

YUKON UTILITIES BOARD

IN THE MATTER OF the Public Utilities Act, R.S.Y. 2002, c. 186;

AND IN THE MATTER OF the ATCO Electric Yukon 2023-2024 General Rate Application.

**BOOK OF AUTHORITIES TO THE REPLY ARGUMENT OF ATCO ELECTRIC
YUKON**

TAB	AUTHORITY
1.	<i>Public Utilities Act</i> , RSY 2002, c 186
2.	<i>Rate Policy Directive, 1995</i> , YOIC 1995/90
3.	Board Order 2022-13, Appendix A – Reasons for Decision
4.	AEY 2022 Rate Application, July 18, 2022
5.	Board Order 2017-01, Appendix A – Reasons for Decision
6.	AUC Decision 27084-D01-2022 (March 31, 2022)
7.	AUC Decision 27084-D02-2023 (October 9, 2023)

TAB 1



PUBLIC UTILITIES ACT

RSY 2002, c. 186

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LRY 2002, ch. 186

**UNOFFICIAL CONSOLIDATION OF THE
STATUTES OF YUKON**

**CODIFICATION NON OFFICIELLE DES
LOIS DU YUKON**

PUBLIC UTILITIES ACT

RSY 2002, c. 186; amended by SY 2012, c.14;
SY 2014, c.3

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LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LRY 2002, ch. 186; modifiée par LY 2012, ch. 14;
LY 2014, ch.3

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PUBLIC UTILITIES ACT

TABLE OF CONTENTS

Section	Page
1 Interpretation	1

PART 1

YUKON UTILITIES BOARD

2 Yukon Utilities Board	3
3 Term of office	3
4 Substitute members	3
5 Expenses of members	4
6 Chair and vice-chair	4
7 Board meetings	4
8 Decisions of the board	4
9 Vacancies in the membership of the board	5
10 Rules of the board	5
11 Conflict of interest	5
12 Confidentiality of board information	6
13 Board staff and records	7
14 Technical assistance	7
15 Inquiry by board member	7
16 Use of public service by the board	8
17 Directions from the Commissioner in Executive Council	8
18 Investigations and duties of the board	9
19 Annual report of the board	9

PART 2

REGULATION OF PUBLIC UTILITIES

20 Franchise requirement	10
21 Grant of franchise	10
22 Interim permission	11
23 Books and records of public utilities	11
24 Review by the board	11
25 Reports to the board	11

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

TABLE DES MATIÈRES

Article	Page
1 Définitions	1

PARTIE 1

RÉGIE DES ENTREPRISES DE SERVICE PUBLIC

2 Constitution	3
3 Mandat	3
4 Suppléance	3
5 Frais	4
6 Président et vice-président	4
7 Réunions de la Régie	4
8 Décisions de la Régie	4
9 Vacance	5
10 Règles	5
11 Conflit d'intérêts	5
12 Confidentialité	6
13 Personnel et livres	7
14 Expertise	7
15 Enquête par un membre	7
16 Utilisation des fonctionnaires	8
17 Instructions du commissaire en conseil exécutif	8
18 Enquêtes et obligations de la Régie	9
19 Rapport annuel	9

PARTIE 2

RÉGLEMENTATION DES ENTREPRISES DE SERVICE PUBLIC

20 Agrément	10
21 Octroi de l'agrément	10
22 Permission temporaire	11
23 Livres et registres des entreprises	11



TABLE OF CONTENTS

TABLE DES MATIÈRES

26	Maintenance of property and equipment	12
27	Board orders	12
28	Rate changes	13
29	Factors affecting rates	13
30	Guidelines respecting cost increases	14
31	Contracts setting rates	14
32	Rate base of public utilities	14
33	Service extensions	15
34	Joint use of equipment	16
35	Exemptions	16

PART 3**ENERGY PROJECTS**

36	Interpretation	17
37	Energy project certificate	17
38	Energy operation certificate	18
39	Applications for certificates	18
40	Review of applications	18
41	Report and recommendations of the board	18
42	Grant or refusal of applications	18
43	Report on energy project	19

PART 4**ADMINISTRATION AND ENFORCEMENT
COMPLAINTS AND INVESTIGATIONS**

44	Complaints	19
45	Action on complaints	19
46	Investigation of complaints	20
47	Settlement of complaints	20
48	Investigation without complaint	20
49	Investigation procedure	20

HEARINGS

50	Requirement for approval	21
51	Powers of the board	21
52	Hearing procedure and jurisdiction	21
53	Evidence	22
54	Disqualification of board members	22
55	Combination of proceedings	23
56	Costs	23

ORDERS

57	Powers of the board	23
58	Types of orders	23
59	Extension of time for compliance	23
60	Requirement for a hearing	24
61	Effect of order on service	24
62	Variation of orders	24
63	Interim and reserved orders	24

ENFORCEMENT

24	Examen par la Régie	11
25	Rapport à la Régie	11
26	Entretien	12
27	Ordonnances	12
28	Modifications des taux	13
29	Critères liés aux taux	13
30	Critères liés aux augmentations de frais	14
31	Contrats stipulant les taux	14
32	Taux de base des entreprises de service public	14
33	Extension du service	15
34	Utilisation conjointe d'équipements	16
35	Exemptions	16

PARTIE 3**PROJETS ÉNERGÉTIQUES**

36	Définitions	17
37	Certificat de construction	17
38	Certificat d'exploitation	18
39	Demande de certificats	18
40	Examen des demandes	18
41	Rapport et recommandations de la Régie	18
42	Octroi ou refus	18
43	Rapport sur un projet énergétique	19

PARTIE 4**MISE EN ŒUVRE ET CONTRÔLE D'APPLICATION
PLAINTES ET ENQUÊTES**

44	Plaintes	19
45	Suivi	19
46	Enquêtes	20
47	Règlement des plaintes	20
48	Enquête sans plainte	20
49	Procédure	20

AUDIENCES

50	Approbation obligatoire	21
51	Attributions de la Régie	21
52	Procédure des audiences et compétence	21
53	Preuve	22
54	Empêchement	22
55	Jonction	23
56	Dépens	23

ORDONNANCES

57	Pouvoirs de la Régie	23
58	Ordonnances	23
59	Prorogation du délai	23
60	Audience obligatoire	24
61	Portée des ordonnances	24
62	Modification des ordonnances	24
63	Ordonnances provisoires	24



64	Powers of the board and staff	25
65	Appointment of administrator for a public utility	25
66	Enforcement in the Supreme Court.....	26
67	Evidence of board orders and decisions.....	26
68	Offence and penalty	26

APPEALS

69	Leave to appeal to the Court of Appeal	27
70	Appeal procedure and costs.....	27
71	Effect of order or decision under appeal	27
72	Jurisdiction of the Court of Appeal.....	27
73	References to the Court of Appeal.....	28
74	Hearing and determination of appeals.....	28

MISCELLANEOUS

75	Expenditure of public money	28
76	Regulations	28
77	Existing franchises	29

PART 5

PUBLIC UTILITY COMPANIES

78	Application of this Part	30
79	Incorporation requirements	30
80	Reference to engineers or other experts.....	31
81	Incorporation of public utility companies.....	31
82	Existing companies	31
83	Power to pass bylaws.....	31
84	Annual report.....	32
85	Books open to inspection.....	32
86	Appointment of inspector	32
87	Power to construct and operate works	33
88	Meters and fittings	34
89	Laying mains and wires on streets	34
90	Company's rights regarding mains and pipes.....	34
91	Parts of buildings having different owners or tenants.....	35
92	Breaking up of passages	35
93	Compensation	35
94	Public safety.....	36
95	Limitation of powers of company	36
96	Privileges of other companies.....	36
97	Individual rights.....	36
98	Exemption from distress and seizure.....	37
99	Nonpayment of rates, etc.	37
100	Entry of premises by employees of company	37
101	Discontinuance of service	38
102	Expropriation	38
103	Powers and duties of arbitrators	39
104	Payment of award.....	39
105	Failure to appoint arbitrator.....	39
106	Duty of company to supply utility service	39

CONTRÔLE D'APPLICATION

64	Pouvoirs de la Régie et du personnel.....	25
65	Nomination d'un administrateur	25
66	Exécution à la Cour suprême.....	26
67	Preuve	26
68	Infraction et peine	26

APPELS

69	Demande d'appel à la Cour d'appel	27
70	Procédure et dépens	27
71	Effet de l'appel sur la décision ou l'ordonnance	27
72	Compétence de la Cour d'appel	27
73	Renvois.....	28
74	Audition et règlement des appels	28

DISPOSITIONS DIVERSES

75	Engagement de fonds publics.....	28
76	Règlements.....	28
77	Agréments existants	29

PARTIE 5

SOCIÉTÉS DE SERVICE PUBLIC

78	Champ d'application de la présente partie	30
79	Dispositions obligatoires	30
80	Renvoi à des ingénieurs ou autres experts	31
81	Constitution en personne morale	31
82	Sociétés existantes.....	31
83	Adoption de règlements administratifs.....	31
84	Rapport annuel.....	32
85	Accès aux livres	32
86	Nomination d'un inspecteur	32
87	Pouvoir de construire et d'exploiter des ouvrages.....	33
88	Compteurs et accessoires.....	34
89	Installation de canalisations.....	34
90	Droits de la société relativement aux canalisations.....	34
91	Parties de bâtiments ayant différents propriétaires ou locataires	35
92	Rupture de passages.....	35
93	Indemnisation	35
94	Sécurité publique.....	36
95	Restriction aux pouvoirs des sociétés.....	36
96	Privilèges des autres sociétés.....	36
97	Droits individuels	36
98	Insaisissabilité	37
99	Non-paiement.....	37
100	Droit d'entrée du personnel	37
101	Interruption du service	38
102	Expropriation	38
103	Attributions des arbitres	39



104	Paiement de l'indemnité.....	39
105	Défaut de nommer un arbitre.....	39
106	Obligation des sociétés.....	39





PUBLIC UTILITIES ACT

1 Interpretation

(1) In this Act,

“**board**” means the Yukon Utilities Board established by section 2; « *Régie* »

“**compensation**” means a rate, remuneration, gain, or reward of any kind paid, payable, promised, demanded, received, or expected directly or indirectly by a public utility, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it; « *redevance* »

“**costs**” includes fees, counsel fees, and expenses; « *dépens* »

“**customer**” refers to a purchaser of electricity; « *client* »

“**excluded undertaking**” means a prescribed undertaking or an undertaking that consists only of

- (a) generation and distribution by a person of electricity, if
 - (i) the electricity is consumed only by the person, their employees or their tenants, and
 - (ii) if the electricity is generated on one property and consumed on another
 - (A) the electricity is carried between the properties by a transmission or distribution line that the person owns and operates, and

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

1 Définitions

(1) Les définitions qui suivent s'appliquent à la présente loi.

« **audience publique** » Audience pour laquelle un avis public a été donné, qui est ouverte au public et à laquelle peut être entendue la personne dont la Régie décide qu'elle est un intéressé. “*public hearing*”

« **client** » Acheteur d'électricité. “*customer*”

« **dépens** » S'entend notamment des frais et honoraires d'avocat. “*costs*”

« **entreprise de service public** » ou « **entreprise** » S'entend d'une personne, à moins qu'elle n'agisse dans une entreprise exclue, qui remplit l'une des conditions suivantes :

- a) au Yukon et pour une contrepartie, elle génère, produit, emmagasine, achemine, vend, livre ou fournit de l'électricité ou du gaz;
- b) elle est propriétaire d'équipements ou d'installations qui sont utilisés pour faire toute chose indiquée à l'alinéa a). “*public utility*”

« **entreprise exclue** » S'entend d'une entreprise visée par règlement ou d'une entreprise qui limite ses activités à l'un des secteurs d'activités suivants :

- a) la production et la distribution d'électricité par une personne, lorsque les conditions suivantes s'appliquent :
 - (i) l'électricité est consommée seulement par cette personne, ses employés ou ses locataires,
 - (ii) lorsque l'électricité est produite sur une

(B) the resulting electrical system

- (I) is connected with the facilities neither of a public utility nor of any other customer, and
- (II) does not duplicate any existing or planned facility of a public utility,

(b) engagement in the petroleum industry or in the well-head production of oil, natural gas, or other natural petroleum substances, or

(c) the sale or delivery of gas otherwise than by a pipeline; « *entreprise exclue* »

“**expenses**” includes expenses of the board; « *frais* »

“**gas**” means methane and propane; « *gaz* »

“**member**” means a member of the board; « *membre* »

“**methane**” means, in addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide; « *méthane* »

“**propane**” means, in addition to its normal scientific meaning, a mixture mainly of propane which ordinarily may contain some ethane or butanes; « *propane* »

“**public hearing**” means a hearing of which public notice is given, which is open to the public, and at which any person the board determines has an interest in the matter may be heard; « *audience publique* »

“**public utility**” means a person who, otherwise than in an excluded undertaking

- (a) in the Yukon, for consideration, produces, generates, stores, transmits, sells, delivers or furnishes electricity or gas, or
- (b) owns equipment or facilities that are used to do anything described in paragraph (a); « *entreprise de service public* » or « *entreprise* »

“**rate**” includes a general, individual, or joint rate, fare, toll, charge, rental, or other compensation charged or chargeable by a public utility, any rule, regulation, practice, measurement, classification, or contract of a public utility relating to a rate, and any schedule or tariff respecting a rate; « *taux* »

“**service**” includes the use and accommodation

propriété et consommée sur une autre

(A) l'électricité est transportée entre les propriétés par des lignes de transmission ou de distribution dont cette personne est le propriétaire-exploitant,

(B) le système électrique qui en découle :

- (I) n'est pas relié à une entreprise de service public ou à tout autre client,
- (II) ne fait pas double emploi avec les établissements existants ou à venir d'une entreprise de service public;

b) la participation à l'industrie des hydrocarbures ou à l'extraction à la tête de puits de pétrole, de gaz naturel ou d'autres hydrocarbures naturels;

c) la vente ou la livraison du gaz autrement que par un pipeline. “*excluded undertaking*”

« **frais** » S'entend des frais de la Régie. “*expenses*”

« **gaz** » Le méthane et le propane. “*gas*”

« **membre** » Membre de la Régie. “*member*”

« **méthane** » S'entend, en plus de son acception scientifique courante, d'un mélange composé principalement de méthane et pouvant contenir de l'éthane, de l'azote, de l'hélium ou du bioxide de carbone. “*methane*”

« **propane** » S'entend, en plus de son acception scientifique courante, d'un mélange composé principalement de propane et pouvant contenir de l'éthane, ou des butanes. “*propane*”

« **Régie** » La Régie des entreprises de service public du Yukon constituée par l'article 2. “*board*”

« **redevance** » Toute contrepartie payée, payable, promise, demandée, reçue ou attendue — directement ou indirectement — par une entreprise de service public; y sont assimilés la promesse ou l'engagement par une entreprise de service public d'offrir un service en contrepartie d'une proposition ou d'un contrat visant l'aliénation d'un bien-fonds ou d'intérêts sur celui-ci, ou comme stipulation d'une telle proposition ou d'un tel contrat. “*compensation*”

« **service** » Y sont assimilés l'usage et les locaux, les



provided and a product or commodity furnished by a public utility, and also the plant, equipment, apparatus, appliances, property, and facilities employed by or in connection with a public utility in providing service or in furnishing a product or commodity for the purposes in which the public utility is engaged. « service »

produits ou marchandises fournis par une entreprise de service public, ainsi que les usines, équipements, appareils, biens et installations qu'elle utilise relativement à la fourniture du service ou des produits ou marchandises dans la réalisation de l'activité de l'entreprise de service public. "service"

« **taux** » Redevance — générale, individuelle ou conjointe — qu'exige ou que peut exiger une entreprise de service public; la présente définition vise également les règles, règlements, pratiques, mesures, catégories, classes ou contrats y afférents, ainsi que les barèmes et tarifs correspondants. "rate"

(2) In this section, a reference to a person includes any lessee, trustee, receiver or liquidator of the person.

[S.Y. 2014, c.3, s.2] [S.Y. 2002, c. 186, s. 1]

(2) Au présent article, le terme « personne » vise également le preneur, le syndic, le séquestre ou le liquidateur de cette personne.

[L.Y. 2014, ch. 3, art. 2] [L.Y. 2002, ch. 186, art. 1]

PART 1

YUKON UTILITIES BOARD

2 Yukon Utilities Board

(1) The Yukon Utilities Board is established, composed of not fewer than three nor more than five persons appointed by the Minister.

(2) The board is responsible to the Minister for the administration of this Act.

(3) For the purpose of carrying out the duties and exercising the powers imposed or conferred on it under this Act, the board may enter into contracts with the Government of the Yukon.

[S.Y. 2002, c. 186, s. 2]

3 Term of office

(1) The term of office for which a member may be appointed is three years.

(2) A member is eligible for re-appointment on the expiration of their term of office.

[S.Y. 2002, c. 186, s. 3]

4 Substitute members

(1) The Minister may appoint a substitute member to act in the place of a member who is for any reason unable to perform their duties.

PARTIE 1

RÉGIE DES ENTREPRISES DE SERVICE PUBLIC

2 Constitution

(1) Est constituée la Régie des entreprises de service public du Yukon composée de trois à cinq membres nommés par le ministre.

(2) La Régie est responsable de l'application de la présente loi. À ce titre, elle relève du ministre.

(3) Aux fins de l'exécution de ses obligations et de l'exercice de ses pouvoirs qui lui sont imposés ou attribués en vertu de la présente loi, la Régie peut conclure des contrats avec le gouvernement du Yukon.

[L.Y. 2002, ch. 186, art. 2]

3 Mandat

(1) Le mandat des membres est de trois ans.

(2) Le mandat des membres est renouvelable.

[L.Y. 2002, ch. 186, art. 3]

4 Suppléance

(1) Le ministre peut nommer un suppléant pour remplacer le membre incapable d'agir.

(2) When a substitute member is appointed under subsection (1), the substitute member may attend all meetings of the board even though there is no vacancy in the permanent membership, but shall not vote unless one of the permanent members is absent.

[S.Y. 2002, c. 186, s. 4]

5 Expenses of members

A member may be paid transportation, accommodation, and living expenses incurred in connection with the performance of their duties as a member of the board away from their ordinary place of residence but, except as otherwise provided by the regulations, the payment of those expenses shall conform as nearly as possible in all respects to the payment of those expenses for members of the public service of the Yukon.

[S.Y. 2002, c. 186, s. 5]

6 Chair and vice-chair

(1) The Minister shall appoint one of the members to be the chair and another to be the vice-chair.

(2) The chair is the chief executive officer of the board, and shall

- (a) supervise and direct the work of the board; and
- (b) preside at sittings of the board.

(3) If the chair is unable at any time for any reason to exercise the powers or perform the duties of office, the vice-chair may act in place of the chair.

[S.Y. 2002, c. 186, s. 6]

7 Board meetings

(1) The board shall meet at the call of the chair, who shall convene any meetings necessary for the conduct of the business of the board.

(2) Despite subsection (1), the board shall meet at least twice a year.

[S.Y. 2002, c. 186, s. 7]

8 Decisions of the board

(1) A majority of the members is a quorum, but no quorum exists unless the chair or vice-chair is present.

(2) Le suppléant peut assister aux réunions de la Régie, même s'il n'y a pas de vacance en son sein, mais il ne peut voter qu'en l'absence d'un membre régulier.

[L.Y. 2002, ch. 186, art. 4]

5 Frais

Les membres ont droit aux frais de déplacement et de séjour entraînés pour l'accomplissement de leurs fonctions hors de leur lieu ordinaire de résidence; sauf disposition contraire des règlements, le remboursement de ces frais se conforme autant que possible au remboursement de frais semblables aux fonctionnaires du Yukon.

[L.Y. 2002, ch. 186, art. 5]

6 Président et vice-président

(1) Le ministre choisit parmi les membres le président et le vice-président.

(2) Le président est le premier dirigeant de la Régie; à ce titre, il en assure la direction et préside ses réunions.

(3) En cas d'empêchement du président, le vice-président assume la présidence.

[L.Y. 2002, ch. 186, art. 6]

7 Réunions de la Régie

(1) La Régie se réunit à l'initiative du président; celui-ci convoque les réunions nécessaires à la conduite de ses activités.

(2) La Régie doit toutefois se réunir au moins deux fois l'an.

[L.Y. 2002, ch. 186, art. 7]

8 Décisions de la Régie

(1) La majorité des membres constitue le quorum, le président ou le vice-président devant être présent.



(2) Subject to subsection (1), a decision of a majority of the members present at a meeting of the board is a decision of the board, but in the event of an evenly divided opinion between members including the chair, the matter shall be decided in accordance with the vote of the chair.

[S.Y. 2002, c. 186, s. 8]

9 Vacancies in the membership of the board

A vacancy in the membership reduces the number of members required for a quorum and, subject to section 8, does not impair the right of the remaining members to act.

[S.Y. 2002, c. 186, s. 9]

10 Rules of the board

(1) Subject to this Act, the board may by order make rules respecting

- (a) the conduct of its meetings and business;
- (b) the notices authorized or required to be given under this Act;
- (c) the records to be kept in respect of its business, including the custody, preservation, and provision of access to those records;
- (d) the procedure for making applications and representations to the board;
- (e) the conduct of hearings by or before the board;
- (f) the filing and investigation of complaints, including the information to be provided in support of complaints; and
- (g) generally, the procedures of the board and any other matter that reasonably is necessary for the effective and orderly conduct of the business of the board.

(2) Orders under this section shall be published in the *Yukon Gazette*.

[S.Y. 2002, c. 186, s. 10]

11 Conflict of interest

(1) If a member has a direct or indirect personal interest in a matter or a corporation under review by

(2) Sous réserve du paragraphe (1), la décision de la majorité des membres présents à une réunion de la Régie vaut décision de la Régie; en cas de partage, le président a voix prépondérante.

[L.Y. 2002, ch. 186, art. 8]

9 Vacance

Les vacances réduisent le nombre de membres requis pour le quorum et, sous réserve de l'article 8, n'entravent pas son fonctionnement.

[L.Y. 2002, ch. 186, art. 9]

10 Règles

(1) Sous réserve des autres dispositions de la présente loi, la Régie peut, par ordonnance, établir des règles concernant :

- a) la tenue de ses réunions et la conduite de ses activités;
- b) les avis à donner en application de la présente loi;
- c) les livres à tenir relativement à ses activités, y compris la garde, la conservation de ceux-ci et l'accès à ceux-ci;
- d) la procédure applicable à la présentation des demandes et au dépôt des observations faites à la Régie;
- e) la conduite des audiences par elle ou devant elle;
- f) le dépôt de plaintes, y compris les renseignements à donner au soutien de celles-ci, et les enquêtes y afférentes;
- g) de façon générale, sa procédure et toute autre question qui, d'une manière raisonnable, est nécessaire à la bonne conduite de ses activités.

(2) Les ordonnances visées au présent article sont publiées dans la *Gazette du Yukon*.

[L.Y. 2002, ch. 186, art. 10]

11 Conflit d'intérêts

(1) Les membres qui ont un intérêt personnel même indirect dans une affaire ou une personne morale



the board, that member shall refrain from participating in any way in the review of the matter or corporation by the board.

(2) A member shall not, directly or indirectly,

- (a) hold or acquire a beneficial interest in any share or other security of a corporation or other person subject to regulation under this Act;
- (b) have a significant beneficial interest in all or part of any article or process that is required or used by a corporation or other person referred to in paragraph (a) for the purpose of its equipment or service; or
- (c) have a significant beneficial interest in a contract for the construction of works or the furnishing of a service for or by a corporation or other person referred to in paragraph (a).

(3) A member in whom a beneficial interest referred to in subsection (2) is or becomes vested shall, within three months after the member's appointment or acquisition of the property, as the case may be, divest themselves of the interest.

(4) The use or purchase for personal or domestic purposes of heat, light, power, electricity, or gas or service from a corporation or other person subject to regulation under this Act is not a contravention of this section and does not disqualify a member from acting in any matter affecting the corporation or other person.

[S.Y. 2002, c. 186, s. 11]

12 Confidentiality of board information

(1) Every member and every official of the board, and every person involved in the administration of this Act, shall keep confidential from all other persons all information acquired by them in confidence in the course of their duties, except insofar as disclosure is necessary for the administration of this Act or the board authorizes the release of the information.

faisant l'objet d'une enquête par la Régie sont tenus de s'abstenir d'y participer.

(2) Les membres ne peuvent, même indirectement :

- a) détenir ou acquérir un intérêt à titre de bénéficiaire dans une action ou autre titre d'une personne morale ou autre assujettie à la réglementation sous le régime de la présente loi;
- b) avoir un intérêt important à titre de bénéficiaire dans tout ou partie d'un bien ou procédé qui est requis ou utilisé par une personne morale ou autre mentionnée à l'alinéa a) aux fins de son équipement ou de son service;
- c) avoir un intérêt important à titre de bénéficiaire dans un contrat de construction d'ouvrage ou de fourniture de service par ou pour une personne morale ou autre mentionnée à l'alinéa a).

(3) Le membre qui devient investi d'un tel intérêt est tenu de s'en départir dans les trois mois de sa nomination ou de l'acquisition du bien.

(4) L'utilisation ou l'achat à des fins personnelles ou domestiques de chauffage, d'éclairage, d'électricité ou de gaz ou d'un service d'une personne morale ou autre assujettie à la réglementation sous le régime de la présente loi ne constitue pas une violation du présent article et n'a pas pour effet d'empêcher un membre d'agir dans les affaires visant la personne morale ou cette autre personne.

[L.Y. 2002, ch. 186, art. 11]

12 Confidentialité

(1) Les membres et le personnel de la Régie ainsi que quiconque œuvre à l'application de la présente loi sont tenus à la confidentialité pour tous les renseignements portés à leur connaissance à titre confidentiel dans le cadre de leurs fonctions, sauf si la communication est nécessaire à l'application de la présente loi ou si la Régie en autorise la communication.



(2) No person referred to in subsection (1) shall be required to testify in a civil action to which the board is not a party about information obtained by the person in the discharge of their duty.

[S.Y. 2002, c. 186, s. 12]

13 Board staff and records

(1) The board may, despite the *Public Service Act*, make provision for a secretary to the board and for other administrative support services.

(2) The secretary shall

- (a) keep a record of the proceedings of the board;
- (b) ensure that copies of every rule and order of the board are filed in the records of the board; and
- (c) carry out the instructions and directions of the board under this Act or the regulations respecting the secretary's duties or office.

(3) On the application of any person who pays the prescribed fee, the secretary shall give that person a certified copy of any rule or order of the board, or report of the board under section 19.

(4) The board may appoint an acting secretary in the absence of the secretary.

(5) The board may use any premises it considers necessary from time to time for its efficient operation.

[S.Y. 2002, c. 186, s. 13]

14 Technical assistance

The board may from time to time engage one or more persons having special, technical, or other knowledge to inquire into and report to it on any matter arising in connection with its business.

[S.Y. 2002, c. 186, s. 14]

15 Inquiry by board member

(1) The board or the chair may authorize one or more of the members to inquire into and report to the board on any question or matter arising in connection with the business of the board.

(2) Les personnes mentionnées au paragraphe (1) ne peuvent être tenues de témoigner dans une action civile à laquelle la Régie n'est pas partie relativement à des renseignements obtenus dans le cadre de leurs fonctions.

[L.Y. 2002, ch. 186, art. 12]

13 Personnel et livres

(1) Malgré la *Loi sur la fonction publique*, la Régie peut prévoir la nomination d'un secrétaire et du personnel de soutien.

(2) Le secrétaire :

- a) tient le relevé des délibérations de la Régie;
- b) verse aux livres de la Régie copie de ses règles et ordonnances;
- c) met en œuvre les instructions et directives de la Régie données sous le régime de la présente loi ou des règlements relativement à ses attributions.

(3) Sur demande de quiconque paie les droits prescrits, le secrétaire est tenu de lui remettre une copie certifiée de toute règle ou ordonnance de la Régie ou d'un rapport fait en application de l'article 19.

(4) La Régie peut nommer un secrétaire intérimaire en l'absence du titulaire.

(5) La Régie peut utiliser tout lieu dont elle a besoin, selon elle, pour son fonctionnement efficace.

[L.Y. 2002, ch. 186, art. 13]

14 Expertise

La Régie peut, le cas échéant, retenir les services d'un ou plusieurs experts en vue de faire enquête et rapport sur tout aspect relatif à ses activités.

[L.Y. 2002, ch. 186, art. 14]

15 Enquête par un membre

(1) La Régie ou le président peut autoriser un ou plusieurs membres à faire enquête et rapport sur toute question liée à ses activités.

(2) A member authorized pursuant to this section to report to the board on a question has and may exercise all the powers of the board for the purpose of taking evidence or acquiring the necessary information for the purposes of their report.

(3) The report of a member under this section may be adopted as an order of the board or otherwise dealt with as the board considers proper.

[S.Y. 2002, c. 186, s. 15]

16 Use of public service by the board

(1) Subject to subsection (2), for the purpose of carrying out the duties and exercising the powers imposed or conferred on it under this Act, the board may avail itself of the services of any officer or employee of any board, commission, agency, or department of the Government of the Yukon.

(2) Every officer or employee of a board, commission, agency, or department of the Government of the Yukon shall give to the board whatever service, assistance, and information they are able to give and the board requires, subject to the approval of the Minister in charge of the administration of the service in which the officer or employee is employed.

[S.Y. 2002, c. 186, s. 16]

17 Directions from the Commissioner in Executive Council

(1) Despite any other provision of this Act, the board shall comply with any general or special direction of the Commissioner in Executive Council with respect to the exercise of the powers and functions of the board.

(2) A direction under subsection (1) is a regulation within the meaning of the *Regulations Act*.

(3) The board may request a review of a direction under subsection (1), and on receipt of such a request from the board by the Minister, the Commissioner in Executive Council may

- (a) suspend or continue the operation of the direction until the completion of a review; or
- (b) confirm, vary, or revoke the direction.

(2) Ce membre dispose de tous les pouvoirs de la Régie en matière de preuve ou pour recueillir les renseignements nécessaires à l'établissement de son rapport.

(3) Le rapport peut être adopté au même titre qu'une ordonnance de la Régie ou être traité selon ce que celle-ci estime indiqué.

[L.Y. 2002, ch. 186, art. 15]

16 Utilisation des fonctionnaires

(1) Sous réserve du paragraphe (2), la Régie peut, pour l'exercice de ses fonctions et de ses pouvoirs, recourir aux services des agents ou fonctionnaires de tout organisme ou ministère du gouvernement du Yukon.

(2) Ces fonctionnaires sont tenus de donner à la Régie les services, l'aide et les renseignements qu'ils peuvent donner et que la Régie leur demande, sous réserve de l'agrément du ministre responsable de l'administration du service dont ils font partie.

[L.Y. 2002, ch. 186, art. 16]

17 Instructions du commissaire en conseil exécutif

(1) Malgré les autres dispositions de la présente loi, la Régie est tenue de se conformer aux instructions générales ou spéciales du commissaire en conseil exécutif relativement à l'exercice de ses pouvoirs et fonctions.

(2) L'instruction est assimilée à un règlement pour l'application de la *Loi sur les règlements*.

(3) La Régie peut demander la révision d'une instruction et, sur réception d'une telle demande par le ministre, le commissaire en conseil exécutif peut suspendre ou proroger l'effet de l'instruction jusqu'à la fin de la révision ou confirmer, modifier ou annuler l'instruction.



(4) The board may, in respect of any matter arising in connection with the business of the board, transmit to the Minister a request that the Commissioner in Executive Council issue a direction under this section.

(5) If a direction is issued under this section during the course of any matter under consideration by the board, any party to the matter

- (a) may be granted any adjournment the board considers necessary to deal with any change in circumstances; and
- (b) may be awarded any costs the board considers just and fair in the circumstances.

[S.Y. 2002, c. 186, s. 17]

18 Investigations and duties of the board

(1) The board shall conduct any investigations, make any reports and perform any duties, in addition to the duties assigned to it by this Act, that the Minister may request.

(2) If the Minister requests a report from the board on a matter of general public policy, the board may seek any representations from the public or from interested persons or organizations that the board considers appropriate and, subject to section 50, may hold hearings.

(3) A report requested pursuant to subsection (1) shall be delivered within any time specified by the Minister.

(4) A report under this section is not binding on the Executive Council.

[S.Y. 2002, c. 186, s. 18]

19 Annual report of the board

The board shall make a report to the Minister not later than June 30 in each year on the activities and affairs of the board during the year ending on March 31 of that year.

[S.Y. 2002, c. 186, s. 19]

(4) La Régie peut, relativement à toute affaire liée à ses activités, demander au ministre de lui donner des instructions au titre du présent article.

(5) Si une instruction est donnée en application du présent article dans le cadre d'une affaire dont la Régie est saisie, toute partie peut bénéficier d'un ajournement que la Régie estime nécessaire pour lui permettre de répondre à tout changement de circonstances et avoir droit aux frais que celle-ci estime justes dans les circonstances.

[L.Y. 2002, ch. 186, art. 17]

18 Enquêtes et obligations de la Régie

(1) La Régie exécute les fonctions — y compris la tenue d'enquêtes et la préparation de rapports — que le ministre peut lui demander en plus de celles qui lui sont assignées par la présente loi.

(2) Si le ministre demande un rapport à la Régie sur une affaire d'intérêt public, celle-ci peut, selon ce qu'elle estime indiqué, demander l'avis du public ou des personnes ou organismes intéressés, et, sous réserve de l'article 50, tenir des audiences.

(3) Le rapport visé au paragraphe (1) est à remettre dans le délai que fixe le ministre.

(4) Le rapport visé au présent article ne lie pas le Conseil exécutif.

[L.Y. 2002, ch. 186, art. 18]

19 Rapport annuel

Au plus tard le 30 juin, la Régie remet au ministre un rapport sur ses activités pour l'exercice terminé le 31 mars précédant.

[L.Y. 2002, ch. 186, art. 19]

PART 2**REGULATION OF PUBLIC UTILITIES****20 Franchise requirement**

No public utility shall operate in the Yukon unless it has been granted a franchise by the Commissioner in Executive Council.

[S.Y. 2002, c. 186, s. 20]

21 Grant of franchise

(1) The Commissioner in Executive Council may, with the approval of the board and subject to any terms and conditions that the board may recommend,

- (a) grant a franchise to a public utility; or
- (b) renew, alter, or revoke a franchise granted to a public utility or deemed by section 77 to have been granted.

(2) The board may give its approval for the purposes of subsection (1) if, after hearing representations from, or with the consent of, any persons that the board considers appropriate, the board determines that

- (a) the franchise is necessary and proper for the public convenience and properly conserves the public interests;
- (b) the scheme proposed is reasonable and sufficient having regard to the general circumstances; and
- (c) having regard to the availability of any other source of supply in the area to be served and to any other circumstances, the granting of the franchise is to the general benefit of any area directly or indirectly affected by it.

(3) The board may, in approving the grant, renewal, or alteration of a franchise, recommend the imposition of any terms or conditions as to construction, equipment, maintenance, service, or operation that, in the opinion of the board, the public convenience or interest reasonably requires.

[S.Y. 2002, c. 186, s. 21]

PARTIE 2**RÉGLEMENTATION DES ENTREPRISES DE SERVICE PUBLIC****20 Agrément**

Aucune entreprise de service public ne peut être exploitée au Yukon sans l'agrément du commissaire en conseil exécutif.

[L.Y. 2002, ch. 186, art. 20]

21 Octroi de l'agrément

(1) Le commissaire en conseil exécutif peut, sur approbation de la Régie et sous réserve des modalités et des conditions que celle-ci recommande, agréer une entreprise de service public ou renouveler, modifier ou révoquer l'agrément qui lui a été donné ou qui est réputé lui avoir été donné au titre de l'article 77.

(2) La Régie peut donner son approbation aux fins du paragraphe (1) si, après avoir entendu les personnes qu'elle estime indiquées ou sur consentement de celles-ci, elle conclut que :

- a) l'agrément est d'intérêt public;
- b) le plan proposé est acceptable compte tenu des circonstances générales;
- c) compte tenu de la disponibilité de toute autre source d'approvisionnement dans la région à desservir et des autres circonstances, l'agrément profitera généralement à la région directement ou indirectement concernée.

(3) La Régie peut assortir la délivrance, le renouvellement ou la modification de l'agrément des conditions ou modalités qu'elle estime nécessaires à l'intérêt public en matière de construction, d'équipement, d'entretien, de service ou d'exploitation.

[L.Y. 2002, ch. 186, art. 21]



22 Interim permission

Despite section 20, if in respect of any place no franchise has been granted, the board may recommend to the Commissioner in Executive Council that an interim permission be granted to a person to operate a public utility, subject to any terms and conditions that the board may recommend.

[S.Y. 2002, c. 186, s. 22]

23 Books and records of public utilities

(1) Every public utility shall

- (a) keep any books, records, and accounts that afford a reasonable understanding of the conduct of its business; and
- (b) maintain depreciation, amortization, and depletion accounts in accordance with any rates and methods that the board directs.

(2) A public utility shall not change its accounting practices under subsection (1) except with the prior approval of the board.

[S.Y. 2002, c. 186, s. 23]

24 Review by the board

(1) The board may review the affairs, earnings, and accounts of any public utility.

(2) A person whose interest, in the opinion of the board, is affected or likely to be affected by the result of a review is entitled, on payment of reasonable costs, to obtain from the board the result of the review, including all information in the board's possession in respect of the earnings of the public utility.

[S.Y. 2002, c. 186, s. 24]

25 Reports to the board

(1) Every public utility shall, within three months after the end of each of its financial years, file with the board

- (a) a statement showing its rates;
- (b) financial statements for the financial year in the form and verified in the manner directed by the board; and
- (c) a statement setting forth the name, address, and duties of every officer and every director of the public utility.

22 Permission temporaire

Malgré l'article 20, si, relativement à un lieu donné, aucun agrément n'a été délivré, la Régie peut recommander au commissaire en conseil exécutif la délivrance, selon les modalités et aux conditions qu'elle recommande, d'une permission temporaire pour l'exploitation d'une entreprise de service public.

[L.Y. 2002, ch. 186, art. 22]

23 Livres et registres des entreprises

(1) Les entreprises de service public sont tenues de tenir les livres, registres et comptes suffisants pour permettre de comprendre raisonnablement la conduite de leurs activités et de maintenir des comptes de dépréciation, d'amortissement et d'épuisement conformes aux taux et méthodes que la Régie prescrit.

(2) Une entreprise de service public ne peut modifier ses pratiques comptables sans l'approbation préalable de la Régie.

[L.Y. 2002, ch. 186, art. 23]

24 Examen par la Régie

(1) La Régie peut examiner les affaires, les revenus et les comptes des entreprises de service public.

(2) La personne dont l'intérêt est, selon la Régie, visé ou risque d'être visé à la suite de l'examen a droit, sur paiement des frais raisonnables, de se faire communiquer le résultat de l'examen, y compris les renseignements qui sont en la possession de la Régie relativement au revenu de l'entreprise.

[L.Y. 2002, ch. 186, art. 24]

25 Rapport à la Régie

(1) Les entreprises de service public sont tenues de déposer auprès de la Régie, dans les trois mois de la fin de leur exercice :

- a) un énoncé de leurs taux;
- b) le bilan pour l'exercice en la forme et après la vérification que la Régie prescrit;
- c) une déclaration portant les noms, adresses et fonctions des dirigeants et administrateurs de l'entreprise.

(2) A public utility shall notify the board within 10 days of every change in its officers or directors.

[S.Y. 2002, c. 186, s. 25]

26 Maintenance of property and equipment

Every public utility shall maintain its property and equipment in such a condition as to provide safe, adequate, and proper service.

[S.Y. 2002, c. 186, s. 26]

27 Board orders

The board may make orders

- (a) setting rates of a public utility;
- (b) prohibiting or limiting any proposed rate change;
- (c) setting proper and adequate rates and methods of depreciation, amortization, or depletion in respect of the property of any public utility;
- (d) setting just and reasonable standards, classifications, regulations, practices, measurements, or services to be observed, provided, or followed by a public utility;
- (e) determining the areas to which a public utility shall provide service, and requiring the public utility to establish, construct, maintain, and operate any reasonable expansion of its existing services; and
- (f) determining the conditions that may be imposed by a public utility to establish, construct, maintain, or operate an expansion of its existing services.

[S.Y. 2002, c. 186, s. 27]

(2) Les entreprises de service public sont tenues de communiquer dans les 10 jours tout changement parmi leurs dirigeants ou administrateurs.

[L.Y. 2002, ch. 186, art. 25]

26 Entretien

Les entreprises de service public sont tenues de conserver leurs biens et équipements dans un état qui leur permet d'offrir un service sûr, suffisant et efficace.

[L.Y. 2002, ch. 186, art. 26]

27 Ordonnances

La Régie peut, par ordonnance :

- a) fixer les taux d'une entreprise de service public;
- b) interdire ou restreindre tout projet de modification des taux;
- c) fixer un taux acceptable et des méthodes de dépréciation, d'amortissement ou d'épuisement pour les biens d'une entreprise de service public;
- d) fixer des normes raisonnables, des catégories, règlements, pratiques, mesures ou services à observer, à offrir ou à suivre par une entreprise de service public;
- e) déterminer les zones où une entreprise de service public devra offrir le service et exiger qu'elle établisse, construise, entretienne et exploite toute extension raisonnable de ses services existants;
- f) fixer les conditions à imposer par l'entreprise de service public pour établir, construire, maintenir ou exploiter une telle extension de ses services existants.

[L.Y. 2002, ch. 186, art. 27]



28 Rate changes

(1) No public utility shall charge any rate for the supply of the service for which it is franchised other than the rate set by the board pursuant to this Act unless, 90 days before it proposes to charge a different rate,

- (a) a statement showing the new rate is filed with the board; and
- (b) a notice showing the new rate is sent by mail or delivered to each municipality in which the service is provided and to the Minister.

(2) No public utility shall begin to charge a new rate except on receipt from the board of an order or interim order authorizing it to do so.

[S.Y. 2002, c. 186, s. 28]

29 Factors affecting rates

In setting rates that a public utility is permitted to charge,

- (a) the board may consider the revenues and costs of the public utility in the financial year in which the proceedings for setting the rates and charges began or in any period immediately following, without considering the allocation of those revenues and costs to any part of that period;
- (b) the board may give effect to that part of any excess of revenue received or deficiency incurred that is in the opinion of the board applicable to the whole of the financial year of the public utility in which the proceeding was initiated as the board considers just and reasonable;
- (c) the board may give effect to any part of any excess revenue received or deficiency incurred after the commencement of the proceeding as the board determines has been due to undue delay in the hearing and determining of the matter; and
- (d) the board shall by order approve the method by which and the period during which any excess revenue received or deficiency incurred is to be used or dealt with.

[S.Y. 2002, c. 186, s. 29]

28 Modifications des taux

(1) Une entreprise de service public ne peut exiger, pour la fourniture d'un service agréé, un taux autre que celui fixé par la Régie en application de la présente loi, à moins que 90 jours précédant la prise d'effet de la modification, une déclaration indiquant le nouveau taux ne soit déposée auprès de la Régie et qu'un avis mentionnant le nouveau taux ne soit expédié par la poste ou remis à chaque municipalité sur le territoire de laquelle le service est offert, ainsi qu'au ministre.

(2) Une entreprise ne peut exiger un nouveau taux sans avoir reçu de la Régie une ordonnance ou une ordonnance provisoire à cet effet.

[L.Y. 2002, ch. 186, art. 28]

29 Critères liés aux taux

Pour l'établissement des taux qu'une entreprise de service public est autorisée à exiger, la Régie :

- a) peut considérer les revenus et les dépenses de l'entreprise pour l'exercice au cours duquel la procédure d'établissement des taux et des charges est entamée ou pour la période qui suit, sans tenir compte de la ventilation de ces revenus et dépenses à toute partie de cette période;
- b) peut tenir compte de la partie de tout excédent ou déficit qu'elle estime applicable à la totalité de l'exercice au cours duquel la procédure est entamée, selon ce qu'elle estime juste et raisonnable;
- c) peut tenir compte de la partie de tout excédent ou déficit réalisé après le début de la procédure qu'elle conclut avoir été causé par un retard indu dans l'audition de l'affaire et son règlement;
- d) doit, par ordonnance, approuver la méthode de traitement des excédents ou des déficits et la période liée à ceux-ci.

[L.Y. 2002, ch. 186, art. 29]

30 Guidelines respecting cost increases

(1) The board, by order, may issue guidelines to be followed by any public utility that generates electricity by the use of petroleum products purchased pursuant to a contract under which provision is made for

- (a) the progressive increase in their cost to the public utility; or
- (b) the redetermination of their cost either by agreement of the parties or pursuant to arbitration.

(2) Guidelines under subsection (1) may make provision for establishing a new schedule of rates to be charged by the public utility occasioned by any change in the cost of petroleum products.

(3) Nothing in this section limits the jurisdiction of the board to set rates under section 27.

(4) This section applies, with any necessary changes, when a public utility purchases electrical power from a producer for distribution and sale to the public.

(5) When a public utility enters into a contract under which provision is made for any of the matters referred to in subsection (1) or (4), it shall file a copy of the contract with the board.

[S.Y. 2002, c. 186, s. 30]

31 Contracts setting rates

Any contract for the supply of a service to a person by a public utility that sets a fixed or variable rate either for a present or future supply of the service is deemed to include a clause under which the board has the jurisdiction, on application of one of the parties, to increase or reduce the rate to a rate that the board considers fair and reasonable.

[S.Y. 2002, c. 186, s. 31]

32 Rate base of public utilities

(1) The board, by order, shall determine a rate base for the property of a public utility used or required to be used to provide service to the public, and may include a rate base for property under construction, or constructed or acquired, and intended to be used in the future to provide service to the public.

30 Critères liés aux augmentations de frais

(1) La Régie peut, par ordonnance, imposer des lignes directrices à une entreprise de service public qui produit de l'électricité grâce à des produits pétroliers achetés dans le cadre d'un contrat qui en stipule l'augmentation progressive du coût à l'entreprise ou sa redétermination, soit par entente mutuelle des parties, soit à la suite d'un arbitrage.

(2) Ces lignes directrices peuvent prévoir l'établissement d'un nouveau barème de taux à exiger par l'entreprise de service public à la suite du changement du coût des produits pétroliers.

(3) Le présent article n'a pas pour effet de limiter la compétence de la Régie de fixer les taux en application de l'article 27.

(4) Le présent article s'applique, compte tenu des adaptations nécessaires, lorsqu'une entreprise de service public achète de l'électricité à un producteur pour distribution et vente au public.

(5) Quand une entreprise de service public conclut un contrat stipulant l'un ou l'autre des points mentionnés aux paragraphes (1) ou (4), elle en dépose copie auprès de la Régie.

[L.Y. 2002, ch. 186, art. 30]

31 Contrats stipulant les taux

Tout contrat de fourniture, pour l'immédiat ou dans l'avenir, de services à une personne par une entreprise de service public pour un taux fixe ou variable est réputé comporter une clause stipulant que la Régie a compétence, sur demande d'une des parties, pour augmenter ou réduire le taux selon ce qu'elle estime juste et raisonnable.

[L.Y. 2002, ch. 186, art. 31]

32 Taux de base des entreprises de service public

(1) La Régie fixe, par ordonnance, le taux de base pour les biens d'une entreprise de service public utilisés ou devant être utilisés à la fourniture du service au public et peut inclure un taux de base pour les biens en construction ou construits ou acquis et destinés à être utilisés dans l'avenir à cette fin.



(2) The board, by order, shall set a fair return on the rate base.

(3) In determining a rate base the board shall give due consideration to the cost of the property when first devoted to public utility use, to prudent acquisition cost less depreciation, amortization, or depletion, and to necessary working capital.

(4) In setting the fair return that the public utility is entitled to earn on the rate base, the board shall give due consideration to all those facts that in the opinion of the board are relevant.

(5) Despite the other provisions of this section, the board may adopt any just and reasonable basis for determining a method of calculating a fair return on property that is being constructed or that has been constructed or acquired but is not yet being used to provide service to the public.

[S.Y. 2002, c. 186, s. 32]

33 Service extensions

(1) The board shall not require a public utility to construct, maintain, or operate an extension of its existing services unless, in the judgment of the board,

- (a) the extension is reasonable and practical and will furnish sufficient business to justify the expense of its construction, maintenance, and operation; and
- (b) the financial position of the public utility reasonably warrants the capital expenditure required.

(2) The Commissioner in Executive Council may, by direction under section 17, instruct the board to require a public utility to construct, maintain, or operate an extension of its existing services despite subsection (1), but if the Commissioner in Executive Council does so the public utility is not required to construct, maintain, or operate the extension except on the agreement of the Commissioner in Executive Council

- (a) to pay any additional expenses incurred by the public utility that are not justified under paragraph (1)(a); and

(2) La Régie fixe, par ordonnance, un juste rendement sur le taux de base.

(3) Pour fixer le taux de base, la Régie tient compte du coût d'un bien au moment de son affectation à l'utilisation de l'entreprise, du coût d'acquisition raisonnable moins la dépréciation, l'amortissement ou l'épuisement, et du capital nécessaire.

(4) En établissant le rendement équitable auquel l'entreprise a droit sur le taux de base, la Régie tient compte de tous les facteurs qu'elle estime pertinents.

