June 30, 2011). The Company also stated that a revision to the current plan would be filed in the event of a material change such as the final RS 3808 PPA contract with BC Hydro having significantly different terms than those FortisBC is currently anticipating, a significant change in the marketplace (such as a marked increase in natural gas prices) or an unforeseen addition of major new loads onto the system. (T5:821-822)

The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines.

8.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relevant merits of each as a planning tool.	25
2.	The Commission Panel reaffirms its Decision of November 30, 2011, to maintain the current ROE and capital structure pending determinations made in the GCOC proceeding.	32
3.	The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC.	34
4.	The Commission Panel directs FortisBC to reduce its Power Purchase Expense forecasts by $1.5 million in 2012 and 2013.	35
5.	FortisBC is directed to adjust its power purchase expense forecast to reflect this change.	35
6.	The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of $142,000 in each of 2012 and 2013	38
7.	The Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses.	38
8.	The Commission Panel also agrees with this assessment and therefore denies the proposal to implement a PRM at this time and the proposed additional $310,000 in planned Power Purchase Expense for 2013	41
9.	The Panel directs FortisBC to include any variances related to water fees in that deferral account.	42
10.	FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.	44

11.	The Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.	47
12.	The Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant. The Commission Panel also approves the proposed handling of cross charges for executives based on a fully loaded wage only.	49
13.	The Commission Panel has determined that acceptance of the IBEW contract as it applies to rates is reasonable.	55
14.	The Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.	58
15.	The Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.	59
16.	The Commission Panel directs FortisBC to reduce O&M expenditures for labour for each of 2012 and 2013 by $250,000. The Panel believes this reduction should be applied to the specific areas where concerns have been raised but will leave the decision as to where these costs are applied to the discretion of FortisBC.	63
17.	The Panel denies the $0.8 million deferral account treatment sought by FortisBC in pursuit of the Asset Management Program.	66
18.	The Panel approves funds in the amount of $150,000 which may be required for external assistance over the test period. These funds may be included in the O&M budget.	66
19.	The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder. Consistent with the 2012 FEU RRA Decision, the remaining budgeted amounts are to be shared equally between the shareholder and the ratepayer.	69
20.	The Commission Panel will only approve an increase equal to the forecast BC CPI of 2.2 percent in 2012 and another 1.9 percent in 2013. (Exhibit B-1, Tab 4, p. 43) FortisBC is directed to reduce its non-labour expense forecast for this department by $113,000 in 2012 and $100,000 in 2013.	70

21.	The Commission Panel approves the requested capitalized overhead rate of 20 percent for the test period. For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time.	72
22.	The Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.	75
23.	FortisBC is directed to prepare and file a report with the Commission by September 30, 2012, explaining this apparent inconsistency. If an amount greater than the 20 percent approved for capitalized overhead has been used in the calculation of rates, FortisBC is directed to adjust the capitalized overhead rates downward to reflect the approved amount for capitalized overhead.	75
24.	Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification.	77
25.	The Commission Panel is reluctant to take issue with the forecasts that have been prepared by FortisBC and approves the forecast expenditures, as requested.	78
26.	The Panel directs FortisBC to use the most recent interest rate forecasts available at the time of the oral phase of the proceeding of 2.85 percent for short-term and 3.45 percent for long-term debt.	82
27.	The Commission Panel approves FortisBC's continued use of recognizing actual asset removal costs as incurred, as requested.	86

28.	While the Commission Panel endorses the relocation of a spare transformer to the Grand Forks Terminal to reduce the downtime associated with a failure of the current transformer, we reject the proposed expenditure of $7.205 million for the Grand Forks Transformer Addition Project because the need for increased reliability is not apparent. In addition, the Panel notes that FortisBC was previously directed to apply for a CPCN for certain elements of the proposed project and failed to do so. If FortisBC intends to proceed with advancing either the fibre optic communications portion of the proposed project or the installation of the spare transformer at Grand Forks Terminal, it is directed to apply for a separate CPCN. In pursuing a CPCN for fibre optic communications, FortisBC is expected to diligently pursue the extension of the fibre leasing agreement to preserve the potential benefit to ratepayers.	95
29.	The Commission Panel is concerned about the estimate quality and control of actual costs associated with the PCB Mitigation project, and directs FortisBC to file a comprehensive scope and schedule for this project by October 1, 2012 and semi-annual progress reports thereafter.	99
30.	The Commission Panel rejects the expenditures for the Kelowna 138 kV Loop Fibre Installation project. FortisBC may provide Class 3 estimates for both Option E and Option F and additional justification for its recommendation in a future filing.	101
31.	Based on our review of the 2012-13 CEP the Commission Panel is of the view that an overall reduction to the CEP of $17.6 million over the test period is possible. However, the Panel believes imposing all of the reductions related to the $17.6 million may not provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion. By reducing the amount of $17.6 million to $10.5 million (which is approximately 60 percent), the Panel can be reasonably assured that FortisBC can achieve the level of service it requires and will still have sufficient flexibility to manage its projects and workforce. Accordingly, the Commission Panel directs FortisBC to reduce its capital expenditure budget by $10.5 million in addition to the two projects which have been specifically rejected above.	103
32.	The Commission Panel therefore directs that such deferral accounts, with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates.	106
33.	FortisBC is directed to commence the amortization of this deferral account into rates in the next test period if the associated project has not commenced by that time.	107