(5) Malgré les autres dispositions du présent article, la Régie peut adopter tout critère juste et raisonnable en vue de déterminer une méthode de calcul du rendement juste sur le bien en construction ou qui, étant construit ou acquis, n'est pas encore utilisé pour fournir un service au public.

[L.Y. 2002, ch. 186, art. 32]

33 Extension du service

(1) La Régie ne peut exiger d'une entreprise de service public qu'elle construise, entretienne ou exploite une extension de ses services existants, à moins qu'elle n'estime :

- a) que l'extension est raisonnable et pratique et offrira suffisamment d'affaires pour justifier les frais de sa construction, de son entretien et de son exploitation;
- b) que la situation financière de l'entreprise justifie l'immobilisation requise.

(2) Le commissaire en conseil exécutif peut, par instruction donnée au titre de l'article 17, ordonner à la Régie d'exiger d'une entreprise de service public qu'elle construise, entretienne ou exploite une extension de ses services existants, malgré le paragraphe (1), mais, le cas échéant, l'entreprise n'est pas tenue de construire, d'entretenir ou d'exploiter l'extension, sauf sur accord du commissaire en conseil exécutif :

- a) de payer les frais additionnels engagés par l'entreprise qui ne sont pas justifiés au titre de l'alinéa (1)a);

- (b) to underwrite any capital expenditure not reasonably warranted under paragraph (1)(b).

[S.Y. 2002, c. 186, s. 33]

34 Joint use of equipment

(1) When it is in the public interest or, as a means of saving expense, it is in the interest of public utilities or telecommunications companies that there be a joint use of poles, conduits, or equipment or other means of distribution, the board may, after notice to all parties concerned, in cases where it is practicable,

- (a) order the joint use;
- (b) declare the terms of the joint use; and
- (c) make any other orders for the convenient carrying out of the work and the operation of the services that use the poles or equipment.

(2) In this section, “**telecommunications**” means any transmission, emission, or reception of signs, signals, writings, images, sounds, data, message, or intelligence of any nature by wire, radio communications, cable, waves, or any electronic, electro-magnetic, or optical means, but does not include the transmission, emission, or reception of broadcasting that is a radiocommunication in which the transmissions are intended for direct reception by the general public, and “**telecommunications company**” means a company that provides any service that is provided principally through telecommunications.

(3) The board shall on the application of a public utility or telecommunications company adjudicate on any dispute arising out of the joint use of any poles, conduits, or equipment pursuant to this section or any prior arrangement between the parties, and may make any order after hearing the parties that may be required.

[S.Y. 2002, c. 186, s. 34]

35 Exemptions

The Minister may, by order, on the recommendation of the board, exempt a person from any provisions of this Part that the Minister may specify in the order.

[S.Y. 2002, c. 186, s. 35]

- b) d’assurer l’immobilisation qui n’est pas raisonnablement justifiée au titre de l’alinéa (1)b).

[L.Y. 2002, ch. 186, art. 33]

34 Utilisation conjointe d’équipements

(1) S’il est dans l’intérêt public ou, s’agissant d’épargner de l’argent, dans l’intérêt d’entreprises de service public ou de compagnies de télécommunication d’utiliser conjointement des poteaux, des canalisations ou de l’équipement, ou tout autre moyen de distribution, la Régie peut, après avis donné aux parties intéressées, ordonner l’utilisation conjointe, prononcer les conditions la régissant et prendre toute autre ordonnance pour la bonne réalisation des ouvrages et l’exploitation des services qui utilisent les poteaux ou l’équipement.

(2) Au présent article, « **télécommunication** » vise la transmission, l’émission ou la réception de signes, signaux, écrits, images, sons, données, messages de toute nature par fil, radiocommunication, câble, ondes ou tout moyen électronique, électromagnétique ou optique, mais ne vise pas la transmission, l’émission ou la réception d’une radiodiffusion qui est une radiocommunication dans laquelle la transmission est destinée à la réception par le grand public, et « **compagnie de télécommunication** » vise la compagnie qui fournit un service offert principalement via les télécommunications.

(3) Sur demande d’une entreprise de service public ou d’une compagnie de télécommunication, la Régie tranche tout différend découlant de l’utilisation conjointe au titre du présent article ou de toute entente antérieure entre les parties et rend toute ordonnance qu’elle estime nécessaire après audition de celles-ci.

[L.Y. 2002, ch. 186, art. 34]

35 Exemptions

Le ministre peut, par décret et sur recommandation de la Régie, exempter une personne de telles des dispositions de la présente partie qu’elle y précise.

[L.Y. 2002, ch. 186, art. 35]



PART 3 ENERGY PROJECTS

36 Interpretation

In this Part,

"energy operation certificate" means a certificate issued under this Part authorizing the holder of the certificate to operate a regulated project; *« certificat d'exploitation »*

"energy project" means

- (a) any plant, smelter, refinery, or other undertaking or facility designed to use, convert, or process an energy resource or coal,
- (b) a facility for the generation of electricity from the motion of wind or water, or the combustion of natural gas, oil, petroleum products, coal, or plant products or geothermal energy, or
- (c) an oil or natural gas transmission pipeline, including all associated structures, machinery, appliances, fixtures, and equipment, and storage and handling facilities; *« projet énergétique »*

"energy project certificate" means a certificate issued pursuant to this Part to construct a regulated project; *« certificat de construction »*

"energy resource" means natural gas, oil, and all other forms of petroleum and hydrocarbon, in gaseous or liquid state, and electricity; *« ressource énergétique »*

"regulated project" means any energy project that the Commissioner in Executive Council considers to be significant in the matter of any form of energy and, by order, designates as a regulated project. *« projet agréé »*

[S.Y. 2002, c. 186, s. 36]

37 Energy project certificate

No person shall construct a regulated project except in accordance with an energy project certificate.

[S.Y. 2002, c. 186, s. 37]

PARTIE 3 PROJETS ÉNERGÉTIQUES

36 Définitions

Les définitions qui suivent s'appliquent à la présente partie.

« certificat de construction » Certificat délivré en application de la présente partie en vue de la construction d'un projet agréé. *"energy project certificate"*

« certificat d'exploitation » Certificat délivré en application de la présente partie et autorisant son titulaire à exploiter un projet agréé. *"energy operation certificate"*

« projet agréé » Projet énergétique que le commissaire en conseil exécutif estime important sur le plan énergétique et désigne tel par décret. *"regulated project"*

« projet énergétique »

- a) Installation — usine, fonderie, raffinerie ou autre — conçue pour l'utilisation ou la transformation de l'énergie ou du charbon;
- b) installation destinée à la production d'électricité par le mouvement du vent ou de l'eau ou la combustion de gaz naturel, de pétrole, de produits pétroliers, de charbon ou de plantes ou d'énergie géothermique;
- c) pipeline de transmission de gaz ou de pétrole auquel sont assimilés les constructions, machineries, appareils, accessoires et autres équipements connexes, ainsi que les installations de stockage et de manutention. *"energy project"*

« ressource énergétique » Le gaz naturel, le pétrole et toute autre forme de pétrole et d'hydrocarbure, de forme gazeuse ou liquide, ainsi que l'électricité. *"energy resource"*

[L.Y. 2002, ch. 186, art. 36]

37 Certificat de construction

Il est interdit de construire un projet agréé, sauf conformément à un certificat de construction.

[L.Y. 2002, ch. 186, art. 37]



38 Energy operation certificate

No person shall operate a regulated project except in accordance with an energy operation certificate.

[S.Y. 2002, c. 186, s. 38]

39 Applications for certificates

An application for an energy project certificate or energy operation certificate shall be made to the Minister and shall contain the prescribed information.

[S.Y. 2002, c. 186, s. 39]

40 Review of applications

On receipt of an application, the Minister shall refer the application to the board for a review.

[S.Y. 2002, c. 186, s. 40]

41 Report and recommendations of the board

(1) On receipt of an application from the Minister under section 40, the board may, subject to subsection (2) and section 50, hold a public hearing in accordance with any terms of reference specified by the Minister, and on conclusion of the review the board shall submit a report and recommendations to the Minister.

(2) The board may, for the purpose of receiving information or evidence that the board considers is of a confidential character, exclude the public from a hearing under this section while it receives that information or evidence.

[S.Y. 2002, c. 186, s. 41]

42 Grant or refusal of applications

(1) On receipt of the report and recommendations of the board, the Minister, may

- (a) refuse the application; or
- (b) grant the application subject to any terms or conditions the Minister considers to be in the public interest.

(2) The conditions for an energy project certificate under paragraph (1)(b) may include any terms or conditions the Minister considers necessary to be included in an energy operation certificate for the project.

[S.Y. 2002, c. 186, s. 42]

38 Certificat d'exploitation

Il est interdit d'exploiter un projet agréé, sauf conformément à un certificat d'exploitation.

[L.Y. 2002, ch. 186, art. 38]

39 Demande de certificats

La demande de certificat de construction ou d'exploitation est déposée auprès du ministre avec les renseignements réglementaires.

[L.Y. 2002, ch. 186, art. 39]

40 Examen des demandes

Sur réception d'une demande, le ministre la remet à la Régie pour examen.

[L.Y. 2002, ch. 186, art. 40]

41 Rapport et recommandations de la Régie

(1) Sur réception de la demande remise à elle par le ministre en application de l'article 40, la Régie peut, sous réserve du paragraphe (2) et de l'article 50, tenir une audience publique conformément aux modalités précisées par celui-ci, et, à la fin de l'examen, elle lui remet un rapport et ses recommandations.

(2) Pour l'application du présent article, la Régie peut prononcer le huis clos pour recueillir des renseignements ou éléments de preuve qu'elle estime confidentiels.

[L.Y. 2002, ch. 186, art. 41]

42 Octroi ou refus

(1) Sur réception du rapport et des recommandations de la Régie, le ministre peut refuser la demande ou l'accorder sous réserve des modalités et des conditions qu'il estime d'intérêt public.

(2) Les conditions auxquelles un certificat de construction est assujéti peuvent comporter toutes les modalités et les conditions que le ministre estime nécessaires d'inclure dans un certificat d'exploitation pour le projet.

[L.Y. 2002, ch. 186, art. 42]



43 Report on energy project

(1) On completion of the construction of a regulated project for which an energy project certificate has been issued, the person to whom the certificate was issued shall submit a report to the Minister in accordance with the certificate and the regulations.

(2) On receipt of a report under subsection (1), and on being satisfied that the conditions of the energy project certificate have been substantially complied with, the Minister shall issue an energy operation certificate for the regulated project, and may include in the certificate the terms or conditions referred to in subsection 42(2).

[S.Y. 2002, c. 186, s. 43]

PART 4

ADMINISTRATION AND ENFORCEMENT

COMPLAINTS AND INVESTIGATIONS

44 Complaints

(1) Any person may file a complaint with the board respecting

- (a) the rates of a public utility;
- (b) a proposed rate change;
- (c) the manner in which a public utility provides service;
- (d) the areas to which a public utility provides service; or
- (e) the conditions imposed by a public utility to establish, construct, maintain, or operate an expansion of its service.

(2) A copy of every complaint filed with the board shall be served on the public utility to which it applies within the time set by the rules of the board.

[S.Y. 2002, c. 186, s. 44]

45 Action on complaints

(1) Subject to section 50, if a complaint is made to the board, the board has the power to determine, generally, whether any action on its part shall or shall not be taken.

(2) The board may decide not to deal with a complaint if it appears to the board that

43 Rapport sur un projet énergétique

(1) À la fin des travaux de construction d'un projet agréé ayant fait l'objet d'un certificat de construction, le titulaire est tenu de remettre un rapport au ministre conformément au certificat et aux règlements.

(2) Sur réception du rapport visé au paragraphe (1) et s'il est convaincu que les conditions du certificat de construction ont été pour l'essentiel remplies, le ministre délivre un certificat d'exploitation à l'égard du projet et peut l'assortir des modalités et des conditions mentionnées au paragraphe 42(2).

[L.Y. 2002, ch. 186, art. 43]

PARTIE 4

MISE EN ŒUVRE ET CONTRÔLE D'APPLICATION

PLAINTES ET ENQUÊTES

44 Plaintes

(1) Quiconque peut déposer une plainte à la Régie relativement :

- a) aux taux d'une entreprise de service public;
- b) à un projet de modification des taux;
- c) à la façon dont une entreprise de service public fournit son service;
- d) aux zones dans lesquelles une entreprise de service public fournit son service;
- e) aux conditions imposées par l'entreprise de service public pour établir, construire, entretenir ou exploiter une extension de son service.

(2) Un double de chaque plainte déposée à la Régie est signifié à l'entreprise visée dans le délai prévu par les règles de la Régie.

[L.Y. 2002, ch. 186, art. 44]

45 Suivi

(1) Sous réserve de l'article 50, la Régie saisie d'une plainte peut, de façon générale, décider des mesures à prendre pour y donner suite.

(2) La Régie peut décider de ne pas donner suite à une plainte, si elle est convaincue, selon le cas, que :



- (a) the complaint is one that could or should be more appropriately dealt with under another Act;
- (b) the subject matter of the complaint is trivial, frivolous, or vexatious;
- (c) the complaint is made in bad faith; or
- (d) the complaint is not within the jurisdiction of the board.

(3) The board may decide not to deal with a complaint if it is of the opinion that the facts on which the complaint is based occurred more than six months before the complaint was filed, unless the board is satisfied that the delay was incurred in good faith and no substantial prejudice will result to any person affected by the delay.

(4) If the board decides not to deal with a complaint, it shall advise the complainant in writing of the decision and the reasons for it.

[S.Y. 2002, c. 186, s. 45]

46 Investigation of complaints

Subject to section 45, the board shall, without undue delay, investigate every complaint.

[S.Y. 2002, c. 186, s. 46]

47 Settlement of complaints

(1) If the board considers it appropriate, the board may endeavour to effect a settlement of a complaint.

(2) If a settlement of a complaint is agreed to in writing, signed by the public utility and the complainant, and approved by the board, the settlement binds the parties and its terms are enforceable as an order of the board under this Act.

[S.Y. 2002, c. 186, s. 47]

48 Investigation without complaint

The board may, on its own motion, investigate any matter respecting the provision of service by a public utility.

[S.Y. 2002, c. 186, s. 48]

49 Investigation procedure

(1) An investigation by the board may be made by a member of the board or its staff who is authorized by the board for the purpose.

- a) celle-ci pourrait ou devrait être réglée sous le régime d'une autre loi;
- b) son objet est dénué de tout fondement, frivole ou vexatoire;
- c) la plainte est faite de mauvaise foi;
- d) la plainte ne relève pas de sa compétence.

(3) La Régie peut décider de ne pas donner suite à une plainte si elle estime que les faits sur lesquels elle est fondée se sont produits plus de six mois avant son dépôt, sauf si elle est convaincue que le retard s'est produit de bonne foi et qu'aucun préjudice important ne sera causé aux intéressés.

(4) Si elle décide de ne pas donner suite à une plainte, la Régie en avise l'auteur par écrit et lui communique les motifs de sa décision.

[L.Y. 2002, ch. 186, art. 45]

46 Enquêtes

Sous réserve de l'article 45, la Régie fait enquête sur toute plainte dans les meilleurs délais.

[L.Y. 2002, ch. 186, art. 46]

47 Règlement des plaintes

(1) Si elle l'estime indiqué, la Régie peut faire le nécessaire pour régler la plainte.

(2) Tout règlement d'une plainte accepté par écrit et signé par l'entreprise de service public et le plaignant et agréé par la Régie lie les parties et est assimilé à une ordonnance de la Régie.

[L.Y. 2002, ch. 186, art. 47]

48 Enquête sans plainte

La Régie peut, d'office, faire enquête sur tout aspect touchant la fourniture d'un service par une entreprise de service public.

[L.Y. 2002, ch. 186, art. 48]

49 Procédure

(1) L'enquête de la Régie peut être conduite par un de ses membres ou par son personnel qu'elle autorise à ces fins.



(2) Notice of an investigation shall be given to the public utility under investigation.

(3) The board or a person authorized under subsection (1) may

- (a) enter on and inspect at any reasonable time any place, building, works, or other property of a public utility;
- (b) require the attendance of any persons the board or the person considers necessary to summon and examine, and take the testimony of those persons;
- (c) require the production of any books, plans, specifications, and other documents that the board or the person considers necessary; and
- (d) administer oaths, affirmations, or declarations.

[S.Y. 2002, c. 186, s. 49]

(2) Un avis de l'enquête est donné à l'entreprise de service public visée.

(3) La Régie ou la personne autorisée en application du paragraphe (1) peut :

- a) pénétrer à toute heure raisonnable dans tout lieu, bâtiment, ouvrage ou autre bien d'une entreprise de service public et le visiter;
- b) exiger la présence des personnes qu'elle estime nécessaires, les interroger et recueillir leur témoignage;
- c) exiger la production des livres, plans, devis et autres documents qu'elle estime nécessaires;
- d) faire prêter les serments et recueillir les déclarations ou affirmations solennelles.

[L.Y. 2002, ch. 186, art. 49]

HEARINGS

50 Requirement for approval

Despite any other provision of this Act, the board shall not hold any inquiry or public hearing under this Act without the advance written approval of the Minister for the necessary expenses.

[S.Y. 2002, c. 186, s. 50]

AUDIENCES

50 Approbation obligatoire

Malgré les autres dispositions de la présente loi, la Régie ne peut tenir d'enquête ou d'audience publique sous le régime de la présente loi sans l'approbation écrite préalable du ministre relativement aux frais à engager.

[L.Y. 2002, ch. 186, art. 50]

51 Powers of the board

The board may on its own motion inquire into, hear, and determine any matter or thing respecting the production, transmission, delivery, or furnishing of electricity or gas to the public.

[S.Y. 2002, c. 186, s. 51]

51 Attributions de la Régie

La Régie peut, d'office, faire enquête et se prononcer sur toute affaire touchant la production, la transmission, la livraison ou la fourniture d'électricité ou de gaz au public.

[L.Y. 2002, ch. 186, art. 51]

52 Hearing procedure and jurisdiction

Subject to the other provisions of this Act and the regulations and to the need to abide by the fundamental principles of justice, the board in respect to any inquiry or hearing

- (a) has the exclusive jurisdiction and authority to determine any question of fact, law, or mixed fact and law required to be decided;

52 Procédure des audiences et compétence

Sous réserve des autres dispositions de la présente loi et sous réserve des règlements et des règles de justice naturelle, pour les besoins d'une enquête ou d'une audience, la Régie :

- a) a compétence exclusive pour trancher toute question de fait, de droit ou de droit et de fait;



- (b) may receive any evidence or other information that it considers appropriate, whether or not the evidence is given under oath or affirmation, and whether or not it would be admissible in a court of law;
- (c) has the powers, privileges, and immunities of a board of inquiry under the *Public Inquiries Act*;
- (d) may determine the persons to whom notice of the proceedings shall be given; and
- (e) may determine its own procedures.

[S.Y. 2002, c. 186, s. 52]

- b) peut recueillir des témoignages et tout renseignement qu'elle estime nécessaires, que ces témoignages soient rendus sous serment ou par affirmation solennelle, peu importe s'ils sont ou non admissibles en justice;
- c) a les mêmes pouvoirs, privilèges et immunités qu'une commission d'enquête régie par la *Loi sur les enquêtes publiques*;
- d) peut décider à qui les avis de l'instance seront donnés;
- e) peut fixer sa propre procédure.

[L.Y. 2002, ch. 186, art. 52]

53 Evidence

(1) If the board exercises its power to issue a summons requiring the production in evidence of documents or things it may, on the production of the documents or things before it, adjourn the proceedings to permit the parties to examine the documents or things.

(2) Oral evidence or submissions need not be recorded in written form, but the board shall cause electronic sound recordings to be made of all statements made orally at its public hearings, and shall make those recordings as well as all relevant documents available on reasonable conditions for inspection or copying by any person who so requests, and by any court exercising jurisdiction over the board.

[S.Y. 2002, c. 186, s. 53]

53 Preuve

(1) Si elle exerce son pouvoir de décerner une assignation exigeant la production de documents ou d'objets en preuve, la Régie peut, lors de leur production, ajourner la procédure pour permettre aux parties de les examiner.

(2) Il n'est pas nécessaire de consigner par écrit les témoignages et observations, mais la Régie doit prévoir l'enregistrement électronique de toutes les déclarations faites au cours de ses audiences publiques et rendre ces enregistrements ainsi que tous les documents pertinents accessibles pour examen ou copie aux conditions qu'elle estime raisonnables à toute personne qui en fait la demande ainsi qu'aux juridictions supérieures par rapport à la Régie.

[L.Y. 2002, ch. 186, art. 53]

54 Disqualification of board members

(1) A member is not disqualified from participating in a public hearing or any other proceeding respecting a complaint because they have previously taken part in any investigation or consideration of the subject matter of the complaint before the hearing unless they have communicated directly or indirectly with any party or their representative without notice to and opportunity for all parties to participate before any final decision.

(2) Despite subsection (1), the board or a member may seek legal advice from an advisor independent of the parties, but in that case the nature of the advice shall be made known to the parties in order that they may make submissions as to the law.

[S.Y. 2002, c. 186, s. 54]

54 Empêchement

(1) Un membre n'est pas empêché de participer à une audience publique ou à toute autre procédure touchant une plainte parce qu'il a auparavant participé à toute enquête ou à l'examen de l'objet de la plainte avant l'audience, à moins qu'il n'ait communiqué, même indirectement, avec une partie ou son représentant sans avoir donné avis aux autres parties et leur avoir donné la possibilité d'y participer avant la décision définitive.

(2) Malgré le paragraphe (1), la Régie ou un de ses membres peut demander l'avis juridique d'un conseiller indépendant des parties, mais, dans ce cas, la nature de l'avis est communiquée aux parties de sorte qu'elles puissent faire valoir leurs observations quant au droit.

[L.Y. 2002, ch. 186, art. 54]



55 Combination of proceedings

The board may combine two or more complaints or other matters under this Act and deal with them in the same proceeding if

- (a) they relate to the same public utility; or
- (b) they have questions of law or fact in common.

[S.Y. 2002, c. 186, s. 55]

56 Costs

The board may order to whom or by whom any costs incidental to any proceeding before the board are to be paid, and may set the costs to be paid.

[S.Y. 2002, c. 186, s. 56]

ORDERS

57 Powers of the board

The board may make any order authorized under this Part on its own motion, or on the complaint or application of an interested person.

[S.Y. 2002, c. 186, s. 57]

58 Types of orders

(1) The board may order any person to do anything that the person is or may be required to do under this Act, and may forbid the doing of anything that is contrary to this Act.

(2) An order issued under subsection (1) may prescribe the time and the manner in which the order is to be carried out.

[S.Y. 2002, c. 186, s. 58]

59 Extension of time for compliance

If the circumstances of the case so require the board may, on any notice to persons affected that it considers reasonable, or in its discretion without notice, extend the time specified in any board order or decision for compliance with the order or decision.

[S.Y. 2002, c. 186, s. 59]

55 Jonction

La Régie peut combiner deux ou plusieurs plaintes ou toute autre affaire prévue par la présente loi et les traiter dans la même procédure, si elles visent la même entreprise ou si elles ont en commun des points de droit ou de fait.

[L.Y. 2002, ch. 186, art. 55]

56 Dépens

La Régie peut fixer le montant des dépens et déterminer à la charge de qui ils seront.

[L.Y. 2002, ch. 186, art. 56]

ORDONNANCES

57 Pouvoirs de la Régie

La Régie peut, d'office, rendre toute ordonnance qu'elle est autorisée à rendre sous le régime de la présente partie ou à la suite d'une plainte ou d'une demande d'un intéressé.

[L.Y. 2002, ch. 186, art. 57]

58 Ordonnances

(1) La Régie peut ordonner à une personne d'accomplir tout acte qu'elle peut ou doit accomplir sous le régime de la présente loi et lui interdire d'accomplir tout acte contraire à celle-ci.

(2) L'ordonnance visée au paragraphe (1) peut fixer les délais et les modalités de son exécution.

[L.Y. 2002, ch. 186, art. 58]

59 Prorogation du délai

Si les circonstances de l'affaire l'exigent, la Régie peut, après avoir donné les avis nécessaires aux intéressés ou même sans délai, proroger le délai fixé dans une ordonnance ou une décision relativement à l'application de celle-ci.

[L.Y. 2002, ch. 186, art. 59]

60 Requirement for a hearing

(1) Except in cases of urgency, of which the board shall be the sole judge, the board shall not without a hearing make any order involving an outlay by, or a loss or deprivation to, a public utility.

(2) If an order under subsection (1) is made without a hearing, the board, on the application of an interested person, shall as soon as practicable hear and reconsider the matter and make any further or other order that it considers advisable.

(3) If any order is made by the board without a hearing, any person affected by the order may, within 10 days of the making of the order or within any further time that the board may allow, apply to the board to amend or rescind the order.

[S.Y. 2002, c. 186, s. 60]

61 Effect of order on service

(1) Every order and decision of the board is final and binding until changed or amended by the board, but no order of the board shall be effective until a copy of it is served on the person to whom it is directed.

(2) If in any case it is made to appear to the satisfaction of the board that service of any document cannot be made by personal service on a person or, in the case of a corporation, at its head office or chief place of business in the Yukon, the board may allow substituted service by publication in a local newspaper or by prepaid registered or certified mail.

[S.Y. 2002, c. 186, s. 61]

62 Variation of orders

The board may review, change, or cancel any decision or order made by it, and may re-hear any application or complaint before deciding it.

[S.Y. 2002, c. 186, s. 62]

63 Interim and reserved orders

The board may, in any matter before it,

- (a) make any interim orders on appropriate terms that it may consider necessary to facilitate its inquiry or to prevent serious harm occurring before its decision; and
- (b) reserve further direction either for an adjourned hearing or for further application.

60 Audience obligatoire

(1) Sauf en cas d'urgence, dont elle est seule juge, la Régie ne peut, sans tenir d'audience, rendre une ordonnance qui aurait pour effet d'obliger une entreprise de service public à effectuer une dépense ou à subir une perte.

(2) Si elle rend une ordonnance sans tenir d'audience, la Régie est tenue, à la demande de tout intéressé, d'entendre et de réexaminer l'affaire dès que possible et de rendre toute autre ordonnance qu'elle estime nécessaire.

(3) Si elle rend une ordonnance sans tenir d'audience, tout intéressé peut, dans les 10 jours de sa prise, ou dans le délai plus long que la Régie peut lui donner, demander à celle-ci de la modifier ou de l'annuler.

[L.Y. 2002, ch. 186, art. 60]

61 Portée des ordonnances

(1) Les ordonnances et les décisions de la Régie sont définitives et obligatoires jusqu'à ce qu'elle les modifie; cependant, aucune ordonnance ne prend effet avant la signification d'une copie à l'intéressé.

(2) Si elle est convaincue que la signification d'un document ne peut être effectuée par signification personnelle ou, dans le cas d'une personne morale, à son siège social ou à son principal établissement au Yukon, la Régie peut ordonner un autre mode de signification par publication d'un avis dans un journal local ou par courrier recommandé ou certifié.

[L.Y. 2002, ch. 186, art. 61]

62 Modification des ordonnances

La Régie peut réviser, modifier ou annuler toute décision ou ordonnance qu'elle a rendue et entendre à nouveau toute demande ou plainte avant d'en décider.

[L.Y. 2002, ch. 186, art. 62]

63 Ordonnances provisoires

La Régie peut, dans toute affaire dont elle est saisie, rendre toute ordonnance provisoire aux conditions qu'elle estime nécessaires en vue de faciliter l'enquête ou de prévenir tout préjudice grave pouvant survenir avant la décision et réserver toute autre directive pour la reprise de l'audience ou pour une autre demande.

[L.Y. 2002, ch. 186, art. 63]



[S.Y. 2002, c. 186, s. 63]

ENFORCEMENT

64 Powers of the board and staff

- (1) The board may take any steps necessary for the enforcement of any order made by it.
- (2) Subject to the *Public Service Act*, the Minister may, on the request of the board, appoint persons to enforce orders of the board.

[S.Y. 2002, c. 186, s. 64]

65 Appointment of administrator for a public utility

- (1) If the board considers it necessary for the enforcement of an order, the board may, with the approval of the Minister, authorize a person appointed under section 64 to act as administrator of the affairs of a public utility.
- (2) An administrator may enter on and take possession of the property, books, and offices of a public utility and, until the order has been enforced, may
 - (a) assume and take over the management of the public utility for and in the interests of the shareholders and the public; and
 - (b) assume all the powers of the directors and officers of the public utility, including the power to employ and dismiss officers and servants of the public utility.
- (3) If an administrator takes possession of a public utility, every officer and employee shall obey the orders of the board or the administrator in the management of the public utility.
- (4) The board and the administrator may, on taking possession of a public utility, determine, receive, and pay out all money due or owing by the public utility, and give cheques and receipts for money, to the same extent as the proper officers.
- (5) The costs and expenses of proceedings under this section are in the discretion of the board.

[S.Y. 2002, c. 186, s. 65]

CONTRÔLE D'APPLICATION

64 Pouvoirs de la Régie et du personnel

- (1) La Régie peut prendre les mesures nécessaires à l'exécution de ses ordonnances.
- (2) Sous réserve de la *Loi sur la fonction publique*, le ministre peut, à la demande de la Régie, nommer les agents d'exécution des ordonnances de la Régie.

[L.Y. 2002, ch. 186, art. 64]

65 Nomination d'un administrateur

- (1) Si elle l'estime nécessaire à l'exécution d'une ordonnance, la Régie peut, avec l'agrément du ministre, autoriser une personne nommée en application de l'article 64 à agir comme administrateur d'une entreprise de service public.
- (2) L'administrateur peut entrer sur les lieux de l'entreprise et prendre possession de ses biens, livres et bureaux et, jusqu'à ce que l'ordonnance ait été exécutée, il peut assurer et prendre en charge sa gestion, compte tenu des intérêts des actionnaires et du public, et exercer les pouvoirs des administrateurs et dirigeants de l'entreprise, y compris le pouvoir de recruter et de congédier les dirigeants et le personnel de l'entreprise.
- (3) Si l'administrateur prend possession de l'entreprise, les dirigeants et le personnel sont tenus d'obéir aux ordonnances de la Régie ou de l'administrateur rendues dans le cadre de sa gestion.
- (4) La Régie et l'administrateur peuvent, lors de la prise de possession de l'entreprise de service public, déterminer, recevoir et payer les créances et les dettes et émettre des chèques et reçus tout comme pourraient le faire les dirigeants.
- (5) Les frais et dépens de la procédure visée au présent article sont laissés à l'appréciation de la Régie.

[L.Y. 2002, ch. 186, art. 65]



66 Enforcement in the Supreme Court

An order of the board becomes an order of the Supreme Court immediately on filing with the clerk of the court of a certified copy of the order, and the order may then be enforced in like manner as any order of the Supreme Court.

[S.Y. 2002, c. 186, s. 66]

67 Evidence of board orders and decisions

In any action or proceeding, a copy of any order or decision of the board purporting to be certified by a member or the secretary to be a true copy is *prima facie* evidence without proof of the signature or the appointment of the secretary or member.

[S.Y. 2002, c. 186, s. 67]

68 Offence and penalty

(1) A person who fails to comply with any of the provisions of this Act commits an offence and is liable on summary conviction,

- (a) in the case of an individual, to a fine not exceeding \$1,000, and in default thereof to imprisonment for a term not exceeding one year; and
- (b) in the case of a corporation, to a fine not exceeding \$5,000.

(2) Any person who advises, solicits, or persuades, or knowingly instructs, directs, or orders any officer, agent, or employee of a public utility to perform, commit, or do any act that is contrary to an order of the board or to the requirements of this Act, commits an offence and is liable on summary conviction to a fine not exceeding \$1,000 or to imprisonment for a term not exceeding one year, or both.

[S.Y. 2002, c. 186, s. 68]

66 Exécution à la Cour suprême

Les ordonnances de la Régie deviennent des ordonnances de la Cour suprême sur dépôt auprès du greffier de ce tribunal d'une copie certifiée conforme de celles-ci; elles peuvent dès lors être exécutées comme celles de la Cour suprême.

[L.Y. 2002, ch. 186, art. 66]

67 Preuve

La copie d'une ordonnance de la Régie censée certifiée copie conforme par un membre ou le secrétaire constitue une preuve *prima facie* sans qu'il soit nécessaire de prouver la signature ou la qualité du signataire.

[L.Y. 2002, ch. 186, art. 67]

68 Infraction et peine

(1) Quiconque contrevient à la présente loi commet une infraction et est passible, sur déclaration de culpabilité par procédure sommaire :

- a) s'agissant d'un particulier, d'une amende maximale de 1 000 \$ et, à défaut de paiement, d'un emprisonnement maximal d'un an;
- b) s'agissant d'une personne morale, d'une amende maximale de 5 000 \$.

(2) Quiconque conseille, demande, persuade ou sciemment demande ou ordonne à tout dirigeant, mandataire ou employé d'une entreprise de service public d'accomplir tout acte qui constitue une contravention à une ordonnance de la Régie ou à la présente loi commet une infraction et est passible, sur déclaration de culpabilité par procédure sommaire, d'une amende maximale de 1 000 \$ et d'un emprisonnement maximal d'un an, ou de l'une de ces peines.

[L.Y. 2002, ch. 186, art. 68]



APPEALS

69 Leave to appeal to the Court of Appeal

(1) On application to the Court of Appeal within 30 days of a decision or order of the board or within a further time allowed by the Court of Appeal in special circumstances, the Court of Appeal may grant leave to appeal to that court from the order or decision on a question of law or excess of jurisdiction.

(2) The granting of leave to appeal and the costs of the application are in the discretion of the Court of Appeal.

(3) The applicant shall give notice of the application stating the grounds of appeal to the board, to the Minister, and to any party adverse in interest, at least three clear days before the hearing of the application.

[S.Y. 2002, c. 186, s. 69]

70 Appeal procedure and costs

(1) If leave is granted, the appellant shall, within 15 days, give notice of appeal to the board, to the Minister and to any party adverse in interest.

(2) The board and the Minister may be heard by counsel on the appeal.

(3) Neither the board nor an officer, employee, or agent of the board is liable for costs in respect of an application or appeal under this section.

[S.Y. 2002, c. 186, s. 70]

71 Effect of order or decision under appeal

An appeal to the Court of Appeal shall not of itself stay or suspend the operation of the decision or order appealed from, but either the Court of Appeal or the board has the power to suspend the operation of the decision or order on any terms set by the court or the board, as the case may be.

[S.Y. 2002, c. 186, s. 71]

72 Jurisdiction of the Court of Appeal

(1) The Court of Appeal has the same jurisdiction and powers on appeals as it has for appeals from orders of the Supreme Court.

APPELS

69 Demande d'appel à la Cour d'appel

(1) Sur demande à la Cour d'appel formée dans les 30 jours d'une décision ou d'une ordonnance de la Régie ou dans le délai plus long que la Cour d'appel peut accorder dans des circonstances spéciales, celle-ci peut accueillir la demande d'autorisation d'interjeter appel de l'ordonnance ou de la décision sur une question de droit ou d'excès de compétence.

(2) La Cour d'appel a toute latitude pour accorder l'autorisation d'appeler et les dépens afférents à la demande.

(3) Le demandeur avise la Régie, le ministre et toute partie adverse de sa demande trois jours francs avant l'audition de la demande. L'avis comporte les moyens d'appel.

[L.Y. 2002, ch. 186, art. 69]

70 Procédure et dépens

(1) Si l'autorisation est accordée, l'appelant doit, dans les 15 jours, en aviser la Régie, le ministre et les parties adverses.

(2) La Régie et le ministre peuvent être représentés par avocat lors de l'appel.

(3) Ni la Régie ni ses dirigeants, employés et mandataires ne peuvent être tenus aux dépens relativement à la demande ou à l'appel au titre du présent article.

[L.Y. 2002, ch. 186, art. 70]

71 Effet de l'appel sur la décision ou l'ordonnance

L'appel à la Cour d'appel n'a pas pour effet de suspendre l'effet de la décision ou de l'ordonnance en cause, mais la Cour d'appel ou la Régie peut en suspendre l'effet aux conditions qu'elle peut fixer.

[L.Y. 2002, ch. 186, art. 71]

72 Compétence de la Cour d'appel

(1) La Cour d'appel a la même compétence et les mêmes pouvoirs en appel que ceux qu'elle possède pour les appels des ordonnances de la Cour suprême.

(2) Except as otherwise provided in this Act, appeals shall conform as far as possible with the rules governing appeals from the Supreme Court.

[S.Y. 2002, c. 186, s. 72]

73 References to the Court of Appeal

The board may at any stage of its proceedings refer any question of law, jurisdiction, practice, or procedure to the Court of Appeal for hearing and determination.

[S.Y. 2002, c. 186, s. 73]

74 Hearing and determination of appeals

An application, appeal, or reference to the Court of Appeal under this Act shall be heard and determined without delay in a summary way.

[S.Y. 2002, c. 186, s. 74]

MISCELLANEOUS

75 Expenditure of public money

No provision of this Act authorizes or requires the expenditure of public money except with the approval of the Minister.

[S.Y. 2002, c. 186, s. 75]

76 Regulations

(1) The Commissioner in Executive Council may make any regulations considered necessary for carrying the purposes and provisions of this Act into effect, including but not limited to regulations that

- (a) prescribe undertakings to be excluded undertakings;
- (b) in respect of undertakings prescribed under paragraph (a), prescribe how the undertakings are to be developed, connected or operated or impose any other standard, condition or requirement;
- (c) provide for the remuneration of members of the board or the reimbursement of their expenses;
- (d) prescribe a fee for the provision under subsection 13(3) of a certified copy of a document;
- (e) prescribe requirements for applications under section 39 for energy project certificates or

(2) Sauf disposition contraire de la présente loi, les appels sont régis, dans la mesure du possible, par les règles régissant les appels qui frappent les décisions de la Cour suprême.

[L.Y. 2002, ch. 186, art. 72]

73 Renvois

La Régie peut en tout état de cause déferer une question de droit, de compétence, de pratique ou de procédure à la Cour d'appel pour audience et avis.

[L.Y. 2002, ch. 186, art. 73]

74 Audition et règlement des appels

Les demandes, appels ou renvois à la Cour d'appel que prévoit la présente loi sont entendus et tranchés sans délai en procédure sommaire.

[L.Y. 2002, ch. 186, art. 74]

DISPOSITIONS DIVERSES

75 Engagement de fonds publics

La présente loi n'a pas pour effet d'autoriser ou d'exiger l'engagement de fonds publics, sauf avec l'agrément du ministre.

[L.Y. 2002, ch. 186, art. 75]

76 Règlements

(1) Le commissaire en conseil exécutif peut prendre les règlements qu'il estime nécessaires ou utiles à la mise en œuvre des objets et des dispositions de la présente loi, notamment :

- a) prévoir les entreprises qui sont des entreprises exclues;
- b) en ce qui concerne les entreprises exclues prévues à l'alinéa a), déterminer comment elles doivent se développer, être reliées ou exploitées, ou établir toute autre norme, condition ou obligation;
- c) fixer la rémunération des membres de la Régie ou le remboursement de leurs frais
- d) fixer les droits pour une copie certifiée d'un document en vertu du paragraphe 13(3);
- e) établir les exigences qui s'appliquent aux demandes de certificat de construction ou



- energy operation certificates;
- (f) relate to the jurisdiction and procedures of the board; or
 - (g) define a word or expression that this Act uses but does not define.
- (2) A regulation under subsection (1) may
- (a) incorporate by reference, in whole or in part or with modifications, any written standard, protocol, rule, guideline, code or other document, either as it reads on a date specified in the regulation or as it is amended from time to time; or
 - (b) delegate any matter to, or confer a discretion in respect of any matter on, a person.

[S.Y. 2014, c. 3, s. 3] [S.Y. 2002, c. 186, s. 76]

77 Existing franchises

- (1) The Northern Canada Power Commission is deemed to have been granted a franchise by the Commissioner in Executive Council pursuant to this Act subject to any terms and conditions that have been imposed on or accepted by the Northern Canada Power Commission pursuant to the *Electrical Public Utilities Act* immediately before the coming into force of this Act.
- (2) The Yukon Electrical Company Limited is deemed to have been granted a franchise by the Commissioner in Executive Council pursuant to this Act subject to any terms and conditions that have been imposed on or accepted by the Yukon Electrical Company Limited pursuant to the *Electrical Public Utilities Act* immediately before the coming into force of this Act.
- (3) The Yukon Hydro Company Limited is deemed to have been granted a franchise by the Commissioner in Executive Council pursuant to this Act subject to any terms and conditions that have been imposed on or accepted by the Yukon Hydro Company Limited pursuant to the *Electrical Public Utilities Act* immediately before the coming into force of this Act.
- (4) Nothing in this section limits the power of the Commissioner in Executive Council to revoke or vary the terms or conditions of any franchise granted or deemed to have been granted under this or any other Act.

[S.Y. 2002, c. 186, s. 77]

- d'exploitation en vertu de l'article 39;
- f) établir la procédure qui s'applique à la Régie et les compétences de cette dernière
 - g) définir tout terme ou toute expression utilisé dans la présente loi mais qui n'y est pas défini.
- (2) Un règlement en vertu du paragraphe (1) peut :
- a) incorporer par renvoi, en tout ou en partie ou en les modifiant, toute norme écrite, protocole, règle, directive, code ou tout autre document, soit dans leur version à une date précisée au règlement, soit avec leurs modifications successives;
 - b) déléguer ou attribuer un pouvoir discrétionnaire à une personne sur toute question.

[L.Y. 2014, ch. 3, art. 3] [L.Y. 2002, ch. 186, art. 76]

77 Agréments existants

- (1) La Commission d'énergie du Nord canadien est réputée avoir reçu l'agrément du commissaire en conseil exécutif au titre de la présente loi, sous réserve des modalités et des conditions qui lui ont été imposées ou qu'elle a acceptées sous le régime de la loi intitulée *Electrical Public Utilities Act* à l'entrée en vigueur de la présente loi.
- (2) La Société Yukon Electrical Company Limited est réputée avoir reçu l'agrément du commissaire en conseil exécutif au titre de la présente loi, sous réserve des modalités et des conditions qui lui ont été imposées ou qu'elle a acceptées sous le régime de la loi intitulée *Electrical Public Utilities Act* à l'entrée en vigueur de la présente loi.
- (3) La Société Yukon Hydro Company Limited est réputée avoir reçu l'agrément du commissaire en conseil exécutif au titre de la présente loi, sous réserve des modalités et des conditions qui lui ont été imposées ou qu'elle a acceptées sous le régime de la loi intitulée *Electrical Public Utilities Act* à l'entrée en vigueur de la présente loi.
- (4) Le présent article n'a pas pour effet de limiter la compétence du commissaire en conseil exécutif de révoquer ou de modifier les modalités et les conditions d'un agrément accordé ou réputé accordé sous le régime de la présente loi ou de toute autre loi.

[L.Y. 2002, ch. 186, art. 77]



PART 5**PUBLIC UTILITY COMPANIES****78 Application of this Part**

This Part applies to all applications for incorporation of companies intended to operate or control any public or municipal franchise, undertaking, or utility, including water, gas, electric, and telephone companies, or that may require for its purposes the erection of any permanent structure in or on any highway, stream, or adjoining navigable waters, and to those companies when incorporated.

[S.Y. 2002, c. 186, s. 78]

79 Incorporation requirements

With the application for incorporation the applicants shall file with the registrar and produce to the Minister

- (a) evidence that the proposed capital is sufficient to carry out the objects for which the company is to be incorporated, that the capital has been subscribed or underwritten and that the applicants are likely to command public trust and confidence in the undertaking;
- (b) a detailed description of the plant, works, and intended operations of the company, and an estimate of their cost;
- (c) a bylaw of every municipality in which the operations of the company are to be carried on authorizing the execution thereof in the manner set out in the detailed description above referred to;
- (d) if the undertaking is to be carried on in an unorganized district a letter from the Minister approving of the undertaking; and
- (e) if it is proposed that the company shall acquire any plant, works, land, undertaking, good will, contract, or other property or assets, a detailed statement of the nature and value thereof.

[S.Y. 2002, c. 186, s. 79]

PARTIE 5**SOCIÉTÉS DE SERVICE PUBLIC****78 Champ d'application de la présente partie**

La présente partie s'applique aux demandes de constitution en personne morale de sociétés destinées à exploiter ou à régir un agrément public ou municipal, une entreprise ou un service public y compris d'eau, de gaz, d'électricité et de téléphone, ou qui peut requérir à ces fins l'érection d'une construction permanente sur ou au-dessus d'une route, d'un ruisseau ou d'un cours d'eau navigable, ainsi qu'à ces sociétés une fois constituées.

[L.Y. 2002, ch. 186, art. 78]

79 Dispositions obligatoires

Les requérants annexent à leur demande de constitution en personne morale déposée auprès du registraire et expédiée au ministre :

- a) la preuve que le capital proposé est suffisant pour mener à bien les objectifs pour lesquels la société sera constituée en personne morale, que ce capital a été souscrit ou garanti et que les requérants recevront vraisemblablement l'appui et la confiance du public dans l'entreprise;
- b) une description détaillée de l'usine, des ouvrages et des activités projetées de la société et une estimation de leur coût;
- c) un règlement municipal de chaque municipalité sur le territoire de laquelle les activités de la société seront menées autorisant celles-ci, ces activités devant être menées conformément à la description mentionnée ci-dessus;
- d) si l'entreprise doit être menée dans un territoire non organisé, une lettre du ministre l'approuvant;
- e) s'il est projeté que la société se portera acquéreur de toute usine, ouvrage, bien-fonds, entreprise, achalandage, contrat ou autre bien ou élément d'actif, une description détaillée de leur nature et de leur valeur.

[L.Y. 2002, ch. 186, art. 79]



80 Reference to engineers or other experts

(1) The Minister may refer the application and all statements, evidence, and material filed thereon to engineers, architects, valuers, or other experts for consideration, investigation, and report regarding the public necessity for the undertaking of the company, the amount of capital required therefor, the value of any plant, works, lands, undertaking, good will, contract, or other property or assets to be acquired by the company and any other matter that may appear to be in the public interest regarding the undertaking.

(2) For the purposes of this Part, “**registrar**” means the registrar as defined in the *Business Corporations Act*.

[S.Y. 2002, c. 186, s. 80]

81 Incorporation of public utility companies

The incorporation of any company hereafter formed for the purpose of operating any public utility under this Part, either solely or in conjunction with other objects, shall be by articles of incorporation under Part 2 of the *Business Corporations Act*.

[S.Y. 2002, c. 186, s. 81]

82 Existing companies

The provisions of this Part continue to apply to any company formed by letters patent or by memorandum of association under Part II of the *Companies Act*.

[S.Y. 2002, c. 186, s. 82]

83 Power to pass bylaws

The company may pass bylaws regarding the control and management of its undertakings, its dealings with the public it is incorporated to serve, and the setting and collection of tolls, charges, rates, or levies for the public service given by the company, except that no such bylaws shall have any force or effect or be acted on until approved by the Minister and, in the case of bylaws affecting its dealings with the public, the setting and collection of tolls, charges, rates, or levies for the public service given by the company, published twice in a public newspaper at the place where the undertaking of the company is carried on or as near thereto as may be and in the *Yukon Gazette*.

[S.Y. 2002, c. 186, s. 83]

80 Renvoi à des ingénieurs ou autres experts

(1) Le ministre peut renvoyer la demande et les documents annexés à des experts — ingénieurs, architectes, évaluateurs ou autres — pour enquête et rapport concernant la nécessité de l’entreprise, le montant du capital requis, la valeur des usines, ouvrages, biens-fonds, entreprises, achalandages, contrats ou autres biens ou éléments d’actif à acquérir par la société et sur tout autre point qui peut sembler concerner l’intérêt public en ce qui touche l’entreprise.

(2) Pour l’application de la présente partie, « **registraire** » vise le registraire selon la définition que donne de ce mot la *Loi sur les sociétés par actions*.

[L.Y. 2002, ch. 186, art. 80]

81 Constitution en personne morale

La constitution en personne morale d’une société formée en vue d’exploiter un service public sous le régime de la présente partie, que ce soit ou non avec d’autres objets, s’effectue par statuts constitutifs sous le régime de la partie 2 de la *Loi sur les sociétés par actions*.

[L.Y. 2002, ch. 186, art. 81]

82 Sociétés existantes

Les dispositions de la présente partie continuent à s’appliquer à toute société formée par lettres patentes ou par acte constitutif sous le régime de la partie II de la *Loi sur les compagnies*.

[L.Y. 2002, ch. 186, art. 82]

83 Adoption de règlements administratifs

La société peut adopter des règlements administratifs concernant la régie et la gestion de son entreprise, ses rapports avec le public et la fixation et la perception de droits ou de taux pour son service public; cependant, ces règlements n’ont aucune validité tant qu’ils n’ont pas été approuvés par le ministre et, dans le cas de règlements visant les rapports avec le public, la fixation et la perception de droits et de taux, avant d’avoir été publiés deux fois dans un journal publié à l’endroit où l’entreprise est exploitée ou le plus près possible de cet endroit et dans la *Gazette du Yukon*.

[L.Y. 2002, ch. 186, art. 83]

84 Annual report

In addition to other returns that may be required by this or any other Act, the company shall on or before March 1 in each year make a report to the registrar under oath of the president and secretary, which shall specify,

- (a) the cost of work, plant, and undertaking of the company;
- (b) the amount of its capital, and the amount paid thereon;
- (c) the amount received during the year from tolls, levies, rates, and charges and all other sources, stating each separately;
- (d) the amount and rate of dividends paid;
- (e) the amount expended for repairs; and
- (f) a detailed description of any extension or improvement of the works or of any new works proposed to be undertaken in the current year, together with an estimate of the cost thereof.

[S.Y. 2002, c. 186, s. 84]

85 Books open to inspection

The books of account of the company shall be at all reasonable times open to the inspection and examination of any shareholder.

[S.Y. 2002, c. 186, s. 85]

86 Appointment of inspector

If the Minister has any doubts as to the correctness or truth of any statements furnished by the company, the Minister may appoint a person to inspect and examine those books, and every person so appointed may take copies or extracts from them, and may require and receive from the keeper of the books, and also from the president and each of the directors of the company, and all other officers and servants thereof, all information as to the books and the affairs of the company generally, that the person so appointed considers necessary for the full and satisfactory investigation into and report on the state of affairs of the company, so as to enable them to determine the correctness of statements furnished by the company.

[S.Y. 2012, c. 14, s. 26] [S.Y. 2002, c. 186, s. 86]

84 Rapport annuel

En plus des autres rapports que peuvent exiger la présente loi ou toute autre loi, la société doit, au plus tard le 1^{er} mars, remettre un rapport au registraire accompagné du serment du président et du secrétaire; le rapport mentionne :

- a) le coût de l'ouvrage, de l'usine et de l'entreprise de la société;
- b) le montant de son capital et les montants libérés;
- c) les montants reçus durant l'année des taux et autres droits ainsi que de toute autre source, les indiquant individuellement;
- d) le montant et taux des dividendes versés;
- e) le montant des réparations;
- f) un état détaillé des agrandissements ou améliorations des ouvrages ou de tout projet d'ouvrage à entreprendre dans l'exercice en cours avec une estimation de leurs coûts.

[L.Y. 2002, ch. 186, art. 84]

85 Accès aux livres

Les livres comptables de la société sont mis à la disposition des actionnaires pour consultation à toute heure convenable.

[L.Y. 2002, ch. 186, art. 85]

86 Nomination d'un inspecteur

S'il a des doutes quant à l'exactitude ou à la véracité des déclarations de la société, le ministre peut nommer une personne chargée d'inspecter ces livres; celle-ci peut en prendre des copies ou des extraits et exiger et recevoir des préposés à leur garde et du président et de chacun des administrateurs de la société, ainsi que de son personnel, les renseignements concernant les livres ainsi que les affaires de la société de façon générale, qu'elle estime nécessaires à la conduite d'une enquête complète et à l'établissement d'un rapport sur les affaires de la société qui lui permette d'établir l'exactitude des déclarations de la société.

[L.Y. 2002, ch. 186, art. 86]



87 Power to construct and operate works

(1) A company incorporated for any of the purposes to which this Part applies has, respectively, full power to construct, maintain, complete, and operate works and apparatus for the production, sale, and distribution of gas, water, electricity, or other products for the purpose of light, heat, or power or of operating a system of telephones, or for any other purpose that the company may be incorporated for, as the case may be, and may construct and operate them by any means through, under, along, or over streets, highways, and public places.

(2) The powers of a company under subsection (1) are subject to any agreement in respect thereof that shall be made between the company and the municipal corporation within whose jurisdiction they are situate, ratified by a bylaw of the council of the municipality, and the municipality may, by agreement ratified as aforesaid, contract with any such company for the purchase of water, gas, or electricity and for the purchase or renting of any apparatus connected with the production, sale, or distribution thereof for any number of years not in the first instance exceeding 10 years, and renew any such contract from time to time for any period not exceeding 10 years as the council desires.

(3) In the case of streets, highways, and public places not within the limits of any municipality, the right of any such gas, water, electric, or telephone company to make use of those streets, highways, or public places to the extent indicated in this Part shall be subject to any terms that may be imposed by the Minister on application first made by the company.

[S.Y. 2002, c. 186, s. 87]

87 Pouvoir de construire et d'exploiter des ouvrages

(1) Une société dotée de la personnalité morale pour l'un des objets visés par la présente partie peut construire, entretenir, compléter et exploiter les ouvrages et dépendances pour la production, la vente et la distribution de gaz, d'eau, d'électricité ou autre produit aux fins de l'éclairage, du chauffage ou de la distribution d'énergie ou en vue de l'exploitation d'un système de téléphone ou à toute autre fin pour laquelle elle peut être constituée; elle peut également les construire et les exploiter le long des routes, chemins publics et places publiques ou au-dessus ou au-dessous de ceux-ci.

(2) Les pouvoirs mentionnés au paragraphe (1) sont assujettis aux accords qui peuvent être conclus entre la société et la municipalité sur le territoire de laquelle elle est située et ratifiés par un règlement municipal de son conseil; cette municipalité peut, par accord ratifié, conclure des contrats avec la société pour l'achat d'eau, de gaz ou d'électricité et pour l'achat ou la location de tout équipement lié à leur production, à leur vente ou à leur distribution pour une période initiale, maximale de 10 ans, et les renouveler pour une période maximale de 10 ans, selon ce qu'il estime indiqué.

(3) Dans le cas des rues, routes, chemins et lieux publics qui ne se trouvent pas sur le territoire d'une municipalité, le droit de la société de gaz, d'eau, d'électricité ou de téléphone de les utiliser aux fins mentionnées dans la présente partie est assujetti aux conditions qui peuvent être imposées par le ministre lors de la première demande faite par la société.

[L.Y. 2002, ch. 186, art. 87]

88 Meters and fittings

Every such company may sell and dispose of gas meters and gas, water, and electric fittings of every description for the use of private and public houses or for any establishment, company, or corporation whatsoever, as well as coke, coal, tar, and all the products of their works, refuse, or residuum arising to be obtained from the materials used or necessary for the manufacture of gas or electricity, and every company may let out to hire gas meters and gas, water, and electric fittings of every kind and description at any rate and rents that may be agreed on between the consumers and tenants and the company.

[S.Y. 2002, c. 186, s. 88]

89 Laying mains and wires on streets

Any such company may break up, dig, and trench and use so much and so many of the streets, squares, highways, lanes, and public places of the locality for supplying them with gas, water, electricity, or other product or service or either of them the company has been incorporated that are necessary for laying the mains and pipes to conduct the gas or water or for placing the wires and connections to conduct the electricity or other product and to supply those services from the works of and by the company to and for the consumers or users thereof, doing no unnecessary damage in the premises and taking care as far as may be to preserve a free and uninterrupted passage through those streets, squares, highways, lanes, and public places while the works are in progress.

[S.Y. 2002, c. 186, s. 89]

90 Company's rights regarding mains and pipes

(1) When any such company has laid down mains, pipes, wires, or conductors for the supply of gas, water, or electricity through any of the streets, squares, or public places of any locality, no other person or body politic or corporate shall, without the prior consent of the company nor otherwise than on payment to the company of any compensation that may be agreed on, or in default of agreement being arrived at, settled by arbitration, lay down any pipe, wire, or conductor for the supply of gas, water, or electricity within six feet of the company's main pipes, wires, or conductors or if it be impracticable to cut drains for those other main pipes, wires, or conductors

88 Compteurs et accessoires

Ces sociétés peuvent vendre et aliéner des compteurs à gaz et des accessoires pour gaz, eau et électricité de quelque sorte pour usage dans des immeubles résidentiels ou publics ou pour tout établissement ou personne morale, ainsi que du charbon, du goudron ainsi que tous les produits de leurs ouvrages, y compris les rejets ou résidus qui proviennent des matériaux utilisés dans le cadre de la fabrication de gaz ou d'électricité, et chaque société peut louer ces compteurs et accessoires au taux et moyennant le loyer qui peuvent être convenus entre les consommateurs et locataires et cette société.

[L.Y. 2002, ch. 186, art. 88]

89 Installation de canalisations

Ces sociétés peuvent creuser et utiliser la partie des rues, squares, chemins publics, allées et lieux publics de la localité en vue, d'une part, de fournir du gaz, de l'eau, de l'électricité ou tout autre produit ou service, ou les deux, pour lequel elles ont été constituées, travaux nécessaires à l'installation de conduites de gaz ou d'eau ou des fils électriques pour les installations de transport d'autres produits et, d'autre part, d'offrir ces services aux consommateurs et utilisateurs sans causer de dommage inutile aux lieux et en prenant les mesures voulues pour y préserver un passage libre et ininterrompu durant les travaux.

[L.Y. 2002, ch. 186, art. 89]

90 Droits de la société relativement aux canalisations

(1) Lorsqu'une société a installé des canalisations, des conduites, des fils ou des conducteurs pour la fourniture de gaz, d'eau ou d'électricité sous les rues, squares ou lieux publics d'une localité, il est interdit à quiconque, sans le consentement de la société ni autrement que sur paiement à celle-ci de la compensation qui peut être acceptée ou, à défaut d'entente, qui peut être fixée par arbitrage, d'installer toute canalisation, fil ou conducteur à ces fins dans les six pieds des installations de la société ou, s'il est impossible de couper les drains pour ces autres canalisations, fils ou conducteurs, à une distance plus grande, mais aussi proche de six pieds que les



at a greater distance than as nearly six feet as the circumstances of the case will admit.

(2) This section applies to mains, pipes, wires, or conductors crossing as well as running or parallel with other mains, pipes, wires, or conductors.

[S.Y. 2002, c. 186, s. 90.]

91 Parts of buildings having different owners or tenants

When there are buildings in the locality the different parts whereof belong to different proprietors or are in possession of different tenants or lessees, the company may carry pipes, wires, or conductors to any part of any building so situate passing over the property of one or more proprietors or in the possession of one or more tenants to convey the gas, water, or electricity to the property of another or in the possession of another, and those pipes, wires, or conductors shall be carried up and attached to the outside of the building.

[S.Y. 2002, c. 186, s. 91.]

92 Breaking up of passages

The company may also break up and uplift all passages common to neighbouring proprietors or tenants and dig or cut trenches therein for the purpose of laying down pipes, wires, or conductors or taking up or repairing them, doing as little damage as may be in the execution of the powers granted by this Part.

[S.Y. 2002, c. 186, s. 92.]

93 Compensation

(1) Every company shall make satisfaction to the owners or proprietors of buildings or other property or to the public for all damages by them sustained in or by the execution of all or any of the powers referred to in this Part, subject to which provisions this Part shall be sufficient to indemnify every such company and their servants, and those by them employed for what they or any of them do in pursuance of the powers hereby granted.

(2) Every person claiming compensation from the company under this section shall proceed by originating summons.

[S.Y. 2002, c. 186, s. 93.]

circonstances le permettent.

(2) Le présent article s'applique aux canalisations, conduites, fils ou conducteurs franchissant d'autres canalisations, conduites, fils ou conducteurs ou qui y sont parallèles.

[L.Y. 2002, ch. 186, art. 90.]

91 Parties de bâtiments ayant différents propriétaires ou locataires

S'il y a des bâtiments dans la localité dont les parties appartiennent à différents propriétaires ou sont en la possession de différents locataires, la société peut installer les canalisations, conduites, fils ou conducteurs à travers toute partie de ces bâtiments et franchir la propriété de ces propriétaires ou celle qui est en la possession d'un ou plusieurs locataires pour acheminer le gaz, l'eau ou l'électricité vers la propriété d'un autre; ces canalisations, conduites, fils ou conducteurs devant être fixés à l'extérieur du bâtiment.

[L.Y. 2002, ch. 186, art. 91.]

92 Rupture de passages

La société peut également couper et soulever les passages communs à des propriétaires ou locataires avoisinants et y creuser des tranchées aux fins d'y installer des canalisations, fils ou conducteurs, ou de les entretenir, en prenant soin de causer aussi peu de dommages qu'il est possible dans l'exécution des pouvoirs conférés par la présente partie.

[L.Y. 2002, ch. 186, art. 92.]

93 Indemnisation

(1) Les sociétés sont tenues d'indemniser les propriétaires de bâtiments ou d'autres biens et le public pour les dommages subis à l'occasion de l'exécution de leurs pouvoirs; le cas échéant, la présente loi leur confère l'immunité, ainsi qu'à leurs employés, pour ce qui est accompli dans le cadre de ces pouvoirs.

(2) Quiconque réclame une indemnité à une société sous le régime du présent article est tenu de procéder par avis introductif.

[L.Y. 2002, ch. 186, art. 93.]

94 Public safety

Every such company shall construct, locate, and operate its gas works, water works, or electric or telephone system and all apparatus and appurtenances thereto belonging or appertaining or therewith connected and wheresoever situated so as not to endanger the public health or safety.

[S.Y. 2002, c. 186, s. 94]

95 Limitation of powers of company

Nothing in this Part authorizes any such company or any person acting under the authority of it to take, use, or injure for the purposes of the company any house or other building or any land used or set apart as a garden, orchard, yard, park, paddock, plantation, planted walk, or avenue to a house, or nursery ground for trees, or to convey from the premises of any person any water already appropriated and necessary for their domestic uses without the prior consent in writing of the owner.

[S.Y. 2002, c. 186, s. 95]

96 Privileges of other companies

Nothing in this Part authorizes any company established under it to interfere with or infringe on any exclusive privilege granted to any other company.

[S.Y. 2002, c. 186, s. 96]

97 Individual rights

Nothing in this Part prevents any person from constructing any works for the supply of gas, water, electricity, or telephones to their own premises, but any person supplying electricity, water, or telephone to any other premises than their own shall be subject to the provisions of this Part and shall pay the licence or fee at any time imposed on any other company or person supplying similar utilities in the same city, town, or district.

[S.Y. 2002, c. 186, s. 97]

94 Sécurité publique

Ces sociétés doivent ériger et placer leurs ouvrages de gaz, d'eau ou d'électricité ou de téléphone ainsi que les appareils et accessoires liés à ceux-ci de façon à ne pas mettre en danger la sécurité ou la santé du public.

[L.Y. 2002, ch. 186, art. 94]

95 Restriction aux pouvoirs des sociétés

La présente partie n'a pas pour effet d'autoriser ces sociétés ou les personnes qui agissent pour leur compte à prendre, à utiliser ou à endommager, pour l'accomplissement de leurs objets, toute maison ou autre bâtiment ou terrain utilisé comme jardin, verger, parc, plantation, promenade ou allée conduisant à une maison ou à une pépinière ou pour transporter des lieux de toute personne de l'eau déjà affectée à ses besoins domestiques et nécessaires à ces fins sans le consentement écrit du propriétaire.

[L.Y. 2002, ch. 186, art. 95]

96 Privilèges des autres sociétés

La présente partie n'a pas pour effet d'autoriser une société constituée sous son régime à porter atteinte aux privilèges exclusifs accordés à une autre société.

[L.Y. 2002, ch. 186, art. 96]

97 Droits individuels

La présente partie n'a pas pour effet d'empêcher une personne de construire tout ouvrage pour la fourniture de gaz, d'eau, d'électricité ou d'un service téléphonique sur ses lieux propres, mais quiconque fournit de l'électricité, de l'eau ou un service téléphonique à tout autre lieu que le sien propre doit être assujéti à la présente partie et payer la licence ou les droits imposés à toute autre société ou personne qui offre un service public semblable dans la même ville, cité ou district.

[L.Y. 2002, ch. 186, art. 97]



98 Exemption from distress and seizure

Neither the service nor the connecting pipes, wires, or conductors of the company, nor any meters, lustres, lamps, pipes, gas fittings, electric fittings, or any other property of any kind whatsoever of the company shall be subject to or liable for rent nor liable to be seized or attached in any way by the possessor or owner of the premises wherein they may be, nor be in any way whatsoever liable to any person for the debt of any person to and for whose use or the use of whose house or building they may be supplied by the company despite the actual or apparent possession thereof by the person.

[S.Y. 2002, c. 186, s. 98]

99 Nonpayment of rates, etc.

If any person supplied by the company with gas, water, electricity, or other product, telephone, or other service neglects to pay the rent, rate, or charge due to the company at any of the times set for the payment thereof, the company or anyone acting under its authority on giving 48 hours previous notice to the person supplied may stop the supply of gas, water, electricity, or other product from entering or being supplied, may cut off the telephone or other service to the premises of and to the person in arrears by cutting off the service pipe or pipes, wires, or conductors or by any other means that the company or its officers see fit, and may recover the rent or charge due up to that time together with the expense of cutting off the gas, water, electricity, or other product or service as the case may be, in any competent court despite any contract to furnish for a longer time.

[S.Y. 2002, c. 186, s. 99]

100 Entry of premises by employees of company

(1) In all cases where the company may lawfully cut off and take away the supply of gas, water, electricity, or other product or service from any house, building, or premises the company, their agents, or their workers on giving 48 hours previous notice to the person in charge or the occupier may enter into the house, building, or premises between the hours of nine o'clock in the forenoon and five o'clock in the afternoon, making as little disturbance and inconvenience as possible, and may remove and take away any pipe, meter, cock, branch, lamp, fitting, telephone, or other apparatus the property of and

98 Insaisissabilité

Ni le service, ni les canalisations, fils ou conducteurs d'une société ni les autres biens d'une société — compteurs, lampes, tuyaux, installations de gaz ou installations électriques — ne peuvent être saisis pour non-paiement de loyer par le possesseur ou le propriétaire des biens où ils se trouvent, ni répondre de la dette de toute personne à la maison ou aux bâtiments de laquelle ils peuvent être fournis par la société en dépit de toute possession réelle ou apparente de cette personne.

[L.Y. 2002, ch. 186, art. 98]

99 Non-paiement

Si une personne à qui une société fournit du gaz, de l'eau, de l'électricité ou tout autre produit, un service téléphonique ou autre omet de payer les loyers, taux ou droits dus à la société dans les délais prévus pour leur paiement, la société ou toute personne qui peut agir pour celle-ci peut, après lui avoir donné un préavis de 48 heures, interrompre la fourniture ou le service par les moyens qu'elle ou son personnel estime indiqués, y compris par débranchement des canalisations, des conduites, des fils ou des conducteurs; elle peut recouvrer ces arriérés et les frais liés à l'interruption du service devant tout tribunal compétent, en dépit de tout contrat prévoyant la fourniture pour une durée plus longue.

[L.Y. 2002, ch. 186, art. 99]

100 Droit d'entrée du personnel

(1) Dans les cas où elle peut légalement interrompre la fourniture du service de gaz, d'eau, d'électricité ou de tout autre produit ou service d'une maison, d'un bâtiment ou d'un lieu, la société, ses mandataires ou ses travailleurs peuvent, sur préavis de 48 heures à la personne en charge ou à l'occupant des lieux, y pénétrer entre 9 h et 17 h et, avec le moins d'interruption ou d'inconvénient possible, retirer tout équipement lui appartenant.

belonging to the company.

(2) Any servant duly authorized by the company may between the hours referred to in subsection (1) enter any house into which gas, water, electricity, or other product or service have been taken or supplied for the purpose of repairing and making good any such house, building, or premises or for the purpose of examining any meter, pipe, apparatus, or fitting belonging to the company or used for their gas, water, electricity, or other product or service.

(3) If any person does not permit the servants and officers of the company to enter and perform the acts referred to in subsection (1) or (2), the person so refusing or obstructing shall incur a penalty to the company, for every such offence, of \$20, and a further penalty of \$4 for every day during which the refusal or obstruction continues.

[S.Y. 2002, c. 186, s. 100]

101 Discontinuance of service

If any customer discontinues the use of the gas, or other means of lighting or heating, or water, electricity, or power or other product or service furnished or supplied by a company subject to the provisions of this Part, or the company lawfully refuses to continue any longer to supply it, the officers and servants of the company may at all reasonable times enter the premises in or on which the customer was supplied with gas, or other means of lighting or heating, water, electricity, power, or other product or service for the purpose of removing therefrom any fittings, machine, apparatus, meters, pipes, wires, conductors, telephones, or other things, being the property of the company, in or on the premises and may remove them therefrom, doing no unnecessary damage.

[S.Y. 2002, c. 186, s. 101]

102 Expropriation

(1) If it is deemed proper to conduct any of the pipes, wires, or conductors or to carry any of the works of the company through the lands of any person lying within or without 10 miles of the locality for supplying which the company is incorporated and the consent of the person cannot be obtained for that purpose, the company may take or use the land required and nominate and appoint a disinterested person and the owner or owners of the land taken or damaged may nominate and appoint a third person and those three

(2) Le personnel dûment autorisé par la société peut, durant ces heures, entrer dans toute maison où un service de gaz, d'eau ou d'électricité ou d'autre produit ou service a été offert afin de réparer cette maison, ce bâtiment ou ce lieu ou afin d'examiner tout compteur, canalisation, appareil ou installation appartenant à la société ou utilisé pour la fourniture de gaz, d'eau, d'électricité ou d'autre produit ou service.

(3) Quiconque ne permet pas au personnel de la société de pénétrer sur les lieux et d'accomplir les actions mentionnées aux paragraphes (1) et (2) est passible d'une amende de 20 \$ payable à la société pour toute violation et de 4 \$ pour toute journée pendant laquelle le refus ou l'obstruction continue.

[L.Y. 2002, ch. 186, art. 100]

101 Interruption du service

Si un client interrompt l'utilisation de gaz ou de tout autre moyen de chauffage ou d'électricité, ou cesse d'utiliser de l'eau, de l'électricité ou de l'énergie ou tout autre produit ou service fourni par une société assujettie à la présente partie ou que la société refuse légalement de continuer à les offrir, son personnel peut à toute heure convenable entrer sur les lieux où le service ou le bien était fourni afin d'y enlever, sans causer de dommages inutiles, les installations, appareils, canalisations, accessoires, conducteurs, téléphones et autres objets lui appartenant.

[L.Y. 2002, ch. 186, art. 101]

102 Expropriation

(1) S'il est réputé indiqué de faire passer des canalisations, fils ou conducteurs ou de mener des travaux à travers le bien-fonds d'une personne, s'ils sont situés à moins ou à plus de 10 milles de la localité pour l'approvisionnement de laquelle la société a été constituée en personne morale, et que le consentement de cette personne ne peut être obtenu à cette fin, la société peut prendre et utiliser le bien-fonds requis et nommer toute personne désintéressée, et le propriétaire du terrain en cause peut nommer une



persons shall act as arbitrators in the matter between the company and the owner or owners of the property.

(2) Nothing in this section authorizes the company to take or use any house, land, or property in contravention of section 94.

[S.Y. 2002, c. 186, s. 102]

103 Powers and duties of arbitrators

The arbitrators shall examine all witnesses and administer all necessary oaths or declarations to them, and the arbitrators or a majority of them shall award, determine, and adjudge what sum or sums of money respectively shall be paid to the owner or owners of the property so taken or damaged by the company.

[S.Y. 2002, c. 186, s. 103]

104 Payment of award

The sum or sums of money so awarded shall be paid within three months after the date of the award and in default of the payment the owner or owners may resume the possession of the property with all the rights appertaining thereto, but the company shall be held liable to the owner for any damage it may have done to the property.

[S.Y. 2002, c. 186, s. 104]

105 Failure to appoint arbitrator

In the event of the company or the owner of the property failing to appoint an arbitrator after eight days notice from one of the parties to the other or of the two arbitrators failing to appoint a third, a judge of the Supreme Court may appoint a third arbitrator and the decision of the three arbitrators or a majority of them shall be binding on all parties concerned.

[S.Y. 2002, c. 186, s. 105]

106 Duty of company to supply utility service

All companies having the privileges conferred by this Part shall supply the utility controlled by them to all persons within the area covered by the privilege except in those cases where the company may lawfully refuse to supply the utility.

[S.Y. 2002, c. 186, s. 106]

tierce personne, et ces trois personnes agissent à titre d'arbitres entre la société et le propriétaire.

(2) Le présent article n'a pas pour effet d'autoriser la société à prendre ou à utiliser une maison, un bien-fonds ou des biens contrairement à l'article 94.

[L.Y. 2002, ch. 186, art. 102]

103 Attributions des arbitres

Les arbitres interrogent les témoins et font prêter les serments ou passer les déclarations nécessaires, et eux-mêmes ou une majorité d'entre eux déterminent la somme d'argent destinée à indemniser le ou les propriétaires en cause.

[L.Y. 2002, ch. 186, art. 103]

104 Paiement de l'indemnité

L'indemnité attribuée par les arbitres doit être payée dans les trois mois après la date de la sentence, et, à défaut, le ou les propriétaires peuvent reprendre possession du bien avec tous les droits y afférents, mais la société peut être tenue pour responsable envers eux de tout dommage causé au bien.

[L.Y. 2002, ch. 186, art. 104]

105 Défaut de nommer un arbitre

Si la société ou le propriétaire du bien ne nomme pas un arbitre dans les huit jours d'un avis à l'une ou l'autre partie ou si les deux arbitres omettent d'en nommer un troisième, un juge de la Cour suprême peut nommer le troisième arbitre, et la décision des trois arbitres ou d'une majorité d'entre eux lie les parties concernées.

[L.Y. 2002, ch. 186, art. 105]

106 Obligation des sociétés

Les sociétés disposant des privilèges conférés par la présente partie sont tenues de fournir le service public qu'elles contrôlent à toutes les personnes se trouvant dans la zone visée, sauf si elles peuvent légalement refuser de le faire.

[L.Y. 2002, ch. 186, art. 106]

TAB 2



PUBLIC UTILITIES ACT

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

RATE POLICY DIRECTIVE (1995)

**INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE
(1995)**

O.I.C. 1995/090

DÉCRET 1995/090

Effective Date:

May 29, 1995

Date d'entrée en vigueur :

29 mai 1995

O.I.C. 1995/090
PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE (1995)

Pursuant to sections 17 and 18 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows:

1. Order-in-Council 1991/062 is hereby revoked.
2. The annexed *Rate Policy Directive (1995)* is hereby made.

Dated at Whitehorse, in the Yukon Territory, this 29th day of May, 1995.

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

Le Commissaire en conseil exécutif, conformément aux articles 17 et 18 de la *Loi sur les entreprises de service public*, décrète ce qui suit :

1. Le décret 1991/062 est, par les présentes, abrogé.
2. Les *instructions sur la politique tarifaire (1995)*, paraissant en annexe, sont par les présentes adoptées.

Fait à Whitehorse, dans le territoire du Yukon, ce 29 mai 1995.

Commissioner of the Yukon/Commissaire du Yukon



RATE POLICY DIRECTIVE (1995)

TABLE OF CONTENTS

Section	Page
1. Interpretation	1
2. Normal return on equity	2
2.1 Retail and major industrial rate adjustments	2
3. Normal principles to apply	2
4. Retail rates: non-government customers.....	3
5. Retail rates: government customers.....	3
6. Rates - major and isolated industrial customers	4
7. Wholesale rates	4
8. Fuel Price adjustment	5
9. Fuel costs and low water deferral account.....	5
10. Recovery of costs for demand-side management program	7
11. Recovery of costs for renewable generation project planning or development	8

SCHEDULE A

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

TABLE DES MATIÈRES

Article	Page
1. Définitions	1
2. Rendement normal sur la valeur nette	2
2.1 Ajustements tarifaires pour les clients au détail et industriels majeurs.....	2
3. Application des principes normaux	2
4. Tarifs au détail pour les clients non-gouvernementaux...	3
5. Tarifs au détail pour les clients gouvernementaux.....	3
6. Tarifs pour les clients industriels majeurs et isolés.....	4
7. Tarifs de gros.....	4
8. Ajustement du prix du combustible	5
9. Coûts du combustible et compte de report de bas niveau d'eau	5
10. Recouvrement des coûts d'un programme de gestion axée sur la demande	7
11. Recouvrement des coûts de planification ou de développement de projets de production d'énergie renouvelable	8

ANNEXE A



RATE POLICY DIRECTIVE (1995)

1. Interpretation

In this Directive

“customer” refers to a purchaser of electricity; « *client* »

“government customer” means a retail customer

- (a) who is a federal or territorial department or agency;
- (b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a); « *client gouvernemental* »

“isolated industrial customer” means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer; « *client industriel isolé* »

“major industrial customer” means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer; « *client industriel majeur* »

“natural gas” includes liquefied natural gas; « *gaz naturel* »

[“natural gas” added by O.I.C. 2018/220]

“province” has the same meaning as in the *Interpretation Act*; « *province* »

“renewable generation” means generation of electricity from renewable sources, including hydro, wind, solar, geothermal and biomass sources; « *production d'énergie renouvelable* »

[“renewable generation” added by O.I.C. 2021/16]

“retail customer” means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer, an isolated industrial customer, or a wholesale customer; « *client au détail* »

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

1. Définitions

Les définitions qui suivent s'appliquent aux présentes instructions :

« **client** » Acheteur d'électricité; « *client* »

« **client au détail** » Client de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited qui n'est ni un client industriel majeur, ni un client industriel isolé, ni un client en gros; « *retail Customer* »

« **client en gros** » La Yukon Electrical Company Limited lorsqu'elle achète de l'énergie de la Société d'énergie du Yukon; « *wholesale customer* »

« **client gouvernemental** » Client au détail qui est:

- a) soit un organisme gouvernemental, un ministère fédéral ou territorial;
- b) soit un organisme qui n'exploite aucune entreprise à des fins lucratives et dont le financement provient en totalité, ou pour l'essentiel, d'un organisme décrit à l'alinéa a); « *government customer* »

« **client industriel isolé** » Client qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont l'approvisionnement en électricité est indépendant de celui de tout autre client; « *isolated industrial customer* »

« **client industriel majeur** » Client autre qu'un client industriel isolé qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont la demande de pointe d'électricité dépasse 1 MW. « *major industrial customer* »

« **gaz naturel** » S'entend notamment du gaz naturel liquéfié. « *natural gas* »

[« *gaz naturel* » ajoutée par Décret 2018/220]

« **production d'énergie renouvelable** » Production d'électricité à partir de sources d'énergie renouvelable, y compris l'énergie hydroélectrique, l'énergie éolienne, l'énergie solaire, l'énergie géothermique et la biomasse. « *renewable generation* »

“wholesale customer” means the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation. « *client en gros* »

2. Normal return on equity

(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

(3) When finalizing the interim 1997 rates made by Board Order 1997-6, the Board may adjust the 1997 fair return provided on Yukon Energy Corporation's equity and on Yukon Electrical Company Limited's equity.

[Section 2 replaced by O.I.C. 1998/32]

2.1 Retail and major industrial rate adjustments

(1) The Board must ensure that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

[Subsection 2.1(1) added by O.I.C. 2008/149]

[Subsection 2.1(1) replaced by O.I.C. 2012/68]

[Subsection 2.1(1) amended by O.I.C. 2018/220]

(2)

[Subsection 2.1(2) added by O.I.C. 2008/149]

[Subsection 2.1(2) replaced by O.I.C. 2012/68]

[Subsection 2.1(2) repealed by O.I.C. 2018/220]

(3)

[Subsection 2.1(3) added by O.I.C. 2012/68]

[Subsection 2.1(3) amended by O.I.C. 2014/23]

[Subsection 2.1(3) repealed by O.I.C. 2018/220]

3. Normal principles to apply

Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles

[« production d'énergie renouvelable » ajoutée par Décret 2021/16]

« province » S'entend d'une province au sens de la *Loi d'interprétation*. “*province*”

2. Rendement normal sur la valeur nette

(1) Sous réserve du paragraphe 2, la Régie doit prévoir dans les tarifs de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited les mesures pour réaliser un rendement équitable sur leur valeur nette utilisé pour financer leurs tarifs de base.

(2) La Régie doit inclure dans les tarifs de la Société d'énergie du Yukon des mesures pour réaliser un rendement équitable sur la valeur nette de cette dernière, moins 5 dixièmes pour cent (.5 %).

(3) Lorsqu'elle met au point les tarifs intérimaires de 1997 établis par l'ordonnance 1997-6 de la Régie, cette dernière peut rajuster le rendement équitable de 1997 découlant de la valeur nette de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited.

[Article 2 remplacé par Décret 1998/32]

[Article 2 modifié par Décret 2021/16]

2.1 Ajustements tarifaires pour les clients au détail et industriels majeurs

(1) La Régie veille à ce que les ajustements tarifaires pour les clients au détail et industriels majeurs s'appliquent de façon uniforme en pourcentage à toutes les catégories de clients au détail et à toutes les catégories de clients industriels majeurs.

[Paragraphe 2.1(1) ajouté par Décret 2008/149]

[Paragraphe 2.1(1) modifié par Décret 2012/68]

[Paragraphe 2.1(1) modifié par Décret 2018/220]

[Paragraphe 2.1(1) modifié par Décret 2021/16]

(2)

[Paragraphe 2.1(2) ajouté par Décret 2008/149]

[Paragraphe 2.1(2) modifié par Décret 2012/68]

[Paragraphe 2.1(2) abrogé par Décret 2018/220]

(3)

[Paragraphe 2.1(3) ajouté par Décret 2012/68]

[Paragraphe 2.1(3) modifié par Décret 2014/23]

[Paragraphe 2.1(3) abrogé par Décret 2018/220]

3. Application des principes normaux

Sauf indication contraire dans les présentes instructions ou dans la Loi, la Régie examine et approuve les tarifs aux clients selon les

established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.

principes établis au Canada pour des services publics, y compris les principes établis par les organismes régulateurs des gouvernements fédéral et provinciaux réglementant les entreprises de services publics, que ces derniers soient reliés à l'électricité ou pas.

[Article 3 modifié par Décret 2021/16]

4. Retail rates: non-government customers

(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

- (a) the rates for non-government retail customers must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;
- (b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

(3) The Board must fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non-government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

5. Retail rates: government customers

(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

4. Tarifs au détail pour les clients non-gouvernementaux

(1) La Régie fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire suivante pour le Yukon :

- a) les tarifs pour les clients non-gouvernementaux doivent suffire à générer les recettes nécessaires afin de recouvrer les coûts, lesquels ne doivent pas être récupérés des clients gouvernementaux ou des clients industriels majeurs;
- b) les tarifs pour chaque catégorie de clients au détail non-gouvernementaux s'appliquent uniformément à la grandeur du Yukon et sans distinction entre la Société d'énergie du Yukon et la Yukon Electrical Company Limited.

(2) La Régie doit déterminer une série de primes de dépassement pour chaque catégorie visée de clients au détail non-gouvernementaux, lesquelles s'appliquent à la consommation de chaque client qui excède un niveau de consommation déterminée, au cours d'une période de facturation et un tel niveau de consommation déterminé par client ne peut s'appliquer qu'à la consommation atteignant 1 000 kWh ou plus pour la catégorie résidentielle de clients au détail non-gouvernementaux et de 2 000 kWh pour la catégorie de services généraux de clients au détail non-gouvernementaux.

(3) La Régie doit déterminer des primes de dépassement pour chaque catégorie de clients au détail non-gouvernementaux sur la base de principes pour l'élaboration des taux afin de favoriser l'efficacité et l'économie et, dans cette optique, des primes de dépassement peuvent être permises à l'intention de clients demeurant dans différentes communautés ou dans des zones où les taux diffèrent, en autant que ces primes de dépassement dans chaque catégorie de clients au détail non-gouvernementaux soient les mêmes pour chaque communauté ou chaque zone tarifaire à travers le Yukon, conformément aux principes pour l'élaboration des tarifs.

[Article 4 modifié par Décret 2021/16]

5. Tarifs au détail pour les clients gouvernementaux

(1) La Régie fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit :

- (a) rates for government customers may be adjusted so as to simplify the rate structure and make the rates more consistent throughout Yukon;
- (b) the rate for government customers in a community may not be lower than the rate for similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

- a) les tarifs pour les clients gouvernementaux peuvent être ajustés aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;
- b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited, ou d'un client, la Régie prend une décision sur le statut de client gouvernemental d'un client.

[Article 5 modifié par Décret 2021/16]

6. Rates - major and isolated industrial customers

(1) The Board must ensure that the rates charged to major industrial customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

[Subsection 6(1) amended by O.I.C. 2018/220]

(2) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

(3) Despite subsection (1), the Board must ensure that the rates charged to major industrial customers conform to section 2.1.

[Subsection 6(3) added by O.I.C. 2007/94]

[Subsection 6(3) replaced by O.I.C. 2012/68]

[Subsection 6(3) amended by O.I.C. 2014/23]

[Subsection 6(3) replaced by O.I.C. 2018/220]

6. Tarifs pour les clients industriels majeurs et isolés

(1) La Régie doit s'assurer que les tarifs facturés aux clients industriels majeurs, en vertu d'un contrat ou autrement, suffisent à recouvrer les coûts du service pour cette catégorie de clients. Ces coûts sont déterminés en considérant tout le Yukon comme une zone tarifaire unique et les tarifs facturés par les deux services publics doivent être les mêmes.

(2) Les tarifs s'appliquant aux clients industriels et isolés desservis par la Société d'énergie du Yukon ou la Yukon Electrical Company Limited doivent être conformes à tout contrat entre le client et ces sociétés; les coûts et les revenus liés à ces contrats ne peuvent être considérés par la Régie lorsqu'elle établit les tarifs pour d'autres clients.

(3) Malgré le paragraphe (1), la Régie veille à ce que les tarifs facturés aux clients industriels majeurs soient conformes à l'article 2.1.

[Paragraphe 6(3) ajouté par Décret 2007/94]

[Paragraphe 6(3) remplacé par Décret 2012/68]

[Paragraphe 6(3) modifié par Décret 2014/23]

[Paragraphe 6(3) remplacé par Décret 2018/220]

[Article 6 modifié par Décret 2021/16]

7. Wholesale rates

The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

- (a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

7. Tarifs de gros

La Régie doit déterminer les tarifs facturés par la Société d'énergie du Yukon au client en gros selon la politique tarifaire du Yukon qui suit :

- a) la Société d'énergie du Yukon vend de l'électricité à la Yukon Electrical Company Limited au même tarif de demande et au même tarif d'énergie à la grandeur du Yukon et ces tarifs doivent suffire à la Société d'énergie du Yukon pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

- (b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

- b) le tarif de gros facturé à la Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Société d'énergie du Yukon de recouvrer ses coûts de service au détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s'appliquent à ces services en vertu des présentes.

[Article 7 modifié par Décret 2021/16]

8. Fuel Price adjustment

The Board must permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates to retail customers, major industrial customers, and isolated industrial customers so as to reflect fluctuations in the prices for which the two utilities pay for diesel fuel and natural gas, without the requirement for specific application to and approval of the Board.

[Section 8 amended by O.I.C. 2018/220]

8. Ajustement du prix du combustible

La Régie permet à la Société d'énergie du Yukon et à la Yukon Electrical Company Limited d'ajuster les tarifs facturés aux clients au détail, aux clients industriels majeurs et aux clients industriels isolés de manière à refléter les fluctuations des prix payés pour le mazout et le gaz naturel par ces deux sociétés, sans avoir à faire une demande particulière à la Régie pour obtenir son autorisation.

[Article 8 modifié par Décret 2018/220]

[Article 8 modifié par Décret 2021/16]

9. Fuel costs and low water deferral account

- (1) In this section

“long-term average annual renewable source availability” means the annual amount of renewable generation that would be available to contribute to meeting forecast or actual customer requirements, based on average annual renewable source availability over the life of a renewable generation facility, as determined using available historical water records respecting long-term average annual hydro generation and available information respecting other renewable generation. *« disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable »*

- (2) The Board must include in the rates of Yukon Energy Corporation provision to recover forecast fuel costs for the amount of thermal generation needed to meet forecast customer requirements.

- (3) For the purpose of subsection (2), the Board must determine the forecast fuel costs for a financial year of Yukon Energy Corporation by

- (a) forecasting the amount of renewable generation available to contribute to meeting forecast customer requirements, based on long-term average annual renewable source availability;
- (b) forecasting the amount of thermal generation needed to meet any shortfall between the forecast renewable generation under paragraph (a) and forecast customer requirements; and

9. Coûts du combustible et compte de report de bas niveau d'eau

- (1) La définition qui suit s'applique au présent article.

« disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable » La quantité annuelle de la production d'énergie renouvelable qui serait disponible pour aider à répondre aux besoins prévus ou réels de clients, fondée sur la disponibilité annuelle moyenne de sources d'énergie renouvelable au cours de la durée utile d'une installation de production d'énergie renouvelable, déterminée à l'aide des documents historiques de niveau d'eau disponibles concernant la production hydroélectrique annuelle moyenne à long terme et les renseignements disponibles concernant d'autre production d'énergie renouvelable. *“long-term average annual renewable source availability”*

- (2) La Régie doit prévoir dans les tarifs de la Société d'énergie du Yukon les mesures pour recouvrer les coûts du combustible prévus pour la quantité de production d'énergie thermique nécessaire pour répondre aux besoins prévus de clients.

- (3) Pour l'application du paragraphe (2), la Régie détermine les coûts du combustible prévus pour un exercice de la Société d'énergie du Yukon de la façon suivante :

- a) en prévoyant la quantité de production d'énergie renouvelable disponible pour aider à répondre aux besoins prévus des clients, fondée sur la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable;
- b) en prévoyant la quantité de production d'énergie thermique nécessaire pour combler tout manque entre la production d'énergie renouvelable prévue au titre de l'alinéa a) et les besoins prévus des clients;

- (c) determining the costs of fuel for forecast thermal generation under paragraph (b) based on forecast prices for diesel fuel and natural gas as approved by the Board.

(4) After each financial year of Yukon Energy Corporation, the Board must review and approve the difference between the following:

- (a) the fuel costs for the amount of thermal generation needed to meet actual customer requirements for the financial year as a result of any shortfall between actual renewable generation and actual customer requirements;
- (b) the fuel costs for the amount of thermal generation that would have been needed to meet actual customer requirements for the financial year if renewable generation had been consistent with long-term average annual renewable source availability.

(5) The fuel costs referred to in subsection (4) are to be determined based on the forecast prices referred to in paragraph (3)(c) that are applicable to that financial year.

(6) The Board must require Yukon Energy Corporation to operate a low water deferral account for the purpose of minimizing the effect on rates for retail customers and major industrial customers that would otherwise be caused by the variation in actual renewable source availability, including the variation caused by drought conditions.

(7) For each financial year of Yukon Energy Corporation, the Board must require Yukon Energy Corporation

- (a) to credit the low water deferral account by the amount of the difference in fuel costs for thermal generation approved under subsection (4), if actual renewable source availability is greater than long-term average annual renewable source availability; or
- (b) to charge the low water deferral account by the amount of the difference in fuel costs for thermal generation approved under subsection (4), if actual renewable source availability is less than long-term average annual renewable source availability.

(8) The Board must set the maximum balance and minimum balance for the low water deferral account at amounts sufficient to achieve the purpose described in subsection (6).

(9) The Board must require that Yukon Energy Corporation apply to the Board for approval of an adjustment of rates for customers to enable

- c) en déterminant les coûts du combustible pour la production d'énergie thermique au titre de l'alinéa b) en fonction des prix prévus du mazout et du gaz naturel approuvés par la Régie.

(4) Après chaque exercice de la Société d'énergie du Yukon, la Régie examine et approuve la différence entre les éléments suivants :

- a) les coûts du combustible pour la quantité de production d'énergie thermique nécessaire pour répondre aux besoins réels de clients pour l'exercice résultant de tout manque entre la production d'énergie renouvelable réelle et les besoins réels de clients;
- b) les coûts du combustible pour la quantité de production thermique qui aurait été requise pour répondre aux besoins réels des clients pour l'exercice si la production d'énergie renouvelable avait été conforme à la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable.

(5) Les coûts du combustible mentionnés au paragraphe (4) sont déterminés en fonction des prix prévus mentionnés à l'alinéa (3)c) qui sont applicables à l'exercice en cause.

(6) La Régie exige de la Société d'énergie du Yukon qu'elle gère un compte de report de bas niveau d'eau dans le but d'atténuer les effets sur les tarifs pour les clients au détail et les clients industriels majeurs qui seraient autrement causés par la variation de disponibilité réelle de sources d'énergie renouvelable, y compris la variation causée par des conditions de sécheresse.

(7) Pour chaque exercice de la Société d'énergie du Yukon, la Régie exige de la Société d'énergie du Yukon, selon le cas :

- a) qu'elle porte au crédit du compte de report de bas niveau d'eau les sommes correspondant à la différence des coûts du combustible pour la production énergie thermique approuvés en application du paragraphe (4), si la disponibilité réelle de sources d'énergie renouvelable est supérieure à la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable;
- b) qu'elle débite le compte de report de bas niveau d'eau des sommes correspondant à la différence des coûts du combustible pour la production d'énergie thermique approuvés en application du paragraphe (4), si la disponibilité réelle de sources d'énergie renouvelable est inférieure à la disponibilité annuelle moyenne à long terme de sources d'énergie renouvelable.

(8) La Régie fixe les soldes maximal et minimal du compte de report de bas niveau d'eau aux montants suffisants pour atteindre le but mentionné au paragraphe (6).

(9) La Régie exige que la Société d'énergie du Yukon lui présente une demande d'approbation d'un ajustement tarifaire pour les clients afin de permettre, selon le cas :

(a) a drawdown of the low water deferral account if the balance of the low water deferral account is greater than the maximum balance set under subsection (8); or

(b) a replenishment of the low water deferral account if the balance of the low water deferral account is less than the minimum balance set under subsection (8).

(10) This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force.

[Section 9 added by O.I.C 2021/16]

10. Recovery of costs for demand-side management program

(1) In this section

“demand-side management program” means a measure, action or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity generation or transmission by a public utility, including through the promotion of customer use of electricity that

(a) is more efficient, or

(b) better aligns electricity supply and demand. “*programme de gestion axée sur la demande*”

(2) The Board must include in the rates of a public utility for retail customers and major industrial customers provision to recover costs the public utility reasonably incurs to provide or participate in a demand-side management program.

(3) In determining whether costs are reasonably incurred by a public utility to provide or participate in a demand-side management program, the Board must consider the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant.

(4) This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force.

[Section 10 added by O.I.C 2021/16]

a) le prélèvement du compte de report de bas niveau d'eau si le solde est supérieur au solde maximal fixé en application du paragraphe (8);

b) la reconstitution de ce compte si le solde est inférieur au solde minimal fixé en application du paragraphe (8).

(10) Le présent article s'applique seulement à l'égard d'une demande, d'un rapport ou d'un autre dépôt fait à la Régie en tout premier lieu à compter du 1^{er} novembre 2020 et pour lesquels aucune ordonnance n'a été rendue en vertu de l'article 27 de la Loi avant l'entrée en vigueur du présent article.

[Article 9 ajouté par Décret 2021/16]

10. Recouvrement des coûts d'un programme de gestion axée sur la demande

(1) La définition qui suit s'applique au présent article.

« **programme de gestion axée sur la demande** » Mesure, action ou programme destiné à promouvoir une consommation d'électricité par les clients qui optimise l'économie ou l'efficacité de la production ou la transmission d'électricité par une entreprise de service public, notamment grâce à la promotion d'une consommation d'électricité par les clients qui, selon le cas :

a) est plus efficace;

b) harmonise mieux l'approvisionnement et la demande en électricité. “*demand-side management program*”

(2) La Régie doit prévoir dans les tarifs d'une entreprise de service public pour les clients au détail et les clients industriels majeurs les mesures pour recouvrer les frais que l'entreprise de service public engage raisonnablement pour fournir un programme de gestion axée sur la demande ou y participer.

(3) Pour établir si les frais sont raisonnablement engagés par une entreprise de service public pour fournir un programme de gestion axée sur la demande ou y participer, la Régie tient compte de l'étendue de tout chevauchement entre le programme pour lequel les frais ont été engagés et un programme de gestion axée sur la demande que fournit le gouvernement du Yukon ou auquel il participe.

(4) Le présent article s'applique seulement à l'égard d'une demande, d'un rapport ou d'un autre dépôt fait à la Régie en tout premier lieu à compter du 1^{er} novembre 2020 et pour lesquels aucune ordonnance n'a été rendue en vertu de l'article 27 de la Loi avant l'entrée en vigueur du présent article.

[Article 10 ajouté par Décret 2021/16]

11. Recovery of costs for renewable generation project planning or development

(1) The Board must include in the rates of a public utility for retail customers and major industrial customers provision to recover costs the public utility reasonably incurs to plan or develop renewable generation projects.

(2) This section applies only in respect of an application, report or other filing that is made in the first instance to the Board on or after November 1, 2020 and for which no order is issued under section 27 of the Act before this section comes into force.

[Section 11 added by O.I.C 2021/16]

11. Recouvrement des coûts de planification ou de développement de projets de production d'énergie renouvelable

(1) La Régie doit prévoir dans les tarifs d'une entreprise de service public pour les clients au détail et les clients industriels majeurs les mesures pour recouvrer les frais que l'entreprise de service public engage raisonnablement pour planifier ou développer des projets de production d'énergie renouvelable.

(2) Le présent article s'applique seulement à l'égard d'une demande, d'un rapport ou d'un autre dépôt fait à la Régie en tout premier lieu à compter du 1^{er} novembre 2020 et pour lesquels aucune ordonnance n'a été rendue en vertu de l'article 27 de la Loi avant l'entrée en vigueur du présent article.