34.	The Commission Panel approves the amortization in 2012, as requested, of the following regulatory expense deferral accounts into rates: • Implementation of new rate structures • Residential Inclining Block Rate and Industrial Stepped Rate Applications • 2011 Revenue Requirements Application	108
35.	The Commission Panel rejects FortisBC's proposal to amortize this deferral account into rates.	109
36.	The Commission Panel approves the full amortization of the research costs relating to Irrigation rate payers in 2013, as requested.	108
37.	The Commission Panel approves amortization of these amounts over a shorter, two year period to reduce carrying costs.	110
38.	The Commission Panel approves the amortization of 2011 Revenue Protection expenses into rates in 2012.	110
39.	The Commission Panel approves the continuation of the Right–of-Way litigation deferral account, with the inclusion of any recovered costs following resolution of the dispute, as a non-rate base deferral account, attracting an interest financing charge at FortisBC's WACD.	111
40.	The Commission Panel approves the amortization of costs relating to conversion to US GAAP over the test period.	111
41.	The Commission Panel approves deferral of the set up costs relating to Mandatory Reliability Standards in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD. However, in the Panel's view, the amortization period requested is too long. Therefore, the Commission Panel directs that these costs be amortized into rates over a three year period, as opposed to the five year period sought, to reduce the associated carrying costs.	112
42.	The Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC's WACD until such time as they become part of a specific capital project.	113
43.	The Commission Panel considers this item to be a regulatory expense not a capital expense related to any specific project and therefore, directs that this account attract an interest financing charge at FortisBC's WACD and be amortized into rates over a five year period.	113

44.	The Commission Panel therefore directs that these costs be expensed during the test period.	114
45.	Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD.	115

46.	The Commission Panel therefore approves the following variance deferral accounts as non rate base deferral accounts attracting a short term interest financing charge.
	• Power Purchase Expense Variance Deferral Account
	    o any variance in this account is to be amortized in 2014
	• Revenue Variance Deferral Account
	    o any variance in this account is to be amortized in 2014
	• HST Removal or Reform Variance Deferral Account
	• Property Tax Asset Variance Deferral Account
	• Pension and Other Post-Employment Expense Variance
		115

47.	The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.	134
48.	The Commission Panel finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335).	136
49.	The Commission Panel approves FortisBC's section 44.2 expenditure request for DSM in the amounts of $7.73 million in 2012 and $7.88 million in 2013.	137
50.	The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission.	140
51.	The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.	141

52.	The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP.	147
53.	Based on the Commission's Panel's review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the Act with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected.	149
54.	The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines.	149

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

Original signed by:

D.A. COTE
COMMISSIONER

Original signed by:

A.A. RHODES
COMMISSIONER

Original signed by:

N.E. MACMURCHY
COMMISSIONER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-110-12

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for Approval of 2012-2013 Revenue Requirements and
Review of 2012 Integrated System Plan

BEFORE: D.A. Cote, Commissioner
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

August 15, 2012

O R D E R

WHEREAS:

A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed an application pursuant to sections 44.1, 44.2, 56 and 59 to 61 of the *Utilities Commission Act* (the Act) for approval of its 2012-2013 Revenue Requirements and the review of its 2012 Integrated System Plan (collectively referred to as the Application);

B. The Application contains two parts:

1) FortisBC's 2012-2013 Revenue Requirements (including the Company's 2012-2013 Capital Expenditure Plan filed pursuant to section 44.2(1) of the Act),

2) FortisBC's 2012 Integrated System Plan filed pursuant to section 44.1 of the Act, comprising its 2012 Long Term Capital Expenditure Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan;