[Article 11 ajouté par Décret 2021/16]

SCHEDULE A

("Schedule A, Industrial Primary Rate Schedule 39" added by O.I.C. 2007/94)

("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2012 see Subsection 6(3))

("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2013 see Subsection 6(3), amended by O.I.C. 2012/68)

("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2018 see Subsection 6(3), amended by O.I.C. 2014/23)

(Schedule A repealed by O.I.C. 2018/220)

ANNEXE A

(« Annexe A, Clients industriels annexe tarifaire no 39 » ajoutée par décret 2007/94)

(« Annexe A, Clients industriels annexe tarifaire no 39 » valide jusqu'au 31 décembre 2012, voir paragraphe 6(3))

(« Annexe A, Clients industriels annexe tarifaire no 39 » valide jusqu'au 31 décembre 2013, voir paragraphe 6(3), modifié par Décret 2012/68)

(« Annexe A, Clients industriels annexe tarifaire no 39 » valide jusqu'au 31 décembre 2018, voir paragraphe 6(3), modifié par Décret 2014/23)

(Annexe A abrogée par Décret 2018/220)

TAB 3

Yukon Utilities Board

Board Order 2022-13
Appendix A: Reasons for Decision
November 7, 2022

1 INTRODUCTION

On July 18, 2022, ATCO Electric Yukon (AEY) filed an application with the Yukon Utilities Board (Board) entitled “Rate Relief in the Yukon” (Application). The Application was made pursuant to AEY’s April 29, 2022 letter to the Board and was intended to be consistent with the Government of Yukon Inflation Relief Rebate. In response to an information request (IR) from the Board, AEY stated that the application was being made under Sections 27, 28 and 29 of the *Public Utilities Act (Act)*¹.

On August 9, 2022, the Board issued Board Order 2022-09 which gave public notice of the application and set out a process schedule for the proceeding. Board Order 2022-09 also requested parties intending to participate in the proceeding to register in writing with the Board by August 23, 2022.

The Board received requests for intervener status from Yukon Energy Corporation (YEC), Utilities Consumers’ Group (UCG), and John Maissan. Through Board Order 2022-11, dated August 29, 2022, all requests for intervener status were granted.

All interveners were provided the opportunity to submit information requests and to make final submissions. AEY filed reply submissions.

In reaching the determinations contained within this order, the Board has carefully considered the scope of its legislative mandate as well as all relevant materials comprising the record of this proceeding, including the evidence and submissions provided by each party. Accordingly, references to specific parts of the record in these Reasons for Decision are intended to assist the reader in understanding the Board’s reasoning related to a particular matter and do not imply that the Board did not consider all relevant portions of the record.

The Board considers the record of this proceeding closed as of September 20, 2022.

2 OVERVIEW OF THE APPLICATION

In its application, YEC sought approval for two proposals:

- Approval to refund the balance accumulated in AEY’s existing Rate Case Reserve account to residential and commercial non-government customers² via a new Rider Y, effective November 1, 2022 through February 28, 2023.
- Approval of AEY’s proposed Rider R revenue refund rate relief mechanism to residential and commercial non-government customers, effective the first day of the month following a Board Decision (anticipated September 1, 2022).³

¹ AEY-YUB-1(a), PDF page 2.

² To ensure clarity, the rate classes being referred to in the Application are the residential class and the general service non-government class. For ease of reference in this decision, the Board will use “residential and commercial non-government customers”.

³ AEY Application, PDF page 2, page 2.

Details of each of these proposals will be discussed in turn. AEY requested a decision on its application by August 20, 2022.

Rate Case Reserve Refund

AEY noted that since the approval of its Rate Case Reserve (RCR) in Board Order 2017-01, there have not been significant regulatory expenses. The Rate Case Reserve collects \$0.3 million annually and has an accumulated balance of \$1.30 million to the end of 2021. AEY is proposing to refund the accumulated balance as of December 31, 2021. If the refund were to occur over the November 1, 2022 to February 28, 2022 time period, AEY calculates that its proposed Rider Y would be 7.21%, in favour of residential and commercial non-government customers.

AEY provided the following table on bill impact for the proposed Rider Y:

Table 1 – Bill Impacts for Non-Government Customers – Rider Y

Rate Class	Bill	Impact
	\$	%
Residential (800 kWh)	-\$8.06	-5.4%
General Service (5 kW/1,000 kWh)	-\$9.87	-4.8%

Rider R Revenue Rate Relief

AEY stated that, through Board Order 2017-03, AEY's ongoing Rider R was approved at 0.3% of base rates and applies to all base revenue in the Yukon. AEY's proposed rate relief to residential and commercial non-government customers would be the equivalent of Rider R revenue that is specifically recovered from industrial customers in YEC's service territory, served under Rate Schedule 39, Industrial Primary.

AEY noted that industrial revenue has increased rapidly, is material and exceeded \$0.9 million in 2021. AEY proposes that the Rider R revenue rate relief be the equivalent of the Rider R industrial revenue because it has now reached the point of being material and it has limited correlation with AEY's expenses or operations, as the Rate Schedule 39 industrial customers are located in YEC's service territory.⁴ To facilitate this proposal, AEY will record Rider R industrial revenue into a new deferral account starting in the month following a Board decision on this application. Once the balance in the deferral account accumulates to \$0.250 million, AEY will apply to the Board to disburse the balance in the deferral account via a rider to residential and commercial non-government customers. AEY recommends deferral account treatment, as the revenues for the proposed account are material and are not directly under management control for the following reasons: AEY does not interact with industrial customers in YEC service territory, does not speculate on industrial operations in YEC territory, and does not incur costs related to industrial operations in YEC service territory.

AEY said it would provide customer bill impact details for the proposed Rider R revenue refund rate relief in a future application.

⁴ AEY Application, PDF pages 2-3, pages 1-2

Views of the Parties

John Maissan

Mr. Maissan noted:

Concurrently with industrial and residential growth there has been an increasing public desire to curb climate change by reducing fossil fuel use which is probably increasing customer sales and has increased the need for additional (renewable) electricity supply.

The result has been that AEY's revenues (through Rider R and base rates) have increased substantially while their cost growth has been slower. This is not a situation of AEY's making but a set of circumstances outside of their control but which has resulted in substantially increased revenues and earnings for AEY.⁵

Mr. Maissan also noted that AEY has had five consecutive non-test years; had AEY been as responsible to their ratepayers as to their shareholders, AEY would have been before the Board no later than 2019.⁶ Mr. Maissan concluded that since there has been no scrutiny of AEY's costs and revenues for five years, it is time to have a full and complete review of these costs and revenues in view of substantial growth in industrial and residential loads and shifts in energy demands due to government policy.⁷

Regarding AEY's proposal for the Rate Case Reserve, Mr. Maissan noted that AEY is proposing providing rate relief by dispensing funds built up in the Rate Case Reserve account to the end of 2021 (\$1.30 million) to only residential and commercial non-government ratepayers. The dispensed funds would have been collected from all ratepayers, thus increasing the degree of cross-subsidization between customer classes that is a product of the existing rates. Mr. Maissan recommended that AEY cease collecting the \$300,000 annual amount that goes into the Rate Case Reserve and that amount, effective January 1, 2022, be used to reduce Rider R.

Mr. Maissan also recommended that the balance in the Rate Case Reserve account remain intact for AEY's next GRA.⁸

Mr. Maissan did not support AEY's proposal regarding Rider R revenues collected from industrial customers. In Mr. Maissan's view, AEY's proposal would exacerbate the existing rate class cross-subsidization and contribute to excess earnings. Mr. Maissan also noted that Section 29(a) of the *Act* allows any changes proposed by AEY to apply from January 1, 2022 onward.⁹

The following recommendations were made by Mr. Maissan:

1. That Rider R be further reduced so that the revenue collected by AEY per year is \$1,580,500 less than that which is presently collected.
2. That this Rider R adjustment be made retroactive to January 1, 2022.

⁵ John Maissan Final Argument, PDF page 2, page 1.

⁶ John Maissan Final Argument, PDF page 3, page 2.

⁷ John Maissan Final Argument, PDF page 3, page 2.

⁸ John Maissan Final Argument, PDF page 3, page 2.

⁹ John Maissan Final Argument, PDF page 4, page 3.

3. That the revenues in excess of the reduced Rider R already collected by AEY in 2022 be refunded to all ratepayers during the winter of 2022-2023.¹⁰

In his submission, Mr. Maissan brought forward two other matters. The first was a recommendation that the Board orders AEY to come forward with a 2023-2024 GRA and, if the Board does not have the authority to do so, to call on the Minister of Justice to order AEY to come forward with a 2023-2024 GRA. The second matter Mr. Maissan brought forward was a request for clarification on whether periodic reports filed by utilities can be referenced as relevant information by any party to a proceeding of the Board; he also requested that the Board monitor and review those periodic filings.

Utilities Consumers' Group

The UCG asserted that AEY earned in excess of \$8.4 million above the Board-approved ROE for the period of 2016-2021 inclusive. The UCG also noted that AEY's proposed \$1.3 million rate relief is funded through the Rate Case Reserve and not from return on equity (ROE).¹¹

The UCG submitted that in conjunction with providing the \$1.3 million Rate Case Reserve disbursement and the \$0.9 million deferral account for 2021 for industrial sales, the Board should also order AEY to increase the rate relief by \$4.521 million (from half of the return in excess of the approved rate of return for the years 2018-2021 and industrial revenues received by AEY for the years 2018-2020). It was UCG's position that its proposed rate relief package would total \$6.721 million.¹²

The UCG concluded by requesting that the Board order AEY to share with ratepayers the ROE above the last approved ROE for AEY on a go-forward basis and that all industrial sales received by AEY be returned to ratepayers as rate relief for the years 2022 forward. The UCG's view was that the Board has the authority to grant this under Sections 27(a) and 29(c-d) of the *Act*.

ATCO Electric Yukon

AEY's response to the interveners' position was that the approvals requested are narrow and limited in scope and that the proposals from the interveners are beyond and unconnected to AEY's application. It was added that pursuant to Section 50 of the *Act*, the minister approved a public hearing on AEY's Application, that it is the scope for the proceeding that the Minister approved and that anything beyond that is outside the scope of what the minister approved. AEY asserted that although Section 27(a) of the *Act* gives the Board jurisdiction to set rates, that power must be exercised within the confines of the application before the Board. As the application before the Board is not all-encompassing, such as a GRA, and – as AEY submitted – not an application to change AEY's approved base rates, Section 27(b) of the *Act* does not provide the Board with the jurisdiction to enlarge the scope of the application or impose entirely different rate relief measures.¹³

¹⁰ John Maissan Final Argument, PDF page 5, page 4.

¹¹ UCG Final Argument, PDF page 1.

¹² UCG Final Argument, PDF page 2.

¹³ AEY Reply Argument, PDF pages 3-4, pages 2-3.

AEY noted that UCG did not oppose the Rider Y Rate Case Reserve refund rate relief.¹⁴ AEY asserted that Mr. Maissan's position that the Rider Y proposal will increase rate subsidies between customer classes and create rate discrimination was without merit and should be rejected and, further, that Mr. Maissan's proposal for AEY to cease the collection of the approved allotment of \$300,000 for the hearing reserve effective 2022 should be rejected as it too is outside the scope of the application; the approved allotment is part of AEY's base rates. AEY's proposal simply refunds the balance in the Rate Case Reserve collected from customers, allowing AEY to implement rate relief to some ratepayers in a timely and efficient manner. This does not alter past Board approvals.¹⁵

With respect to AEY's second rate relief proposal, Rider R Revenue Rate Relief, AEY noted that UCG did not object to this proposal but recommended that all industrial rates received by AEY for 2022 onward be returned to ratepayers. AEY said that the UCG recommendation was outside the scope of the application and has no supporting evidence. AEY added: "However, to prematurely direct AEY to provide rate relief of all industrial revenue, regardless of the source, onward and beyond the timeframe contemplated in this Application is simply premature and unsupported."¹⁶

AEY's position is that the requested Rider R deferral account meets the criteria for deferral account treatment, that this is not disputed by interveners and that it should be approved as filed.¹⁷

The following comments were made by AEY regarding rate discrimination:

... AEY has consulted with the Minister of Energy, Mines and Resources to evaluate potential rate relief options for ratepayers in the Yukon. It is clear that the Yukon Government policy is that rate relief measures should be directed at residential and commercial non-government customers. AEY submits that the principle against unjust discrimination in utility rate regulation does not preclude different rates for different classes of customers, where a sufficient rationale exists to justify the distinction. AEY therefore submits that adopting rate relief measures that apply to specific classes of customers, in alignment with government policy, does not result in unjust discrimination. (footnotes removed)

As it relates to cross-subsidization, as AEY explained in response to AEY-YUB-03, a certain level of rate cross-subsidization must be expected – and has previously been approved – in the Yukon. The requirements of OIC 1995/90, whereby a moratorium on rate rebalancing exists, suggest a certain level of acceptability for cross-subsidization. AEY submits that concerns regarding alleged cross-subsidization are not a basis upon which the Application should be denied.¹⁸ (footnote removed)

¹⁴ AEY Reply Argument, PDF page 4, page 3.

¹⁵ AEY Reply Argument, PDF 5, page 4.

¹⁶ AEY Reply Argument, PDF page 6, page 5.

¹⁷ AEY Reply Argument, PDF page 7, page 6.

¹⁸ AEY Reply Argument, PDF page 7, page 6.

AEY also commented on the other recommendations made by the interveners. Firstly, regarding the attempt to capture rate relief through past earnings, AEY rejected these proposals as they view them as a form of retroactive ratemaking and outside the scope of the application.¹⁹

AEY asserted that UCG's interpretation of Section 29(c) of the *Act* is incorrect; Section 29(c) only applies after the commencement of a proceeding and Section 29(c) does not provide legislative jurisdiction to violate the prohibition against retroactive ratemaking.²⁰

Secondly, AEY made the following comments on General Rate Application (GRA) matters:

... this Application is not a GRA. Therefore, matters that are more appropriately considered in a full GRA with all the information – cost information and scope of issues that should be considered in a GRA – should not be explored by the Board in this narrow hearing.

...

Similarly, Mr. Maissan's recommendation that AEY be directed to come forward with a GRA for 2023-2024 is likewise outside the scope of this Application nor does it address the objectives of providing timely and efficient rate relief. Although to be helpful, notwithstanding it is outside the scope of this proceeding, AEY has stated in its IR responses that it is reviewing the need to file a GRA in 2024.

...

AEY is also mindful that having not filed a GRA 2018-2022, in addition to reducing regulatory burden, the accumulated rate reserve is being refunded as rate relief, thereby benefitting ratepayers. In the Yukon, consistent with an appropriate approach to regulation, there is no requirement that AEY file a GRA every year; rather, AEY must apply to the Board for approval prior to changing rates (*Act*, s. 28). Indeed, in the past there have likewise been periods where a rate case was not required to be filed every year, and the utility continued to operate under Board approved rates until bringing forward an Application to change those rates.²¹

AEY submitted that for the above reasons, the recommendations proposed by the interveners should be rejected.

Views of the Board

Scope of the Application

The Board has the legislative jurisdiction to make decisions on actual applications that are before it. In this application, the relief requested is for approval to refund amounts in the Rate Case Reserve account and to establish a deferral account on a go-forward basis. The Application is not

¹⁹ AEY Reply Argument, PDF pages 8-9, pages 7-8.

²⁰ AEY Reply Argument, PDF page 9, page 8.

²¹ AEY Reply Submission, PDF page 10, page 11.

requesting approvals for a change in rates or new rates. As such, it is a misnomer to refer to “rate relief” in the Application.

The Board has jurisdiction to set rates under Sections 27, 28 and 29 of the Act. In accordance with these sections, the Board authorized on April 27, 2017, in Appendix A to Board Order 2017-01, a deferral account entitled “Rate Case Reserve” in which money collected from customers is placed in the deferral account to be used for hearing costs for applications. Money from this account cannot be used for any other purpose. This has resulted in the request to refund the money in the deferral account to certain customers. The other requested relief is to create a deferral account for purposes of providing a refund to certain classes of customers. Money collected from industrial customers in YEC’s service territory, served under Rate Schedule 39, Industrial Primary, would be placed in the deferral account and any refund from such an account would be addressed in a future application.

Although the interveners have asked the Board to consider additional remedies such as considering past ROEs, changes to rates or directing AEY to file a General Rate Application, the Board considers that these requests are outside the scope of this Application.

Rate Case Reserve

The Board notes that AEY has proposed to disburse \$1.30 million accumulated in the Rate Case Reserve to residential and commercial non-government customers to the end of 2021. The amount accumulated in the RCR was collected from all rate classes.²² The Board is of the view that refunding this amount solely to residential and commercial non-government customers would result in discrimination between customer classes. The Board considered whether refunding this amount to only residential and commercial non-government customers would result in discrimination between customer classes. The Board noted that the principles governing utility regulation allow for discrimination in situations where a utility fails to treat all users of a public utility equally if there is a compelling distinction to be found between those favoured and those not favoured. Unless there is sufficient rationale to justify different treatment for different classes of customers, the difference in treatment results in unjust discrimination in utility rate regulation.

In assessing whether the proposed refund would result in unjust discrimination, the Board considered the submissions of AEY noted above, which took the position that its proposed refund did not result in unjust discrimination. The Board also considered the following response by AEY when asked if the proposed refunding of the balance in the RCR account was rate discrimination:

As discussed in AEY-YUB-01, the proposed rate relief outlined in the Application aligns with the Government of Yukon’s initiative to provide rate relief via the Inflation Relief Rebate. Like AEY’s proposal, that government initiative was only available to non-government residential and commercial customers.

²² AEY-YUB-1-3(a), PDF page 5.

Furthermore, AEY submits a certain level of rate cross-subsidization must be expected – and has previously been approved – in the Yukon. The requirements of OIC 1995/90, whereby a moratorium on rate rebalancing exists, suggest a certain level of acceptability for cross-subsidization. The very nature of approved government & non-government rates for the same class of service also suggest a certain level of acceptability for cross-subsidization.²³

The Board finds that the proposed rationale provided by AEY for refunding the amount collected from all customers to only some customers does not justify treating customer classes differently. Although the Government of Yukon’s policy only applies to certain classes, it does not override the general regulatory principle that all customer classes be treated equally unless there is sufficient justification for proposed treatment of different customer classes. Further, any cross-subsidization that exists due to the requirements of OIC 1995/90 is mandated by that legislative instrument and not by government policy. The Board finds that the proposed refund would result in unjust discrimination among customer classes.

Therefore, the Board does not approve the Application for Rider Y as proposed and directs AEY to refund to all customer classes the accumulated amounts to the end of 2021 in the RCR account. In other words, AEY shall disburse the amounts in the RCR account accumulated to the end of 2021 through a Rider Y over a similar term as proposed in the current application across all rate classes. AEY shall provide its compliance to this direction by November 30, 2022. The compliance application will be effective December 1, 2022, and AEY shall treat its compliance filing as a filing for acknowledgement (meaning no further process) and will provide a Word version of the Rider Y schedule to the Board.

Rider R Rate Relief

As described above, the Board notes that AEY has proposed to create a deferral account to track Rider R industrial revenue for purposes of a refund to certain classes of customers. The tracking is to begin the first day of the month following a Board Order on this application. Once the deferral account balance accumulates to \$0.25 million, AEY will apply to the Board to disburse the amounts in this deferral account to residential and commercial non-government customers. AEY added that it will update the rider on a periodic basis to provide ongoing rate relief as necessary.²⁴

The Board accepts the submission from AEY that this industrial revenue “has limited correlation with AEY’s expenses or operations as the Rate 39 industrial customers are located in YEC’s service territory.”²⁵ AEY further supported this position by stating:

As AEY is seeking a deferral account to track Rider R Industrial Revenue for the purposes of the proposed rate relief, AEY addresses below how this deferral is in line with the standard criteria for a deferral account as set out in Order 2014-06, which includes:

²³ AEY-YUB-1-03(b), PDF pages 5-6.

²⁴ AEY Application, PDF pages 3-4, pages 2-3.

²⁵ AEY Application, PDF page 3, page 2.

- Under management's control: AEY does not interact with Industrial customers in YEC's service territory, so has limited visibility into their operations. AEY does not monitor or forecast metal commodity markets and is unable to speculate on ongoing industrial operations in YEC's service territory. Finally, AEY does not incur any specific costs related to industrial operations in YEC's service territory that might vary in tandem with increased or decreased industrial operations or revenue.
- Materiality: Rider R Industrial Revenue has increased to more than \$0.9 million in 2021. Also, AEY notes Rider R Industrial Revenue changes have no corresponding adjustment to AEY's expenses.²⁶

Therefore, the Board is satisfied that AEY has made a case for a deferral account to record all industrial sales revenues recovered from industrial customers in YEC's service territory served under Rate Schedule 39, Industrial Primary, from the date of this decision and to continue to do so on a go-forward basis. This is because it is not readily apparent that AEY has placed any end date with respect to this proposed deferral account. AEY stated that "AEY will update the refund rider on a periodic basis, as necessary, to provide ongoing rate relief."²⁷ Therefore, the Board directs that AEY set up such a deferral account.

Once the balance in the deferral account accumulates to \$0.25 million, AEY will make an application to the Board to dispense with the balance in that deferral account.

Regarding future disbursements from this deferral account to solely residential and commercial non-government customers, the Board finds that there is justification for the distribution of the balance of the deferral account to these customer classes alone and that it does not result in unjust discrimination for the following reasons. This deferral account is established to contain future revenue from Rate Schedule 39 industrial customers that would otherwise be retained by AEY. Also, AEY does not incur any specific costs related to industrial operations in YEC's service territory that might vary in tandem with increased or decreased industrial operations or revenue. Further, the Board considers that any disbursement from this deferral account is billing relief and not a refund to such customers.

For these reasons, the Board finds that any disbursement of the balance in this deferral account may apply solely to residential and commercial non-government customers.

Other Matters

Mr. Maissan inquired whether information filed with the Board by the regulated utilities (AEY and YEC) can be referenced and relied upon. All information filed with the Board is public information and may be referenced in a proceeding on an application.

²⁶ AEY Application, PDF page 4, page 3.

²⁷ AEY Application, PDF page 4, page 3.

TAB 4



July 18, 2022

Yukon Utilities Board
PO Box 31728
Whitehorse, YK Y1A 6L3

Attention: Mr. Richard Buchan
Chair

**Re: ATCO Electric Yukon's (AEY)
Rate Relief in the Yukon**

Attached please find ATCO Electric Yukon's (AEY) Application regarding rate relief in the Yukon.

Please contact me at chris.cullingham@atco.com if you have any questions about this submission.

Yours truly,

Chris Cullingham
Manager, Regulatory

I. Introduction

1. Pursuant to ATCO Electric Yukon's (AEY) April 29, 2022 letter to the Yukon Utilities Board (YUB), and in alignment with government initiatives regarding the Inflation Relief Rebate, AEY submits this Application to propose rate relief for residential and commercial non-government ratepayers¹ in the Yukon.
2. This Application seeks approval for two proposals related to rate relief which can be implemented in a timely fashion:
 - Approval to refund the balance accumulated in AEY's Rate Case Reserve account to residential and commercial non-government customers, via a new Rider Y, effective November 1, 2022 through February 28, 2023.
 - Approval of AEY's proposed Rider R revenue refund rate relief mechanism to residential and commercial non-government customers, as described below, effective the first day of the month following a Board Decision (anticipated September 1, 2022).
3. Because this Application is straightforward and has a narrow scope, AEY is proposing a streamlined schedule which would entail, if required, a deadline for participant registration, followed by written submissions regarding the rate relief proposals. To prepare to track and subsequently refund Rider R revenue for an anticipated starting date of September 1, 2022, AEY is requesting a decision by August 20, 2022.

II. Discussion

Rate Case Reserve Refund

4. The Rate Case Reserve deferral was approved as part of AEY's 2016/17 General Rate Application (GRA) in Board Order 2017-01.²

¹ The Yukon Government announced the Inflation Relief Rebate on March 22, 2022. Accessed here on May 17, 2022: <https://yukon.ca/en/news/new-temporary-inflation-relief-rebate-save-yukoners-and-local-businesses-150-their-electricity-bills>. The rebate will be applied automatically to all residential and commercial ATCO Electric Yukon and Yukon Energy electricity bills in the coming months.

² Appendix A to Board Order 2017-01, Paragraph 395.

5. Since that proceeding, AEY has not incurred significant regulatory expense. Due to the annual collection of \$0.3 million Rate Case Reserve costs in base rates, the Rate Case Reserve balance has accumulated to approximately \$1.3 million (as of December 31, 2021). AEY will continue to collect the annual amount in its base rates, however, is proposing to refund the accumulated balance as of December 31, 2021.
6. Forecast non-government residential and commercial base revenue for AEY and YEC customers for the November 1, 2022 to February 28, 2023 period is \$18.03 million.
7. The Rider is determined as follows:

$$\text{Rider Y} = \frac{\$1.3 \text{ M}}{\$18.03 \text{ M}} = 7.21\%$$

8. Rider R Revenue Rate Relief

9. In Board Order 2017-03, AEY's ongoing Rider R was approved at 8.3% of base rates. Rider R applies to all base revenue in the Yukon. AEY proposes that the rate relief would be the equivalent of Rider R revenue that is specifically recovered from industrial customers in YEC's service territory served under Rate Schedule 39, Industrial Primary ("Rider R Industrial Revenue").
10. Since AEY's 2016/17 General Rate Application, Rider R Industrial Revenue has increased rapidly and is now material – exceeding \$0.9 million in 2021. AEY proposes that the Rider R Revenue rate relief be the equivalent of the Rider R Industrial Revenue because it is now material,³ and it has limited correlation with AEY's expenses or operations as the Rate 39 industrial customers are located in YEC's service territory. This is further discussed below.
11. To facilitate the proposed Rider R Revenue rate relief, AEY is proposing to record Rider R Industrial Revenue in a new deferral account, beginning the first day of the month following a Board Decision. Once this deferral account's balance has accumulated to

³ Using Rider R Industrial Revenue from 2021, the estimated rider refund to non-government residential and commercial customers is approximately 2%.

\$0.250 million, AEY will apply to the Board to begin refunding this deferral account via a rider to residential and commercial non-government customers.⁴ AEY will update the refund rider on a periodic basis, as necessary, to provide ongoing rate relief.

12. As AEY is seeking a deferral account to track Rider R Industrial Revenue for the purposes of the proposed rate relief, AEY addresses below how this deferral is in line with the standard criteria for a deferral account as set out in Order 2014-06, which includes:

- Under management's control: AEY does not interact with Industrial customers in YEC's service territory, so has limited visibility into their operations. AEY does not monitor or forecast metal commodity markets and is unable to speculate on ongoing industrial operations in YEC's service territory. Finally, AEY does not incur any specific costs related to industrial operations in YEC's service territory that might vary in tandem with increased or decreased industrial operations or revenue.
- Materiality: Rider R Industrial Revenue has increased to more than \$0.9 million in 2021. Also, AEY notes Rider R Industrial Revenue changes have no corresponding adjustment to AEY's expenses.

III. Customer Bill Impact

13. Bill impacts for non-government customers resulting from the requested Rider Y (Rate Case Reserve Refund Rate Relief) are provided in the following table. Bills include all Riders but exclude the GST.

Table 1 - Bill Impacts for Non-Government Customers – Rider Y

Rate Class	Bill Impact	
	\$	%
Residential (800kWh)	-\$8.06	-5.4%
General Service (5kW / 1,000kWh)	-\$9.87	-4.8%

14. AEY will provide customer bill impact details for the proposed Rider R revenue refund rate relief in a future application (as discussed above).

⁴ As noted above, the Yukon Government's Inflation Relief Rebate is applicable to all non-government residential and commercial ATCO Electric Yukon and Yukon Energy customers.

IV. Implementation Date & Board Approval

15. As this Application is straightforward, has a narrow scope and is in line with government rate relief measures, AEY is proposing a streamlined schedule which would entail, if required, a deadline for participant registration, followed by written submissions regarding the rate relief proposals. If the proposal is approved, AEY will begin recording Rider R Industrial Revenue in a new deferral account on the first day of the month following a Board Decision and will implement Rider Y from November 1, 2022 to February 28, 2023, as described above.

TAB 5

Yukon Utilities Board

Board Order 2017-01

Appendix A: Reasons for Decision

April 27, 2017

Contents

1	Introduction	7
2	AEY Sales and Revenue	9
2.1	Overview	9
2.2	Views of the Applicant.....	10
2.2.1	Residential sales forecast.....	11
2.2.2	Commercial sales forecast	11
2.2.3	Views of interveners	12
2.2.4	Views of the Board	13
3	Purchase power	14
3.1	Views of interveners.....	15
3.2	Applicant responses to interveners	15
3.3	Views of the Board	15
3.4	Deferral Account — Purchase Power Flow-Through.....	15
3.4.1	Views of interveners	15
3.4.2	Applicant responses to interveners	16
3.4.3	Views of the Board	16
4	Fuel costs	16
4.1	Views of the Board	17
4.2	Deferral Account — LNG Fuel.....	17
4.3	Views of interveners.....	18
4.4	Applicant responses to interveners	18
4.5	Views of the Board	19
5	Operations and maintenance expense.....	19
5.1	Labour	19
5.1.1	Labour complement.....	20
5.1.2	Views of interveners	20
5.1.3	Views of the Board	20
5.2	Vacancy rate	21
5.2.1	Views of interveners	21
5.2.2	Views of the Board	21
5.3	Labour inflation.....	21
5.3.1	Views of interveners	21
5.3.2	Views of the Board	22
5.4	Pension matters	23
5.4.1	Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account	23
5.4.2	Views of the Board	24
5.5	Other Inflation.....	24
5.5.1	Views of interveners	24
5.5.2	Views of the Board	24
5.6	Non-labour costs	25
5.6.1	Views of interveners	25

5.6.2	Views of the Applicant	26
5.6.3	Views of the Board	27
6	Taxes Other Than Income	30
6.1	Views of interveners	31
6.2	Applicant responses to interveners	31
6.3	Views of the Board	31
7	Depreciation	31
7.1	Technical update to determine updated depreciation rates	32
7.1.1	Views of interveners	32
7.1.2	Views of the Board	32
7.2	Use of the mid-year convention for calculation of depreciation expense	34
7.2.1	Views of the Board	35
7.3	Supporting documentation for the amortization of accumulated depreciation reserve differences	35
7.3.1	Views of the Board	35
8	Return on rate base	36
8.1	Cost of capital	36
8.1.1	Rate of return on capital	36
8.1.2	Applicant responses to interveners	36
8.1.3	Views of the Board	37
8.1.4	Equity premium	37
8.1.4.1	Views of interveners	38
8.1.4.2	Applicant responses to interveners	40
8.1.4.3	Views of the Board	40
8.1.5	Common equity ratio	44
8.1.5.1	Views of the Board	45
8.1.6	Cost of debt	45
8.1.6.1	Views of interveners	46
8.1.6.2	Applicant responses to interveners	46
8.1.6.3	Views of the Board	46
8.2	No Cost Capital	47
8.2.1	Views of the Board	48
9	Capital additions	48
9.1	Views of interveners	49
9.2	Applicant responses to interveners	50
9.3	Views of the Board	50
9.4	Distribution Plant additions	50
9.4.1	Views of interveners	51
9.4.2	Views of the Board	51
9.4.3	New Extensions	51
9.4.3.1	Views of interveners	52
9.4.3.2	Views of the Board	52
9.4.4	Distribution improvement projects	53
9.4.4.1	Views of interveners	53
9.4.4.2	Views of the Board	54

9.4.5	Meters	54
9.4.5.1	Views of interveners	55
9.4.5.2	Views of the Board	55
9.5	Conversion of existing LED streetlights	55
9.5.1	Views of interveners	56
9.5.2	Applicant responses to interveners	56
9.5.3	Views of the Board	56
9.6	Project cost overruns (related to Direction 13 — Board Order 2014-06)	57
9.6.1	Views of interveners	58
9.6.2	Applicant responses to interveners	59
9.6.3	Views of the Board	60
9.7	Major capital projects	61
9.7.1	Fish Lake System expenditures	61
9.7.1.1	Fish Lake Ditch 3 Diversion project (Appendix 1)	61
9.7.1.2	Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)	61
9.7.1.3	Views of interveners	62
9.7.1.4	Applicant responses to interveners	62
9.7.1.5	Views of the Board	62
9.7.2	Watson Lake Bi-Fuel Project (Appendix 3)	63
9.7.2.1	Views of interveners	65
9.7.2.2	Applicant responses to interveners	66
9.7.2.3	Views of the Board	67
9.7.3	Old Crow Unit 3 replacement (Appendix 5)	70
9.7.3.1	Views of interveners	70
9.7.3.2	Applicant responses to interveners	71
9.7.3.3	Views of the Board	71
9.7.4	Destruction Bay unit replacement	71
9.7.4.1	Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)	71
9.7.4.2	Views of interveners	72
9.7.4.3	Applicant response to interveners	73
9.7.4.4	Views of the Board	73
9.7.5	McIntyre subdivision rebuild (Appendix 8)	74
9.7.5.1	Views of the Board	75
9.7.6	Significant capital projects	76
9.7.6.1	Views of the Board	77
10	Income tax	77
10.1	Views of the Board	77
11	Previous Board directions	77
12	Deferral accounts	81
12.1	LNG Fuel Deferral	81
12.2	Board Orders or Changes in Legislative Provisions Deferral	82
12.2.1	Views of interveners	82
12.2.2	Views of the Board	82
12.3	Statutory Federal and Territorial Income Tax Rates Deferral	83

12.3.1 Views of the Board	84
12.4 Deferred Charges and Credits	84
12.4.1 Demand Side Management (DSM) Program Study Deferral Account	84
12.4.1.1 Views of interveners	85
12.4.1.2 Views of the Board	85
12.4.2 Watson Lake LNG Study Deferral Account	85
12.4.2.1 Views of interveners	86
12.4.2.2 Views of the Board	86
12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account	86
12.4.3.1 Views of interveners	87
12.4.3.2 Views of the Board	88
12.4.4 Joint Smart Grid Study Deferral Account.....	90
12.4.4.1 Views of interveners	90
12.4.4.2 Views of the Board	90

List of tables

Table 1.	AEY energy sales by customer class – 2013 to 2017 (MWh)	9
Table 2.	AEY updated test period sales forecast by customer class (MWh).....	9
Table 3.	Comparison of weather-normalized UPC methodologies	10
Table 4.	Actual and forecast purchase power – 2013 to 2017 (\$000s)	14
Table 5.	Actual and forecast fuel costs — 2013 to 2015 (\$000s).....	17
Table 6.	Operations and maintenance expense (\$000)	19
Table 7.	Key Assumptions	19
Table 8.	2013 to 2017 placeholder amounts for pension costs (\$000s)	23
Table 9.	Account 88800 — Maintenance, Company-Owned Houses — “Other” costs (\$000s) ...	28
Table 10.	Account 88900 — Maintenance, Warehouse and Office — “Other” costs (\$000s).....	29
Table 11.	Account 72100 Administrative — “Other” costs (\$000s)	29
Table 12.	Approved, actual and forecast property taxes 2013 to 2017 (\$000s)	30
Table 13.	Approved, actual and forecast depreciation expense — 2013 to 2017 (\$000s)	32
Table 14.	Return on rate base — 2013 to 2017 (\$000s)	36
Table 15.	Forecast long-term debt rates.....	45
Table 16.	Continuity for NCC Mid-Year Balance — 2013 to 2017 (\$000s)	48
Table 17.	AEY Capital Expenditures and Additions – 2013 to 2017 (\$000s)	48
Table 18.	Controllable Capital Expenditures — 2013 to 2015 (\$000s).....	49
Table 19.	Distribution Plant Additions — 2013 to 2017 (\$000s)	50
Table 20.	Project Completion Summaries (\$000s).....	57
Table 21.	Business Cases for Completed Projects (\$000s).....	58
Table 22.	Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs (\$000s)	61
Table 23.	Watson Lake bi-fuel project — Phase 1 and 2 capital costs	64
Table 24.	Comparison of potential suppliers and fuel price forecasts	68
Table 25.	McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs (\$000s)	75
Table 26.	Summary of existing and proposed deferral accounts	81

1 Introduction

1. On May 11, 2016, pursuant to the *Public Utilities Act* and Order-in-Council 1995/90, the Yukon Electrical Company Limited (YECL or Applicant),¹ carrying on business as ATCO Electric Yukon (AEY), filed an application with the Yukon Utilities Board (Board) requesting an order approving forecast revenue requirements for the years 2016 and 2017 (test period) (Application). AEY is seeking approval of a revenue requirement of \$53,890,000 for 2016 and \$56,173,000 for 2017. The applied-for revenue requirement represents cumulative rate increases of 4.4 percent for 2016 and 7.5 percent for 2017, and year-over-year rate increases of 4.4 percent and 3.1 percent respectively.

2. Additionally, AEY sought approval of:

- an interim refundable rate rider of 11.62 percent, effective July 1, 2016;
- the continued use of currently approved deferral accounts, including purchase power flow-through, fuel price flow-through, and defined benefit pension costs during the test period; and
- new deferral accounts related to liquefied natural gas (LNG) fuel price changes, statutory tax rate changes, feasibility studies, and costs arising from Board Orders or legislative provisions not currently contemplated.

3. AEY is a private investor-owned utility serving more than 17,000 customers in 19 communities in the Yukon. AEY purchases power from Yukon Energy Corporation (YEC) for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek and a variety of rural areas surrounding Whitehorse. The company maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption. AEY also owns and operates the Fish Lake Hydro plant which generates power, and generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River.

4. On May 27, 2016, the Board issued Board Order 2016-01, in which the Board ordered AEY to publish a Notice of Application and Hearing for the General Rate Application (GRA) no later than June 3, 2016 in appropriate local news publications in AEY's service area to provide adequate notice to the public. AEY was also directed to make the Application and supporting materials available on its website: www.atcoelectricityukon.com, as well as in hardcopy upon request to AEY. Board Order 2016-01 set out a process schedule, pending ministerial approval, for the Application, with a hearing to commence on November 1, 2016.

5. On June 17, 2016, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to section 50 of the *Public Utilities Act*.

¹ Yukon Electrical Company Limited is the legal entity, and ATCO Electric Yukon is the brand name that is now used for the company's utility service operations in Yukon.

6. The Board, through Board Order 2016-02, issued June 24, 2016, granted intervenor status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (JM)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)

7. In Board Order 2016-02, the Board also approved a 9.41 percent interim, refundable rate adjustment rider, effective July 1, 2016. Subsequently, in Board Order 2016-02 Errata, the Board changed the interim rate adjustment rider to 11.62 percent, in order to account for a calculation error.

8. In its intervenor registration letter, dated June 17, 2016, and subsequently, UCG indicated that it had contacted the Pacific Economics Group (PEG) to help UCG determine if it was possible to benchmark the costs and productivity of AEY. UCG requested that the Board issue a letter to PEG so it can be assured that it would have an opportunity to access recovery of its costs through the cost claims process set by the Board. UCG also indicated that the process schedule would need to be altered to allow for a series of interrogatories to determine if benchmarking was possible.

9. On June 21, 2016, the Board set out a process to address UCG's request. Submissions were received from AEY and UCG. On July 4, 2016, after consideration of the UCG request and parties' submissions, the Board, in Board Order 2016-03, denied the UCG request for a letter of comfort to PEG. No revision to the process schedule was required.

10. On August 12, 2016, UCG submitted a motion requesting that the Board issue an order requiring AEY to provide adequate responses to certain UCG Information Requests (IRs). The Board invited comments from AEY on the UCG motion and reply comments from UCG. In Board Order 2016-04, issued on September 2, 2016, the Board ruled on the UCG motion and directed AEY to provide further and better information responses by September 9, 2016. In that Board Order, the Board amended the process schedule to allow UCG to file its evidence after the receipt of the additional information responses.

11. The Board held an oral public hearing in Whitehorse, Yukon from November 1 to 3, 2016. The Board was comprised of Robert Laking, Chair, and members Andre Fortin, Meagan Hannam, Bonnie King and Phillip Fitzgerald.

12. At the hearing, the Board confirmed that Final Argument was due on November 24, 2016 and Reply Argument on December 15, 2016. The Board considers the record of the proceeding closed on December 15, 2016.

13. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this Board Order to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be

taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 AEY Sales and Revenue

2.1 Overview

14. AEY stated that its sales and revenue forecast was based on a detailed analysis of historical sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. This data consists of information gathered by AEY staff who work in the communities as well as information resulting from consultation with the City of Whitehorse, Yukon government officials and various local agencies and developers.

15. The following table summarizes AEY's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013 to 2014, and 2015:

Table 1. **AEY energy sales by customer class – 2013 to 2017 (MWh)**

Customer class	Actuals			Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Residential	148,780	147,253	148,605	147,111	151,617
Commercial	159,322	154,709	155,346	152,187	153,336
Street Lights	3,719	3,765	3,886	3,944	4,008
Private Lights	551	544	519	492	472
Total Retail Primary	313,372	306,272	308,356	303,735	309,433
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total	316,687	312,182	315,816	313,592	319,289

Source: Application, Table 1, page 2-1.

16. Due to the changes in the energy sales by customer class, AEY's total primary non-industrial sales are forecast to decrease by 1.5 percent in 2016, and increase by 1.9 percent in 2017.

17. AEY provided an update to its test-period sales forecast to include nine months of actuals to September 30, 2016, as shown in the following table:

Table 2. **AEY updated test period sales forecast by customer class (MWh)**

Customer Class	Forecasts (Test Period)	
	2016	2017
Residential	146,698	153,275
Commercial	153,635	154,639
Street lights	3,922	3,978
Private lights	496	480
Total retail primary	304,751	312,373

Secondary sales	9,429	9,429
Wholesale sales	427	427
Total	314,607*	322,229

Source: Exhibit B-20, AEY undertaking; *Corrected for addition.

2.2 Views of the Applicant

18. In 2015, AEY provided electricity services to approximately 17,600 non-lighting customers in its service area and supplied a total of 308.4 GWh to residential, commercial and lighting customers. This represents an increase in total primary sales of 0.7 percent from 2014 levels. This increase follows decreases of 2.0 and 0.6 percent respectively in 2014 and 2013, from prior year levels.

19. After experiencing strong growth in the Yukon from 2004 to 2012, AEY submitted that the pace of economic activity in the Yukon has slowed down significantly. Slower population growth has also contributed to minimal customer gains in the residential and commercial sectors of AEY. It expected that the overall impact of the economic and population growth slowdown to continue to impact AEY's customer growth and sales over the test period.

20. AEY added that its demand-side management (DSM) program and the Yukon government's energy initiatives, such as those related to the commercial energy incentive program and micro-generation, which were introduced in the Yukon over the last few years, have also contributed to lower electricity sales experienced in the period from 2013 to 2015.

21. AEY reviewed its two-step approach for determining weather-normalized use per customer (UPC), where:

In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in the first step is multiplied by the difference between the actual HDD and the "Normal" HDD.²

22. In its Application, AEY proposed to update the timeframes used to determine the weather-normalized UPC. The existing methodology uses a longer time period and the proposed methodology uses the last three years of data, as illustrated in the table below:

Table 3. **Comparison of weather-normalized UPC methodologies**

	Regression data for UPC (Step 1)	"Normal" HDD (Step 2)
Prior Methodology	15 years	20-year average
Current Methodology	3 years	3-year average

Source: Application, page 2-5.

² Exhibit BB-1, Application, page 2-5, lines 3-7.

23. In the proposed methodology, AEY would apply the growth rates experienced over the period from 2013 to 2015 to derive the forecast UPC for the test period.

24. In support of its proposal, AEY stated:

... over the past few years, in addition to changes in electric heating, there has been an increase in energy efficiency programs in the Yukon such as Demand Side Management and the Commercial Energy Incentive program. These trends, combined with a decline in economic activity and increasing effects of global warming have contributed to an overall downward trend in UPC over the 2013-2015 time period.³

25. AEY submitted that using the 2013 to 2015 timeframe for weather-normalizing and forecasting the UPC was more appropriate, as it encompasses trends occurring in the Yukon over the last few years.

2.2.1 Residential sales forecast

26. Respecting its residential sales forecast, AEY stated that the forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.

27. AEY submitted that the residential average UPC for all communities (except for Keno City, Stewart Crossing and Swift River) is calculated by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC. For Keno City, Stewart Crossing and Swift River, AEY used the actual UPC of the previous year as a base⁴ and applied the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC for these communities was “used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature.”⁵ The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.2 Commercial sales forecast

28. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.

29. AEY stated that Whitehorse’s commercial UPC for the test period is forecast using the weather-normalized UPC of the previous year and applying the 2013 to 2015 growth in weather-normalized UPC. AEY added that it expects three new large commercial customers to be added during the test period in Whitehorse. AEY added:

³ Exhibit BB-1, Application, page 2-5, lines 14-19.

⁴ Exhibit B-9, YUB-YECL-7 (a): “For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year.”

⁵ Exhibit BB-1, Application, page 2-6, lines 11-12.

ATCO Electric Yukon has considered these new large customers individually, and has forecast the load each customer will bring to the system each year based on the start-up time and other pertinent information provided by the customer. The commercial energy sales for Whitehorse are then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.⁶

30. With the exception of Whitehorse, AEY submitted that the commercial UPC forecast for all communities is determined by using the actual UPC of the previous year, and applying the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

31. In response to UCG, AEY reiterated that three main factors have contributed to the declining trend in residential and commercial UPC, and these factors support the updated forecast methodology. These are:

- (a) the economic slowdown in the Yukon;
- (b) a continuous warming trend, starting in 2013; and
- (c) recent energy conservation initiatives, which have been implemented in the Yukon.

32. AEY added that the proposed change from 15 years to three years to run its regression model for UPC and HDDs results in a more accurate portrayal of the current context in which AEY operates, and is necessary in order to appropriately account for the factors that have led to the change in UPC behaviour since 2012.⁷

33. During the oral hearing, AEY updated its sales forecasts to incorporate nine months of actuals, as of September 2016. The updated sales forecast provided in a table in response to the undertaking showed energy sales to be with 0.3 percent of actuals.⁸

2.2.3 Views of interveners

34. Mr. Maissan noted that residential and commercial sales are expected to decrease slightly in 2016 and then increase modestly in 2017. Mr. Maissan further noted the secondary sales were forecast to increase by 2.4 GWH in the test years. Mr. Maissan recommended that the Board accept AEY's sales forecast as filed.

35. UCG pointed out that AEY has consistently realized sales that were below the approved amounts. UCG submitted that this is in part due to AEY's forecasting methodology, as well as under-estimating the impact of weather, the economy and DSM initiatives. Given the downturn in the Yukon economy and the uncertainty created by a new territorial government, UCG submitted that AEY had erred in simply applying the

⁶ Exhibit BB-1, Application, page 2-6 (lines 26 to 27) to page 2-7 (lines 1 to 3)

⁷ YECL Final Argument, paragraph 24.

⁸ Transcript, Volume 2, November 2, 2016, page 347, lines 1 to 4.

sales growth rates experienced over the 2013-2015 period to derive the weather-normalized UPC for the test period.⁹

36. UCG submitted that AEY should be directed to update its most recent sales forecast provided in its undertaking found at Exhibit B-2 with actuals from 2016 and 2017. This update should be provided when AEY submits its compliance filing and should use the most recent actuals and forecast to determine revenue requirements.

2.2.4 Views of the Board

37. The Board notes that AEY argued that the major reason for the shift in timeframe from 15 years to three years regarding its running of the regression model for UPC and HDDs was due to the shift and the change in direction respecting UPC starting in 2012.¹⁰ AEY has affirmed the contributing factors as being the downturn in the economy and conservation initiatives.¹¹

38. The Board finds that recent trends in the Yukon underpin AEY's proposed change in its methodology but the Board has concerns that a recent trend may or may not be reflective of future forecasts required in a test period. The Board considers it important that a methodology be adopted that is representative of energy sales and reflective of UPC and HDD in future years. The Board has concerns that if, for example, there is economic growth prior to the next GRA, a further adjustment to the methodology will be required due to a short time period being used to forecast energy sales.

39. With respect to its updated sales forecast, AEY's original forecast was within 0.3 percent compared to actuals for the 2016 test year. However, the Board notes that there is a one-percent variance in total retail primary sales for 2017 when the updated forecast is compared to the original forecast.

40. The Board notes AEY's submission that, "Had AEY not revised its methodology... AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016."¹² Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data.¹³ Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast,

⁹ UCG Final Argument, paragraph 76.

¹⁰ Transcript, Volume 2, November 2, 2016, page 341 (line 24) to page 342 (line 2).

¹¹ Transcript, Volume 2, November 2, 2016, page 342, lines 4 to 22.

¹² AEY Final Argument, paragraph 26.

¹³ Transcript, Volume 2, November 2, 2016, page 343, lines 17 to 20.

incorporating its prior methodology¹⁴ using a 10-year timeframe for UPC regression and normalizing HDD.

3 Purchase power

41. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table shows the actual and forecast purchase power over the period from 2013 to 2017:

Table 4. **Actual and forecast purchase power – 2013 to 2017 (\$000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized¹⁵	(402)	-	(72)	(110)	(86)
Total Purchase Power¹⁶	25,442	24,918	25,107	24,756	25,250

Source: Exhibit BB-1, Application, page 3-1.

42. The purchase deferral account is related to increases or decreases to the cost of purchased power, which is based on YEC's rates for primary energy sales and secondary sales.