C. FortisBC sought, among other things, approval of interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. FortisBC also sought a permanent rate increase of 6.9 percent effective January 1, 2013;

D. The Company requests a determination from the British Columbia Utilities Commission (the Commission) on whether the 2012-2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3)(a) and satisfies the requirements of section 45(6) of the Act;

E. The Company also requested a Commission determination on whether the 2012 Integrated System Plan, which is comprised of three components (the 2012-2013 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand-Side Management Plan), is in the public interest pursuant to section 44.1 (6);

F. A Workshop to review the Application was held in Kelowna on July 22, 2011;

G. The Company filed an Evidentiary Update to the Application on November 4, 2011, which reduced the rate increase sought to 1.5 percent in 2012 and a 6.5 percent increase in 2013;

H. The 2011 Annual Review was held in Kelowna on November 22, 2011, to review the Company's performance for the 2011 year, followed by a Procedural Conference to hear submissions on procedural matters regarding the current Application;

I. By Order G-199-11, the Commission approved a 1.5 percent interim rate increase for FortisBC, effective January 1, 2012;

J. Pursuant to Order G-214-11, the Oral Public Hearing to review the Application took place between March 5 and March 9, 2012 in Kelowna;

K. Between April 5 and April 23, 2012, FortisBC and Interveners filed their Final Submissions. FortisBC filed its Reply Submission on May 3, 2012;

L. The Commission has considered the Application, the evidence and all the submissions as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. Pursuant to sections 59 to 61 of the *Act*:

   a. The requested permanent rate increase of 1.5 percent in 2012 and 6.5 percent in 2013 is not approved, as filed.

   b. Cross charges between FortisBC and its affiliates regulated by the Commission are approved to be based on fully loaded costs, not including overhead.

   c. The proposed Deferral Account for Power Purchase Expense variances from forecast is approved and is to be amortized into rates in 2014. The proposed Revenue Variance Deferral Account is also approved and is to be amortized into rates in 2014.

   d. Determinations for the new proposed Deferral Accounts and treatment for existing Deferral Accounts are set out in Section 5.4.4 of the Decision.

   e. Costs of Removal of $4.7 million for 2011, $5.4 million for 2012 and $4.0 million for 2013 are approved to be included in Rate Base as set out in Section 5.4.2 of the Decision.

2. Pursuant to section 44.2(3) of the *Act*, FortisBC's 2012-2013 Capital Expenditure Plan is approved subject to the determinations and reductions set out in Section 5.4.3 of the Decision.

3. The Commission Panel accepts FortisBC's Long Term Capital Plan is in the public interest and the Long Term Resource Plan meets the requirements of the Act except for the Planning Reserve Margin as set out in Section 7.0 of the Decision.

…/3

4. FortisBC is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 30 days of this Order.

5. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision. FortisBC is to provide all customers, by way of an information notice, of the change in rates.

6. If the 2012 permanent rates are less than the interim rates, FortisBC is to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which FortisBC conducts its business. If the 2012 permanent rates exceed the interim rates, FortisBC is to reflect this difference in customer rates over the balance of 2012.

7. FortisBC is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

BY ORDER

Original signed by:

D.A.Cote
Commissioner

Sections 59 through 61 *Utilities Commission Act*

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Rate schedules to be filed with commission

61 (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.

(3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

(4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.

(5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,

(a) on complaint of a person whose interests are affected, or

(b) on its own motion,

direct an inquiry into the new schedule of rates having regard to the setting of a rate that is not unjust or unreasonable.

(6) After an inquiry under subsection (5), the commission may

(a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or

(b) confirm the increase or part of it.

Section 44.2 *Utilities Commission Act*

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

(a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

(b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

(c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6), must

(a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider

(a) the applicable of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

Clean Energy Act – Section 2

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

APPEARANCES

G.A. FULTON, Q.C.	Commission Counsel
G.A. MACINTOSH L. HERBST	FortisBC Inc.
C. WEAFER	British Columbia Municipal Electrical Utilities
R. HOBBS	Zellstoff Celgar Limited Partnership, Atco Wood Products Ltd., Kalisnikoff Lumber Company Ltd., Porcupine Wood Products, Springer Creek Forest Products, and International Forest Products Limited
S. KHAN	British Columbia Old Age Pensioners' Organization *et al.*
W. J. ANDREWS	B.C. Sustainable Energy Association, Sierra Club of Canada, British Columbia Chapter
A. WAIT	Self
N. GABANA	Self