43. AEY submitted that the test period purchase power forecast takes into account the Fish Lake hydro generation output, which is based on the lifetime average output for Fish Lake Unit #2 from 1960-2015 plus the two-year average for the new Fish Lake Unit #1 adjusted for planned decreases in generation due to capital builds.¹⁷ The drivers of the forecasts for 2016 and 2017 were stated as:

The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.¹⁸

44. Furthermore, consistent with the approach approved in Board Order 2014-06, AEY submitted that lines losses are calculated on a five-year average and total 6.2 percent.¹⁹

¹⁴ The methodology used in its 2013-2015 GRA.

¹⁵ Exhibit BB-1, Application, page 3-1, footnote 1: "Consistent with Board Order 2009-2, AEY will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds."

¹⁶ Rider J has not been included, as these are flow-through amounts to YEC.

¹⁷ Exhibit BB-1, Application, page 3-1 (lines 17-18) to 3-2 (lines 1-2).

¹⁸ Exhibit B-9, YUB-YECL-9(a).

¹⁹ AEY Final Argument, paragraph 31.

3.1 Views of interveners

45. UCG submitted that the incremental purchased power costs to be capitalized should only relate to planned capital projects and not maintenance or other projects that were not included in the capital budget reviewed by the Board.²⁰

3.2 Applicant responses to interveners

46. In response to UCG's submission, AEY stated that its understanding of Board Order 2009-02 is consistent with UCG's on this matter.

3.3 Views of the Board

47. The Board's determination in Board Order 2009-02 respecting the capitalization of purchase power costs required because of the Fish Lake hydro was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with Fish Lake hydro rebuilds."²¹ The Board directed AEY, at the time of its next GRA, to provide clear documentation of these incremental power purchases due to the Fish Lake hydro rebuilds.

48. In the current Application, AEY has capitalized the forecast purchased power costs related to the Fish Lake hydro rebuilds for 2016 and 2017. In the Board's view, this is consistent with directions provided in Board Order 2009-02:

The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time. *(footnotes omitted)*²²

49. The Board approves the forecast primary and secondary purchase power costs as filed because the methodology used is reasonable and consistent with the previous GRA.

3.4 Deferral Account — Purchase Power Flow-Through

50. AEY requested a Purchase Power Flow-Through Deferral Account (PPFTDA). AEY noted that the cost of purchase power in the Application is based on rates from YEC for primary energy and secondary sales and do not include any adjustments due to YEC's energy reconciliation adjustment (ERA). Any increases or decreases to the YEC rates or any ERA adjustments are to be flowed through to customers.

3.4.1 Views of interveners

51. UCG acknowledged that a deferral account is a reasonable way to track unforeseen changes in costs related to purchased power. However, UCG submitted that

²⁰ UCG Final Argument, paragraph 89.

²¹ Board Order 2009-02, Appendix A, Reasons for Decision, page 9.

²² Board Order 2009-02, Appendix A, Reasons for Decision, page 10

AEY must ensure that it limits as much as possible the charges from YEC by actively participating in reviews of YEC revenue requirements and implementing DSM initiatives that reduce the need for purchased power.²³

3.4.2 Applicant responses to interveners

52. AEY responded to the UCG submission that AEY has participated in YEC regulatory applications that impact both AEY's customers and its share-owners and will continue to do so. AEY also submitted that it expects to continue working collaboratively with YEC on initiatives that impact Yukon electricity customers.²⁴

3.4.3 Views of the Board

53. The Board notes AEY's responses to IRs on the PPFTDA. More specifically, the Board takes note of the response to YUB-YECL-47(b), in which AEY stated:

... under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate... AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.²⁵

54. Further, AEY stated that this account will ensure that there is an additional margin²⁶ if sales are greater than forecast.²⁷ Parties were asked to comment on that additional margin in argument²⁸, but no comments were received.

55. The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

4 Fuel costs

56. Fuel costs included in the AEY Application are reproduced in Table 5 below:

²³ UCG Final Argument, paragraph 88.

²⁴ AEY Reply Argument, paragraph 27.

²⁵ Exhibit B-9, YUB-YECL-47(b).

²⁶ By allowing the PPFTDA, a positive margin is maintained on incremental sales as incremental costs are covered through the deferral account.

²⁷ Transcript Vol. 3, page 520, lines 19-23.

²⁸ Transcript Vol 3., page 518, lines13-19.

Table 5. **Actual and forecast fuel costs — 2013 to 2015 (\$000s)**

Actuals				Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Fuel Costs	6,708	6,760	6,621	5,225	5,268

Source: Exhibit BB-1, Application, page 4-1.

57. AEY explained that it purchases fuel on an ongoing basis for each of its five isolated plants via a diesel fuel tendering process, where a vendor is selected to be the provider of diesel fuel to AEY. AEY further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

58. AEY stated that the forecast cost decrease in 2016 is mainly due to lower fuel prices than previously approved, which are currently used as the base fuel prices in Rider F. AEY added that the fuel costs forecast is a function of forecast sales, line losses, plant efficiencies and delivered prices. The fuel-deferral methodology used for this account was described, as follows:

The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or 'heat rate', kWh / Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.²⁹

59. AEY submitted that the variance between actual and forecast fuel prices is refunded to or recovered from customers by means of Rider F, a fuel-price flow-through rider.

4.1 Views of the Board

60. The Board accepts and approves AEY's fuel cost forecast, as filed. AEY is proposing to continue the deferral for fuel prices for the test period.

4.2 Deferral Account — LNG Fuel

61. Notwithstanding the above, if the Watson Lake bi-fuel project is approved, AEY anticipated that, beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. Accordingly, AEY submitted that it required a deferral account to track and subsequently refund or recover changes in costs due to the differential in actual LNG fuel prices and the price included in rates. AEY explained that:

Similarly to the Diesel Fuel Deferral Account, the LNG Fuel Deferral Account will use the GRA-approved community-based plant efficiencies and the plant's monthly gross generation to determine the volume of litres of diesel equivalent

²⁹ Exhibit BB-1, Application, page 4-2, lines 20-24.

for the monthly fuel deferral calculation. Actual diesel volumes used for the diesel fuel deferral account calculation will be subtracted from this volume, with remaining allowable litres of diesel equivalent for use in the calculation of the LNG fuel deferral.³⁰

62. AEY went on to explain that the difference between the actual and GRA-approved price per litre of diesel equivalent is then multiplied by the remaining allowable litres of diesel equivalent to arrive at the LNG fuel-deferral amount for the month.

63. AEY proposed to include the LNG price variances in the Rider F deferral account, stating that the principles supporting a diesel price variance deferral are the same as those supporting an LNG price variance deferral or a fuel price variance deferral, namely:

- Commodity prices are subject to material fluctuations outside the utilities' control; and
- It is not in ratepayers', the Board's, or the utilities' interests to speculate on these price fluctuations.³¹

64. AEY argued that it is well within the Board's authority to approve deferral accounts in general. Furthermore, should the Board determine that the wording of the Order in Council does not allow for the inclusion of LNG price variances in the existing Rider F, AEY submitted that a new deferral account and subsequent rider should be approved. Such a rider should operate in the same manner as Rider F.³²

4.3 Views of interveners

65. UCG noted that Rider F was last approved in Board Order 2012-02, dated February 29, 2012. Noting that the Board, in Board Order 2011-15, confirmed that Rider F applies to all diesel fuel consumed in a period, UCG submitted that it is unclear whether AEY has applied to the Board for the inclusion of LNG price variances in Rider F.

66. Given that AEY is not using LNG at this time and only anticipates using LNG-fuelled generators late in 2017, at the earliest, UCG submitted that the Board should not allow AEY to establish a LNG-related deferral account until a need is established and an application has been made to change Rider F.

67. UCG further submitted that the Board cannot approve the proposed changes to Rider F for fuel used in Watson Lake without changes to section 8 of Order-in-Council 1995/90 to account for LNG use.

4.4 Applicant responses to interveners

68. AEY responded that section 8 of Order-in-Council 1995/90 provides for fuel-price adjustments and sets out that the Board must allow AEY and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to

³⁰ Exhibit BB-1, Application, page 4-3, lines 7-12.

³¹ Exhibit B-6, UCG-AEY-22

³² Exhibit B-6, UCG-AEY-22

reflect fluctuations in the price for diesel fuel, without the requirement for specific application to and approval from the Board. However, simply because AEY is entitled to flow-through diesel fuel prices without Board approval, it does not mean that it is somehow prevented, upon Board approval, from flowing through the impact of changes to LNG prices.

4.5 Views of the Board

69. Considering the Board's determination in section 9.7.2 of this decision with respect to the Watson Lake bi-fuel project, the Board does not approve the LNG deferral account.

5 Operations and maintenance (O&M) expense

70. For 2016 and 2017, AEY requested approval of O&M expenses, totalling \$11.993 million and \$12.181 million respectively. The following table shows forecast and actual amounts for the period 2013-2015, and the forecast for the test years:

Table 6. Operations and maintenance expense (\$000)

2013		2014		2015		2016	2017
Approved	Actual	Approved	Actual	Approved	Actual	Forecast	Forecast
11,604	11,718	11,882	11,698	11,944	11,616	11,993	12,181

Source: Exhibit BB-1, Application, Schedule 5.1

5.1 Labour

71. In the Application, AEY forecasted a complement of 70.38 full-time equivalents (FTEs) for each of the test years. This was an increase of 1.25 FTEs over the actual complement at the end of 2015.

72. AEY discussed labour costs in section 5 of the Application and stated that labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. The labour costs are then distributed to O&M accounts or capital accounts, depending on the nature of work being performed by the staff in the job class. Further, in section 1 of the Application, under the heading "Key Assumptions", AEY provided the following:

Table 7. Key Assumptions

	2016	2017
Labour inflation	3.25%	3.00%
Other inflation	2.20%	2.20%
Vacancy rate	4.00%	4.00%
Long-term debt rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 1-5.

5.1.1 Labour complement

73. AEY proposes a labour complement of 70.38 FTEs for each of the test years.

5.1.2 Views of interveners

74. Intervenors did not provide any direct comments with regard to AEY's labour complement levels.

5.1.3 Views of the Board

75. Staff complement is one of the elements reviewed by the Board in relation to labour costs and the Board is concerned with the escalation of labour costs and the growth of Administration and General (A&G) costs. In this Application, AEY has requested an increase in its complement by two positions (an Engineering Technologist (1 FTE) and a Supervisor, Business Support Services (0.25 FTE)).

76. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change³³ in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY.³⁴ This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a position that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY.³⁵ Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the position be removed from AEY's complement.

77. As of the close of record, the Engineering Technologist position has yet to be filled. AEY did not provide any evidence that the work forecast for the Engineering Technologist position was not already being done by any of the other two existing engineering technologist positions or other members of the two engineering groups.

78. In Board Order 2014-16, AEY was directed to remove the corporate accountant position (1 FTE). It did not do so and did not request a review and variance of that direction.³⁶ To continue the position or rename the position as an Operational Accountant ignores the direction and concerns of the Board.

79. Therefore, AEY's requested approval for a complement of 70.38 FTEs for both test years is not approved. The Board approves a complement of 68.13 FTEs. The

³³ Referring to the change from reporting to the Manager (Whitehorse-based) to the Business Support Services Supervisor (Yellowknife-based).

³⁴ Transcript Vol 2, page 365, lines 1-13.

³⁵ Exhibit B-9, YUB-YECL-34(a).

³⁶ Transcript Volume 2, page 372, lines 1-17.

complement level of 68.13 FTEs is determined by removing the Engineering Technologist position (1 FTE), the Supervisor, Business Support Services position (0.25 FTE), and the Corporate/Operational Accountant position (1 FTE) as directed in the 2013-2015 GRA. AEY is to reflect this finding in its compliance filing to this decision.

5.2 Vacancy rate

80. As noted above, AEY has forecasted a vacancy rate for each of the test years of 4.0 percent, or approximately three FTEs. AEY said that the vacancy rate is based on a five-year historical average and is consistent with the methodology approved in Board Orders 2009-02 and 2014-06.

5.2.1 Views of interveners

81. Intervenors did not comment on AEY's proposed vacancy rates.

5.2.2 Views of the Board

82. The Board has reviewed the submissions of AEY on its vacancy rate in this proceeding. The Board finds the vacancy rate requested is reasonable because it is based on a five-year historical average and is consistent with the methodology approved in Board Order 2009-02 and applied in Board Order 2014-06.³⁷ For these reasons, the Board approves a vacancy rate for AEY of 4.0 percent for each of the test years.

5.3 Labour inflation

83. AEY stated that the labour escalation for 2016 was based on AEY's existing collective agreement which covers in-scope employees and AEY applied the escalators in that agreement to both in-scope and out-of-scope employees.

84. AEY reiterated its submission from the Application (section 5) that its inflationary increases were consistent with several decisions in Alberta.³⁸ It added that AEY was appropriately staffed and did not undergo the growth incurred by ATCO Electric prior to the economic downturn in Alberta; therefore, it was not impacted by the economic downturn in Alberta or the ATCO Group reorganization.³⁹

5.3.1 Views of interveners

85. In argument, intervenors did not make any specific comments on labour inflation. However, in Reply Argument, UCG stated "... it is inconsistent to have labour inflation rates from another jurisdiction dictate what Yukoner ratepayers should pay when Yukon-specific labour and wages information is readily available. UCG submits that AEY's labour inflation should be held to the most recent Yukon statistics available."⁴⁰

³⁷ Appendix A to Board Order 2014-06, section 5.2.2, page 23.

³⁸ AEY noted the following decisions in its argument: 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff), 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA), 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker) and 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker), at paragraph 66 of AEY's Final Argument.

³⁹ AEY Final Argument, paragraph 68.

⁴⁰ UCG Reply Argument, paragraph 20.

86. In addition, several of the interveners expressed concerns regarding AEY's costs. CW was concerned with AEY's pattern of over-forecasting.⁴¹ John Maissan observed that AEY is able to control overall O&M costs.⁴² UCG supported CW's concerns regarding over-forecasting, additionally mentioning "artificial inflation of rates".⁴³

5.3.2 Views of the Board

87. The Board notes that, in the September 9, 2016 updated response to YUB-YECL-27(a), AEY stated that in 2015, 10 employees (15 percent of staff) did not receive wage increases, and in 2016, 11 employees (17 percent of staff) did not receive wage increases.

88. In response to Board questioning, AEY confirmed that the staff who did not receive wage increases in 2015 and 2016 were all out-of-scope employees.⁴⁴ Further, AEY stated that for the 2016 and 2017 test years, the labour inflation forecast was based on AEY's existing collective agreement, which expires on December 31, 2016. The labour-escalation rate for the test period is forecast to be 3.25 percent. AEY did not submit any information that a new collective agreement had been reached or would be in place for January 1, 2017. The Board considers that the 2017 forecast labour escalator is not based on a collective agreement that would be in force in 2017.

89. The Board notes that built into the determination of revenue requirement for 2015 was labour inflation of 3.5 percent. However, out-of-scope employees did not receive inflation increments for that year, nor for 2016. In-scope employees received 2015 and 2016 labour-inflation increments of 3.25 percent. For 2015, this was 0.25 percent lower than what was built into the 2015 revenue requirement.

90. As a result, for out-of-scope employees, the Board awards, for 2016, a labour-inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision.

91. For in-scope employees, the Board considered that a collective agreement was in place for the 2016 test period and approves the labour-inflation rate of 3.25 percent as requested for that year.

92. However, for 2017, since the Board has no evidence of the existence of a collective agreement, the Board has to determine the inflationary increase to be awarded for in-scope and out-of-scope employees. In making its determination, the Board considered the May 2016 *Yukon Economic Outlook*.⁴⁵ The Board notes that, based on the *Yukon Economic Outlook*, Yukon experienced an economic downturn in 2015 due to reasons such as:

- 2015 GDP was down by 3.8 percent;

⁴¹ Exhibit C3-3, CW Evidence; CW Final Argument, paragraph 27.

⁴² JM Final Argument, page 4.

⁴³ UCG Final Argument, paragraph 98.

⁴⁴ Transcript Volume 3, pages 400, line 16, to 401, line 8. .

⁴⁵ Exhibit B-9, YUB-YECL-30(a), Attachment 1.

- Average employment was down slightly;
- Unemployment rate was up 2.0 percent;
- Building permits were down 9.7 percent; and
- A modest decrease in the CPI for Whitehorse of 0.2 percent.

93. The preliminary forecast for 2017 discussed in the outlook is for Yukon's real GDP to fall by 5.7 percent, and employment and the labour force to be relatively flat. The Consumers Price Index (CPI) for Whitehorse is expected to be just under 2.0 percent.

94. For these reasons, the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction.

5.4 Pension matters

5.4.1 Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account

95. AEY provided the following placeholder amounts for pension costs in its Application:⁴⁶

Table 8. 2013 to 2017 placeholder amounts for pension costs (\$000s)

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Defined Benefit	1,041	902	578	578	578
Defined Contribution	209	242	267	276	286
Total Pension Costs	1,250	1,144	845	854	864

Source: Exhibit BB-1, Application, page 5-3.

96. AEY sought Board approval for these amounts to be tied to the outcome of the upcoming ATCO Utilities Pension Application, to be filed before the Alberta Utilities Commission (AUC). In addition, AEY is seeking continuation of its pension deferral account to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. For the defined contribution pension plan, AEY noted that the company's contributions rate was set at 6.0 percent.⁴⁷

97. In an update⁴⁸ to defined benefit pension costs, AEY stated the costs for 2016 are forecasted to be \$505,000, assuming a COLA of 100-percent CPI.

98. Further, AEY confirmed that if the deferral account is granted for pension costs, ratepayers would experience "actual cost" rather than placeholder amounts⁴⁹ and also

⁴⁶ Exhibit BB-1, Application, page 5-3.

⁴⁷ Exhibit BB-1, Application, page 5-3.

⁴⁸ Exhibit B-9, YUB-YECL-36(f).

⁴⁹ Exhibit B-5, JM-AEY-9.

confirmed that AEY would exclude any amounts the AUC does not approve for inclusion in utility rates in the Alberta 2016 pension application.⁵⁰

99. In argument, AEY submitted that the assumption for 2016 of the COLA at 100 percent is based on changed circumstances, as the pension has moved from an unfunded liability to a funding-excess position.⁵¹

100. In its submission, UCG recommended that if the defined benefit pension deferral account was to be continued, its intended use should be clear, along with how it is to be used.⁵² No other interveners made submissions on pension costs or this deferral account.

5.4.2 Views of the Board

101. The Board finds the requested pension amounts are reasonable. As a result, the Board approves the revised defined benefit pension amounts of \$505,000 for each of the test years. The Board also approves the defined contribution rate of 6.0 percent, to be applied to the labour rates determined in section 5.3.1 of this decision.

102. Further, the Board approves AEY's request to continue with the Defined Benefit Pension Deferral Account (DBPDA). The Board finds that adjusting for the result of the ATCO Utilities 2016 Pension Application is a reasonable approach because it will reflect actual pension costs.

5.5 Other Inflation

103. As noted in the key assumptions,⁵³ AEY has requested other inflation of 2.20 percent for each of the test years. AEY stated that this forecast for the 2016 test year was based on the *Yukon Economic Outlook* dated October 2015. AEY added that since no public forecast was available for Yukon for 2017, it applied the 2016 forecast for that test year.

5.5.1 Views of interveners

104. Parties did not provide any specific comments on Other Inflation.

5.5.2 Views of the Board

105. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response.⁵⁴ In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent⁵⁵ for 2017. AEY is directed to reflect this change in its compliance filing to this decision.

⁵⁰ Exhibit B-4, CW-YECL-15(b).

⁵¹ AEY Final Argument, paragraph 71.

⁵² UCG Reply Argument, paragraph 21.

⁵³ Exhibit BB-1, Application, page 1-5.

⁵⁴ Exhibit B-9, YUB-YECL-30(a), Attachment 1.

⁵⁵ Exhibit B-9, YUB-YECL-30(b).

5.6 Non-labour costs

106. Non-labour costs were discussed in the Application. Schedule 5-1 provided a summary of actual and forecast costs. Schedule 5-2 provided year-over-year variance explanations.

107. AEY stated that non-labour costs are forecasted in two parts: (1) ongoing operational and administrative activities, and (2) new programs or projects. AEY added that it was not forecasting any new programs or projects for this test period.⁵⁶

108. For ongoing operational and administrative activities, the forecast was based on historic spending and adjusted for known changes in work to be completed in the forecast period.

5.6.1 Views of interveners

109. CW submitted evidence challenging the forecast accuracy of AEY, stating:

When the actual costs are systematically lower than forecast, one must question the reasonableness of the forecasts. When the approved forecast is continually higher than the actual costs for a cost category or item, it means customers are paying for costs the utility will not incur. While the utility is entitled to benefit from efficiency gains in the test period, the regulator must ensure that savings are from efficiency gains, and not the result of over forecasting. When there is a continual pattern of over-forecasting, that usually means that there is an issue with the forecast, and the subsequent forecast should be adjusted. Further, these savings should be captured in the subsequent rate application, to the benefit of customers.⁵⁷

110. CW asserted that a pattern of over-forecasting for the production, distribution and general functions existed.⁵⁸ CW recommended that production costs be reduced by 15 percent⁵⁹ and that distribution and general costs be reduced by \$272,000 in 2016 and \$369,000 in 2017.⁶⁰

111. UCG argued that "... there has been a pattern of over-forecasting and artificial inflation of rates in 2013-2015 with respect to O&M costs related to AEY's production facilities (\$938,000) and overspending on administration and general (\$458,000)."⁶¹ UCG noted the variance between approved and actual affiliate charges for the 2013-2015 period. It recommended that affiliate charges should be reduced by 25 percent.

112. John Maissan submitted that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. He recommended that forecasted O&M costs for the 2016-2017 test years should be reduced by 1.1 percent.⁶²

⁵⁶ Exhibit BB-1, Application, page 5-3.

⁵⁷ Exhibit C3-3, CW evidence, A5, pages 2-3.

⁵⁸ Exhibit C3-3, CW evidence, A6, pages 3-4.

⁵⁹ CW equated the 15-percent reduction in production costs to be \$314,000 in 2016 and \$306,000 in 2017.

⁶⁰ Exhibit C3-3, CW evidence, A7, pages 4-5.

⁶¹ UCG Final Argument, paragraph 98.

⁶² JM Final Argument, page 4, point 6.

113. In Reply Argument, UCG submitted:

... that AEY has not provided the Board or interveners any alternative but to review O&M cost components. The only way to justify AEY's claim that O&M should only be reviewed in aggregate is if AEY has presented an integrated business strategic plan upon which its O&M is based.⁶³

114. With respect to production costs, CW stated:

... that in assessing the likely accuracy of any forecast in the application, the Board can and should take into account a pattern of over-forecasting in areas where that can be demonstrated.⁶⁴ (*underlining omitted*)

5.6.2 Views of the Applicant

115. In argument, AEY stated:

Furthermore, the Bell Evidence does not take into account the oral testimony provided by Mr. Massie where he described a forecasting process that continuously informs the process with the best available information. Adjustment to the process are made based on historical costs and known costs looking forward. As noted by Mr. Massie, adjustments have been made to accounts going forward and these changes are reflected in the 2016-2017 test year forecasts.⁶⁵ (*footnotes omitted*)

116. AEY later added that it is more appropriate to look at total O&M costs and not isolate only those functions that are experiencing increases. In terms of \$/MWh and O&M cost per customer, AEY argued that those metrics are influenced by the level of retail sales and those sales were actually decreasing by 1.5 percent. The forecasted average annual O&M cost per customer is flat with historical actuals.⁶⁶

117. In reply to CW, AEY noted that CW did not provide any evidence as to why its method of forecasting is appropriate for the O&M categories in question. AEY went on further to say that CW failed to account for inflationary increases, based on the table provided in its argument that AEY has a history of accurately forecasting its O&M expenses.⁶⁷

118. In reply to John Maissan's recommendation that O&M costs should be reduced by 1.1 percent, AEY said Mr. Maissan's recommendation ignored inflation as well as known increases in excess of inflation.⁶⁸

119. In Reply Argument, AEY challenged UCG's request that affiliate charges be reduced by 25 percent. AEY stated that the difference between 2014-2015 actual amounts for affiliate charges related to the change in service provider and that change was fully reflected in the forecast for each of the test years.

⁶³ UCG Reply Argument, paragraph 17.

⁶⁴ CW Reply Argument, paragraph 7.

⁶⁵ AEY Final Argument, paragraph 54.

⁶⁶ AEY Final Argument, paragraphs 58-59.

⁶⁷ AEY Reply Argument, paragraph 33.

⁶⁸ AEY Reply Argument, paragraph 35.

120. Regarding Administration and General O&M costs per customer, AEY countered the UCG argument by referring to corrected tables filed on November 10, 2016 to replace the original response to CW-YECL-13 Attachments 1 and 2. The update showed Administration and General O&M costs per customer to be less for the 2017 forecast than the 2015 actual.

121. AEY stated that its submissions for Financial Reporting and Regulatory Support affiliate costs should be seen as reasonable in comparison to 2013 amounts, especially given the regulatory events expected in 2017.⁶⁹

5.6.3 Views of the Board

122. The Board is of the view, based on the evidence of CW, that AEY appears to have, at a high level, over-forecasted for each year in the 2013-2015 period. The Board views each year separately and not in aggregate. The forecast for each year is driven by different assumptions and different stages of planned programs. However, the Board agrees with AEY that the high-level approach submitted by CW can be overly simplistic. It is beneficial to have such a high level review, but the trend uncovered by that type of review should be the starting point for further investigation and not taken at face value. From an O&M perspective, deviations can occur due to changes in the capital/O&M mix. Deviations can also be related to deferring planned programs or increased work in other functions. Identifying a trend is insufficient. Identifying root causes and making recommendations for specific accounts or functions are necessary.

123. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.

124. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period.⁷⁰ However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also

⁶⁹ The content of the preceding three paragraphs was derived from the AEY Reply Argument, paragraphs 36-41.

⁷⁰ Transcript Volume 3, page 444, lines 2-25.

directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs.

125. The Board will now discuss costs at the function level. Changes due to complement levels, vacancy rates, and inflation rates (labour and other) are discussed in earlier sections of this decision and those determinations impact production, distribution, public information and customer accounting function costs.

126. Other⁷¹ costs, as provided in general function costs — in particular, Account 88800 (Maintenance for Company-Owned Houses), Account 88900 (Warehouse and Office Maintenance) — and administration and general function costs — particularly Account 72100 (Administrative) — are discussed in the following paragraphs.

127. **Account 88800 (Maintenance for Company-owned Houses).** “Other” costs were provided in AEY’s response to City of Whitehorse’s IRs. ⁷²Variance explanations were provided in Schedule 5.2 of the Application but only for Account 88900 and only for the change from the year 2013 to 2014. The following table shows the actual and forecast “Other” costs for this account:

Table 9. **Account 88800 — Maintenance, Company-Owned Houses — “Other” costs (\$000s)**

Account 88800				
2013	2014	2015	2016	2017
Actual	Actual	Actual	Forecast	Forecast
18	27	41	54	51

Source: CW-YECL-14(a), Attachment 1, page 3.

128. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.”⁷³ However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800 and \$7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other” (Account 88800) is \$47,000, and the 2017 balance for “Other” (Account 88800) is \$44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

⁷¹ Other costs do not include the labour and fringe elements as provided in Attachment 1 of CW-YECL-14(a).

⁷² CW-YECL-14(a), Attachment 1.

⁷³ Exhibit BB-1, Application, page 5-3.

129. **Account 88900 (Maintenance, Warehouse and Office).** “Other” costs were provided in Attachment 1 to CW-YECL-14(a) and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the forecast and actual “Other” costs for this account:

Table 10. **Account 88900 — Maintenance, Warehouse and Office — “Other” costs (\$000s)**

Account 88900				
2013	2014	2015	2016	2017
Actual	Actual	Actual	Forecast	Forecast
137	156	133	150	153

Source: CW-YECL-14(a), Attachment 1, page 3.

130. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.”⁷⁴ However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800, and \$7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is \$143,000, and the approved 2017 balance for “Other” (Account 88900) is \$146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

131. **Administrative and General function costs.** Schedule 5.2 provided explanations for the labour portions but did not explain the increase in “Other”. Except for an explanation related to \$21,000 for employee association agreement negotiations.

132. **Account 72100 (Administrative).** “Other” costs were provided in Attachment 1 to CW-YECL-14(a), and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the actual and forecasted “Other” costs for this account:

Table 11. **Account 72100 Administrative — “Other” costs (\$000s)**

Account 72100				
2013	2014	2015	2016	2017
Actual	Actual	Actual	Forecast	Forecast
1,481	1,541	1,256	1,556	1,585

⁷⁴ Application, page 5-3.

133. In YUB-YECL-45, AEY was asked to explain the increases in each of the “Admin and General” Accounts (Accounts 72100 through 72900). AEY provided explanations; for Account 72100, the explanation chiefly related to labour costs.

134. The three-year average (2013-2015) for “Other” for Account 72100 is \$1,426,000. The Board finds that it is reasonable to use the three-year average for this account. \$1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the \$1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be \$1,455,000. For 2017, the forecast value is \$1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision.

6 Taxes Other Than Income

135. Taxes Other Than Income consist of property taxes paid to communities for AEY’s office building, generation facilities, substation properties and power lines.

136. The following table summarizes AEY’s recently approved, actual and forecasted amounts for property taxes:

Table 12. **Approved, actual and forecast property taxes 2013 to 2017 (\$000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	257	265	273		
Actual (A) / Forecast (F)	273	251	256	262	267
Actual (under) or over approved	16	(14)	(17)		

Source: Exhibit BB-1A, 2016-2017 GRA Schedule S1.1, line 10.

137. AEY stated that the increase in actual 2013 property taxes over the approved amount was due to payments made to the Town of Watson Lake.⁷⁵ Increases in property taxes that had been forecast for the years 2014 and 2015 did not occur because planned capital work, upon which property tax calculations are in part determined, did not materialize. Therefore, any year-over-year increases in property taxes paid during 2014 and 2015 were due primarily to inflation.

138. AEY has forecasted property taxes in the amount of \$0.262 million for the year 2016 and \$0.267 million for the year 2017.

139. AEY stated that property tax increases in the amounts of \$0.006 million and \$0.005 million for 2016 and 2017 respectively are due to inflationary increases applicable to each test year.

⁷⁵ Exhibit B-6, YECL Responses to UCG requests, UCG-AEY-28(b), PDF, page 150 of 260.

6.1 Views of interveners

140. In argument, UCG stated that AEY should not be allowed to increase property taxes for the test years due to a lack of evidence, such as the utility's property tax assessments.

6.2 Applicant responses to interveners

141. AEY replied that the position of UCG constituted new evidence that should be struck from the record or be given no weight by the Board.

6.3 Views of the Board

142. The Board considers that it is reasonable for AEY to forecast its 2016-2017 Taxes Other Than Income based on the application of relevant inflation rates by using, as a starting point, its 2015 actual property taxes paid. With respect to the issue of property tax assessments raised in Final Argument, the Board does not have sufficient information on the record of the current proceeding to determine that consideration of property tax assessments is required. If UCG wishes to explore the issue of whether property tax assessments should be provided in support of AEY's Application, it may bring forward this issue for examination in AEY's next GRA.

143. The Board approves AEY's "Taxes Other Than Income" amounts forecasted in the amount of \$0.262 million for the year 2016 and \$0.267 million for the year 2017, as filed.

7 Depreciation

144. In its Application, AEY forecasted depreciation expense in the amount of \$5.792 million for the year 2016 and \$6.283 million for the year 2017. This resulted in an increase from 2015 actual expense in the amount of \$0.380 million in 2016 and \$0.491 million in 2017. AEY explained that the increases were the result of forecasted growth in property, plant and equipment and subject to depreciation expense.

145. AEY stated that the depreciation rates used in the calculations of 2016 and 2017 depreciation expense were developed by way of a technical update, which relied on the depreciation parameters approved by the Board in Board Order 2014-06 for AEY's 2013-2015 GRA. In that application, AEY submitted a full depreciation study in support of the depreciation parameters ultimately approved by the Board. AEY also stated that in 2016 and 2017, it would continue to record the annual amortization of the accumulated depreciation reserve differences credit in the amount of \$0.402 million,^{76 77} which was at the same level approved in Board Order 2014-06.

146. The following table summarizes AEY's recently approved, actual and forecast amounts for depreciation expense:

⁷⁶ This would have the effect of reducing YECL annual depreciation expense by \$0.402 million.

⁷⁷ YECL 2016-2017 GRA Schedules, Schedule S7.4, line 50.

Table 13. **Approved, actual and forecast depreciation expense — 2013 to 2017 (\$000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	4.520	5.252	5.778		
Actual (A)/Forecast (F)	4.382	4.895	5.412	5.792	6.283
Actual (under) or over approved	(0.138)	(0.357)	(0.366)		

Source: Exhibit 2016-2017 GRA Schedule S1.1, line 11.

147. During the course of this proceeding, three issues were raised with respect to depreciation, each of which is discussed in the sections that follow.

7.1 Technical update to determine updated depreciation rates

7.1.1 Views of interveners

148. There were concerns raised by UCG that AEY had not indicated nor requested approval in its application of the revised depreciation rates used in its calculation of depreciation expense for the test years stemming from the results of a technical update to its previous depreciation study.

149. UCG argued that since actual depreciation expense incurred for the 2013-15 test period had been lower than the amount approved to be recovered through AEY's tariff, this was evidence of an over-recovery of depreciation expense in the amount of \$1.1 million⁷⁸ over the 2013-15 period.

150. UCG submitted that AEY's request for increases to its depreciation expense should be denied because of these two issues.

7.1.2 Views of the Board

151. The Board observes that there appears to be some confusion by parties pertaining to certain depreciation-related elements. The Board has provided the following general information with respect to the differences between a full depreciation study and a technical update to a depreciation study.

152. Depreciation expense typically encompasses three components of capital cost recovery: (1) the depreciation related to the original cost of the asset; (2) estimations related to net salvage costs (also referred to in this proceeding as future removal and site restoration); and (3) in some circumstances, the amortization of accumulated reserve differences that arise, in part, from changes in depreciation methodologies or depreciation parameters determined during the course of a depreciation study.

153. Periodically, a new depreciation study is conducted and three depreciation "parameters" — consisting of the average service life, the standard "Iowa curve" and dispersion pattern (collectively referred to as the life-curve parameters) and the net salvage percent parameter — are confirmed or revised. The actual accumulated depreciation recorded to date, based on the prior approved depreciation parameters,

⁷⁸ UCG Final Argument, PDF page 21 of 40.

can differ from the theoretical amount of accumulated depreciation that would have been recorded for each account using the updated parameters. The resulting difference — termed the accumulated reserve difference or variance — is measured in dollars and may be recovered or refunded through depreciation expense as a stand-alone true-up amount, or may be combined into a depreciation rate that includes the amortization of the accumulated reserve differences true-up amount.

154. During the preparation of full depreciation studies, technical updates are often conducted. The purpose of a technical update (which is less costly to prepare than a depreciation study) is to apply the currently approved depreciation parameters to the recent actual plant balance information provided by the utility in order to develop the most current and relevant depreciation rates for the test years. The most recent plant balances will reflect both plant additions and retirements occurring since the time of the last depreciation study or technical update.

155. To summarize, it is during the course of examining a depreciation study that the depreciation parameters of life-curve, net salvage percentages and the amortization of accumulated reserve differences are approved. The rates that are proposed by the utility are used as an input in depreciation expense calculations and are a direct result of the depreciation parameters being applied to the most recent actual plant-in-service information. During the course of a technical update, approved depreciation parameters are similarly applied to the most recent plant balances for the purposes of updating depreciation rates, which will then be used in depreciation expense calculations.

156. In its 2016-17 GRA, AEY submitted a technical update to its December 31, 2011 depreciation study, which had been submitted as part of the record in the 2013-15 GRA.

157. The technical update undertaken by AEY relied on currently approved life-curve depreciation parameters to determine updated depreciation rates for the 2016 and 2017 test years based on December 31, 2015 plant-in-service balances. The result was a total decrease in depreciation expense of approximately \$0.100 million over the test years.⁷⁹

158. In the case of AEY, and consistent with past Board Orders, there is no estimation made for recovery of any future net salvage costs. As a result, there is no depreciation parameter related to or reflective of a net salvage percent that would otherwise form a part of AEY's depreciation rates and therefore depreciation expense.

159. Furthermore, AEY has historically recovered any amortization of accumulated reserve differences as a dollar amount, which is generally determined and approved during the course of examining a depreciation study.

160. With respect to the 2016-17 amortization of accumulated reserve differences amount, AEY stated that it had "... simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences..."⁸⁰ The

⁷⁹ Transcript, Volume 1 page 148.

⁸⁰ Transcript, Volume 3, page 424.

result was a credit, or refund, of depreciation expense in the amount of \$0.402 million per year.

161. Based on the foregoing, the Board is not convinced by the concerns raised by UCG that there is a need to deny or adjust AEY's depreciation expense calculations due to its December 31, 2015 technical update. Consistent with common depreciation practice, AEY's technical update relied on currently approved life-curve depreciation parameters applied to its most recent plant balances for the purposes of updating its depreciation rates, which were used to inform its 2016-17 depreciation expense calculations. The Board finds there is not an issue with the derivation of AEY's forecast depreciation expense.

162. With respect to UCG's assertion of over-collection of depreciation expense for the years 2013-15, the Board determines the revenue requirement on a prospective basis. Depreciation parameters and the resultant rates are estimates applied to forecasted plant balances to determine forecasted depreciation expense. While the depreciation rates themselves will remain static during the test years, actual plant balances — upon which those rates are applied — may differ from those forecasted by the utility. The end result, as observed by UCG, may be differences between approved and actual depreciation expense.

163. For the purpose of calculating AEY's depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense.

7.2 Use of the mid-year convention for calculation of depreciation expense

164. During the oral hearing, Board counsel questioned AEY as to why, in its depreciation expense calculation for Account 493 — Demand Side Management, the mid-year convention had not been applied. The question posed was directed toward a common regulatory convention related to depreciation expense calculations whereby only a half-year of depreciation expense is taken in the year in which an asset has been capitalized into rate base, followed by full-year depreciation expense calculations in subsequent years. This mid-year convention supports that in the absence of having to consider individual and exact dates of capitalization for any given asset, an assumption can be made for depreciation purposes that, on average, all assets are capitalized at the mid-point of the year.

165. An examination of AEY's schedules indicated that depreciation expense had not been taken for any of the amounts on Account 493 — Demand Side Management 2016 capital addition. The amounts had been deferred to the year 2017 where a full year depreciation expense was recorded.

166. AEY witness, James Grattan, advised that if the Board determined that coincident with the capitalization of the asset in 2016 it should attract a half-year of depreciation expense in that same year, he would not be opposed to this calculation.⁸¹

7.2.1 Views of the Board

167. The Board considers that consistent with AEY's depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

168. For clarity, the Board confirms AEY's use of a five-year amortization period is acceptable for this depreciation expense calculation, in accordance with the findings in Board Order 2014-06.⁸²

7.3 Supporting documentation for the amortization of accumulated depreciation reserve differences

169. During the IR process, AEY confirmed that costs related to net salvage had not been included in the depreciation expense for the years 2013-2017.⁸³

170. AEY also confirmed during the oral hearing that despite its Schedule 7.4 — Schedule of Amortization of Differences identified for each account number, negative net salvage in varying percentages, the schedule did not include any costs related to the recovery of net salvage. James Grattan, witness for AEY, stated that Schedule 7.4 "... simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences..."⁸⁴

7.3.1 Views of the Board

171. The Board is satisfied that the 2016-2017 depreciation expense calculated by AEY, including the calculation related to its amortization of accumulated depreciation reserve differences, does not include any amounts related to the recovery of net salvage.

172. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.

⁸¹ Transcript, Volume 3, page 427.

⁸² Board Order 2014-06, Appendix A, page 101..

⁸³ Exhibit B-6, UCG-AEY-29(a).

⁸⁴ Transcript, Volume 3, page 424.

8 Return on rate base

173. AEY included the following information on return on rate base:

Table 14. **Return on rate base — 2013 to 2017 (\$000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Return on Rate Base	5,550	5,782	5,838	6,945	7,400

Source: Exhibit BB-1, Application, page 8-1.

AEY explained that the growth in rate base is a result of capital additions and an increase in the return on equity (ROE). This resulted in the increase in return on rate base for the forecast period.

8.1 Cost of capital

174. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding as the benchmark for determining ROE. In addition, AEY is seeking a 60-basis-point risk premium over the BCUC GCOC benchmark to determine its ROE for each of the test years.

8.1.1 Rate of return on capital

175. In response to YUB-YECL-50, AEY cited the BCUC's most recent GCOC decision (G-75-13) but did not provide that decision as requested. In that decision, the benchmark rate was determined to be 8.75 percent.

176. AEY, YEC⁸⁵ and John Maissan⁸⁶ accepted the BCUC rate. CW did not comment on the rate established by the BCUC. UCG recommended that the Board use the most recent GCOC decision from the AUC.⁸⁷

177. UCG added that given AEY's direct tie to the Alberta market, AEY should not be allowed to link its ROE for the 2016-2017 test period to the recently approved BCUC GCOC benchmark rate of 8.75 percent plus a risk premium of 0.60 percent.

178. YEC disagreed with the UCG position and stated:

The Board has previously determined that the BCUC model is the precedent for Yukon; as such, in Yukon Energy's view there is no basis for using a different benchmark ROE for the current review.⁸⁸

8.1.2 Applicant responses to interveners

179. AEY submitted that UCG has ignored past decisions of the Board and the clear statements of the Board as they relate to equity ratio and ROE in Board Order 2014-06.

⁸⁵ YEC Final Argument, page 3.

⁸⁶ JM Final Argument, page 6.

⁸⁷ UCG Final Argument, paragraphs 137-150.

⁸⁸ YEC Reply Argument, pages 3-4.

8.1.3 Views of the Board

180. In Board Order 2009-02, the Board ruled that the BCUC generic cost of capital (GCOC) model is the most appropriate and is generally accepted by parties.⁸⁹

181. The Board, in Board Order 2009-08 stated:

The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.

The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.

Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board.⁹⁰

182. The Board continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon for the reasons set out above. The Board does not agree with the submissions of UCG on this issue as no evidence was filed to persuade the Board to change its approach. Accordingly, the Board finds that AEY is to use the BCUC GCOC benchmark for ROE of 8.75 percent.

8.1.4 Equity premium

183. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what that risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.⁹¹

184. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore warrants a risk premium. Concentric submitted that the premium should be 60 basis points.⁹²

185. Concentric, based on its research, recommended a risk premium of between 40 and 75 basis points in comparison to the BCUC benchmark utility. The range was framed by FortisBC Electric at a 40-basis-point premium and PNG-West (Pacific Northern Gas-West), representing the upper boundary. Concentric chose 60 basis points, as it matched the 9.35-percent ROE awarded to Maritime Electric, a utility Concentric submitted had similar business risk as AEY but had a deemed equity ratio of 40.9 percent.⁹³

⁸⁹ Board Order 2009-02 Appendix A: Reasons for Decision, page 29.

⁹⁰ Board Order 2009-08, paragraphs 280-282.

⁹¹ Exhibit BB-1, Application, page 8-3.

⁹² Exhibit BB-1, Application, page 8-4.

⁹³ Exhibit BB-1, Application, Attachment 8.1, page 6.

186. Concentric added:

In most respects, the business risk of AEY has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. Weak economic conditions in the province, coupled with the impact of energy efficiency and DSM programs, and increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales;

The business risk profile of AEY is most similar to that of Maritime Electric, which derives a higher percentage of its electricity supply from company owned generation than AEY, but which serves five times more retail customers. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity;

The business risk profile of AEY is also similar in many respects to that of Newfoundland Power, except that AEY is substantially smaller in terms of both customers served and rate base. Newfoundland Power has an ROE of 8.80 percent on 45 percent common equity; and

The business risk of AEY is lower than that of PNG-West, which is similar in size but faces more risk than AEY due to the loss of a major customer that caused throughput to decline by 87 percent from 2003-2012. PNG West has an authorized ROE of 9.50 percent (or 75 basis points above the BC benchmark) on 46.5 percent common equity.⁹⁴

187. AEY submitted that the business risks it faces encompass market demand, operational risks, small size and geographic environment and that these risks expose it to a higher degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.⁹⁵

8.1.4.1 Views of interveners

188. YEC took the position that it is appropriate to use the BCUC benchmark ROE of 8.75 percent as the foundation, and that for Yukon utilities, it is appropriate to “apply a risk premium adder above the benchmark in order to reflect additional risks faced by northern utilities on an isolated grid.”⁹⁶ However, YEC said that AEY’s proposal deviates from the BCUC approach and from past Yukon precedent. AEY’s approach maintains a requirement for expert evidence and testimony to determine ROE for Yukon utilities that potentially increases both the cost and complexity of these proceedings.

189. YEC recommended that the Board use the same methodology and justification for determining ROE that was established in the 2005 GRA — that is, a point midway between YEC and FortisBC Electric of 48.5 basis points.⁹⁷

⁹⁴ Exhibit BB-1, Application, Attachment 8.1, page 32.

⁹⁵ Exhibit BB-1, Application, page 8-3.

⁹⁶ YEC Final Argument, page 3.

⁹⁷ YEC Final Argument, page 5.

190. In Reply Argument, YEC stated:

BCUC decisions referenced in the current Board proceedings have confirmed the requirement for a risk premium relative to the approved benchmark for various BC utilities to reflect the relative size of the utility and the characteristics of its service area.⁹⁸

191. YEC later added that in Board Order 2009-02, the Board stated:

... that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.⁹⁹

192. YEC then stated that the bookends for assessing a risk premium against the BCUC benchmark are FortisBC Electric and PNG-West.¹⁰⁰

193. John Maissan argued that the position that AEY faces increased sales forecast risk due to customers switching home heating sources is speculative. Based on the conclusion of Concentric, the sales forecast risk does not have a material effect on the risk profile for AEY.¹⁰¹

194. Mr. Maissan noted that the concern regarding variation in earnings did not appear to hold. He referred to YUB-YECL-63(b), arguing that in spite of significant economic variations and sales variabilities in 2014 and 2015, AEY, with the exception of 2015, has consistently earned above approved ROE levels.¹⁰²

195. Mr. Maissan recommended:

... that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor [sic] is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more that adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%.¹⁰³

196. CW noted that Concentric concluded that, "In most respects, the business risk of AEY has not materially changed since 2009..."¹⁰⁴ CW submitted that the request for a risk premium was unwarranted.¹⁰⁵

197. UCG argued that the appropriate benchmark should be based on the latest AUC GCOC proceeding and therefore did not make any recommendation with respect to an equity premium.¹⁰⁶

⁹⁸ YEC Reply Argument, page 4.

⁹⁹ Board Order 2009-02, Appendix A: Reasons for Decision, page 29.

¹⁰⁰ YEC Reply Argument, page 5.

¹⁰¹ JM Final Argument, page 5.

¹⁰² JM Final Argument, page 6.

¹⁰³ JM Final Argument, page 6.

¹⁰⁴ Exhibit BB-1, Application, Attachment 8.1 (Concentric Report), page 31. Concentric did subsequently state that "the most important change has been uncertainty; and unpredictability associated with usage per customer, especially among the residential class".

¹⁰⁵ CW Final Argument, paragraph 26.

¹⁰⁶ UCG Final Argument, paragraphs 137-150.

8.1.4.2 Applicant responses to interveners

198. AEY challenged CW's interpretation that the Board, in Board Order 2014-06, ruled that a risk premium was not necessary or that there was no incremental business risk. Rather, AEY submitted that the Board ruled that the determination of whether a risk premium should be applied was not clear, and the Board directed AEY to provide justification in its next GRA.¹⁰⁷

199. AEY contended that Mr. Maissan's position that the Board only use the BCUC benchmark ignores the evidence that FortisBC Energy has lower business risk than AEY.¹⁰⁸

200. In response to YEC argument, AEY said the approach it took was in response to a direction from Board Order 2014-06. Further, AEY disagreed with the submission of YEC that AEY's business risks have not changed, noting that AEY's usage per customer has made it more difficult to accurately forecast sales.¹⁰⁹

201. For risk due to small size, Concentric stated:

Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).¹¹⁰

8.1.4.3 Views of the Board

202. The Board made its determinations with respect to an ROE risk premium in Board Order 2009-02 and 2009-08 as follows:

Should a risk premium be applied?

In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation.

¹⁰⁷ AEY Reply Argument, paragraphs 57-63.

¹⁰⁸ AEY Reply Argument, paragraphs 64-66.

¹⁰⁹ AEY Reply Argument paragraphs 77 and 80.

¹¹⁰ Exhibit B-9, YUB-YECL-62(a).

The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

What risk premium should be applied to YECL?

In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.¹¹¹ (footnotes omitted)

203. The Board continues to maintain this view. For this Application, as in past GRA decisions, the Board does not have a recent YEC decision to determine one of the bookends for the risk premium range and to use to calculate an ROE premium as it did for Board Order 2009-02.

204. The Board notes that Concentric concluded that AEY's business risks have not materially changed since 2009.¹¹² Further, Concentric stated that weak economic conditions in Yukon, coupled with the impact of energy efficiency and DSM programs, as well as increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales.