LIST OF ACRONYMS

2012 LTRP	2012 Long Term Resource Plan
2012-13 CEP	2012-2013 Capital Expenditure Plan
AAM	automatic adjustment mechanism
AEUB	Alberta Energy and Utilities Board
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
Atco Electric	ATCO Electric Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	The British Columbia Municipal Electrical Utilities
BCPSO	The British Columbia Pensioners' Organization *et al.*
BCSEA	The BC Sustainable Energy Association and the Sierra Club of British Columbia
BPPA	Brilliant Power Purchase Agreement
Commission	British Columbia Utilities Commission
COPE	Canadian Office and Professional Employees Union
CPA	Canal Plant Agreement
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
DSM	Demand-Side Management
EEC	Energy Efficiency and Conservation
FEU	FortisBC Energy Utilities (FortisBC Energy Inc.; FortisBC Energy (Vancouver Island) Inc.; FortisBC Energy (Whistler) Inc.)
FortisBC or the Company	FortisBC Inc.
FTE	Full Time Equivalent

GCOC	Generic Cost of Capital
IBEW	International Brotherhood of Electrical Workers Union
IEP	Integrated Electricity Plan
IFRS	International Financial Reporting Standards
IR	Information Request
ISP	Integrated System Plan
LTCP	Long Term Capital Plan
LTRP	Long Term Resource Plan
M&E Plan	Monitoring and Evaluation Plan
MRS	Mandatory Reliability Standards
mTRC	Modified total resource cost
NSA	Negotiated Settlement Agreement
NSP	negotiated settlement process
O&M	operations and management
OTR	Okanagan Transmission Reinforcement Project
PBR	Performance Based Regulation
PLTs	Power Line Technicians
PPA	Power Purchase Agreement
PPA	Power Purchase Agreement
PPEVDA	Power Purchase Expense Variance Deferral Account
PPME	Power Purchase Management Expense
PRM	Planning Reserve Margin
ROE	return on equity
RS 3808 PPA	Rate Schedule 3808 Power Purchase Agreement

SAIDI	System Average Interruption Duration
SAIFI	System Average Interruption Frequency
SCADA	Supervisory Control and Data Acquisition
SERP	Supplemental Employee Retirement Program
T&D	Transmission and Distribution
the *Act*	*Utilities Commission Act*
the Committee	Load Forecast Technical Committee
TRC	total resource cost
ULE	Upgrade and Life Extension
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WAX CAPA	Waneta Expansion Project capacity purchase agreement
WECC	Western Electricity Coordinating Council

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
2012 – 2013 Revenue Requirements and
Review of 2012 Integrated System Plan Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated June 30, 2011 and Order G-111-11 – Establishing an Initial Regulatory Timetable and Procedural Conference
A-2	Letter dated July 19, 2011 – Commission Appointment of Panel
A-3	Letter dated August 10, 2011 – Commission Information Request No. 1
A-4	Letter dated August 24, 2011 – Letter L-65-11 issuing Revised Initial Regulatory Timetable
A-5	Letter dated September 30, 2011 – Commission Information Request No. 2
A-6	**CONFIDENTIAL** Letter dated September 30, 2011 – CONFIDENTIAL Commission Information Request No. 2
A-7	Letter dated October 4, 2011 – Order G-167-11 and Revised Preliminary Regulatory Timetable
A-8	Letter dated October 7, 2010 – Commission Information Request No. 1 on Exhibit B-7
A-9	Letter dated November 2, 2011 – Notice of 2011 Annual Review and Procedural Conference
A-10	Letter dated November 10, 2011 – Commission Information Request No. 1 to BCSEA et al on Intervener Evidence
A-11	Letter dated November 10, 2011 – Procedural Conference Agenda
A-12	Letter dated November 18, 2011 – Letter to Participants Zellstoff/Celgar

Exhibit No.	Description
A-13	Letter dated November 30, 2011 – Order G-199-11 issuing Amended Regulatory Timetable with Reasons
A-14	Letter dated December 15, 2011 – Order G-214-11 issuing Amended Regulatory Timetable
A-15	Letter dated February 10, 2012 - Panel Letter to FBC
A-16	Letter dated February 10, 2012 – Oral Public Hearing Information
A-17	Letter dated March 23, 2012 – Request for Comments on FortisBC's Testimony Clarification
A-18	Letter dated April 19, 2012 – Response to FortisBC request for Filing Extension
A2-1	Submitted at Oral Hearing March 5, 2012 – Commission Staff Filing EXTRACT FROM "REPORT 8: OCTOBER 2011; BC HYDRO: THE EFFECTS OF RATE-REGULATED ACCOUNTING…OFFICE OF THE AUDITOR GENERAL OF BRITISH COLUMBIA"
A2-2	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXECUTIVE SUMMARY FROM 1994 BC GAS PHASE 1 REVENUE REQUIREMENT APPLICATION
A2-3	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM BC GAS UTILITY LIMITED 2003 REVENUE REQUIREMENTS APPLICATION DECISION DATED FEBRUARY 4, 2003
A2-4	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE BC GAS UTILITY LIMITED MULTI-YEAR PERFORMANCE-BASED RATE PLAN FOR 2004/2008 APPLICATION
A2-5	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE FORTISBC ENERGY UTILITIES 2012-2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES APPLICATION, EXHIBIT B-1
A2-6	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing DOCUMENT ENTITLED "BCUC STAFF WITNESS AID - SERP…"
A2-7	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing ORDER G-64-07 AND AN EXTRACT FROM THE ACCOMPANYING DECISION

Exhibit No.	Description
A2-8	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing COMMISSION DECISION DATED APRIL 3, 1992 ON A RATE APPLICATION OF PACIFIC NORTHERN GAS LIMITED
A2-9	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE DECISION OF THE ALBERTA ENERGY UTILITY BOARD IN THE MATTER OF ATCO ELECTRIC LIMITED 2005/2006 GENERAL TARIFF APPLICATION DATED MARCH 17, 2006
A2-10	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM ONTARIO ENERGY BOARD, CHAPTER 2 OF THE FILING REQUIREMENTS FOR TRANSMISSION AND DISTRIBUTION APPLICATIONS, JUNE 22, 2011
A2-11	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM ONTARIO ENERGY BOARD, RP-2004-0188, 2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK, REPORT OF THE BOARD, 2005 MAY 11
A2-12	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing "BCUC STAFF WITNESS AID: FINANCING COSTS, FORTISBC 2012-2013 RRA & ISP"
A2-13	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing "WITNESS AID - DEFERRAL ACCOUNTS"
A2-14	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing EXTRACT FROM BCUC DECISION "BRITISH COLUMBIA HYDRO AND POWER AUTHORITY AND F2009 AND F2010 REVENUE REQUIREMENTS DECISION, MARCH 13, 2009"
A2-15	Submitted at Oral Hearing March 8, 2012 – Commission Staff Filing STAFF "WITNESS AID, FORTISBC, DSM PANEL"
A2-16	Submitted at Oral Hearing March 8, 2012 – Commission Staff Filing LETTER FROM FORTISBC DATED SEPTEMBER 29, 2011, WITH ATTACHED EXCERPT OF "FORTISBC INC., SEMIANNUAL DSM REPORT, SIX MONTHS ENDED JUNE 30, 2011
A2-17	Submitted at Oral Hearing March 9, 2012 – Commission Staff Filing FORTISBC F2012-2013 RRA & ISP WITNESS AID - CAPITAL EXPENDITURES PLAN
A2-18	Submitted at Oral Hearing March 9, 2012 – Commission Staff Filing EXCERPT FROM BCUC "FORTISBC INC. 2011 CAPITAL EXPENDITURE PLAN DECISION", DATED DECEMBER 17, 2010

Exhibit No.	Description
APPLICANT DOCUMENTS FORTISBC INC	
B-1	**FORTISBC INC. (FBC)** Letter dated June 30, 2011 – 2012/13 Revenue Requirements and Review of 2012 Integrated System Plan Application
B-1-1	Letter dated June 30, 2011 – FBC Submitting 2012 Integrated System Plan Volume 1
B-1-2	Letter dated June 30, 2011 – FBC Submitting 2012 Integrated System Plan Volume 2
B-1-3	**CONFIDENTIAL** Letter dated June 30, 2011 – FBC Submitting Confidential Page 34 of Tab 4, Section 4.3.2.1 of the Application
B-1-4	Letter dated July 11, 2011 – FBC Submitting Addendum to Tab 7 (Financial Schedules) of the Application
B-1-5	Letter dated July 21, 2011 – FBC Submitting Errata 1 to the Application
B-1-6	Letter dated September 9, 2011 – FBC Errata 2 to Application
B-2	Letter dated July 22, 2011 – FBC Presentation submitted at July 22, 2011 Workshop
B-3	Letter dated July 25, 2011 – FBC Submitting Adoption of US Generally Accepted Accounting Principles and 2012/ 2012 Revenue Requirements Application Compliance Filing Order G-117-11
B-4	Letter dated September 9, 2011 - FBC Responses to IR No. 1 from BCUC
B-5	Letter dated September 9, 2011 - FBC Responses to IR No. 1 from Interveners BCOAPO, BCSE, Celgar, and Alan Wait
B-6	Letter dated September 16, 2011 – FBC Submitting comments regarding Material Updates to the Application
B-7	Letter dated September 16, 2011 – FBC Submitting responses to BCUC and BCOAPO System Losses Information Requests
B-8	Letter dated October 21, 2011 - FBC Submitting Responses to BCUC IR2
B-8-1	**CONFIDENTIAL** Letter dated October 21, 2011 - FBC Submitting Responses to BCUC CONFIDENTIAL IR2
B-8-2	Letter dated March 2, 2012 - FBC Submitting Errata to its Responses to Information Request No. 2 - Replacement pages