205. However, although forecasting sales volume may be more difficult, the table in the preamble to YUB-YECL-52 shows that AEY's actual sales — with the exception of one major growth year (2012) — are consistently within two percent of the previous year's levels. Further, Concentric concluded that sales forecast risk due to changing heating fuel sources does not have a material effect on the risk profile of AEY.¹¹³

206. Additionally, AEY testified:

That we, as a utility, should be able to do come up with a forecast that's somewhat accurate to what our actual sales are going to be. It's changing and there's lot of challenges. You've got weather. You've got all the new demand side management programs, including micro-grid generation. There's lots to it. But I think it should be something that is expected that we should be able to take a guess at. Better than a guess. We should be able to do a thorough analysis and come up with a reliable forecast...¹¹⁴ I would just add that we did know the existence or lack of existence of a weather-normalization account for ATCO Electric, but we didn't frame it as an adder to the risk premium per se.¹¹⁵

¹¹¹ Appendix A to Board Order 2009-02: Reasons for Decision, page 29 of 49.

¹¹² Exhibit BB-1, Application, Attachment 8.1, page 29.

¹¹³ Exhibit BB-1, Application, Attachment 8.1, page 27.

¹¹⁴ Transcript Volume 1, page 86, lines 2-13.

¹¹⁵ Transcript Volume 1, page 87, lines 9-12.

207. Based on AEY testimony, sales volume risk is a risk AEY can manage and, in the Board's view, it is a risk that does not attract a risk premium. However, through the submissions of YEC and AEY and the comparisons with FortisBC Energy (the BCUC benchmark utility), the Board is persuaded that AEY can be eligible for a risk premium relative to the BCUC benchmark utility to mitigate risks other than those related to sales volume. The following paragraphs discuss the Board's determination of the appropriate level of the risk premium.

208. The Concentric report made the following comparisons:

The 2016 Generic Cost of Capital proceeding is currently underway in British Columbia and a decision is expected by July 2016. The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY. As a gas distributor, FortisBC Energy owns its regulated gas distribution system, whereas AEY owns the electric distribution system and some generation facilities. As discussed in more detail later in the report, investors and credit rating agencies view companies that own generation as higher risk than pure transmission and/or distribution utilities. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity, while AEY currently has the same ROE and a slightly higher equity ratio of 40 percent...¹¹⁶ FortisBC Electric was awarded an ROE risk premium of 40 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk.¹¹⁷

209. "Section IV — Risk Assessment" of the Concentric report listed the following risks:

- small size,
- generation risk,
- fuel and purchased power risk,
- volume/demand risk,
- regulatory environment,
- deferral/variance accounts, and
- competition from alternative fuels.¹¹⁸

210. The Board considers the two greatest risks to be size and generation. Discussion of the remaining listed risks follows. Fuel and purchased power are addressed through

¹¹⁶ Exhibit BB-1, Application, Attachment 8.1, pages 4-5.

¹¹⁷ Exhibit BB-1, Application, Attachment 8.1, page 5.

¹¹⁸ Exhibit BB-1, Application, Attachment 8.1, page 1.

deferral accounts. AEY has stated its preference to manage volume/demand risk. Regarding regulatory environment, Concentric has stated that traditional cost of service regulation is generally considered less risky than incentive regulation.¹¹⁹ AEY is under cost-of-service regulation, while FortisBC Energy and FortisBC Electric are under incentive regulation. Concentric did conclude that AEY was at higher risk than other companies due to not having a variance account for weather-related volume risk. As AEY prefers to manage its sales volume risk, the Board does not accept Concentric's conclusion that AEY faces increased regulatory risk because it does not have a weather-related volume risk deferral account. The Board's view is that AEY faces less regulatory risk than FortisBC Energy and FortisBC Electric because it is under cost-of-service regulation. Additionally, Concentric did not state that AEY deserved a risk premium for variance/deferral accounts.¹²⁰ Regarding competition for alternative fuels, Concentric submitted that FortisBC Energy faced competition from electric heat among residential customers and to a lesser extent than did PNG-West. However, Concentric concluded that this type of risk was difficult to quantify and likely does not have a material effect on the risk profile of AEY.¹²¹

211. Based on the foregoing, the Board concludes that in determining relative risk for AEY, the Board should look at size and generation risk.

212. For the comparators provided by Concentric,¹²² the Board does not accept the use of FortisBC Electric for the lower boundary. Although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY. Concentric referenced the BCUC GCOC Stage 2 proceeding¹²³ and the awarding of a 40-basis-point risk premium to FortisBC Electric. Part of the determination of the risk premium for FortisBC Electric was:

The evidence supports the findings that FBC [FortisBC Electric] faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk.¹²⁴

213. Price competitiveness was a major factor in determining the risk premium for FortisBC Electric. Concentric concluded that competitiveness (from alternate supply) did not have a material impact on the risk profile of AEY. Generation assets for FortisBC Electric are materially higher than for AEY. Similarly, the generation assets for Maritime Electric are materially higher than those of AEY. Maritime Electric procures its power from a different jurisdiction.¹²⁵ Due to these factors (competitiveness, relative amount of generation assets), the Board finds that AEY is not directly comparable to FortisBC

¹¹⁹ Exhibit BB-1, Application, Attachment 8.1, page 25.

¹²⁰ Exhibit BB-1, Application, Attachment 8.1, page 26.

¹²¹ Exhibit BB-1, Application, Attachment 8.1, pages 26-27.

¹²² FortisBC Electric for the lower boundary, PNG-West for the upper boundary, and settling on an ROE equivalent to Maritime Electric.

¹²³ Exhibit BB-1, Application, Attachment 8.1, page 5. The reference was to BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014 at page 113.

¹²⁴ Exhibit BB-1 BCUC Generic Cost of Capital Proceeding Stage 2 Decision, Order G47-14, March 25, 2014, page 86 (public document available at www.ordersdecisions.bccub.com)

¹²⁵ Exhibit BB-1, Application, Attachment 8.1, page 21. The Board views cross-jurisdictional transactions as facing higher regulatory risk than those transactions occurring within a single jurisdiction.

Electric or Maritime Electric. Accordingly, the Board does not find generation to be a significant risk for AEY in relation to the risk of Fortis BC.

214. Further, in terms of comparisons to Maritime Electric, the Board notes that its ROE was determined through a settlement agreement. There is no evidence on the record of this proceeding indicating the trade-offs that may have occurred during the negotiation process or how the ROE level was determined. As a result, the Board gives little weight to the ROE determined by way of a settlement agreement.

215. Concentric stated that PNG-West was larger than AEY and added that PNG-West was awarded a higher risk from the BCUC due to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012). Concentric referenced the BCUC GCOC Stage 2 decision for this information. These circumstances do not apply for AEY. Therefore, the Board concludes that AEY is not directly comparable to PNG-West.

216. Although earnings variability has been mentioned by Concentric, the Board also notes that AEY has been able to consistently meet or exceed forecast earnings levels.¹²⁶

217. The Board took note of Concentric's view that the extremely small size of AEY is an important risk factor for the purposes of establishing an appropriate risk premium for AEY.¹²⁷

218. Based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY.

219. The evidence on this record shows that BCUC has set a premium for a small size utility at 25 basis points.¹²⁸ This Board accepts that a 25-basis-point premium over the BCUC benchmark utility is reasonable for this jurisdiction.

220. Further, as AEY will have an equity thickness¹²⁹ greater than that of the BCUC benchmark utility, the Board is of the view that this will compensate AEY for the other differences between it and the benchmark utility.

221. Therefore, the Board approves an ROE of 9.00 percent for AEY for both test years. AEY is to reflect this change in its compliance filing to this decision.

8.1.5 Common equity ratio

222. AEY requests to maintain the previously approved common equity ratio of 40 percent for each of the test years of 2016 and 2017.

223. John Maissan supported AEY's request for an equity thickness of 40 percent.¹³⁰

¹²⁶ Exhibit B-9, YUB-YECL-63(b).

¹²⁷ Exhibit BB-1, Application, Attachment 8.1, pages 19-20.

¹²⁸ Exhibit B-9, YUB-YECL-62(a).

¹²⁹ Equity thickness refers to the ratio of debt to equity of a utility.

¹³⁰ JM Final Argument, page 6.

224. UCG submitted:

... that linking AEY's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of equity thickness of AEY's capital structure. UCG submits that AEY's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility.¹³¹

8.1.5.1 Views of the Board

225. In Board Order 2014-06, the Board states:

In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application... Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.¹³²

226. The Board continues to view that an equity thickness of 40 percent for AEY is reasonable for the reasons set out above. No evidence was presented in this proceeding in support of another approach. The Board does not accept the submissions of UCG on this issue because no evidence was presented in support of these submissions or the use of an Alberta utility as a comparator in the current proceeding. The Board finds that AEY is to maintain an equity thickness of 40 percent.

8.1.6 Cost of debt

227. AEY discussed its forecast for long-term debt rates in the Application.¹³³ AEY used an average long Canada bond rate and applied a spread to determine the forecast debenture rate. The following was provided by AEY:

Table 15. **Forecast long-term debt rates**

	2016	2017
Long Canada Bond Rate	1.90% - 2.70%	2.30% - 3.30%
Credit Spread	1.80% - 2.20%	1.80% - 2.20%
Debenture Rate	3.70% - 4.90%	4.10% - 5.50%

¹³¹ UCG Final Argument, paragraph 136.

¹³² Board Order 2014-06, Appendix A: Reasons for Decision, page 54.

¹³³ Exhibit BB-1, Application, pages 8-4 to 8-5.

Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-in Rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 8-5.

228. AEY updated its cost of debt numbers in its October 24, 2016 update. The all-in rates were revised to 3.77 percent for 2016 and 4.07 percent for 2017.

8.1.6.1 Views of interveners

229. CW argued that AEY's cost of new debt has a pattern of over-forecasting, and noted that in 2014, the cost of debt was 0.96 percentage points lower than forecasted and for 2015, new debt was 1.08 percentage points lower than forecasted. CW further stated that AEY was protected in 2013 when actual cost was higher than forecasted, as actual cost was determined and approved by the Board for that year.¹³⁴

230. John Maissan argued that for the years 2008-2015, the actual rates for cost of debt were never above the approved rates for cost of debt, but were usually below the approved rates. Mr. Maissan referenced the response to JM-AEY-14 in support of this argument and recommended a cost of debt rate of 4.35 percent for both test years.¹³⁵

231. UCG, based on Board Order 2013-01, recommended that the Board adopt a historic formulaic approach of 120 basis points for forecasting future debt costs.¹³⁶

8.1.6.2 Applicant responses to interveners

232. AEY argued that CW's evidence in relation to a pattern of over-forecasting debt rates should be ignored because AEY actually under-forecasted the rate for cost of debt in one of the years used by CW. AEY added that its October 24, 2016 update to the rate for cost of debt exceeded the recommended reduction in debt rates recommended by CW.¹³⁷

233. AEY submitted that the UCG recommendation that the historical formulaic approach for determining rates for cost of debt should be used for AEY should be rejected due to lack of evidentiary support.¹³⁸

8.1.6.3 Views of the Board

234. The Board notes that AEY did update its cost of debt in its October 24, 2016 update and that update was in response to YUB-YECL-73. The Board also notes that in Argument and Reply Argument, none of the interveners commented on the update to cost of debt.

235. The Board has reviewed the submissions on cost of debt. Originally, AEY forecasted the long Canada bond rate to be 2.50 percent for 2016 and 3.0 percent for

¹³⁴ CW Final Argument, paragraph 33.

¹³⁵ JM Final Argument, page 4.

¹³⁶ UCG Final Argument, paragraphs 152-154.

¹³⁷ AEY Final Argument, paragraphs 98-99.

¹³⁸ AEY Reply Argument, paragraph 81.

2017. In its update, AEY revised those long Canada bond rates to 1.92 percent for 2016 and 2.22 percent for 2017. It appears that AEY has maintained a credit spread of 1.8 percent.

236. The Board is persuaded by the submissions of Mr. Maissan that the AEY response to JM-AEY-14 show that actual costs of debt are never above and are consistently below forecast levels. For this reason, the Board rejects AEY's forecast for 2016 cost of debt.

237. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November¹³⁹ of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

238. Further, in YUB-YECL-73(b), AEY was asked to provide the sources for the long Canada bond rate and credit spreads. Although AEY did provide sources, AEY did not explain the manner in which it determined its credit spreads.

239. In response to YUB-YECL-73(a), AEY provided its historical long Canada bond rates and credit spreads for the years 2011-2015. For that period, the average credit spread was approximately 1.6 percent.

240. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017. The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision.

8.2 No Cost Capital

241. AEY discussed No Cost Capital (NCC) in its Application. It stated that NCC related to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans and the Reserve for Injuries and Damages (RID).

242. OPEB plans are administered on a combined basis with Canadian Utilities Limited and AEY is assessed a percentage of its payroll at a rate calculated for the plan as a whole. AEY continues to use the cash basis for its pension plan and the OPEB plan. The OPEB plan covers such items as drug, health and dental costs for retirees.

¹³⁹ 2012 is the only year where the issuance was after November 1. The issuance date for that year was November 14.

243. The RID is as an account used for uninsured and uninsurable losses and the deductible portion of insurance claims. Attachments 8.2 (Beaver Creek House Fuel Spill — \$109,700) and 8.3 (Fish Lake #1 Spillway Failure — \$100,000) to the Application provided details of the two incidents that have been included in the RID account.

244. The following continuity schedule for NCC was provided by AEY:

Table 16. **Continuity for NCC Mid-Year Balance — 2013 to 2017 (\$000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Total No Cost Capital	165	(24)	446	660	667

Source: October 24, 2016 Update, Schedule S8.4.

8.2.1 Views of the Board

245. The Board finds AEY's updated NCC costs to be reasonable and approves the updated amounts, subject to any impacts from other sections of this decision.

9 Capital additions

246. AEY submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. AEY's actual and forecasted capital expenditures and additions to rate base for the period from 2013 to 2017 are shown in the following table:

Table 17. **AEY Capital Expenditures and Additions – 2013 to 2017 (\$000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Generation	5,574	8,599	3,060	6,630	5,316
Distribution	7,268	6,236	6,232	7,659	8,994
General Property & Equipment	2,516	2,002	1,402	759	1,008
Capital expenditures total	15,358	16,837	10,694	15,048	15,318
Capital additions to rate base	14,321	18,849	10,252	14,234	14,907

Source: Application, Page 9-1; Application, Schedule 9.1.

247. Using the numbers in the above table, the capital expenditures for the test period are forecasted to increase by approximately 40 percent each year when compared to 2015. Capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively, when compared to 2015.

248. Generally, with the exception of projects described in the following sections, AEY's capital additions are categorized as generation, new extensions, distribution improvements, street and sentinel lights, meters and general property and equipment. Generic descriptions of each category are provided in pages 9-1 to 9-5 of the Application, while a listing of the projects that make up the dollars shown Table 17

(above) of this order are provided in Schedules 9.1 and 9.2 of the Application. A listing of the capital expenditure information for 2016 and 2017, as well as project descriptions for those projects greater than \$100,000, are found in Attachment 9.1 and Attachment 9.2, respectively. Full business cases for major capital projects, \$500,000 or greater, are included in the Application's appendices.

249. AEY provided the following information that shows that its controllable capital was within 3.2 percent the capital expenditure amounts approved in Board Order 2014-06 for its 2013-2015 GRA. The following table shows the variances in AEY's controllable capital expenditures between its actual and approved amounts for 2013-2015:

Table 18. **Controllable Capital Expenditures — 2013 to 2015 (\$000s)**

2013-2015 GRA			
	Actual	Approved	Variance (%)
New Extensions	6,141	15,480	60.3%
Contributions	(4,866)	(13,039)	62.7%
Net New Extensions	1,275	2,441	47.7%
“Controllable” Capital	36,748	37,955	3.2 %
Total Net Capital	38,023	40,396	5.9%

Source: Exhibit B-4, CW-YECL-1.

9.1 Views of interveners

250. Mr. Maissan pointed out that the projects listed in Attachments 11-1 to 11-6 of the Application,¹⁴⁰ relating to project cost overruns, exceeded the forecast budgets by a total of \$4.7 million. The 2013 to 2015 forecast controllable project expenditures spent is \$32.048 million. Mr. Maissan stated that AEY underspent by \$5.947 million or by 15.65 percent of the original forecast. Mr. Maissan went on to state:

... a significant number of forecasted capital projects did not get done, had they been done the “controllable” capital budget would have been exceeded by \$4.7 million or more. Many projects have been dropped or deferred, but AEY provided no information on them.¹⁴¹

251. Mr. Maissan recommended that the Board order AEY to provide detailed information on capital projects that have been deferred or dropped, and the level of detail should be commensurate with the detail required for AEY capital forecasts. Mr. Maissan further recommended that the Board reduce the controllable capital budget, after any and all other adjustments, by three percent. The Board should further order AEY to indicate in a compliance filing where these cuts were made.¹⁴²

¹⁴⁰ Exhibit BB-1, Application, Project Completion Summaries Table, page 11-3.

¹⁴¹ JM Final Argument, page 7.

¹⁴² JM Final Argument, page 7.

9.2 Applicant responses to interveners

252. Responding to Mr. Maissan's submission, AEY referred to its response to YUB-YECL-11(b) Attachment 1, a spreadsheet that includes a list of all projects approved capital projects and deemed capital projects from the 2013-2015 period. AEY pointed out that in this spreadsheet, projects with variances of 10 percent and greater than \$50,000 are accompanied by a corresponding explanation. AEY noted that in its Application it had resubmitted updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but have been deferred to the 2016-2017 test period.¹⁴³

253. AEY stated that the arbitrary reduction of the capital forecast, as recommended by Mr. Maissan, ignores the significant amount of evidence on the record supporting the need and prudence of the capital projects within the capital forecast, pointing out that the capital program throughout 2013-2015 was significantly higher than what AEY has experienced in recent years. AEY submitted that it has incorporated the learnings gained from this experience into its capital forecast by making adjustments in its forecasting methodology and assumptions. AEY submits that the evidence on record does not support Mr. Maissan's recommended reduction.

9.3 Views of the Board

254. The Board has reviewed AEY's capital addition forecasts and corresponding information and considers that AEY has provided sufficient support for its capital forecast for 2016-2017. Although the increase in capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively from 2015, the capital additions are reasonable when compared to the prior three years' actual capital additions. Subject to the Board's findings in the subsections that follow, the forecast capital additions and capital expenditures have been supported by business cases and the Board accepts the explanations in the updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but were deferred.

255. For these reasons, Mr. Maissan's recommendation for a general cut for AEY's controllable capital budget is not warranted.

9.4 Distribution Plant additions

256. AEY provided the following information related to distribution plant additions for the period 2013 to 2017:

Table 19. **Distribution Plant Additions — 2013 to 2017 (\$000s)**

	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Forecast	
							2016	2017
New Extensions	2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
Distribution Improvements	4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
Street & Sentinel Lights	536	420	322	945	466	813	585	1,132
Meters	308	600	166	204	234	207	200	204

¹⁴³ AEY Reply Argument, paragraph 96.

Transformers & Regulators	72	10	75	10	108	10	368	92
Distribution in Total	7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994

Source: AEY Application, Schedule 9.1.

257. AEY pointed out that, as a result of AEY's forecasting, the 2016 forecasts represent a 41-percent reduction compared to the 2015 approved forecast.¹⁴⁴

9.4.1 Views of interveners

258. UCG noted that total actual distribution plant additions for the 2013 to 2015 timeframe were \$19.736 million, compared to the approved forecast amount of \$31.051 million. UCG submitted that ratepayers have paid the costs of \$11.315 million in forecasted distribution plant additions that never took place within the test years.

259. Given this recent track record of overestimating plant additions, UCG recommended that the distribution plant forecast for the 2016-2017 test period be reduced by 40 percent.¹⁴⁵

9.4.2 Views of the Board

260. Regarding the UCG comments that forecasted capital additions were greater than actual capital additions, the Board notes that the approved forecasted plant additions (\$31.051 million) for 2013 to 2015 have been subsequently trued up to now reflect the actual plant additions (\$19.736 million) for 2013 to 2015. It is the actual plant additions that are now reflected in the 2015 actual closing balances that are used to inform the 2016 test year opening capital balances. Furthermore, this is standard process for forward-looking (or prospective) cost-of-service jurisdictions.

261. The Board has reviewed AEY's forecasted planned additions to distribution and corresponding information and considers that AEY has provided sufficient support for its distribution plant additions for 2016-2017. With respect to AEY's test year distribution forecasts compared to previous year's actual and approved numbers, it appears that the primary reason for the increase is related to distribution improvements. The Board's findings related to distribution improvements are addressed in section 9.4.4. Subject to the findings in that section, the Board considers AEY forecasts to be reasonable for distribution plant additions and does not agree with UCG's recommendation to reduce the 2016-2017 test-period forecasts.

9.4.3 New Extensions

262. With respect to New Extensions, AEY stated that the forecast is based on discussions with the Yukon government, the City of Whitehorse and First Nation governments. AEY holds a seat on the Development Review Committee with the City of Whitehorse. As a result, AEY has contact with developers and engineering firms, which informs the new extension forecast. AEY submitted that it also considers historical customer additions in formulating its forecasts to specifically account for walk-in customers who may require service during the test years.

¹⁴⁴ AEY Reply Argument, paragraph 126.

¹⁴⁵ UCG Final Argument, paragraphs 175 to 176.

263. AEY submitted that the reason for lower new extensions expenditures as compared to previously approved numbers is slower economic growth than previously anticipated. AEY added that new extensions are a capital cost not at the control of AEY and are dependent on development within the communities in which the company operates.¹⁴⁶

264. AEY submitted that it uses the best information available when preparing its forecasts, which includes any lessons learned from past test periods. AEY reiterated that its new extension forecast is based on “historical actual experience and incorporated information from the Yukon Government, the City of Whitehorse, and First Nation Governments ... there is no systemic forecast error and ... the forecast has no relation to, or correlation with the 2013-2015 forecast.”¹⁴⁷

9.4.3.1 Views of interveners

265. CW noted that AEY admitted it over-forecasted capital additions related to new extensions over the 2013 to 2015 period. Furthermore, taking customer contributions into account, the forecast for net new extensions over the period is 47.7 percent higher than actuals. CW submitted that the systematic over-forecasting results in customers paying for capital that is not actually put into service. Accordingly, CW recommended the Board reduce the 2016-2017 test period forecast for net new extensions by 47.7 percent to account for the systemic forecast error.¹⁴⁸

9.4.3.2 Views of the Board

266. With respect to the argument put forth by CW, the Board is not convinced that a three-year period of actuals being lower than approved amounts can be classified as systemic. The Board accepts Mr. Tenney’s testimony on behalf of AEY that overall, the three-year forecast period was fairly accurate.¹⁴⁹ However, the Board notes that might not be true on a line-item-by-line-item basis. Mr. Tenney also stated in testimony:

With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that the need to move forward.¹⁵⁰

267. Mr. Massie added:

And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I’d say that we’ve reflected it in our ’16 and ’17 forecasts.¹⁵¹

268. The Board accepts AEY’s testimony that it has adjusted its test period forecasts to account for historical over forecasting. The Board does not accept CW’s and UCG’s recommendations to reduce AEY’s new extension forecast.

¹⁴⁶ Exhibit B-4, CW-YECL-1.

¹⁴⁷ AEY Final Argument, paragraph 130.

¹⁴⁸ Exhibit C3-3, CW Evidence, A8.

¹⁴⁹ Transcript, Volume 3, page 441, lines 13 to 14.

¹⁵⁰ Transcript, Volume 3, page 442, lines 6 to 9.

¹⁵¹ Transcript, Volume 3, page 442, lines 17 to 22.

269. Furthermore, the Board notes that the 2016 new extension forecast is three percent greater than 2015 actuals, and the 2017 forecast is 2.2 percent greater than the 2016 forecast, after the Whistle Bend Stage 3 project is accounted for in the forecast.

270. In the Board's view, AEY is taking into account current economic conditions in the Yukon and information available to it at the time of preparing the forecast. Moreover, the Board notes that AEY's submission that indicated that year-to-date costs for new extensions, as of October 31, 2016, are \$2.116 million, or 98 percent of the 2016 forecast.¹⁵²

271. For these reasons, the Board approves AEY's forecast as filed.

9.4.4 Distribution improvement projects

272. AEY submitted that distribution improvement projects generally fall into four major categories: (1) system performance projects, (2) life extension projects, (3) system replacement projects, and (4) "forced" projects. AEY clarified that these projects are required to maintain system performance at an acceptable level and that this category of capital projects includes system protection, voltage, current and line clearance projects.¹⁵³ AEY added that it tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.¹⁵⁴

273. AEY submitted that the proposed test period forecast distribution improvement projects are prudent in that they ensure the continued supply of safe and reliable electricity to AEY's customers at a reasonable price. Accordingly, AEY submitted that the Board should approve the 2016-2017 distribution improvements as applied for.¹⁵⁵

274. AEY pointed out that it files KPI (key performance indicators) reports on an annual basis. AEY submitted that the reports are available on the Board's website and added that the last such report for year 2015 was filed on May 4, 2016.¹⁵⁶

9.4.4.1 Views of interveners

275. UCG noted that system improvement expenditures increased an average of \$3.75 million per year over the period from 2010 to 2015. UCG further noted that AEY proposed system improvement expenditures of \$4.346 and \$4.178 million in 2016 and 2017 respectively, but has provided no evidence of expected system performance improvements with respect to line losses and interruption indices. UCG included the following in argument:

UCG submits that without an established benchmark, the Board and ratepayers cannot determine how well AEY is actually performing with respect to SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) reliability performance indices. UCG submits that the Board

¹⁵² AEY Reply Argument, paragraph 91; Transcript, Volume 3, page 509, line 25, to 510, lines 1-2.

¹⁵³ Exhibit BB-1, Application, Page 9-2.

¹⁵⁴ Exhibit BB-1, Application, Page 9-3,

¹⁵⁵ AEY Final Argument, paragraph 138.

¹⁵⁶ AEY Reply Argument, paragraph 46.

should establish performance and reliability benchmarks and AEY should be directed to report its actual performance against these benchmarks.¹⁵⁷

276. Considering the above, UCG submitted that AEY should be denied distribution expenditures in 2016 and 2017 since evidence has not been provided that demonstrates a benefit to customers.

9.4.4.2 Views of the Board

277. The Board approves AEY's proposed distribution improvement expenditures as filed. Nonetheless, with respect to system performance projects, the Board notes AEY submission that it:

... tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. To this end, AEY reviews unplanned outages that may be attributed to system deficiencies, prepares a report for each, and implements corrective action.¹⁵⁸

278. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings.

9.4.5 Meters

279. AEY submitted that capital additions for meters should include new meter installations that are required to replace end-of-life meters consistent with Measurement Canada requirements. This category of capital additions also includes the installation of new meters required to accommodate load growth associated with customer requests for service. The capital meter additions forecast is based on known areas of development and expected connection repairs.

280. AEY pointed out that it purchases meters from ATCO Electric at cost and, in so doing, is able to take advantage of the economies of scale realized by ATCO Electric in its meter purchases. This is a significant benefit to AEY and its customers. AEY submitted "this is undoubtedly the least cost alternative given that it is able to purchase its meters, but with the buying power of a utility the size of ATCO Electric."¹⁵⁹ Furthermore, other than AEY and its customers benefiting from this relationship, AEY submitted that it is unclear as to what benefit could be derived by the ATCO family of companies, given that the meters are purchased at cost.

¹⁵⁷ UCG Final Argument, paragraph 231.

¹⁵⁸ AEY Final Argument, paragraph 136.

¹⁵⁹ AEY Reply Argument, paragraph 136.

9.4.5.1 Views of interveners

281. With respect to meter replacement and new installations, UCG commented that over the period 2013-2015, AEY had actual expenditures of \$708,000 that were well below the approved \$1 million total. UCG submitted that this significant over-forecasting trend should be used to reduce the forecasts proposed for 2016 and 2017. UCG also referred to AEY's submission that it purchases meters from ATCO Electric's meter shop in Grande Prairie. UCG submitted that there should be further clarification on how this arrangement was determined to be the least cost alternative supply point and whether the affiliate relationship had been used to provide benefits to the ATCO family of companies.¹⁶⁰

9.4.5.2 Views of the Board

282. The Board accepts AEY's submission that it is able to purchase its meters at cost from ATCO Electric. Accordingly, the Board finds that no further information is required. The meters are supplied by the affiliate at cost, and the mere existence of the affiliate arrangement for the provision of these meters, in these circumstances, does not merit further clarification by AEY at this time. UCG's request is denied.

9.5 Conversion of existing LED streetlights

283. AEY indicated that it has been in discussions with its customers, some of which are municipalities, regarding recent developments related to the conversion of existing streetlights to light-emitting diode (LED) lamps. Considering there is capital outlay associated with the conversion of existing streetlights to LED, AEY submitted that it is seeking the Board's direction

... as to the appropriate method of accounting for the capital costs associated with customers requesting conversions of existing streetlights to LED. ATCO Electric Yukon considers there to be two available options:

- (1) A full customer contribution required for all associated capital costs; or
- (2) All capital costs associated with requested conversions would be a system cost, not subject to a customer contribution.¹⁶¹

284. AEY explained that the rationale for this project being a system cost would be that the initial streetlight cost was contributed by the customer when the streetlight was originally installed. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.¹⁶²

285. AEY acknowledged the benefit of reducing load on the electrical system and that the longer lifespan of equipment used under this project could lead to reduced costs in operation and maintenance of the lights. AEY submitted that converting all existing high-pressure sodium (HPS) streetlights to LED streetlights in AEY's communities would cost approximately \$2 million and the project would need to be completed over several years due to resource constraints.

¹⁶⁰ UCG Final Argument, paragraphs 221 to 222.

¹⁶¹ Exhibit BB-1, Application, page 9-3.

¹⁶² Exhibit B-9, YUB-YECL-10(c).

286. AEY provided two cost-benefit analyses for converting lights in thermal communities and hydro communities for each of the two options: customer contributions or system costs.¹⁶³ The cost-benefit analyses showed that a greater net present value (NPV) would result if the conversions were done in diesel-served (thermal) communities compared to hydro communities. AEY reiterated that it is not applying for approval of a wholesale replacement of all existing HPS streetlights but is seeking Board direction as to the appropriate method of accounting for the costs associated with customer conversions of existing streetlights to LED.¹⁶⁴

9.5.1 Views of interveners

287. Mr. Maissan indicated his support for the LED-conversion project and recommended that the Board direct AEY to proceed with the conversion of streetlights (i.e. HPS to LED lights) as a system cost and that priority be given to diesel-served communities.

288. CW indicated its support for the conversion of existing streetlights to LED lamps. However, CW submitted that it is inappropriate for AEY to request the Board to issue direction as to the method of accounting for the associated capital costs in the absence of a fully supported proposal by AEY on that issue. Accordingly, CW recommended that the Board direct AEY to submit a proposal, supported by evidence, which can be tested by the Board in order for it to make a determination on this issue.

9.5.2 Applicant responses to interveners

289. AEY submitted that it is not clear as to what additional information CW is proposing that AEY file with the Board. From AEY's perspective, the decision is relatively straightforward in that either the conversion costs are treated as a system cost or the local municipality must pay for the conversion cost as a contribution in aid of construction. AEY pointed out that economic analyses of both treatments as well as the total estimated costs involved are on the record. All parties have had an opportunity to submit IRs and cross-examine AEY with respect to the information. AEY submitted that the record is complete and the Board has ample information to render a decision on the treatment of costs for streetlight conversions.

Moreover, the treatment of such costs will likely inform the decisions of the relevant communities and/or municipalities with regard to such conversions.¹⁶⁵

290. AEY asserted that requiring it to come forward with a fully supported proposal is entirely unnecessary and would only serve to add inefficiencies to the regulatory process.

9.5.3 Views of the Board

291. The Board supports AEY's rationale for a streetlight project to be treated as a system cost, as outlined:

¹⁶³ Exhibit B-9, YUB-YECL-10(b) Attachment 1.

¹⁶⁴ Exhibit B-4, CW-YECL-27 (h).

¹⁶⁵ AEY Reply Argument, paragraph 95.

... the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.¹⁶⁶

292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.

293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction.

9.6 Project cost overruns (related to Direction 13 — Board Order 2014-06)

294. Responding to Direction No. 13 of Board Order 2014-06, in relation to project cost overruns, AEY included project completion summaries for all projects that were forecast in AEY's 2013-2015 GRA for which actual costs were 100 percent and \$100,000 greater than the original forecast. AEY's compliance with Direction 13 is discussed in section 11 of this decision.

295. The following table contains the list of projects and the related attachment in section 11 of the Application wherein the project descriptions and summaries are provided. Actual and approved forecast costs are included in the summaries, as well as explanations for the variances:

Table 20. **Project Completion Summaries (\$000s)**

Project	Attachment	Approved Forecast	Actuals
Fish Lake Dyke Upgrade	Attachment 11.1	1,720	2,552
Old Crow Plant Expansion	Attachment 11.2	1,950	4,566
Beaver Creek PLC Upgrade	Attachment 11.3	180	377
McIntyre Subdivision Rebuild	Attachment 11.4	725	1,453
Deep Creek Subdivision Connection	Attachment 11.5	60	213
Old Crow Staff Accommodations	Attachment 11.6	100	274

Source: Exhibit BB-1, Page 11-3, Attachments 11.1 to 11.6.

¹⁶⁶ Exhibit B-9, YUB-YECL-10(c)

296. AEY provided business cases for projects where the actual costs were in excess of \$100,000 and for which no business case was provided. The following table includes the list of projects and the actual costs:

Table 21. **Business Cases for Completed Projects (\$000s)**

Project	Attachment	Actuals
Old Crow #2 Replacement	Attachment 11.7	161
Whistle Bend Subdivision Stages 1 & 2	Attachment 11.8	513
Whistle Bend Underground Residential Service	Attachment 11.9	116
City of Whitehorse Range Road Widening	Attachment 11.10	188
4L314 Chilkoot Way Upgrade	Attachment 11.11	483
Azure Road Extension	Attachment 11.12	151
2nd Ave Rebuild	Attachment 11.13	115

Source: Exhibit BB-1, Page 11-4, Attachments 11.7 to 11.13.

9.6.1 Views of interveners

297. With respect to the Old Crow plant expansion project, which went over-budget by \$2.616 million, Mr. Maissan asserted that AEY has been operating in Old Crow for many years and submitted that AEY should have suspended and re-assessed the project when it ran into design cost overruns and local logistical difficulties. Mr. Maissan recommended that the Board retain experts to review and audit the project execution process and cost, or the Board disallow \$1 million of the \$2,616 million cost overruns and remove it from rate base.¹⁶⁷ With respect to the Old Crow Unit 4 Addition project, Mr. Maissan recommended that the Board direct AEY to provide a business case for this project, as it was completed \$112,000 over budget.¹⁶⁸

298. UCG expressed concerns with the significant expenditures over approved budget amounts for many of the capital projects that had been previously approved. UCG submitted, “If there is no evidence that these extra costs were prudently incurred, they should not be allowed to be added to AEY’s rate base.”¹⁶⁹ UCG stated that additions to AEY’s rate base should be limited to allowed cost estimates unless AEY can provide evidence that the cost overruns were prudently incurred. In particular, UCG submitted that the doubling of the cost for the McIntyre Subdivision Rebuild should be the responsibility of AEY, not ratepayers. It concluded with respect to the McIntyre Subdivision Rebuild:

AEY’s evidence is that this project went well beyond the Board approved level because the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This along with other issues resulted in a requirement to develop an entirely new project scope. This resulted in AEY incurring an additional \$728,000 in costs (for a project originally assumed to cost \$725,000) and doubling the cost of the project.¹⁷⁰

¹⁶⁷ JM Final Argument, page 8.

¹⁶⁸ JM Final Argument, page 9.

¹⁶⁹ UCG Final Argument, paragraph 160.

¹⁷⁰ UCG Final Argument, paragraphs 177.

299. UCG further submitted that AEY should not be able to arbitrarily add capital projects to rate base that have not been previously approved by the Board.¹⁷¹ Furthermore, expressing concerns respecting the rapid increase in AEY's rate base in the 2013-2015 timeframe, UCG submitted that AEY should be required to submit detailed asset management plans and/or distribution system plans, the elements of which "will drive the development of investment and maintenance for the test year(s) and beyond."¹⁷²

9.6.2 Applicant responses to interveners

300. Notwithstanding the comprehensiveness of the Old Crow business case, as acknowledged by Mr. Maissan, AEY submitted that project timing was restricted given the timing of the construction of the ice road. Furthermore, the magnitude and extent of the many challenges that arose could not have been foreseen. AEY submitted that although the business and community need did not change, AEY proceeded with the project knowing the costs would be fully examined in a future GRA. AEY confirmed that it would be:

... submitting a Post Completion Summary of the project, that clearly indicates the variances, and gives the Board and Interveners an opportunity to examine the Project during the entirety of a regulatory proceeding is the most appropriate process, without putting the supply of power to the community at risk.¹⁷³

301. Respecting Mr. Maissan's recommendation that AEY submit a business case for the Old Crow Unit 4 addition costs because project costs exceeded the original estimate by more than \$100,000, AEY pointed out that the costs did not exceed 100 percent of the approved forecast. As such, AEY submitted "the business case type description of the cost overrun sought by Maissan is not required" and AEY submitted that there is sufficient information on the record to deem the project useful and prudent.¹⁷⁴

302. Responding to UCG, AEY replied that it does not arbitrarily add capital projects to rate base. AEY's capital expenditure forecasts are based on the best available information at the time of its GRA. AEY submitted that unknown costs that arise and are not included in test period forecasts are subsequently included as actuals in future applications, thus providing the Board and interveners with the opportunity to assess the need and prudence of such costs. AEY submitted that despite UCG's claims, there is ample evidence on the record to demonstrate that all costs related to McIntyre Stage 1 have been prudently incurred. AEY argued that project planning was comprehensive and many assumptions were validated. It could not have predicted what caused the project scope to be adjusted. AEY indicated that, "Project planning and execution was constantly reviewed and updated with the best available information, all while ensuring the customer and Project needs are addressed."¹⁷⁵

¹⁷¹ UCG Final Argument, paragraph 162

¹⁷² UCG Final Argument, paragraph 165

¹⁷³ AEY Reply Argument, paragraph 104.

¹⁷⁴ AEY Final Argument, paragraph 106.

¹⁷⁵ AEY Reply Argument, paragraph 129.

303. AEY added that there is no evidence on the record indicating that the “capital projects put forward by AEY are not needed or that they have not been completed prudently.”¹⁷⁶ With respect to the UCG submission that AEY provide a detailed asset management plan, AEY submitted that such an undertaking is beyond the scope of this proceeding and is being put forward by UCG with limited explanation and no evidence to justify such a request.¹⁷⁷

9.6.3 Views of the Board

304. The Board notes that in its Application, AEY has provided:

- (a) project completion summaries that were forecast in its 2013-2015 GRA, for which actual costs were 100-percent and \$100,000 greater than the original forecast; and
- (b) business cases for projects where actual costs were greater than \$100,000 and for which no business cases were provided.

305. As a result, AEY provided a business case (Appendix 11) for the Destruction Bay Unit 3 replacement where actual costs exceeded the \$450,000 forecasted by \$184,000. The Board further acknowledges that AEY provided a comparison of forecast and actual costs,¹⁷⁸ accompanied with an explanation for projects with variances of 10 percent and greater than \$50,000.

306. When costs are provided in a GRA on a forecast basis, the Board accepts the information available at the time of filing the Application or that becomes available prior to the close of record of the proceeding. Providing the Board with the best available information at the time that it must make its decision assists the Board in determining a revenue requirement for the utility that most closely matches a utility’s expected costs given facts known at the time the application was made or before the close of record. It is incumbent on the utility to do so, and for the utility to plan and budget in preparing its forecasts. Unforeseen projects may arise after a Board Order is issued with respect to the forecast test period. In these cases, the Board reviews the project costs and the variances in the subsequent GRA to ensure that the costs were prudently incurred by the utility.

307. Despite the magnitude of some of the variances between forecast and actual capital expenditures for certain capital projects, the Board accepts the variance explanations provided by AEY.

308. Considering the above, the Board accepts the information found in the project completion summaries and business cases for completed projects. No further direction from the Board is required. The projects and their corresponding costs are discussed in the following sections.

¹⁷⁶ AEY Final Argument, paragraph 122.

¹⁷⁷ AEY Reply Argument, paragraph 125.

¹⁷⁸ Exhibit B-9, YUB-YECL-11(b) Attachment 1.

9.7 Major capital projects

309. In the Application, AEY provided 11 business cases found in Appendix 1 to Appendix 11, in support of major capital projects where forecast costs were \$500,000 or greater. Major capital projects and the underlying business cases are discussed in the sections below.

9.7.1 Fish Lake System expenditures¹⁷⁹

310. AEY noted that the Fish Lake hydro system was built around 1950 and the aging infrastructure is coming to the end of its useful life. In order to maintain Inflow Design Flood (IDF) rates and comply with its water licence for Fish Lake, AEY proposed two projects: the Fish Lake Ditch 3 Diversion project and Fish Lake #2 Head Pond Spillway replacement.

9.7.1.1 Fish Lake Ditch 3 Diversion project (Appendix 1)

311. This project was previously approved in AEY's 2013-2015 GRA. On May 31, 2013, AEY was granted a 25-year extension to its water-use licence, HY12-065. AEY submitted that during the water licence application process, it was identified that the Fish Lake Ditch 3 diversion structure and spillway were not adequately built to withstand a 100-year flood event, which is required to meet IDF rates and comply with its water licensing requirements. AEY is planning to replace and upgrade the Ditch 3 diversion structure and spillway to an engineered design that will allow it to meet these requirements. Accordingly, AEY provided an updated cost forecast with respect to this project, which is reproduced below:

Table 22. **Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs (\$000s)**

Year	Actuals	Forecasts	Total
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

Source: Exhibit BB-1, Application, Appendix 1, page 2.

9.7.1.2 Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)

312. Investigative repairs of the Fish Lake #2 head pond spillway structure identified that the overall structure was in need of replacement. AEY explained that it will have to replace the existing spillway structure in order to adequately handle IDF flows while maintaining safe access to AEY generation facilities. AEY submitted that the project was designed in 2016 and construction is expected to be completed in 2017. Design and engineering costs are estimated to be \$20,000 and the current construction costs are forecasted to be \$593,000.

¹⁷⁹ Exhibit BB-1, Application: Appendix 1, Fish Lake Ditch 3 Diversion Replacement and Appendix 2, Fish Lake 2 Head Pond Spillway Replacement.

9.7.1.3 Views of interveners

313. UCG noted that over the period from 2006 to 2015, AEY has spent \$11.429 million in capital and \$1.96 million in O&M expenditures, while AEY, over the same period, has recovered \$5.87 million in revenue requirement from ratepayers. UCG pointed out that AEY is now looking to spend over \$3 million on the Fish Lake Ditch 3 replacement project and an additional \$0.593 million on the Fish Lake #2 Head Pond Spillway replacement project. Considering the limited amount of total load that is supplied via the Fish Lake plant, it is questionable whether spending this level of funds on a deteriorating plant is providing ratepayers value for their money.¹⁸⁰

9.7.1.4 Applicant responses to interveners

314. AEY submitted that the projects were being completed on water management structures that direct and control water and water flows in the Fish Lake system in compliance with AEY's water licence. AEY specified with respect to water licensing requirements that:

As indicated in the Water License, there are maximum and minimum flows that must be maintained throughout the system. Also, a condition of AEY's Water License is that works associated with the License will be maintained to a sound engineering standard (condition 27 of the Water License).¹⁸¹

315. AEY further clarified by stating that the specific recommendations for these projects can be found in its *2014 Dam Safety Report*.¹⁸²

9.7.1.5 Views of the Board

316. The Board accepts the need for both of these projects, as they are a condition of the water licence.

317. In the case of the Fish Lake Ditch 3 diversion project, a higher standard in regard to water licence HY12-065 was directed for this project. The change in standard caused a delay as draft designs and spillway channel brushing were required in 2014, additional surveying was necessary to enable updated design models and adjustments in 2015, and further construction and civil work was scheduled to be completed in 2016.

318. The requirement for the Fish Lake #2 Head Pond Spillway Project was not discovered until repairs in 2013 brought to light a sinkhole near this dam structure. Further, investigative work resulting in the 2014 Dam Safety Report recommended replacement of the structure by the end of 2017. Accordingly, the Board does not accept UCG's recommendation to deny the expenditures for this project.

319. The Board accepts the updated forecast costs for the Fish Lake Ditch 3 diversion project as these costs are necessary to meet the standards of the new water licence. The Fish Lake #2 Head Pond Spillway costs have not been challenged in this proceeding, and for the reasons provided in this decision, the Board finds these costs are reasonable.

¹⁸⁰ UCG Final Argument, paragraphs 218 to 220.

¹⁸¹ AEY Reply Argument, paragraph 134.

¹⁸² Exhibit B-9, YUB-YECL-14(a), Attachment 1.

9.7.2 Watson Lake Bi-Fuel Project (Appendix 3)

320. AEY is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to bi-fuel. The two phases were described as:

- Phase 1: 2016 – 2017: Source Liquefied Natural Gas (LNG) storage equipment; upgrade Watson Lake plant to meet the safety standard for LNG equipment; install Bi-Fuel technology to one of the six engines; and conduct environmental assessment of engines as directed by Yukon Environmental and Socio-economic Assessment Board (YESAB).
- Phase 2: 2018: Source and install Bi-Fuel technology to the remaining five diesel engines at the Watson Lake plant and increase the volume of LNG storage onsite.¹⁸³

321. If Board approval of the project is received in Q1 of 2017, AEY added that Phase 1 could be completed as early as Q3 of 2017. AEY submitted that Phase 2 of the project is expected to be completed following Yukon Environmental and Societal Assessment Board (YESAB) approval of Phase 1.¹⁸⁴

322. AEY submitted that this project achieves the federal and Yukon governments' goals of displacing diesel and managing electricity costs by using LNG as an alternative fuel source. Using LNG will reduce diesel consumption of its power generation plant in Watson Lake by approximately 50 percent because it is a cheaper fuel source than diesel. AEY asserted that it "... expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project" and that "These savings would be passed directly on to customers."¹⁸⁵

323. AEY pointed out that forecasted cost savings are dependent on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. AEY added that the bulk of the delivered LNG price is attributed to the cost of liquefaction and transportation fees. Recognizing the uncertainty as to the future prices for diesel and natural gas, AEY provided 20-year NPV analyses using 12 different scenarios where fuel prices were escalated at differing fixed rates from the 2015 historical price of diesel and natural gas.¹⁸⁶

324. AEY estimated the total cost of this project to be approximately \$5 million, albeit at this time, AEY is seeking approval for \$3.3 million to implement Phase 1 of the project. AEY submitted that it will competitively tender each of the major elements of the project,¹⁸⁷ excluding the equipment purchased from ATCO Gas. Further:

ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for

¹⁸³ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.

¹⁸⁴ AEY Final Argument, paragraph 150.

¹⁸⁵ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.

¹⁸⁶ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, Table 2, page 7, and Table 3, page 8.

¹⁸⁷ The major elements of the project are described in the Application, Appendix 3, page 3.

Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.¹⁸⁸

325. AEY estimates the annual incremental O&M costs that are not included in the 2016-2017 forecasted costs but will apply in future years to be approximately \$50,000 per year. AEY submitted that the O&M contract specific to the LNG equipment will be competitively tendered, will include periodic maintenance, and will involve additional safety training for AEY's operational staff.¹⁸⁹

326. Asked why it would choose a new unit that requires field modifications to burn both diesel and natural gas rather than purchasing a new unit that is factory capable of burning both fuels, and with nameplate performance ratings, AEY responded:

Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.¹⁹⁰

327. AEY submitted that all of the project-related costs presented in the following table are budgetary, except for the actual costs incurred to date:

Table 23. **Watson Lake bi-fuel project — Phase 1 and 2 capital costs**

	Phase 1			Phase 2
	2012-15	2016	2017	2018
Study costs	\$222,000			
Engineering, design, and permitting	\$272,000	\$55,000	\$152,000	\$105,000
LNG vaporizer and LNG storage tank			\$1,194,000	
Installation (civil, mechanical, and electrical) and boarding			\$1,090,000	
Conversion of remaining units to bi-fuel				\$700,000
Tank expansion, piping, cryopump and installation				\$905,000
Phase sub-total			\$2,985,000	\$1,710,000
Total				\$4,695,000

Source: Exhibit B-9, YUB-YECL-13(b).

328. AEY submitted that it believes there are environmental benefits to this project, which it has previously discussed and which have further been the subject of a review pursuant to the *Yukon Environmental and Socio-economic Assessment Act*. A decision document that supported the project was issued in August 2013.¹⁹¹

¹⁸⁸ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 3.

¹⁸⁹ Exhibit B-9, YUB-YECL-13(e).

¹⁹⁰ Exhibit B-9, YUB-YECL-24(h).

¹⁹¹ AEY Final Argument, paragraph 143.

329. With respect to project expenditures, AEY submitted that Phase 1 expenditures are the only costs to be incurred within the test period and AEY is seeking to recover those as part of this GRA. AEY explained that Phase 2 of this project is necessary to provide all of the benefits to ratepayers and reduce costs over the long-term by increasing consumption of LNG over the life of the project. AEY submitted that the objective in this GRA is “to obtain Board approval to complete both phases of this Project and AEY will bring forth Phase 2 costs for a prudency determination as part of a future general rate application.”¹⁹²

9.7.2.1 Views of interveners

330. With respect to the results of the analysis provided by AEY in its business case¹⁹³ and the fuel price scenarios for diesel and natural gas over the period from 2017 to 2037, Mr. Maissan referred to the following:

Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below \$2 million in NPV. Four scenarios are at \$5 million NPV or higher.¹⁹⁴

331. Mr. Maissan pointed out that the analysis did not account for renewable generation and assumed that all electrical loads will be served by diesel or LNG for the next 20 years. Noting Mr. Tenney’s acknowledgement of this on behalf of AEY, Mr. Maissan pointed out that the Yukon’s Independent Power Producers (IPP) policy provides for 2,100 MWh of generation to be available to Watson Lake under the standing offer program portion of the IPP policy. Mr. Maissan submitted that any further generation added under the micro-generation program will displace more diesel generation and weaken the economics of the bi-fuel conversion project.¹⁹⁵

332. Mr. Maissan noted AEY’s submission that the project will break even over 20 years when the price per litre of LNG on a diesel-litre-equivalent basis (DLE) is 75.6 percent of the cost of delivered diesel. Considering the price of LNG over the past 12 months, Mr. Maissan argued that the project is uneconomical if LNG were sourced from FortisBC and is just economical if LNG is sourced from AltaGas in Alberta. Mr. Maissan suggested that in his view, there was a high likelihood that the price differential between natural gas and diesel would approach historic levels (i.e. natural gas prices growing closer to diesel prices). If this were to occur, it would make the project uneconomical regardless of which supplier is liquefying and transporting the natural gas.¹⁹⁶

333. Considering the above, Mr. Maissan recommended that the Board deny the Watson Lake bi-fuel project. Mr. Maissan further recommended that of AEY’s project-related costs to date, approximately \$549,000 (\$494,000 + \$55,000) be amortized over a five-year period. On a related matter, Mr. Maissan suggested that the

¹⁹² AEY Final Argument, paragraph 154.

¹⁹³ Exhibit BB-1, Application, Appendix 3, Table 3, page 8.

¹⁹⁴ JM Final Argument, page 12.

¹⁹⁵ JM Final Argument, page 13.

¹⁹⁶ JM Final Argument, page 14.

Board direct AEY to "... channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy."¹⁹⁷

334. Should the Board accept AEY's proposed Watson Lake bi-fuel project, UCG submitted that the associated Watson Lake study costs be rolled into capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.¹⁹⁸

335. YCS recommended that all project-related costs not be allowed into rate base. YCS argued that the project is not economically prudent nor is the project environmentally prudent. YCS submitted that AEY has not made a case for how this project would help governments meet goals to eliminate or reduce the dependence on diesel in indigenous, remote and northern communities with renewable, clean energy as submitted in its GRA filing. YCS also submitted that the project would not help Watson Lake integrate any new renewable energy, but would effectively act as a "barrier to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low."¹⁹⁹

336. With respect to AEY's claim that the project would result in cost savings for ratepayers, YCS described the claim as dubious and echoed Mr. Maissan's submission, stating the following:

... the Watson Lake LNG Bi-fuel project is already marginal even with the current fossil fuel prices. Depending on the fuel source, the project is already uneconomic from one supplier. Any shift toward the historical trend (LNG and diesel closer in cost) will make this project uneconomic regardless of which supplier is liquefying and transporting the natural gas.²⁰⁰

337. Additionally, YCS submitted that the AEY analysis did not consider the impacts of renewable energy inputs onto the Watson Lake grid within the project lifetime, did not calculate how that would reduce utilization of this project and, by extension, negatively affect the economics and business case. Therefore, considering that the project is not environmentally or economically prudent, the financial risk to the ratepayer from fuel price changes, and the addition of renewable energy to the Watson Lake grid, YCS recommended that the Board deny the Watson Lake bi-fuel project.²⁰¹

9.7.2.2 Applicant responses to interveners

338. Noting that Mr. Maissan and YCS criticized the project business case for not considering the impact of renewables, AEY submitted that it "must make decisions based on the best information it has available to it and there is no evidence of any IPP program developers proposing renewable energy projects in Watson Lake."²⁰² Given the restriction on nameplate capacity, AEY pointed out that it would take three separate projects to meet the limit of 2,100 MWh/year. Notwithstanding, in order to demonstrate the economic viability of the Watson Lake bi-fuel project, AEY submitted that it re-ran its

¹⁹⁷ JM Final Argument, page 14.

¹⁹⁸ UCG Final Argument, paragraph 172.

¹⁹⁹ YCS Final Argument, page 9.

²⁰⁰ YCS Final Argument, page 4.

²⁰¹ YCS Final Argument, page 5.

²⁰² AEY Reply Argument, paragraph 141.

model,²⁰³ assuming the availability of 2,100 MWh/year of renewable generation, as of January 1, 2020. AEY submitted that "... there still remains a positive NPV in all six scenarios using AltaGas pricing and three of the six scenarios using the Fortis pricing."²⁰⁴ Moreover, AEY stated that there is a positive 20-year internal rate of return in all 12 scenarios. AEY added the models were predicated on only two suppliers of LNG, but it is entirely reasonable to expect additional suppliers to come on-line in the near term.

339. AEY pointed out that the current economic evaluation included in the NPVs set out in Table 2 and Table 3 of Appendix 3, and later updated in response to YUB-YECL-13(b), do not include the impact of any Yukon territorial or federal carbon tax.²⁰⁵ However, should a carbon tax be imposed, AEY submitted that it would likely favour the use of natural gas for electricity generation, the effect of which would be that the NPV of the bi-fuel would increase.²⁰⁶

340. AEY submitted that there is no evidence to support any of the statements that YCS made regarding the environmental impacts or lack thereof of the Watson Lake bi-fuel project. AEY further submitted that the Yukon Environmental and Socio-economic Assessment Board heard and considered the environmental evidence in relation to this project and has approved Phase 1.

9.7.2.3 Views of the Board

341. In Board Order 2014-06, the Board stated with respect to this project:

The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."²⁰⁷ (*footnotes omitted*)

342. In Board Order 2014-06, the Board had also denied the project due to concerns regarding fair market value of certain equipment to be leased from ATCO Gas. On page 82 of that decision, the Board found that fair market value of the lease of equipment assets was best determined through a competitive tender process.

343. In this Application AEY proposed:

... to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.²⁰⁸

²⁰³ The model is embedded in the table provided in response to UCG-AEY-53(d), Attachment 1 (Exhibit B-9).

²⁰⁴ AEY Reply Argument, paragraph 144.

²⁰⁵ Exhibit BB-1, Application, Appendix 3, Page 5.

²⁰⁶ AEY Reply Argument, paragraph 146.

²⁰⁷ Board Order 2014-06 – Appendix A: Reasons for Decision, Page 81.

²⁰⁸ Exhibit BB-1, Application, Appendix 3, page 3.

344. The Board acknowledges that AEY indicated that the Watson Lake Phase 1 and Phase 2 bi-fuel projects were submitted to address the Board's concerns.

345. AEY provided the information related to a comparison of potential suppliers and fuel price forecasts, as well as alternative fuel-escalation scenarios. A compiled table of this information is below:

Table 24. **Comparison of potential suppliers and fuel price forecasts**

	Supplier	Simple Payback (years)	20-year NPV (\$M)	Supplier	Simple Payback (years)	20-year NPV (\$M)
Sproule price forecast	Fortis	12	0.4	Fortis	11	0.6
	AltaGas	10	2.1	AltaGas	9	2.4
Both Commodities escalate at 5%	Fortis	11	2.7	Fortis	11	3.0
	AltaGas	9	5.6	AltaGas	9	5.9
Scenario 3: both commodities escalated at 2.5%	Fortis	15	(0.9)	Fortis	15	(0.7)
	AltaGas	11	1.7	AltaGas	10	2.0
Scenario 4: diesel escalated at 5%; natural gas at 2.5%	Fortis	11	3.5	Fortis	11	3.7
	AltaGas	9	6.1	AltaGas	9	6.4
Scenario 5: diesel escalated at 2.5%; natural gas at 5%	Fortis	17	(1.7)	Fortis	16	(1.4)
	AltaGas	11	1.2	AltaGas	11	1.5
Scenario 6: both commodities doubled	Fortis	7	7.1	Fortis	6	7.4
	AltaGas	5	10.2	AltaGas	5	10.5

Source: Exhibit BB-1, Appendix 3: Table 2, Page 7; Table 3, Page 8.

Source: Exhibit B-9, response to YUB-YECL-13(b), Page 3 of 6.

346. With respect to Table 24, the Board notes that of the 12 original scenarios provided by AEY, two scenarios have negative-20-year NPVs, three scenarios have NPVs below \$2 million, and four scenarios have NPVs of \$5 million or higher. AEY provided a further 12 scenarios wherein it accounted for the decrease in costs related to the LNG vaporizer and the LNG storage tank. The table shows that the project economics improved only marginally under the additional 12 scenarios examined.

347. Further, when AEY re-ran the model assuming a scenario of 2,100 MWh/year of renewable generation as of January 1, 2020, the generation from the bi-fuel engines was reduced. However, three (instead of two) of the six scenarios using Fortis pricing were negative.²⁰⁹

348. That being said, the Board agrees with Mr. Maissan's concern that the economic comparison provided by AEY with respect to diesel and LNG in Watson Lake must sufficiently take into account potential fluctuations in the delivery costs²¹⁰ for these fuels.

²⁰⁹ AEY Reply Argument, paragraph 144.

²¹⁰ Delivery costs include the costs of liquefaction and transportation of LNG.

Mr. Maissan pointed out that the liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transporting diesel, and he submitted that the economic evaluations must include the delivered costs of these fuels. The Board notes AEY's submission that using "delivered diesel prices based on Sproule forecast, the LNG option breaks even at an average delivered-LNG-price-to-delivered-price ratio of 75.6 percent over the lifetime of the project."²¹¹

349. The Board further notes that it was established on the record that the price of energy in natural gas has historically been slightly less than the cost of energy in diesel. The ratio of price of energy in natural gas to the price of energy in diesel prior to 2006 ranged from 70 to 100 percent. In 2006, this ratio dropped to about 60 percent and, more recently, it is at approximately 36.2 percent.²¹² The Board agrees with Mr. Maissan that it would take only a small increase in the price ratio to make the LNG option uneconomical. In fact, AEY's data in Table 24, as well as AEY's Reply Argument, show that the project would be viable under some scenarios but not under other scenarios. While the Board understands that slightly positive or positive results are expected under some scenarios, the economic benefits of the Watson Lake project are not sufficiently supported given the outcomes of the various scenarios found in Table 24 and given the corresponding assumptions used by AEY that could impact the financial viability and resulting costs for this project.

350. Further, with respect to the Watson Lake bi-fuel project and the use of diesel units, AEY stated in its business case:

ATCO Electric Yukon and the Independent Power Producers (IPPs) are pursuing the generation of electricity with renewable resources, however, it is almost certain that a fossil-fueled base load generation source will continue to be required in the short to medium term for reliability of the system. ATCO Electric Yukon believes the switch to a Bi-Fuel Project best accomplishes this base load generation need.²¹³

351. Mr. Tenney, in testimony, confirmed that while there is development of future technologies, stand-alone bi-fuel units are not currently available other than for marine applications and that is why conversion units are proposed for this project.²¹⁴ Conversion units have not been previously utilized by AEY for utility service to Yukon customers. Conversion of the existing diesel units to bi-fuel is the only option proposed other than use of existing diesel, and in fact, conversion to bi-fuel may be the only other option currently available for the use of LNG at the Watson Lake plant. This raises the issue of whether a bi-fuel conversion should be done at this time given emerging plant technologies related to bi-fuel and LNG instead of relying on the existing diesel units at Watson Lake without bi-fuel conversion. Given the state of emerging technologies and the prospect that such technologies may affect the economic benefits associated with

²¹¹ Exhibit B-5, JM-AEY-24(d).

²¹² Exhibit B-5, JM-AEY-24(a).

²¹³ Exhibit BB-1, Application, Appendix 3, Watson Lake Bi-Fuel Project, Page 7.

²¹⁴ Transcript, Volume 3, page 473, lines 13 to 23, Mr. Tenney stated, "So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant. So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants."

bi-fuel conversion, the Board finds that the approval of the project as proposed by AEY is not reasonable. Because the impact of the conversion of an individual bi-fuel unit on efficiency, the actual capital costs for conversion as well as the benefits to customers are not sufficiently known and base load generation is currently being supplied to the Watson Lake area by the existing diesel units.

352. The Board is also concerned with AEY's request that the Board approve Phase 1 of the Watson Lake bi-fuel project along with Phase 2 of the project, which will occur entirely in a future test period. Between Phase 1 and Phase 2, the total project costs are \$4,695,000 for conversion of diesel units in the power plant that serves Watson Lake and surrounding area, in accordance with AEY's obligation to provide electricity to that area.

353. While the Board acknowledges AEY's position that Phase 2 would be required if Phase 1 is approved and undertaken, the Board does not consider that it is reasonable to approve the need for Phase 2 without the conversion of the unit under Phase 1 given the forecasted costs for the bi-fuel conversion project as proposed.

354. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision.

9.7.3 Old Crow Unit 3 replacement (Appendix 5)

355. AEY submitted that load growth and load duration of the community of Old Crow have steadily diminished the utilization of the 170-kW Old Crow unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, AEY is proposing to purchase and install a new 600-kW unit to replace the existing undersized 170-kW unit. The new unit will be installed in the new building in Old Crow as it will not be able to fit in the existing building.

356. Based on the 2012 load data provided in AEY's 2013-2015 GRA, AEY submitted that the existing 170-kW unit was approved to be replaced with a 250-kW unit. Notwithstanding the Board's approval, in preparation for tender of the new unit in 2015, AEY submitted that a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was recommended to meet load requirements.

9.7.3.1 Views of interveners

357. Mr. Maissan submitted that the desire to have two independent and completely redundant power plants in the community of Old Crow is well beyond any planning criteria approved by the Board. Mr. Maissan went on to state that the need to have a second building is not in question, but "what is in question is the prudence of the decisions about what size generators to put into this plant which operates as an extension of the existing plant."²¹⁵ Mr. Maissan pointed out that a 400-kW generator

²¹⁵ JM Final Argument, page 9.

would be running below manufacturers' recommendation "that units are operated in the range of 50-80% of rated capacity."²¹⁶ AEY's 50-percent loading target appeared tenuous to Mr. Maissan when he noted that additional solar photovoltaic (PV) capacity is planned for Old Crow. Mr. Maissan submitted that plant efficiency will suffer as the larger generators will be very lightly loaded. In addition, Mr. Maissan submitted that a 400-kW unit could be transported into the community easier than a 600-kW unit. Moreover, considering that more solar PV capacity is planned for Old Crow, Mr. Maissan recommended that the Board reject the plan to install a 600-kW generator in Old Crow and authorize the installation of a 400-kW unit at a cost of \$612,000, plus \$100,000 to allow for cost increases from the previous 2014-2015 timeframe for this project.²¹⁷

9.7.3.2 Applicant responses to interveners

358. AEY replied that, in his argument, Mr. Maissan failed to take into account the Old Crow peak loading table that clearly demonstrates the need for a 600-kW unit. AEY submitted that it would not be prudent for AEY to invest in assets such as lower-capacity units which do not meet long-term generation needs, based on the assumption that a non-dispatchable renewable resource (i.e. solar PV capacity) may potentially be installed. Furthermore, there is no evidence that the possible installation of a solar generation resource, even with a storage battery, will supply any firm capacity to be relied upon to meet the capacity needs of the community. AEY submitted that this project ensures a continued safe, reliable power source for the community.²¹⁸

9.7.3.3 Views of the Board

359. The Board accepts the proposal as submitted by AEY. The peak loading table included in the Application²¹⁹ shows continuous growth since 2012 and the need for a higher-capacity generator. Further, as Old Crow is an isolated community, the Board accepts the submissions²²⁰ of AEY that a full contingency backup for that community is required.

9.7.4 Destruction Bay unit replacement

360. The communities of Destruction Bay and Burwash Landing are serviced by three units located at the Destruction Bay generating plant. The Board approved AEY's request to replace two units in Board Order 2014-06 related to AEY's 2013-2015 GRA.

9.7.4.1 Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)

361. AEY submitted that the replacement of Destruction Bay Unit #2 was one of the units approved in Board Order 2014-06. The original scope of the project in AEY's 2013-2015 GRA was to replace the unit with a similar sized unit (300 kW). At the time of the unit tender and selection, capacity requirements were reviewed, and as a result, AEY submitted that it will tender and procure a 400-kW unit. The total cost of this project

²¹⁶ Exhibit B-5, JM-AEY-27 (b).

²¹⁷ JM Final Argument, pages 9 and 10.

²¹⁸ AEY Reply Argument, paragraphs 107 to 109.

²¹⁹ Exhibit BB-1, Application, Appendix 5, pages 1 and 2.

²²⁰ Transcript Volume 3, starting at page 483, line 12 and ending page 485, line 23.

is forecasted to be \$758,000, compared to the \$600,000 capital expenditure previously approved by the Board. AEY indicated that receipt of the unit and installation is scheduled to be completed in 2016.

362. AEY submitted that the replacement of Destruction Bay Unit #3 was one of the units approved in Board Order 2014-06. AEY clarified that the existing 220-kW unit was to be replaced with a larger unit (250 kW) in order to ensure that the unit would continue to operate for a reasonable amount of hours to meet load requirements.

363. AEY stated that the purchase of a new 250-kW unit was put out to tender in 2013; however, none of the bidders in the RFP process submitted bids for a 250-kW unit. Of the bids received, and after a further analysis of best fit for the power plant and community load profile, AEY selected a 312-kW unit. Receipt of the unit and installation was scheduled to be completed in 2014. The total cost of this project was \$634,000, compared to the approved cost of \$450,000.²²¹

364. AEY explained that the actual costs “were higher mainly due to foundation issues discovered, subsequent to the initial forecast, as well as additional control work required due to the delay of the Destruction Bay PLC upgrade.”²²² AEY confirmed that receipt of the unit and installation was “completed, prior to the recent installation of the increased amount of solar PV generation.”²²³

9.7.4.2 Views of interveners

365. With respect to AEY’s proposal to replace the two smaller units in the Destruction Bay diesel plant with larger units, Mr. Maissan pointed out that a fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW in the area. Mr. Maissan expressed concerns that AEY is opting for larger diesel generators than necessary for reasons other than efficient plant performance, and the reasons for his position include that AEY is:

...providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project — which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing...²²⁴

366. Mr. Maissan recommended that the Board direct AEY to replace one of the existing smaller units with the installation of one 400-kW unit. Mr. Maissan also recommended that the Board direct the replacement of Destruction Bay Unit #3 (CUL 230 220 kW unit) with a unit no larger than 250 kW. AEY should be directed to provide the 2015 load duration curves for Destruction Bay plant in its compliance filing. Mr. Maissan recommended:

²²¹ Exhibit BB-1, Application, Appendix 11, page 1.

²²² Exhibit BB-1, Application, Appendix 11, page 1.

²²³ Exhibit B-5, JM-AEY-27 (a).

²²⁴ JM Final Argument, page 15.

... that the Board order AEY, in negotiations for an IPP with the proponents of the Kluane wind project [sic] to allow diesel displacement down to a load level to the lowest normal 2015 dispatch level without penalty or cost to the proponent.²²⁵

9.7.4.3 Applicant response to interveners

367. AEY pointed out that the two Destruction Bay unit replacement projects were scheduled — and in the case of Unit #3 replacement, completed — prior to the recent installation of solar PV generation in the Destruction Bay and Burwash communities. AEY acknowledged that the Burwash Landing wind project may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid. However, AEY submitted that:

... it is not prudent or common practice for a utility to reduce the installed capacity of its generation facilities as a result of the possible installation of a non-dispatchable renewable resource, regardless of whether it is owned and operated by a third party or the utility itself.²²⁶

368. With respect to determining the size of Destruction Bay Unit #2, AEY considered the capacity as well as operational efficiency requirements. AEY submitted that replacement of Unit #2 with a new unit of the same size (300 kW) would not have allowed AEY to meet operational efficiency requirements, as units would have been under or overloaded during automated dispatch. AEY added:

... at the current dispatch level there are times in which Unit 2 is operated at an overload condition in respect to its prime rating. The only solutions to this overload issue are to de-rate the unit or replace it with a larger unit. If the de-rate option was selected, it would negatively impact the operation of Unit 1, forcing it to run in a low loading mode. Selecting a larger unit allows Unit 2 and Unit 1 to be dispatched in a more efficient manner.²²⁷

369. AEY submitted that contrary to Mr. Maissan's assertions, the sizing considerations were done to meet firm capacity requirements and to allow for an efficient dispatch of the units, all of which are in line with AEY's obligation to serve customers with safe and reliable electricity.

9.7.4.4 Views of the Board

370. Destruction Bay Unit #3 was approved in AEY's 2013-2015 GRA. The unit was substantially completed and operational in 2014, with final acceptance in 2015. Further, the Board notes that Unit #3 replacement was completed prior to the recent installation of solar PV generation in Destruction Bay and Burwash Landing.

371. AEY determined through the tender process that the best fit for the power plant and community load profile was a 312-kW unit rather than the originally forecast capacity of 250 kW. The final cost of the project was \$184,000 over the GRA-approved forecast. AEY indicated that the variance between the actual and forecast costs was

²²⁵ JM Final Argument, page 15.

²²⁶ AEY Reply Argument, paragraph 112.

²²⁷ AEY Reply Argument, paragraph 117.

due to foundation issues discovered subsequent to the initial forecast and additional control work. AEY added that movement to the larger generator capacity would increase operational hours of the unit and concomitantly increase the units' efficiency.²²⁸

372. The Board finds the reasons provided by AEY — operational efficiency, community and load profile²²⁹ — support the need for the larger capacity unit. In addition, the cost for the larger unit and the need to mitigate the foundation issues identified are acceptable reasons for the cost variance. The Board approves the costs as filed. Although wind capacity may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid, the Board accepts AEY's submission that wind generation will not contribute to firm capacity requirements within the test period.

373. With respect to Unit #2, the Board notes AEY's submission that replacement of this unit with a similar-sized unit would not have allowed AEY to meet the Operational Efficiency Requirements, as units in the generation plant would have been under or overloaded during automated dispatch. Therefore, the Board approves the additional costs associated with the larger 400-kW unit.

374. Considering the above, the Board approves AEY's replacement of Destruction Bay Units #2 and #3, as filed.

9.7.5 McIntyre subdivision rebuild (Appendix 8)

375. The McIntyre subdivision rebuild is a multi-phase project to replace the existing end-of-life underground electrical infrastructure serving the McIntyre subdivision in the City of Whitehorse. The original forecast for Stage 1 was approved as part of AEY's 2013-2015 GRA in Board Order 2014-06.

376. AEY referred to this project as being a complex "brownfield" infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35 kV and was installed circa 1977. The proposed project will convert the subdivision's operating voltage to the standard 25-kV system. AEY indicated that 25-kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers.

377. The original scope of the project was to install a new 25-kV underground electrical system in close proximity to the existing 35-kV system. As Stage 1 was underway, AEY discovered that the location of the existing underground system would be in constant conflict with the installation of the new system. This made the field construction more time-consuming. Time constraints imposed on construction permits from the Kwanlin Dun First Nation (KDFN) made it necessary that a new project scope be developed. AEY explained the change in project scope due to installation issues:

The new project scope involved the installation of a temporary overhead shadow electrical system which would allow construction crews to install the new underground system with the old underground system safely deenergized. This would allow the construction crews to work at a similar pace to a

²²⁸ Exhibit BB-1, Application, Appendix 11, page 2.

²²⁹ Exhibit BB-1, Application, Attachment 11.4, page 1.

Greenfield project. The work would also include the installation of low voltage pedestals to connect to the overhead system and a new main underground feed to the subdivision.²³⁰

378. The following table shows approved costs, AEY's actual costs, and its forecast costs for the McIntyre subdivision replacement project:

Table 25. McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs (\$000s)

Year	Actual/Forecast	Streetlights	Total	Scope
2013 (A)	656	-	656	Temporary overhead
2014 (A)	418	-	418	Low voltage pedestals, connected to feeds
2015 (A)	379	-	379	Main underground feed to the subdivision
2016 (F)	565	175	740	Hanna and McCandless
2017 (F)	930	256	1,186	Murphy (partial), O'Brien, and McCrimmon
2018 (F)	500	100	600	McClimon
2019 (F)	600	150	750	Complete Murphy, McIntyre up to McCauly
2020 (F)	300	100	400	McCauly to Hamilton to McIntyre
Total	4,348	781	5,129	

Source: Exhibit BB-1, Application, Appendix 8, Table 1, Page 3.

379. In a letter²³¹ dated October 24, 2016, AEY submitted that it is seeking Board direction as to the appropriate treatment of the potential cost savings, should the KDFN accept one of the alternatives such as "Alternative 2" in the business case provided in Appendix 8 of the Application. The business case included the following:

Alternative 2: Explore the benefits of utilizing some of the overhead system in coordination with some of the new underground electrical infrastructure. This would result in a hybrid system as it would be a combination of overhead and underground. This alternative would require the approval of the KDFN.²³²

380. AEY submitted that it is anticipated that "Alternative 2" would alter the work required and result in a potential cost savings in 2018-2020, which is outside of the test years. AEY clarified that it is requesting the Board to provide direction as to whether or not the expected costs savings could be applied as an offset to the contribution required by the KDFN in the future.

9.7.5.1 Views of the Board

381. The Board notes that interveners did not comment on AEY's request.

382. During the hearing, the Board notes AEY's submission that it had extensive meetings with KDFN. AEY submitted, "It's very clear that they want to have an underground power system when we're done in there... that's what they would like to have when we leave that subdivision at the end of the project."²³³ Moreover, the Board

²³⁰ Exhibit BB-1, Application, Attachment 11.4, page 1.

²³¹ Exhibit B-13, YECL letter to YUB re corrections, updates and clarifications, October 24, 2016.

²³² Exhibit BB-1, Application, Appendix 8, McIntyre Subdivision Rebuild, page 3.

²³³ Transcript, Volume 1, page 151, lines 1 to 5.

notes AEY submission that "... there was an original customer contribution when the original system went in back in the '70s, so we wouldn't be asking the customer to recontribute."²³⁴

383. The Board notes that the ultimate scope of the project has not been determined by AEY at this time. AEY submitted two project alternatives: (1) an underground system, or (2) a hybrid system (combination of overhead and underground).

384. The Board accepts AEY's test-period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA.

385. If AEY's proposal for "Alternative 2" (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings.

386. The Board will provide further direction in the next GRA regarding AEY's request as to whether or not the expected cost savings could be applied as an offset to the contribution required by the KDFN.

9.7.6 Significant capital projects

387. In Board Order 2009-2, the Board directed "YECL to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."²³⁵ In Attachments 9.1 and 9.2 of the Application, AEY provided a listing of capital expenditures for 2016-2017, which included project descriptions for projects greater than \$100,000. AEY also provided business cases for all major capital projects (\$500,000 or greater) in Appendix 1 to Appendix 11 of the Application.²³⁶

388. UCG noted the Board's consideration in its January 2007 Report to the Commissioner in Executive Council re YEC's 20-year resource plan²³⁷ that given the smaller rate base in the Yukon and the small number of ratepayers in the Yukon, a \$1-million threshold would be appropriate for capital expenditures to be reviewed by the Board pursuant to Part 3 of the *Public Utilities Act*.

389. Considering the above, UCG recommended that the following projects should be reviewed pursuant to Part 3 of the *Public Utilities Act*:

- (a) McIntyre subdivision rebuild;²³⁸
- (b) Watson Lake bi-fuel projects;²³⁹
- (c) Watson Lake Unit #2 replacement;²⁴⁰

²³⁴ Transcript, Volume 1, page 152, lines 5 to 8.

²³⁵ Board Order 2009-2, Appendix A: Reasons for Decision, page 37.

²³⁶ Exhibit BB-1, Application, page 9-5.

²³⁷ Yukon Utilities Board Recommendations YEC 20-Year Resource Plan: 2006-2025, Page 28, issued January 15, 2007.

²³⁸ UCG Final Argument, paragraph 187.

²³⁹ UCG Final Argument, paragraph 192.

²⁴⁰ UCG Final Argument, paragraph 197.

- (d) Downtown Whitehorse capacity improvement project;²⁴¹
- (e) Old Crow Unit #3 replacement;²⁴²
- (f) Whistle Bend Subdivision Stage 3-C project;²⁴³ and
- (g) Fish Lake Ditch #3 diversion replacement project.²⁴⁴

9.7.6.1 Views of the Board

390. With respect to UCG's submission that the above-mentioned projects be reviewed pursuant to Part 3 of the *Public Utilities Act*, the Board considers that this request is premature because neither application has been made to the minister under section 39 of the *Public Utilities Act*, nor has the minister designated any of the projects as a regulated project under section 37 of the *Public Utilities Act*. Moreover, the Board does not determine that projects are Part 3 projects under the *Public Utilities Act*, but makes recommendations on energy projects only when the minister refers them to the Board. Accordingly, the Board finds that UCG's recommendations on Part 3 projects and associated capital expenditures do not apply.

10 Income tax

391. In its Application, AEY continued to use the flow-through method for calculating income tax expense. This method was approved by the Board in Board Order 2014-06. AEY argued that since the use of the flow-through method was not raised as an issue by any party during the testing of its Application, the Board should continue to approve the use of this method.

10.1 Views of the Board

392. The Board agrees with AEY that there is no reason to change the currently approved flow-through income tax method used by AEY in its Application. AEY's method of determining income tax expense to be recovered through rates is approved as filed.

11 Previous Board directions

393. AEY provided the following responses to prior Board directions from Appendix A: Reasons for Decision from Board Order 2014-06:

Board Direction	AEY Response	Board Comment
<i>Direction 8, Page 51.</i> The Board agrees with the submissions of UCG that no assessment has been provided	<i>Application, page 11-1,</i> ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No

²⁴¹ UCG Final Argument, paragraph 202.

²⁴² UCG Final Argument, paragraph 207.

²⁴³ UCG Final Argument, paragraph 212.

²⁴⁴ UCG Final Argument, paragraph 217.

within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear. The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.	analysis as to whether a risk premium over the BCUC GCOC benchmark utility is appropriate and if so, the quantum of such premium. Their analysis is contained in Attachment 8.1 included in section 8 of this Application.	further response is required.
<i>Direction 12, page 62.</i> The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study.	<i>Application, page 11-2.</i> ATCO Electric Yukon contributed funds (\$20,000) towards this initiative in 2013 and received a report titled “Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update.” ATCO Electric Yukon filed this report in response to Undertaking 17 during the 2013-2015 GRA hearing. Since that time ATCO Electric Yukon has received one further update in early 2014 but ATCO Electric Yukon is no longer engaged in this project and no further contributions have been made to this project, as such, ATCO Electric Yukon is not expecting to receive any further reports arising from this initiative.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

<i>Direction 13, page 64.</i> YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100-percent over and \$100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the nine expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than \$100,000, which may arise between GRAs, YECL, in future applications, is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.	<i>Application, page 11-3 to 11-4.</i> ATCO Electric Yukon has included project completion summaries for all projects listed below that were forecast in the 2013-2015 GRA where actual costs were 100 percent and \$100,000 greater than the original forecast. In addition, ATCO Electric Yukon has included a project completion summary for the Fish Lake Dyke Upgrade to explain the variance in actual costs to forecast for that project. Business cases have also been provided for completed projects where the actual costs were in excess of \$100,000 and for which no business case was provided in the 2013-2015 GRA. ATCO Electric Yukon has included business cases for the completed projects listed below in Attachments 11.7 through Attachment 11.13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
<i>Direction 14, page 70.</i> The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast." Bearing this in mind, in	<i>Application, page 11-5.</i> In section 9, Schedule 9.2 of this Application, ATCO Electric Yukon has provided a detailed listing of all projects completed and actual amounts spent by project from 2013 through 2015. ATCO Electric Yukon has continued to group various projects in the "Other projects less than \$20,000" category in Schedule 9.2, and submits this approach is appropriate considering the aggregate totals in this category are under the threshold of \$100,000 highlighted in Direction 13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL, in future GRAs, to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.		
<i>Direction 15, page 71.</i> The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudence. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than \$500,000.	<i>Application, page 11-6.</i> On Schedule 9.2 of the Application, ATCO Electric Yukon has included the reference to where the business cases can be found in either the 2013-2015 GRA or in Appendix 1-11 of this Application. Business cases have been provided for all projects that span multiple years where costs were expected to be greater than \$500,000.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
<i>Direction 20, page 101.</i> As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the utilities benefit, but if participation rates are higher than expected, the utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA. Further, the Board affirms it does not approve the program for the five-year term requested and that the utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance	<i>Application, page 11-7.</i> The DSM programming costs approved in Board Order 2014-06 for the 2014 and 2015 test period have been tracked as directed in deferred charges. ATCO Electric Yukon was unable to complete the program as originally designed and spend all of the approved DSM program costs in 2014 and 2015 period; therefore the remaining approved amount will be spent in 2016. ATCO Electric confirms that it has not changed the scope of the approved DSM program. In this Application, ATCO Electric Yukon is applying for recovery of these previously approved costs (incurred from 2014 through 2016) over the next five years in a manner consistent with the previously approved DSM costs.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response required.

filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.		
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12 Deferral accounts

394. In its Application, AEY proposed deferral-account treatment for three new cost categories, while maintaining deferral treatment for those categories previously approved by the Board. AEY's summary of existing and proposed deferral accounts is shown in the following table:

Table 26. **Summary of existing and proposed deferral accounts**

Name of existing or proposed deferral account	Existing	Proposed
Rate case costs	X	
Defined benefit pension plan	X	
Feasibility study or program: DSM program (approved program) Watson Lake LNG — phase I (approved study) Renewables study (proposed study) Joint grid study (proposed study)	X	
Purchase power flow-through	X	
Diesel fuel	X	
LNG fuel		X
Board order or changes in legislative provisions		X
Statutory Federal and Territorial income tax rates		X

Source: Summarized from Application

395. The Board has considered the five existing deferral accounts and finds that their respective intent and scope have not changed. AEY's existing deferral accounts continue to be approved.

396. In the following sections, the Board will discuss the three new deferral account categories proposed in AEY's Application and whether they should receive deferral-account treatment.

12.1 LNG Fuel Deferral

397. Please refer to the section 4.5 of this decision.

12.2 Board Orders or Changes in Legislative Provisions Deferral

398. In its Application, AEY sought the ability to flow through, dollar for dollar, costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that AEY operates under for the 2016-2017 test period.

399. The IPP Policy for Standard Offer Prices was cited as one example in support for this deferral account.

400. In argument, AEY claimed that in future, there is no guarantee of stakeholder input or significant lead time. AEY added that it has no control over these policies or programs and has no way to forecast with certainty the impact related to these types of programs, and therefore seeks deferral account treatment.²⁴⁵ In reply, AEY challenged the assertions of Mr. Maissan about the micro-generation program, stating that the response to JM-AEY-5(c-d)²⁴⁶ did not include the full costs incurred by AEY (such as administrative costs), adding that there is no certainty of that program continuing to operate in its current manner.²⁴⁷

401. AEY did agree with Mr. Maissan in that it is a stakeholder in relation to the development of the IPP program. However, AEY countered that it does not control the actual implementation of the program and that it would be at risk for any changes until its next GRA.²⁴⁸

12.2.1 Views of interveners

402. John Maissan did not support the AEY request for a Board Orders or Changes in Legislative Provisions Deferral Account. Mr. Maissan noted that the micro-generation program provided net benefits to AEY. In regard to the IPP program, AEY has been an active participant along with the Yukon government, Yukon Development Corporation (YDC) and YEC .

403. The effects of the commercial energy incentive program run by the Yukon government were another reason cited by AEY for this deferral account. Mr. Maissan argued that the effects of this program are captured within AEY's load-forecasting process, and thus had minimal impact.²⁴⁹

404. UCG stated that a deferral account to track costs related to Board Orders or legislative provisions does not provide AEY with the ability to flow costs through, dollar for dollar, to ratepayers. A deferral account simply tracks costs for review and possible recovery at a later time.²⁵⁰

12.2.2 Views of the Board

405. In AEY's 2013-2015 GRA, AEY requested a deferral account to flow through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions

²⁴⁵ AEY Final Argument, paragraphs 11-12.

²⁴⁶ Exhibit B-5 — YECL Responses to Maissan Requests

²⁴⁷ AEY Reply Argument, paragraph 13.

²⁴⁸ AEY Reply Argument, paragraph 14.

²⁴⁹ JM Final Argument, page 1.

²⁵⁰ UCG Reply Argument, paragraph 13.

resulting in changes to the rules or parameters that AEY operates under or that bear on the nature and extent of AEY's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement.²⁵¹

406. In Board Order 2014-06, the Board ruled that:

... on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented... The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any GRA filing. Therefore the Board rejects YECL's request for this deferral account.²⁵²

407. The Board's views have not changed. The evidence in this proceeding is that AEY has been able to actively participate in potential legislative changes respecting the implementation of new programs, so AEY has not shown the need for such a deferral account. The Board notes Mr. Maissan's comments about little or no impacts of the programs referred to by AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

12.3 Statutory Federal and Territorial Income Tax Rates Deferral

408. In its Application, AEY requested deferral-account treatment for income tax beginning in the year 2016. The deferral amounts would be based on any deviance from enacted federal and territorial statutory rates, which were each currently set at 15 percent. AEY submitted that any changes from these rates would be used to determine an updated revenue requirement that, when compared to final approved revenue requirement, would initiate either a refund to or collection from customers for the difference.

409. AEY cited uncertainty with respect to global economics and recent federal government changes as increasing the possibility of significant tax changes between GRAs. During the hearing, AEY witness James Grattan indicated a further potential for changes to the territorial statutory rate depending on the outcome of the territorial election.

410. In argument, AEY summarized:

- (a) Changes in statutory tax rates can be material;
- (b) Given that the statutory rates are set by the Territorial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding forecast accuracy;
- (c) The statutory rates are determined by the Territorial and Federal Governments, and are therefore beyond AEY's control; and

²⁵¹ Board Order 2014-06 – Appendix A: Reasons for Decision, page 1.

²⁵² Board Order 2014-06 – Appendix A: Reasons for Decision, page 103.

- (d) AEY is not typically at risk with respect to items that are beyond its control and that are material.²⁵³

12.3.1 Views of the Board

411. The Board considers that the need for a deferral account has not been shown given the two-year test period. Further, the criterion for a deferral account is that AEY is typically at risk with respect to items that are beyond its control and that are material. In the Board's view, AEY has not shown that it is at risk or that any risks are material from changes in federal or territorial income tax rates. For these reasons, the Board denies AEY's request for a deferral account for statutory federal and territorial income tax rates.

12.4 Deferred Charges and Credits

412. For those account categories currently approved for deferral-account treatment, AEY monitors charge and credit transactions.²⁵⁴ Generally, AEY will incur the deferral-account related expenditures over time and will subsequently recover the approved costs through deferral account revenue requirement. This is currently the treatment ascribed to hearing costs and deferred pension costs, each of which were forecasted to be recovered in revenue requirement evenly over the years 2016 and 2017.

413. In its Application, AEY proposed similar treatment for the tracking and recovery of costs related to feasibility or other studies, such as those pertaining to Watson Lake, Renewables and Alternative Energy, and a Joint Smart Grid. In some cases, after the study was completed, AEY proposed to recover the study costs within its deferral accounts over a period of two years. In the alternative, and as is the case with the deferred DSM program costs, AEY proposed to capitalize the costs into rate base and amortize them over a specified period of time.

414. UCG provided a general comment that, "All deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."²⁵⁵

415. UCG submitted that study costs do not meet the "used or required to be used" test for consideration as a utility asset providing utility service to customers, despite that the costs may have been incurred prudently.²⁵⁶

416. Intervenors raised other concerns with respect to AEY's proposed recovery of these study-related costs, each of which are discussed in the four sections that follow.

12.4.1 Demand Side Management (DSM) Program Study Deferral Account

417. AEY proposed²⁵⁷ to move costs related to the approved DSM program study out of the deferral account and into rate base. Notwithstanding an issue related to the use of the mid-year convention for depreciation purposes addressed elsewhere in this

²⁵³ AEY Final Argument, paragraph 164.

²⁵⁴ Exhibit BB-1A AEY GRA Schedules, schedule S8.8.

²⁵⁵ UCG Final Argument, paragraph 30.

²⁵⁶ UCG Final Argument, paragraphs 166-174.

²⁵⁷ AEY Final Argument, paragraphs 115-118.

decision, AEY stated that the use of a five-year amortization period (2014-2018) for cost recovery was consistent with the Board's direction in section 12.1 of Board Order 2014-06.

418. AEY stated that evidence of prudent expenditures related to the DSM program was provided in interim evaluation reports and these reports concluded that the DSM programs were well-received by Yukoners, were cost-effective, and that participation met or exceeded most KPIs.

419. In response to UCG's recommendation that deferred study costs should be removed from rate base, and either amortized outside of rate base or rolled into a related capital asset, AEY stated that the DSM program study costs in this case were for programs previously approved by the Board.

12.4.1.1 Views of interveners

420. UCG²⁵⁸ questioned why the deferred DSM program costs would subsequently be treated as a capital item and attract carrying costs like other assets placed into rate base. UCG submitted that AEY was entitled only to the return of, and not a return on, prudently incurred DSM costs.

421. YEC²⁵⁹ disagreed with UCG's suggestion that the DSM study costs should not be treated as capital assets earning a return on the same basis as other rate base elements. YEC submitted that UCG's recommendation should be disregarded by the Board.

12.4.1.2 Views of the Board

422. The Board can find no basis to consider UCG's recommendation that AEY was entitled only to the return of, and not return on, the DSM program study costs. AEY's treatment of these costs — by way of capitalization into rate base, and the attendant calculations of depreciation and return — is consistent with the Board's direction in section 12.1 of Board Order 2014-06. For this reason, the Board does not accept the recommendation made by UCG. The Board approves the transfer of the DSM program study costs out of the deferral account and into rate base to be amortized over a period of five years, as proposed by AEY.

12.4.2 Watson Lake LNG Study Deferral Account

423. In its Application, AEY requested approval for \$494,000 in study and development costs related to the Watson Lake bi-fuel project. AEY proposed to recover these forecast costs evenly over the 2016-2017 test period through the study's associated deferral account. AEY submitted that the study costs were incurred prudently and should be recovered from customers whether or not any of the Watson Lake bi-fuel project capital costs are approved.²⁶⁰

²⁵⁸ UCG Final Argument, paragraph 228,.

²⁵⁹ Yukon Energy Reply Argument, pages 9-10.

²⁶⁰ AEY Final Argument, paragraphs 105-108.

424. As an alternative, AEY stated that it was not opposed to capitalization of the study costs, should the Watson Lake project be approved, with subsequent cost recovery over the lifetime of the related assets.²⁶¹

12.4.2.1 Views of interveners

425. UCG argued that in Board Order 2013-01, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in “Work in Progress” until such time that the project is set aside or the utility comes before the Board for a prudence review. In Board Order 2014-06, the Board determined that Watson Lake bi-fuel project study costs would be held in “Work in Progress” until such time as the project may be completed.

426. UCG submitted that if the Board accepts the proposed Watson Lake bi-fuel project proposed by AEY, then \$494,000 in Watson Lake Study costs should be rolled into the capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.

427. Consistent with his views that the Watson Lake bi-fuel project itself be denied by the Board, Mr. Maissan recommended that all actual study costs expended to date should be amortized over a five-year period.²⁶²

12.4.2.2 Views of the Board

428. The Board does not consider that adding complexity with respect to the recovery of the Watson Lake LNG study costs is necessary. To recover the study costs over the life of the Watson Lake bi-fuel project, as was recommended by UCG, would require an allocation of the study costs to several individual account numbers, each with a unique service life. The Board has determined doing so would not result in an efficient or straightforward process of cost recovery and would be unduly onerous. Further, since in section 9.7.2 of this Order the Board has rejected the Watson Lake bi-fuel project, this issue of rolling the study costs into the capital costs is moot. For these reasons, UCG’s recommendation is denied.

429. The Board accepts Mr. Maissan’s recommendation that recovery of the Watson Lake study costs and development costs forecast in the amount of \$494,000 should be on the basis of an amortization period of five years. This period of time is consistent with that used for the recovery of the DSM program study costs. The Board finds this to be a reasonable approach for the recovery of the Watson Lake bi-fuel study costs.

12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account

430. AEY proposes to include \$300,000 in 2016 and \$200,000 in 2017 as charges related to work it has planned regarding the Renewable and Alternative Energy Feasibility study.²⁶³ The \$500,000 in costs for the study would be recovered through AEY’s deferral account in the amount of \$150,000 in 2016 and \$350,000 in 2017.

²⁶¹ AEY Final Argument, paragraph 108..

²⁶² JM Final Argument, page 15.

²⁶³ Also referred to in AEY’s application as the “Renewables Feasibility Study”; Exhibit BB-1, page 8-8 and Schedule 8.8.

431. AEY proposed to assess individual communities and retain third party expertise to carry out the studies through a combination of competitive processes and “sole-sourcing.”²⁶⁴ The studies are intended to identify the optimal size and configuration of company-built, -owned and -operated renewable and alternative energy generation in each of the five isolated communities served by AEY which currently rely on diesel power generation. The studies will also assess energy storage systems and potential improvement for energy efficiency through waste-heat recovery opportunities in each of the communities.

432. Once the studies are complete, AEY proposed that any technically and economically feasible projects identified therein would be brought forward as business cases in stand-alone proceedings for approval by the Board. This would ensure customers receive more immediate benefit of the studies and resulting projects, without the need to wait for a subsequent GRA.

433. Further, AEY indicated its commitment that, subject to any confidential or proprietary information contained in the renewable energy studies, they would be prepared to share the study publicly in connection with any resulting application or earlier in an appropriate forum, such as the utility’s website.

434. During the oral hearing, AEY witnesses confirmed that preparation of the renewables study was behind schedule and that no work had been completed at that time.²⁶⁵

435. In response to UCG’s recommendation that deferred study costs should be removed from rate base and either amortized outside of rate base or rolled into a related capital asset, AEY stated with respect to feasibility studies, such as the one proposed for renewables, deferral treatment for approved expenditures is appropriate given that such studies may not result in the construction of a project, or a near-term project.²⁶⁶

12.4.3.1 Views of interveners

436. Given that AEY had not commenced development of its proposed renewables study, Mr. Maissan argued it was unreasonable to expect that AEY could incur the entirety of its proposed expenditures in a prudent manner subsequent to a Board Order.

437. Mr. Maissan also took issue with AEY development of company-owned renewable and alternative energy sources, stating that such projects would be in direct competition with IPP proponents. Mr. Maissan viewed it to be inappropriate for ratepayers to fund AEY to, in essence, compete with the private sector, which is funded privately.

438. As an alternative to the Board approving a \$500,000 renewables study, Mr. Maissan recommended that the Board should approve (1) study costs of up to \$150,000 “to prepare for the significant displacement of diesel generation in Destruction

²⁶⁴ AEY Final Argument, paragraph 110..

²⁶⁵ Transcript, Volume 2, page 292.

²⁶⁶ AEY Reply Argument, paragraphs 88-90..

Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV”, and (2) study costs of \$50,000 “for a study on how to improve the fuel efficiency of AEY’s diesel plants, including the utilization of residual heat, that applies to all of AEY’s diesel plants.”²⁶⁷

439. With respect to each of his proposed studies, Mr. Maissan made further recommendation that the Board order AEY to submit detailed terms of reference, submit study reports upon their completion, and also seek Board approval before the implementation of any action arising out of the study findings.

440. YCS expressed similar views to that of Mr. Maissan in that the concept of the renewables study as pursuing a replacement for diesel fuel was flawed and should be denied by the Board. YCS stated that if ratepayers were being asked to pay for the study, then it must be shared as soon as completed and not withheld from viewing until the next GRA.²⁶⁸

441. YEC²⁶⁹ discounted Mr. Maissan’s argument that AEY developing renewable and alternative energy sources would be in competition with IPP proponents. YEC stated there was no basis for Board to restrict prudently incurred expenditures related to studies assessing renewable generation options.

442. YEC also addressed comments from Mr. Maissan and YCS requesting the sharing of any renewable study results prior to AEY’s next GRA, stating that there is no mandate for the Board to address such proposals. YEC expressed similar views with respect to AEY’s proposal to bring forward any business cases stemming from the renewables study in a stand-alone proceeding before the Board without waiting for a subsequent GRA.

12.4.3.2 Views of the Board

443. In this test period, AEY has requested various studies for Board approval to include amounts for studies in rates. The Board considers that such studies are best conducted by industry or funded by government initiatives.

444. In addition, the Board understands that it may be difficult for the utility look to government grants or other sources of funding through customer rates without a fully formulated proposal for a renewable or alternate energy project. This was explained by Mr. Tenney in his testimony:

Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been — become public since you filed your application and your IRs?