Exhibit No.	**Description**
B-9	Letter dated October 21, 2011 - FBC Submitting Responses to Intervener IR2
B-10	Letter dated October 21, 2011 - FBC Submitting Responses to FortisBC Responses to BCUC IR2 (Losses)
B-11	Letter dated October 21, 2011 - FBC Submitting Errata 3 to Application and IR1 Responses
B-12	Letter dated November 4, 2011 - FBC Submitting Evidentiary Update
B-13	Letter dated November 10, 2011 - FBC Submitting IR No. 1 to BCSEA
B-14	Letter dated November 17, 2011 - FBC Submitting comments on Reconsider Application of Order E-29-10 Exhibit C9-4
B-15	Letter dated November 22, 2011 - FBC Submitting Presentations from 2011 Annual Review
B-16	Letter dated November 25, 2011 - FBC Submitting Load Forecast Technical Committee Report
B-17	Letter dated December 7, 2011 – FBC Submitting Request for Amendment to Timetable
B-18	Letter dated February 1, 2012 – FBC Submitting Witnesses Anticipated Testimony
B-19	Letter dated March 1, 2012 - FBC Submitting Opening Statement
B-20	Letter dated March 2, 2012 - FBC Submitting Witness Panel
B-21	Letter dated March 2, 2012 - FBC Submitting Opening Statement of John Walker
B-22	Submitted at Oral Hearing March 7, 2012 – FBC Submitting DOCUMENT HEADED "2005 REVENUE REQUIREMENTS - REGULATORY POLICY/PERFORMANCE STANDARDS - TAB 10"
B-23	Submitted at Oral Hearing March 7, 2012 – FBC Submitting "FORTISBC 2012-2013 REVENUE REQUIREMENTS APPLICATION, ORAL HEARING UNDERTAKINGS FROM MARCH 6, 2012"
B-24	Submitted at Oral Hearing March 8, 2012 – EXTRACT FROM "IMPLEMENTING ENERGY EFFICIENCY: PROGRAM DELIVERY COMPARISON STUDY", IEE WHITEPAPER, MARCH 2010

Exhibit No.	Description
B-25	Submitted at Oral Hearing March 8, 2012 – FORTISBC 2012-13 REVENUE REQUIREMENTS APPLICATION, ORAL HEARING UNDERTAKINGS FROM MARCH 6, 2012"
B-26	Letter dated March 16, 2012 - FBC Submitting Clarifications to testimony at the 2012-13 RRA and ISP Oral Hearing
B-27	Letter dated March 16, 2012 - FBC Submitting Oral Hearing Undertakings
B-28	Letter dated March 23, 2012 - FBC Submitting Oral Hearing Undertaking 51
B-29	Letter dated March 30, 2012 - FBC Submitting Oral Hearing Undertaking 32
B-30	Letter dated April 3, 2012 – FBC Submitting Undertaking 50
B-31	Letter dated April 19, 2012 – FBC Request for Filing Extension

INTERVENER DOCUMENTS

C1-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Online Registration dated July 5, 2011 – Request for Intervener Status by Heather Grant
C1-2	Letter dated July 11, 2011 – Notice of Mr. C. Weafer, Owen Bird as counsel for BCMEU
C1-3	Letter dated August 10, 2011 – BCMEU Information Request No. 1
C1-4	Letter dated September 30, 2011 – BCMEU Information Request No. 2
C1-5	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing REVIEW OF BC HYDRO, JUNE 2011
C1-6	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing NEWS RELEASE FROM OFFICE OF THE PREMIER, MINISTRY OF ENERGY AND MINES, "CANADA STARTS HERE - THE BC JOBS PLAN", DATED FEBRUARY 3, 2012"
C1-7	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing "FORTIS GROUP OF COMPANIES OF BC COMMUNICATIONS & PUBLIC AFFAIRS PLAN 2010/2011, 25 AUGUST 2010"
C1-8	Letter dated April 19, 2012 – BCMEU Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension

Exhibit No.	Description
C2-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCHYDRO)** Online Registration dated July 5, 2011 – Request for Intervener Status by Janet Fraser
C3-1	**WAIT, ALAN (WA)** – Online Registration dated July 6, 2011 – Request for Intervener Status
C3-2	Letter dated August 10, 2011 – WA Information Request No. 1
C4-1	**GABANA, NORMAN (GN)** – Email dated July 7, 2011 Request for Intervener Status
C4-2	Letter dated September 23, 2011 Via Email – GN Information Request No. 2
C4-3	Letter dated November 22, 2011 – GN comments regarding Order E-29-10 review
C5-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION *ET AL.* (BCOAPO)** – Letter dated July 8, 2011 requesting Intervener Status by Ros Salvador
C5-2	Letter dated August 10, 2011 – BCOAPO Information Request No. 1
C5-3	Letter dated September 30, 2011 – BCOAPO Information Request No. 2
C5-4	Letter dated November 10, 2011 – BCOAPO Information Request No. 1 to BCSEA et al on Intervener Evidence
C5-5	Letter dated November 18, 2011 – BCOAPO Submitting change of counsel request
C5-6	Letter dated November 21, 2011 – BCOAPO Submitting clarification on counsel details
C5-7	Letter dated April 19, 2012 – BCOAPO Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C6-1	**BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB OF BRITISH COLUMBIA (BCSEA ET AL.)** – Letter dated July 14, 2011 - Requesting Intervener Status by William J. Andrews
C6-2	Letter dated August 10, 2011 – BCSEA Information Request No. 1
C6-3	Letter dated September 30, 2011 – BCSEA Information Request No. 2
C6-4	Letter dated October 31, 2011 - BCSEA Submitting Evidence
C6-5	Letter dated November 24, 2011 - BCSEA Submitting Response to BCUC IR No. 1

Exhibit No.	Description
C6-5-1	Letter dated November 24, 2011 - BCSEA Submitting Errata
C6-6	Letter dated November 24, 2011 - BCSEA Submitting Response to FBC IR No. 1
C6-7	Letter dated November 24, 2011 - BCSEA Submitting Response to BCOAPO IR No. 1
C6-8	Letter dated February 20, 2012 – BCSEA Submitting Witness Panel Notification
C6-9	Submitted at Oral Hearing March 7, 2012 – BCSEA Submitting COPY OF UTILITIES COMMISSION ACT, DEMAND-SIDE MEASURES REGULATION
C6-10	Submitted at Oral Hearing March 8, 2012 – BCSEA Submitting "A STATISTICAL MODEL FOR PREDICTING FUTURE ELECTRIC ENERGY EFFICIENCY RESOURCES CLASSES (DRAFT)", MARCH 6, 2012
C6-11	Letter dated April 19, 2012 – BCSEA Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C7-1	**REGIONAL DISTRICT OF OKANAGAN SIMILKAMEEN (RDOS) –** Online Registration dated July 15, 2011 – Requesting Intervener Status by Doug French
C8-1	**SLACK, BURYL –** Facsimile Registration dated July 15, 2011 – Requesting Intervener Status
C8-2	Letter dated November 10, 2011 by Fax – SB submitting comments
C9-1	**ZELLSTOFF CELGAR, ATCO WOOD PRODUCTS LTD., INTERNATIONAL FOREST PRODUCTS LIMITED (INTERFOR), KALESNIKOFF LUMBER CO. LTD., PORCUPINE WOOD PRODUCTS, AND SPRINGER CREEK FOREST PRODUCTS COLLECTIVELY, THE INDUSTRIAL CUSTOMERS GROUP (ICG)** – Letter dated July 20, 2011 requesting Intervener Status by Adrian Hay, Brian Merwin and Robert Hobbs
C9-2	Letter dated August 10, 2011 – Celgar Information Request No. 1
C9-3	Letter dated September 30, 2011 – Celgar Information Request No. 2
C9-4	Letter dated November 10, 2011 – Celgar Submitting comments regarding WAX CAPA
C9-5	Letter dated November 28, 2011 – Celgar Submitting additional Interveners Atco Wood Products Ltd., International Forest Products Limited (Interfor), Kalesnikoff Lumber Co. Ltd., Porcupine Wood Products, and Springer Creek Forest Products collectively, the **Industrial Customers Group (ICG)**

Exhibit No.	Description
C9-6	Letter dated November 25, 2011 – Celgar / ICG Submitting reply and comments
C9-7	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT "APPENDIX 1 TO ORDER NO. G-10-03, PAGE 7 OF 25"
C9-8	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT FROM "FORTISALBERTA IN 2010/2011 TARIFF APPLICATION", PAGES 2-27 AND 2-28
C9-9	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 03, NO. 02-APRIL 2010, SETTLEMENT SUMMARIES (FEBRUARY 2010 TO APRIL 2010)"
C9-10	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT FROM DOCUMENT "BUDGET AND FISCAL PLAN, 2012/13 - 2014/15"
C9-11	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 02, NO. 10 - OCTOBER 2009, SETTLEMENT SUMMARIES (AUGUST TO OCTOBER 2009)"
C9-12	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 01, NO. 3 - JULY 2008, SETTLEMENT SUMMARIES (APRIL 2008 TO JUNE 2008)"
C9-13	Submitted at Oral Hearing March 6, 2012 – Celgar / ICG Filing "BC BARGAINING DATABASE, VOL. 05 NO. 01 - JANUARY 2012" QUARTERLY WAGE SETTLEMENTS IN BC (2005-2011)
C9-14	Submitted at Oral Hearing March 6, 2012 – Celgar / ICG Filing "F2012 TO F2014 REVENUE REQUIREMENTS APPLICATION, BC HYDRO, APPENSIC C-2, ORDER IN COUNCIL NO. 021, HERITAGE SPECIAL DIRECTION NO. HC2"
C9-15	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "INITIATIVES FOR INDUSTRIAL CUSTOMERS - PROJECT INCENTIVES TRANSMISSION"
C9-16	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "INTEGRATED RESOURCE PLAN - MEETING #2, JANUARY 27 & 28, 2011"
C9-17	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing EXCERPT FROM "NERC…2010 LONG-TERM RELIABILITY ASSESSMENT, OCTOBER 2010"
C9-18	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "NERC…2011 LONG-TERM RELIABILITY ASSESSMENT, NOVEMBER 2011"

Exhibit No.	Description
C9-19	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing FERC "WINTER 2011-12 ENERGY MARKET ASSESSMENT…OCTOBER 20, 2011"
C9-20	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing DOCUMENT HEADED "PLANNING RESERVE MARGIN, PAGE 1 OF 1"
C9-21	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing "2005 REVENUE REQUIREMENTS, FORECASTS - POWER PURCHASE & WHEELING - TAB 7…NOVEMBER 26, 2004", PAGES 19, 20 AND 21
C9-22	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing "INTEGRATED RESOURCE PLANT, MEETING #2, JANUARY 27 & 28, 2011, 2011 IRP TECHNICAL ADVISORY COMMITTEE SUMMARY BRIEF"
C9-23	Letter dated April 19, 2012 – Celgar / ICG Filing Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C10-1	**IRRIGATION RATEPAYERS GROUP (IRG)** – Letter dated July 20, 2011 requesting Intervener Status by Fred Weisberg
C11-1	**CITY OF TRAIL (CT)** – Letter dated July 20, 2011 requesting Intervener Status by Carolyn MacEachern
C11-2	Letter dated November 4, 2011 withdrawing Intervention

INTERESTED PARTY DOCUMENTS

D-1	**ACTIVE RENEWABLE (BC)** – Online Registration dated July 17, 2011 – Request for Interested Party Status by Bill Daly
D-2	**POWELL, JOHN O.** – Email Registration dated July 14, 2011 – Request for Interested Party Status
D-3	**KAROW, HANS (CORE)** – Email Registration dated November 22, 2011 – Request for Interested Party Status
D-4	**CITY OF PENTICTON (CP)** Letter dated December 21, 2011 – Submitting Letter of Comment
D-5	**FLYNN, JERRY** Online Registration dated January 5, 2011 – Request for Interested Party Status by Jerry Flynn

Exhibit No.	Description
D-5-1	January 25, 2010 **-** Registration of Interested Party Status withdrawn

LETTERS OF COMMENT

E-1	**KRISTIAN, BEN** – Letter of Comment dated July 20, 2011