A. MR. TENNEY: Again, in one of the information responses, we did talk about the last — the 2016 federal budget that they earmarked, I believe it was \$10.6

²⁶⁷ JM Final Argument, page 12.

²⁶⁸ YCS Final Argument, page 9.

²⁶⁹ YEC Reply Argument, pages 7-9.

million for renewable energy programs. We have been working with the Federal Government to see if we can access that.

To date, the message — and I think we — in one of that - October 24th, I believe it was, update that we did, we had originally said that we hadn't included the watt — we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.

What we got back — what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project — the economics work to get it under construction.

So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.²⁷⁰

445. The Board is of the view that studies proposed in the Application would reasonably involve an assessment of need, feasibility and policy objectives that could involve government, academics, YEC, municipalities, customers or other stakeholders.

446. The legislative scheme is intended to provide for the regulation of utilities and to provide the Board with various responsibilities in the public interest, including the setting of rates of the utility in the provision of electricity to customers in the Yukon.

447. There is not sufficient evidence for the Board to approve the Renewable and Alternative Energy Feasibility Study proposed in the Application and, without further information, the Board is unable to assess whether or not these studies should be conducted given the need or feasibility of a study to support a renewable and alternative energy project or projects, and whether proposed costs for these studies should be recovered in customer rates. The Board considers that information that should be provided in support for these types of studies or initiatives would include, but is not limited to:

- An analysis of how the study or initiative proposed is related to the utility's statutory requirements of provision of utility service pursuant to the *Public Utilities Act* and its regulations;
- The drivers, need and feasibility for the study or initiative;
- The scope of the study or initiative;
- An expected budget for studies, preliminary reports, and any other primary or secondary reports, as well as a budget for any known implementation costs or an estimate of any expected implementation costs;

²⁷⁰ Transcript, Volume 3, page 453, lines 11 to 25 and 454 lines 1-15.

- The specific utility projects that are expected to be reviewed or impacted by the proposed initiative(s), as well as corresponding benefits to customers expected as a result of the study and initiative(s); and
- Whether cost-recovery studies and alternative-energy initiatives, energy-saving initiatives, or other initiatives have been explored through grants or other sources of funding, including shareholder funding.

448. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility Study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision.²⁷¹

449. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference, or filing any completed Renewable and Alternative Energy Feasibility Study.

450. Further to the request for two alternative studies as proposed by Mr. Maissan in argument, the Board finds the feasibility and the costs for AEY to undertake these studies has not been examined by the utility or the Board through a proceeding. These recommendations have not received the benefit of being tested by parties during the course of this proceeding. For these reasons, the Board does not support Mr. Maissan's request for AEY to undertake two alternative studies.

12.4.4 Joint Smart Grid Study Deferral Account

451. AEY requested approval for costs related to a Joint Smart Grid Study anticipated to be undertaken in 2017 in partnership with YEC at a cost of \$100,000. The study is intended to assess the potential fit and viability of a smart grid in the Yukon. AEY advised that it intends to have the completed smart grid study filed with the Board and made public.²⁷²

12.4.4.1 Views of interveners

452. Mr. Maissan supported the Board's approval of the \$100,000 budget for the proposed smart grid study, citing that there could be significant benefits to ratepayers in the long term if the utilities were to embrace a smart grid approach in the Yukon.²⁷³

12.4.4.2 Views of the Board

453. The Board considers that such studies are best conducted by industry or funded by government initiatives.

454. There is not sufficient evidence for the Board to approve the Joint Smart Grid Study proposed in the Application and, without further information, the Board is unable to assess whether these studies should be conducted given the need or feasibility of a

²⁷¹ For example, at Transcript, Volume 2, page 291, lines 6-10, Mr. Tenney confirmed that ATCO Electric Yukon is one of the members of the Northern consortium, together with three Crown corporations, that fund the research chair in Northern Energy Innovation at Yukon College.

²⁷² AEY Final Argument, paragraphs 119-122.

²⁷³ JM Final Argument, page 6.

study to support a smart grid project or projects, or whether proposed costs for these studies should be recovered in customer rates.

455. Further, there has been no substantive evidence submitted by parties that provided an indication of any benefits accruing to customers as a result of the proposed study.

456. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecasted expenditures and cost recovery related to its proposals in its compliance filing to this decision.

457. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference or filing any completed Joint Smart Grid Study.

Appendix A – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Board notes AEY's submission that, "Had AEY not revised its methodology... AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016." Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data. Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. Paragraph 40
2. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY. This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a position that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY. Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the position be removed from AEY's complement. Paragraph 76
3. As a result, for out-of-scope employees, the Board awards for 2016, a labour inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision. Paragraph 90
4. For these reasons the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction. Paragraph 94

5. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response. In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent for 2017. AEY is directed to reflect this change in its compliance filing to this decision. Paragraph 105
6. The Board does not accept AEY’s submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual. Paragraph 123
7. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period. However, the Board is concerned about the trends displayed by CW’s evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs. Paragraph 124
8. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.” However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800 and \$7,000 being removed from Account 88900. The revised balance

approved by the Board for 2016 “Other” (Account 88800) is \$47,000, and the 2017 balance for “Other” (Account 88800) is \$44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision..... Paragraph 128

9. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.” However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800, and \$7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is \$143,000, and the approved 2017 balance for “Other” (Account 88900) is \$146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision. Paragraph 130
10. The three-year average (2013-2015) for “Other” for Account 72100 is \$1,426,000. The Board finds that it is reasonable to use the three-year average for this account. \$1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the \$1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be \$1,455,000. For 2017, the forecast value is \$1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision. Paragraph 134
11. For the purpose of calculating AEY’s depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense. Paragraph 163
12. The Board considers that consistent with AEY’s depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.
..... Paragraph 167

13. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.
..... Paragraph 172
14. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.
..... Paragraph 237
15. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017. The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision. Paragraph 240
16. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. Paragraph 278
17. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost. Paragraph 292
18. With respect to LED streetlight installations that are not conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. Paragraph 293

19. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision. Paragraph 354
20. The Board accepts AEY's test period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA. Paragraph 384
21. If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings. Paragraph 385
22. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. Paragraph 448
23. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. Paragraph 456

TAB 6



2023 Generic Cost of Capital

March 31, 2022

Alberta Utilities Commission

Decision 27084-D01-2022

2023 Generic Cost of Capital

Proceeding 27084

March 31, 2022

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The Commission may, within 60 days of the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

Contents

1	Decision summary	1
2	Background and procedural summary	2
3	2023 parameters and completion of current GCOC proceeding	4
3.1	Support from stakeholders	4
3.2	Key economic and market conditions	5
3.2.1	Inflation, interest rate increase and credit spreads	5
3.2.2	Market equity risk premium	7
3.2.3	Market volatility	8
3.2.4	Business risk and earning above awarded ROE	9
3.3	Comparable returns on equity	10
3.4	Prospectivity	11
3.5	Cost of proceedings	12
4	Conclusion	12
5	Costs award	13
6	Order	13
	Appendix 1 – Proceeding participants	15

2023 Generic Cost of Capital

1 Decision summary

1. In this decision, the Alberta Utilities Commission approves the return on equity (ROE) of 8.5 per cent and deemed equity ratio of 37 per cent, except for an approved deemed equity ratio for Apex Utilities Inc. of 39 per cent (together, the ROE and deemed equity ratios are also referred to as “parameters”) for 2023 on a final basis. The established parameters apply to the following utilities:

- AltaLink Management Ltd.¹
- Apex Utilities Inc.²
- ATCO Electric Ltd.³
- ATCO Gas & Pipelines Ltd.^{4 5}
- ENMAX Power Corporation⁶
- EPCOR Distribution & Transmission Inc.⁷
- FortisAlberta Inc.⁸
- KainaiLink L.P.⁹
- City of Lethbridge¹⁰
- PiikaniLink L.P.¹¹
- The City of Red Deer¹²
- TransAlta Corporation¹³

¹ Electricity transmission, including AltaLink Management Ltd. as general partner of AltaLink L.P., KainaiLink L.P. and PiikaniLink L.P.

² Natural gas distribution.

³ Electricity transmission and distribution. Unless otherwise indicated, a reference to ATCO Electric includes both the transmission and distribution operations of this utility.

⁴ ATCO Gas refers to the utility’s natural gas distribution operations. ATCO Pipelines refers to the utility’s natural gas transmission operations.

⁵ Collectively, ATCO Electric, ATCO Gas and ATCO Pipelines are referred to as the ATCO Utilities.

⁶ Electricity transmission and distribution. Unless otherwise indicated, a reference to ENMAX refers to both the transmission and distribution operations of this utility.

⁷ Electricity transmission and distribution. Unless otherwise indicated, a reference to EPCOR refers to both the transmission and distribution operations of this utility.

⁸ Electricity distribution.

⁹ Electricity transmission. The Commission approved the transfer of specific transmission assets from AltaLink to KainaiLink L.P. in Decision 22612-D01-2018: AltaLink Management Ltd., AltaLink L.P. Transfer of Specific Transmission Assets to PiikaniLink L.P. and KainaiLink L.P. and the Associated 2017-2018 General Tariff Applications, Proceeding 22612, November 13, 2018.

¹⁰ Electricity transmission.

¹¹ Electricity transmission. The Commission approved the transfer of specific transmission assets from AltaLink to PiikaniLink L.P. in Decision 22612-D01-2018.

¹² Electricity transmission.

¹³ Electricity transmission.

2. The parameters set out in this decision do not apply to EPCOR Energy Alberta GP Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because these entities are regulated rate providers pursuant to the *Electric Utilities Act* and the *Regulated Rate Option Regulation*. Similarly, the parameters in this decision do not apply to Direct Energy Regulated Services as a default supply provider under the *Gas Utilities Act* and the *Default Gas Supply Regulation*.

3. The parameters for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other Commission proceedings, should issues respecting ROE and deemed equity ratios arise in the regulation of investor-owned water utilities.

2 Background and procedural summary

4. In each of the *Public Utilities Act*, the *Gas Utilities Act* and the *Electric Utilities Act*, the Commission is required to set a fair return for utilities as a component of setting just and reasonable rates.¹⁴ It has been the Commission's practice to consider the components of a fair return, namely the ROE and deemed equity ratio, for all utilities it regulates in a generic cost of capital (GCOC) proceeding.¹⁵

5. While each of the aforementioned statutes requires the Commission to determine a fair return, there is no prescribed method for doing so.¹⁶ Rather, as recently confirmed by the Alberta Court of Appeal, the Commission has broad discretion in determining what factors are relevant in setting a fair return.¹⁷ Determining just and reasonable rates requires the Commission to balance the interests of both the utility and its customers.¹⁸ Rates must provide the utility a reasonable opportunity to earn a fair return on invested capital, while also ensuring that customers are not paying more than is required to maintain safe, reliable and economic service. In applying its judgment, the Commission often assesses conflicting evidence on risk, including the differing interests and perspectives of debt and equity investors.¹⁹

6. The Commission and its predecessors have accepted and considered the following three factors when setting a fair return: comparable investments, capital attraction, and financial integrity.²⁰ The Commission considers these factors to be well established and continues to be satisfied that the fair return standard is met when the return satisfies these three factors, while also understanding that a fair return is one component of the Commission's determination of just and reasonable rates. Another component of just and reasonable rates is a reasonable opportunity to recover costs and expenses including capital costs, operating costs, taxes and depreciation.

¹⁴ *Public Utilities Act*, Section 90(1); *Gas Utilities Act*, Section 37(1); *Electric Utilities Act*, sections 121(2)(a) and 122(1)(a)(iv).

¹⁵ The Commission addressed the fair return standard in Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571-1, November 12, 2009.

¹⁶ See Decision 2009-216, paragraphs 89, 93 and 98.

¹⁷ *The Office of the Utilities Consumer Advocate v Alberta Utilities Commission*, 2021 ABCA 336, paragraph 16.

¹⁸ For example, see the seminal case of *Northwestern Utilities Ltd. v Edmonton (City)* [1929] SCR 186, pages 192-193.

¹⁹ Decision 2009-216, paragraph 110.

²⁰ Decision 2009-216, paragraphs 92-98.

7. Over the past 20 years, the Commission has used various methods to determine the ROE and deemed equity ratios. Historically, the Commission's predecessors considered these parameters for each utility on a case-by-case basis. For the 2004 test year, the Commission set a generic (i.e., the same) ROE for all utilities and adopted an adjustment mechanism formula to determine the ROE in subsequent years.²¹ The formula was used from 2005 to 2008, and then the global financial recession of 2007 to 2009 led the Commission to deviate from the formula-based approach.

8. Starting in 2009, the Commission set the ROE based on economic and financial evidence filed by parties in GCOC proceedings, rather than on the formula-based methodology. In these proceedings, parties submitted a broad range of economic and financial evidence, including trends in Canadian and global capital markets; interest rates; bond yields; utility betas;²² market volatility measures; and monetary policy considerations, among other variables and indicators that were employed in various financial models, to arrive at expectations of reasonable return. From 2009 to 2020, the Commission established the ROE and deemed equity ratios for a series of two- to three-year test periods. The parameters were set following intensive regulatory processes in GCOC proceedings, including oral hearings.

9. For 2021 and 2022, the Commission maintained an ROE of 8.5 per cent and a deemed equity ratio of 37 per cent (39 per cent for Apex Utilities Inc.).²³ These decisions were premised on the Commission's finding that the economic and market data that would normally be used to inform its judgment regarding a fair return were in a state of significant flux, in light of the COVID-19 pandemic. The decisions also took into account that there was conflicting evidence (some of which supported the need for increased returns, some of which supported decreased returns), and that it was not clear that additional process, like that used by the Commission in the period between 2009 and 2020, would provide any greater assurance that the resulting rates would be just and reasonable. Ultimately, the Commission concluded that there was an inadequate basis for departing from the currently approved parameters.

10. On January 3, 2022, the Commission initiated the present 2023 GCOC proceeding and issued a letter²⁴ informing interested parties that it was bifurcating this proceeding, with the first stage establishing the parameters for 2023, and the second stage focusing on 2024 and future years. This decision relates to the first stage.

11. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to a particular matter.

²¹ Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Proceeding 13130, Application 1271597-1, July 2, 2004.

²² β , or beta, measures the sensitivity of a required return of an individual security to changes in the market return.

²³ Decision 24110-D01-2020: 2021 Generic Cost of Capital, Proceeding 24110, October 13, 2020; and

Decision 26212-D01-2021: 2022 Generic Cost of Capital, Proceeding 26212, March 4, 2021.

²⁴ Exhibit 27084-X0004, AUC letter - Proceeding to determine fair return starting in 2023.

3 2023 parameters and completion of current GCOC proceeding

12. Recognizing the lingering uncertainty and continued volatility of financial markets due to the COVID-19 pandemic, the Commission indicated in correspondence dated January 3, 2022, its preparedness to extend for an additional year the cost-of-capital parameters previously approved for 2022. However, before making its decision, the Commission provided all interested parties in this proceeding an opportunity to comment on its proposal to maintain the status quo for another year, i.e., 2023.

13. In the sections that follow, the Commission discusses parties' responses and the reasons for the Commission's determination to maintain the ROE and deemed equity ratios for 2023 consistent with the approved parameters for 2022.

14. The Commission's reasons can be briefly summarized as follows:

- (a) Although the utilities provided evidence to support higher cost-of-capital parameters for 2023, they were prepared to accept extending the 2022 parameters to the end of 2023. One customer group (The City of Calgary) was amenable to such an outcome as well.
- (b) The evidence on some of the key economic indicators and market conditions shows upward pressure associated with inflation and interest rates. Other indicators such as credit spreads and market equity risk premium (MERP) remain largely stable. Market volatility remains elevated, making it difficult to forecast relevant economic conditions for 2023. The evidence on business risk is mixed.
- (c) Submissions from a customer group regarding the use of formulas led to proposed ROEs that were very close to 8.5 per cent, and recent decisions from other Canadian regulators provided additional validation that the current ROE is reasonable and represents a fair return.
- (d) There are significant costs associated with a fully contested GCOC proceeding. The Commission considers that adding further process to the present proceeding would not permit prospective rates (which in turn can increase utilities' risk and future rates). In addition, the Commission is not persuaded that these additional costs, which are ultimately borne by customers, can be justified in this case.

15. The Commission's reasons are outlined in detail in the sections that follow.

3.1 Support from stakeholders

16. The utilities and one of the customer groups, Calgary, did not object to keeping the parameters for 2023 the same as the approved parameters for 2022. Each provided reasons to support the continuation of the approved parameters for 2023. While all of the utilities submitted that the ROE for 2023 should increase,²⁵ and ENMAX²⁶ and ATCO/Fortis/Apex²⁷ also argued that the deemed equity ratio should increase, each of the utilities was prepared to accept keeping

²⁵ Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 5. Exhibit 27084-X0028, ATCO/Apex/Fortis, PDF page 1. Exhibit 27084-X0025, ENMAX, PDF pages 1-2.

²⁶ Exhibit 27084-X0025, ENMAX, PDF page 2.

²⁷ Exhibit 27084-X0028, ATCO/Apex/Fortis, PDF page 2. Exhibit 27084-X0032, Fortis, PDF pages 1-3.

the ROE and deemed equity ratios for 2023 the same as the approved parameters for 2022, in light of other considerations.²⁸ Calgary identified certain economic factors and circumstances that favour keeping the parameters the same and, ultimately, did not object to such an outcome.²⁹ The Commission considers this unanimous support from the utilities, and partial support from the customer groups, weighs in favour of the Commission's proposal.

17. The Commission also took into consideration submissions of parties that opposed keeping the parameters for 2023 the same, namely views of the Office of the Utilities Consumer Advocate (UCA) and the Consumers' Coalition of Alberta (CCA). The Commission discusses pertinent parts of these parties' submissions below.

3.2 Key economic and market conditions

18. Generally, the Commission considers a number of key economic indicators and financial market conditions in determining a just and reasonable ROE and deemed equity ratios. These include the interest rate environment, credit spreads and market volatility, as well as some other indicators that serve as inputs to, and guide the outcome of, the capital asset pricing model (CAPM). While some of these conditions were relatively stable, others have shifted materially over the last two years with the most prominent being substantial changes in inflation. Market volatility, and inflationary pressures especially with respect to food and energy prices, have been amplified by the geopolitical risks, uncertainty, and global economic ramifications of the largest land war the world has witnessed in 75 years triggered by Russia's recent invasion of Ukraine.

19. The Commission finds that the evidence before it shows upward pressure associated with inflation and interest rates. Other indicators such as credit spreads and MERP remain largely stable. Market volatility remains elevated, making it difficult to forecast relevant economic conditions for 2023. The evidence on business risk is mixed. These observations are discussed below.

3.2.1 Inflation, interest rate increase and credit spreads

20. In their submissions,³⁰ utilities made reference to the Bank of Canada (BoC) increasing its policy interest rate, and potential rate increases from both the BoC and the United States Federal Reserve in the upcoming year. The utilities referred to the BoC's latest Monetary Policy Report³¹ and viewed the BoC's projections and commentary as an indication of future interest rate increases. The utilities made note of the BoC's overview of the Canadian economy, which highlighted recent developments such as increased inflationary pressures and absorbed economic slack.³² AltaLink/EPCOR provided data from Statistics Canada showing the year-over-year growth rate in the Canadian consumer price index peaking at 4.8 per cent in December 2021. This was higher than the maximum annual growth rates seen in 2018, 2019 or 2020, and showed no indication of subsiding. These parties stated that the duration and extent of inflationary

²⁸ Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 5. Exhibit 27084-X0028, ATCO/Apex/Fortis, PDF page 2. Exhibit 27084-X0025, ENMAX, PDF pages 1-2.

²⁹ Exhibit 27084-X0021, Calgary, paragraphs 17-18.

³⁰ Exhibit 27084-X0023, AltaLink/EPCOR, paragraphs 11-16, and exhibits 27084-X0025, 27084-X0029 and 27084-X0030.

³¹ <https://www.bankofcanada.ca>, Bank of Canada, Monetary Policy Report, January 2022.

³² Exhibit 27084-X0030, Appendix B, R. Buttke evidence, PDF page 1. Exhibit 27084-X0023, AltaLink, paragraph 14. Exhibit 27084-X0025, ENMAX, PDF pages 9-10.

pressure cannot be reasonably forecast.³³ J. Coyne for ENMAX concluded that “getting inflation under control will take several years.”³⁴

21. The UCA also referred to comments from the BoC’s January 2022 Monetary Policy Report,³⁵ indicating that uncertainty regarding its inflation outlook was high, but lower than that found in previous monetary policy reports.

22. Overall, the utilities submitted that they view inflation and interest rates as positively correlated with authorized ROEs and, with all else equal, the expected future path of the policy interest rate should place upward pressure on authorized ROEs and other rates of return in the capital markets. The Commission notes that the BoC increased its target monetary policy interest rate on March 2, 2022.³⁶

23. The Commission observes that higher interest rates are likely to affect expected utility returns. While interest rates are expected to increase, the magnitude of BoC rate increases (timing and scale of monetary policy rate change) is unknown. This adds a layer of uncertainty in establishing equity risk premiums and expected return values, absent reliance on a formula-based methodology. Under the circumstances, the Commission finds: (i) the utilities’ preparedness to accept the current ROE of 8.5 per cent, coupled with (ii) the ongoing and pervasive uncertainty regarding the timing and extent of future changes in inflation and interest rates, including the potentially significant impact on global food and energy prices occasioned by Russia’s invasion of Ukraine at the end of February 2022, supports a continuation of the current GCOC parameters into 2023, while moving forward with consideration of a formula-based approach in 2024.

24. Intervenors submitted that utility credit spreads³⁷ are within the same range as credit spreads for debt issued by utilities in 2020 and 2018. The CCA³⁸ noted that credit spreads for ATCO Electric Distribution and ATCO Pipelines, when they issued debt in September 2020, was less than the cost of ATCO Electric Transmission’s debt in 2018, which was the year of the last fully litigated GCOC proceeding. The CCA also noted that AltaLink issued debt with a smaller credit spread than previous debt issues, and ENMAX Distribution issued 10-year debt in 2020 at roughly the same spread as in June 2018. The CCA also submitted U.S. data as of February 2022 for corporate A-rated debentures showing a cost of debt at 42 basis points below the 25-year average, and 14 basis points above the one-year trend.

25. The UCA³⁹ referenced the spread between 30-year Canadian A-rated utility bonds and the yield on 30-year Government of Canada bonds (A-rated utility credit spreads). The utility credit spread was at 1.39 per cent in January 2022, which is very close to the long-term average of 1.40 per cent. The same credit spread data in March 2018 was reported to be 1.30 per cent.

26. Consistent with past GCOC decisions, the Commission views credit spreads as a measure of utility bond investors’ risk perceptions and return expectations of utility investors. The spread

³³ Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 11.

³⁴ Exhibit 27084-X0025, ENMAX, PDF page 13.

³⁵ Exhibit 27084-X0031, UCA, paragraph 11.

³⁶ <https://www.bankofcanada.ca>, Bank of Canada increases policy interest rate - Bank of Canada, March 2, 2022.

³⁷ Credit spreads are the difference between the yield for a government bond (i.e., Bank of Canada or U.S. Treasury) and the debt securities of corporations (i.e., utilities). A higher credit spread indicates a higher level of risk.

³⁸ Exhibit 27084-X0026, CCA, PDF pages 4-6.

³⁹ Exhibit 27084-X0031, UCA, PDF page 7.

measured by the difference between 30-year Canadian A-rated utility bonds and 30-year Government of Canada bonds is similar to levels in March 2018, when the parameters were set in the 2018 GCOC decision. The Commission finds that the credit spread data submitted by the interveners indicates that this measure has not deviated significantly since 2018.

3.2.2 Market equity risk premium

27. In the 2018 GCOC proceeding, Dr. Villadsen, on behalf of Apex/ATCO Utilities,⁴⁰ provided the following description of the MERP:

Like the cost of capital itself, the market equity risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can expect to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable, and must be inferred or forecasted based on known market information.⁴¹

28. Estimates of a forward-looking MERP are used as an input in the CAPM and the empirical capital asset pricing model (ECAPM). The greater is the estimate of the forward-looking MERP, the higher will be the ROE generated by the CAPM and the ECAPM, all else being equal. Different approaches can be used to estimate the forward-looking MERP.⁴²

29. In the present proceeding, both the CCA and Dr. Villadsen presented Canadian MERP data; however, while the CCA relied on annual values, Dr. Villadsen focused on monthly data with special emphasis on January 2022. On this basis, she submitted that the forward-looking MERP has increased markedly since the 2018 GCOC decision was issued and since the submission of her evidence in the 2021 GCOC proceeding. She submitted that on average in January 2022, the Canadian forward-looking MERP was 11.07 per cent, which is nearly double the historical average of 5.68 per cent and well above the current U.S. forward-looking MERP of 8.12 per cent.⁴³ With reference to the annual MERP data, the CCA submitted that measures of the equity risk premium have remained largely stable. In support of this view, the CCA provided a table, based on publicly available sources of MERP, showing U.S. and Canadian premiums from 2011 to 2022.⁴⁴ The CCA submitted that the data and other factors support a downward adjustment to the Commission-approved MERP.⁴⁵

30. Dr. Villadsen did not explain why the Canadian forward-looking MERP estimate in January 2022 was much higher than the historical average and much higher than the U.S. forward-looking MERP. Dr. Villadsen's monthly chart shows that MERP values demonstrated some marked "peaks and valleys" in 2020 and 2021; however, the annual average MERPs remained stable as the CCA's data shows. In the absence of any information and support from Dr. Villadsen on whether January 2022 is indicative of a long-term trend or whether it is a temporary change that is expected to reverse, the Commission places greater weight on the data presented by the CCA, which shows that the average annual MERP has remained largely stable

⁴⁰ The ATCO utilities are ATCO Electric - Distribution; ATCO Gas; ATCO Electric - Transmission; and ATCO Pipelines.

⁴¹ Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018, paragraph 300.

⁴² Dr. Villadsen's description of two approaches is quoted in paragraph 300 of Decision 22570-D01-2018.

⁴³ Exhibit 27084-X0029, Appendix A - Dr. Villadsen evidence, PDF pages 4-5.

⁴⁴ Exhibit 27084-X0026, CCA, PDF page 12, paragraph 39.

⁴⁵ Exhibit 27084-X0026, CCA, PDF page 14, paragraph 41.

since 2018, and finds that the data supports a continuation of the current GCOC parameters into 2023.

3.2.3 Market volatility

31. The utilities highlighted persistent heightened market volatility, and the lack of certainty and clarity in available market data. AltaLink/EPCOR⁴⁶ referenced that market volatility reached an all-time high during 2020, and remains highly variable. Using the VIX⁴⁷ index as a short-term measure, AltaLink commented that the market was at least 30 per cent more volatile compared to historical norms. ENMAX⁴⁸ provided similar evidence of heightened market volatility: Canadian and U.S. volatility indexes were still relatively high compared to five-year averages.

32. J. Coyne for ENMAX submitted that investor perceptions of market volatility and expected return, as measured by utility betas, have changed. Data submitted indicated that proxy utility betas were 23 per cent to 38 per cent higher in January 2022 compared to January 2020.⁴⁹

33. The CCA⁵⁰ submitted that it is not clear that the VIX has a substantial effect on the risk premium and expected return demanded by investors. The CCA noted that the correlation between the VIX index and equity risk premium has declined over the last decade.

34. The UCA⁵¹ submitted that the VIX and credit spreads were both within the long-term average, and that there was no basis in maintaining the status quo for the GCOC parameters. The UCA noted the VIX was near its long-term average of 20 at the time of its submission in this proceeding.

35. Parties' submissions also diverged when it came to the timeframe over which a VIX index should be observed, with the UCA emphasizing "that volatility has decreased"⁵² within the 2018-2022 range, while Robert Buttke, on behalf of ATCO Utilities/Apex/Fortis, stated that the "VIX index remains well above its twenty-year historical average."⁵³ R. Buttke further submitted that with the BoC and U.S. Federal Reserve on the cusp of instituting quantitative tightening, the balance of volatility risks remains solidly toward the upside.⁵⁴

36. Consistent with its determinations in past GCOC decisions, the Commission considers market volatility to be relevant to determining the parameters.⁵⁵ In the Commission's view, the heightened volatility and the uncertain outlook remain present and are likely to affect economic and market fundamentals in 2023. The Commission acknowledged this environment in its last GCOC decision, where it referenced AltaLink/EPCOR emphasizing "the COVID-19 pandemic and other related global events that continue to elevate capital market volatility, as well as economic uncertainty, potentially extending through 2021 and beyond, therefore making it

⁴⁶ Exhibit 27084-X0023, PDF pages 3 and 13.

⁴⁷ Chicago Board Options Exchange Volatility Index (VIX), measures the 30-day implied volatility of the S&P (Standard and Poor's) 500 index (representing the stock market in the U.S.).

⁴⁸ Exhibit 27084-X0025, ENMAX, PDF pages 17-18, Table 1.

⁴⁹ Exhibit 27084-X0025, ENMAX, PDF page 18.

⁵⁰ Exhibit 27084-X0026, CCA, PDF page 9.

⁵¹ Exhibit 27084-X0031, UCA, PDF page 5.

⁵² Exhibit 27084-X0031, UCA, paragraph 12.

⁵³ Exhibit 27084-X0030, Appendix B - Mr. Buttke evidence, PDF page 4.

⁵⁴ Exhibit 27084-X0030, Appendix B - Mr. Buttke evidence, PDF page 4.

⁵⁵ Decision 26212-D01-2022, paragraph 19. Decision 20622-D01-2016: 2016 Generic Cost of Capital, Proceeding 20622, October 7, 2016, paragraphs 90-91.

impossible to forecast relevant economic conditions for 2022 with any reasonable degree of accuracy.”⁵⁶ Overall, the Commission finds market volatility remains elevated, making it difficult to forecast relevant economic conditions for 2023. This lends further support to a rollover of GCOC parameters into 2023.

3.2.4 Business risk and earning above awarded ROE

37. Parties submitted conflicting assessments of changes to business risk since the 2018 GCOC decision. The ATCO Utilities/Apex/Fortis⁵⁷ submitted that there have been significant transformations occurring in the utility industry since 2018, including emphasis on decarbonization; a focus on environmental, social and governance standards; the need for grid modernization; and changes in the way in which customers are receiving utility service. These utilities stated that they are directly affected by these transformations, and these changes engender risk and uncertainty for utilities at a level seldom witnessed in the past.⁵⁸

38. J. Coyne, on behalf of ENMAX, pointed to renewable energy investments and high capital expenditure plans in an increasing interest rate environment as contributors to the observed elevated utility risk.⁵⁹ Fortis engaged Dr. Toby Brown of the Brattle Group to assess the business risk of utilities in Alberta. Dr. Brown concluded that the business risk of the utilities in Alberta in 2023 remains elevated and may have increased since the 2021 GCOC proceeding.⁶⁰

39. The UCA submitted that there has been no change in business risk since the 2018 GCOC decision was issued. It stated that the COVID-19 pandemic appeared to have little effect on the utilities’ ability to provide safe and reliable service, and submitted that this confirms the utilities continue to have low business risk and operate within a supportive regulatory environment.⁶¹ The CCA submitted that financial risk and regulatory risk are lower now than they were at the time of the 2018 GCOC proceeding. It noted the reduction in regulatory lag and stated that utility asset disposition risk has been largely eliminated.⁶²

40. Some customer groups pointed to the utilities achieving actual ROEs in excess of the Commission-approved ROEs. For example, Calgary noted that ATCO Gas has been remarkably consistent in earning in excess of its approved ROE over the last four years, even when the economy at large has been decimated. It submitted that this indicates minimal business risk for ATCO Gas.⁶³ The Industrial Power Consumers Association of Alberta (IPCAA) submitted that over the last 10 years, most of the utilities in Alberta have been earning an ROE above the Commission-approved ROE.⁶⁴

41. The Commission considers that historical earnings above or below the approved ROEs do not help it to determine what the ROE for a future test period should be. The Commission agrees with the following submissions made by AltaLink/EPCOR:

⁵⁶ Decision 26212-D01-2021, paragraph 13.

⁵⁷ The ATCO utilities, Apex and Fortis filed a joint submission on the record, which is in Exhibit 27084-X0028.

⁵⁸ Exhibit 27084-X0028, ATCO/Apex/Fortis, page 2.

⁵⁹ Exhibit 27084-X0025, ENMAX, PDF page 18.

⁶⁰ Exhibit 27084-X0032, Fortis, PDF pages 6-7.

⁶¹ Exhibit 27084-X0031, UCA, paragraphs 33-36.

⁶² Exhibit 27084-X0026, CCA, paragraph 53.

⁶³ Exhibit 27084-X0021, Calgary, paragraph 38.

⁶⁴ Exhibit 27084-X0024, IPCAA, paragraphs 7-9.

Invariably, whether or not a utility earns its approved ROE in a given year will depend on utility specific matters, such as the utility's O&M [operating and maintenance] and capital cost performance in that year. Although these matters may be relevant to the regulation of a utility's revenue requirement (whether under cost of service regulation or performance-based regulation), they are not relevant in the context of establishing fair return within a GCOC proceeding.⁶⁵

42. The Commission notes the conflicting evidence and positions of parties with respect to indicators of business risk and whether business risk is increasing or decreasing. The Commission is not persuaded that there is a quantifiable shift in business risk that would require either an increase or decrease in the deemed equity ratios for 2023.⁶⁶

3.3 Comparable returns on equity

43. Some interveners referenced approved ROEs and ongoing GCOC proceedings from other jurisdictions. Calgary, for example, highlighted⁶⁷ two recent determinations of the Newfoundland and Labrador Board of Commissioners of Public Utilities and the New Brunswick Energy and Utilities Board. Both cases resulted in an approved ROE of 8.5 per cent through either a negotiated settlement or an award by a board. In Calgary's view, this is another circumstance accentuating that "the roll-over of 2022 GCOC parameters into 2023 should assure Customers with the comfort that distribution rates will not rise once again due to any parameter adjustments in 2023."⁶⁸

44. The UCA used the Ontario Energy Board's (OEB) formula and, using the Commission's last approved ROE of 8.5 per cent as the base, along with certain market data values as recent as of January 18, 2022, arrived at a calculated ROE of 8.37 per cent. Alternatively, it noted that using a formula proposed by Dr. S. Cleary in the 2021 GCOC proceeding, updated with more current data, would produce an ROE of 8.3 per cent.⁶⁹ In the UCA's view, if the Commission was to set the ROE on a final basis without conducting further process, at a minimum, the approved ROE should be 0.27 per cent below the currently approved ROE of 8.5 per cent (i.e., 8.23 per cent).⁷⁰ The UCA also pointed to the ongoing GCOC proceeding at the British Columbia Utilities Commission (BCUC) notwithstanding "uncertainties in economic conditions, volatility in financial markets and changes in government policies."⁷¹

45. While all utilities supported keeping the ROE at 8.5 per cent, some utilities submitted evidence that current economic indicators would actually lead to a higher ROE for 2023 (as well as higher deemed equity ratios), if the Commission was to carry out a full GCOC proceeding.

46. AltaLink and EPCOR identified a number of relevant data points indicating that investor return expectations for utilities have increased, for example: (i) high inflation puts an upward pressure on interest rates and, as a result, investor-required returns on utility investments;

⁶⁵ Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 27.

⁶⁶ Since the 2009 GCOC decision, it has been the Commission's practice to establish an ROE that uniformly applies to all of the affected utilities and account for particular business risks faced by the affected utilities by incorporating any required adjustments into their respective approved deemed equity ratios, either collectively or on an individual basis.

⁶⁷ Exhibit 27084-X0022, Calgary, paragraph 31.

⁶⁸ Exhibit 27084-X0022, Calgary, paragraph 46.

⁶⁹ Exhibit 27084-X0031, UCA, paragraphs 28-31.

⁷⁰ Exhibit 27084-X0031, UCA, paragraph 27.

⁷¹ Exhibit 27084-X0031, UCA, paragraph 6.

(ii) a higher level of required return for debt instruments, which would correspond to a greater cost of common equity; and (iii) the upward directional movement of beta coefficients indicating an elevated level of observed investor risk and requiring a higher level of return to compensate investors for the additional risk. Nevertheless, AltaLink and EPCOR submitted that when all factors relevant to the Commission's statutory mandate and approval process are considered, it is just and reasonable that the Commission extend the current parameters into 2023 on a final basis.⁷²

47. The Commission notes that matching the ROE and deemed equity ratios awarded by other regulators, on its own, does not satisfy the fair return standard, nor does it establish just and reasonable rates. The objective of the GCOC is to consider the market expectation for the utilities raising capital necessary to provide safe and reliable utility service in Alberta. In setting the GCOC for the utilities in Alberta, other jurisdictions can be a useful indicator or benchmark for evaluating contemporaneous rates of return and whether return expectations are generally increasing or decreasing.

48. In this regard, the Commission observes that the ROEs from other jurisdictions noted by interveners or calculated using formulaic methodologies do not materially depart from the Commission's last approved 8.5 per cent figure and, hence, provide no justification for commencing a full-scale review process given the additional time and costs involved. The Commission also notes that the OEB's latest 2022 approved formulaic cost-of-capital parameters result in an ROE of 8.66 per cent, which is 0.16 per cent higher than the Commission's rate of 8.5 per cent (and represents an increase from the OEB's approved ROE in 2021).⁷³

49. The Commission is also not persuaded by the UCA's argument that just because the BCUC is currently conducting a GCOC proceeding, the Commission should as well. Each regulator makes determinations based on its own circumstances and jurisdiction, using its discretion and the best information available to it. The Commission observes that the benchmark ROE of 8.75 per cent and the benchmark deemed equity ratio of 38.5 per cent last approved by the BCUC has been unchanged for nearly a decade, since January 1, 2013 (and reaffirmed part way in 2016)⁷⁴ and can be distinguished on that basis.

3.4 Prospectivity

50. Nearly all parties⁷⁵ highlighted the importance of ensuring prospectivity of the approved parameters and commended the Commission's significant efforts over the past several GCOC proceedings in this regard. This endeavour helps reduce regulatory lag related to the cost-of-capital element of rates. Parties also emphasized that there would be insufficient time to prepare, file and test relevant cost-of-capital material to permit new parameters to be in place before January 1, 2023. In this respect, the Commission notes that during one of the most recent GCOC proceedings,⁷⁶ parties requested between four weeks and six months of time to prepare their evidence.

⁷² Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 18.

⁷³ <https://www.oeb.ca/sites/default/files/OEB-Ltr-2022-Cost-of-Capital-Update-20211028.pdf>

⁷⁴ https://docs.bcuc.com/Documents/Proceedings/2021/DOC_60592_A-1-GCOC-Proceeding-Notice.pdf

⁷⁵ Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 26; Exhibit 27084-X0028, ATCO/Apex/Fortis, PDF page 3; Exhibit 27084-X0021, Calgary, paragraph 8; Exhibit 27084-X0031, UCA, paragraph 57.

⁷⁶ Proceeding 26212, 2022 GCOC.

51. The UCA submitted that “the Commission’s objective of prospectivity, while commendable, can and should always be subordinate to the objective of establishing a fair return based on the best available information.”⁷⁷ The Commission agrees with this statement but it is also aware that a failure to maintain prospectivity can be a factor that results in unfairness, greater risk and uncertainty, and can put upward pressure on rates.

52. Furthermore, given the bifurcated process established by the Commission, timely conclusion of this first stage of the proceeding provides parties with certainty and finality of 2023 rates while allowing parties and the Commission time to focus on a second stage, which addresses 2024 and future years. This approach is expected to maintain prospectivity, and mitigate risk and cost increases for utilities and their customers.

3.5 Cost of proceedings

53. Full GCOC proceedings are resource intensive and costly to conduct. For example, the most recent fully contested 2018 GCOC proceeding had costs awards that totalled \$1,503,869.⁷⁸ The total costs, including the Commission’s own costs and the costs incurred by parties over and above the Commission’s scale of costs, were in excess of \$4 million. While the amount of awarded costs is not the primary consideration, it is a relevant one for the Commission as these costs are ultimately paid by ratepayers. In the present circumstances, the Commission is not persuaded that incurring these additional costs is justified or would result in a better overall outcome. This view was echoed by AltaLink and EPCOR who stated that a detailed GCOC proceeding for 2023 would be costly and inefficient and, in the end, would be unlikely to provide any greater assurance of a just and reasonable result.⁷⁹

54. For 2023, the Commission considers that its objective of ensuring that utilities earn a fair return and customers pay just and reasonable rates can be met without undertaking complex, lengthy and costly further process. A full process is likely to be frustrated by the need for multiple, potentially significant updates due to the current market volatility and uncertainty as noted by experts and the parties. Evidence, updates to evidence and further regulatory process could result in further delays.

4 Conclusion

55. Given the considerations outlined in this decision, the Commission concludes that there is an inadequate basis to depart from the currently approved ROE and the deemed equity ratios (either up or down). The Commission finds that maintaining the existing ROE of 8.5 per cent will, when combined with the existing deemed equity ratios, provide the utilities with a fair return for 2023. The Commission is satisfied that these parameters support an outcome that will ensure customers are not paying more than is required to maintain safe, reliable and economic service.

56. The Commission is not persuaded that there is a quantifiable shift in business risk that would require an increase or decrease in the deemed equity ratios for 2023. Therefore, the

⁷⁷ Exhibit 27084-X0031, UCA, paragraph 57.

⁷⁸ Decision 23628-D01-2018: 2018 Generic Cost of Capital Costs Award, Proceeding 23628, December 20, 2018.

⁷⁹ Exhibit 27084-X0023, AltaLink/EPCOR, paragraph 21.

Commission finds that the deemed equity ratios for 2023 should remain the same as those approved for 2022.

5 Costs award

57. The Commission will treat the date of this decision as the close of record date for the purpose of filing costs claim applications for the first stage of this proceeding. Accordingly, in accordance with the requirements of Rule 022: *Rules on Costs in Utility Rate Proceedings*, parties may submit their cost applications for the Commission's consideration within 30 days of March 31, 2022.

58. In light of the foregoing, the Commission concludes the first stage of this proceeding and will commence the second stage in due course to address its consideration of a formula-based approach to setting the parameters for 2024 and future years.

6 Order

59. It is hereby ordered that:

- (1) The final approved generic return on equity for Apex Utilities Inc., AltaLink Management Ltd., PiikaniLink L.P., KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is set at 8.5 per cent for the entirety of 2023.
- (2) The final approved deemed equity ratio for Apex Utilities Inc., AltaLink Management Ltd., PiikaniLink L.P., KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is set at 37 per cent (39 per cent for Apex Utilities Inc.) for the entirety of 2023.

Dated on March 31, 2022.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Douglas A. Larder, QC
Vice-Chair

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
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AltaLink Management Ltd. (AltaLink)
Apex Utilities Inc. (Apex)
ATCO Electric Ltd. (ATCO Electric)
ATCO Gas Bennett Jones LLP
Capital Power Corporation (CPC) Dentons Canada LLP
Consumers' Coalition of Alberta (CCA)
ENMAX Power Corporation (ENMAX or EPC)
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI)
FortisAlberta Inc. (Fortis or FAI)
Industrial Power Consumers Association of Alberta (IPCAA)
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The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors

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TAB 7



Determination of the Cost-of-Capital Parameters in 2024 and Beyond

October 9, 2023

Alberta Utilities Commission

Decision 27084-D02-2023

Determination of the Cost-of-Capital Parameters in 2024 and Beyond
Proceeding 27084

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The Commission may, no later than 60 days from the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

Contents

1	Decision summary	1
2	Background and procedural summary	2
3	Fair return standard.....	4
4	Relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision.....	7
4.1	Inflation.....	9
4.2	Economic growth.....	10
4.3	Bond yields	11
4.4	Capital markets	11
5	Formulaic approach to determine ROE	11
5.1	The need for a formulaic approach to setting ROE	11
5.2	ROE formulaic approach	14
5.3	Annual process to determine the ROE through the formulaic approach	16
5.4	Periodic reviews of formulaic approach	17
5.5	Periodic reviews of deemed equity ratios	19
6	Notional ROE and other formula variables	20
6.1	Overview	20
6.2	Comparability of representative utilities.....	21
6.3	Measure of the risk-free rate	22
6.4	Notional ROE.....	25
6.4.1	The CAPM	26
6.4.1.2	CAPM inputs	27
6.4.2	Constant growth DCF model	31
6.4.2.1	Constant growth DCF inputs	32
6.4.3	Multi-stage DCF model	34
6.4.3.1	Multi-stage DCF inputs	35
6.4.4	Other risk premium models	36
6.4.5	Notional ROE and base forecast ERP.....	38
6.5	Other variables of the formulaic approach.....	40
6.5.1	Adjustment factors for changes in GoC bond yield and utility bond yield spread	40
6.5.2	Base and test year values for long-term GoC bond yield	42
6.5.3	Base and test year values for utility bond yield spread.....	42
7	Capital structure	44
7.1	Overview, approved deemed equity ratios for 2024, and review timeframe.....	44
7.2	Requested deemed equity ratios.....	44
7.3	Targeted credit ratings	47
7.4	Credit metrics.....	48
7.4.1	Equity ratios associated with credit metrics.....	50
7.5	Overall assessment of business risk.....	58
7.5.1	Macroeconomic factors.....	58

7.5.2	Regulatory risk.....	59
7.5.3	Utility asset disposition risk and the impact of the Court of Appeal decision in <i>ATCO Electric Ltd. v Alberta Utilities Commission</i> , 2023 ABCA 129.....	59
7.5.4	Decarbonization	60
7.6	Utility-specific business risks	61
7.6.1	Determination of Commission-approved deemed equity ratio for Fortis	61
7.6.2	Determination of Commission-approved deemed equity ratio for Apex.....	62
8	Order	64
	Appendix 1 – Proceeding participants	66
	Appendix 2 – Oral hearing – registered appearances	68
	Appendix 3 – Summary of Commission directions.....	69

List of tables

Table 1.	Risk-free rate recommendations	23
Table 2.	Notional ROE and ERP recommendations by party	25
Table 3.	CAPM recommendations by party	26
Table 4.	Constant growth DCF recommendation by party.....	32
Table 5.	Multi-stage DCF recommendations of parties.....	35
Table 6.	Notional ROE and base forecast ERP from financial models.....	38
Table 7.	Currently approved deemed equity ratios and the deemed equity ratios recommended for 2024.....	45
Table 8.	Parameters for calculating credit metrics	51
Table 9.	Embedded average debt rates, depreciation rates and CWIP percentages by utility	52
Table 10.	Additional analysis of information included in Table 9.....	53
Table 11.	Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision).....	55
Table 12.	Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of zero	55
Table 13.	Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision).....	56

Table 14. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of zero	56
Table 15. Commission guidelines for equity ratios to achieve a credit rating in the A-range	57

1 Decision summary

1. In this generic cost of capital (GCOC) decision, the Alberta Utilities Commission adopts a formulaic approach, utilizing the equity risk premium (ERP) methodology, to calculate the fair rate of return on equity (ROE) for Alberta's electric and gas utilities in 2024 and beyond. The Commission has determined that the ROE resulting from the formulaic approach will uniformly apply to all of the utilities.

2. This decision also outlines the approved deemed equity ratios (sometimes referred to by parties as "equity thickness"; collectively, the ROE and equity ratios, are referred to as "cost-of-capital parameters") for the utilities on a final basis. Specifically, accounting for differences in the risk of each of the utilities, the Commission has determined that no change is required to the deemed equity ratios approved in the 2018 GCOC decision.¹

3. The Commission institutes a mandatory review of cost-of-capital parameters every five years, subject to mid-term reopeners either at its own discretion or upon application from interested parties. The established cost-of-capital parameters will apply to the following utilities:

- AltaLink Management Ltd.
- Apex Utilities Inc.
- ATCO Electric Ltd.
- ATCO Gas and Pipelines Ltd.
- ENMAX Power Corporation
- EPCOR Distribution & Transmission Inc.
- FortisAlberta Inc.
- KainaiLink L.P.
- City of Lethbridge
- PiikaniLink L.P.
- The City of Red Deer
- TransAlta Corporation

4. The Commission's decision to implement the formulaic approach for ROE determination is driven by a commitment to reduce regulatory lag and regulatory burden, enhance transparency, and deliver regulatory certainty, while balancing the interests of all stakeholders. This approach is a significant step for GCOC proceedings towards a more efficient, predictable and cost-effective regulatory process that ultimately benefits ratepayers, utilities and the broader public interest in Alberta.

¹ Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018.

5. The Commission approves the following formulaic approach to determine the ROE in 2024 and subsequent years:

$$ROE_t = 9.0\% + 0.5 \times (YLD_t - 3.10\%) + 0.5 \times (SPRD_t - SPRD_{base})^2$$

6. That is, in each year, the approved ROE will be determined by adjusting the notional ROE of 9.0 per cent approved in this decision by the difference in forecast long-term Government of Canada (GoC) bond yield (YLD_t) and utility bond yield spread ($SPRD_t$) from their base values of 3.10 per cent and the bond yield spread for the month of February 2023, respectively. These forecasts will be calculated by the Commission in early November of each year as follows:

- (i) The forecast long-term GoC bond yield will be calculated as the weighted average of (a) the 30-year GoC bond yield forecasts published by Royal Bank of Canada (RBC), TD Bank (TD) and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (b) the naïve forecast³ representing the average long-term GoC bond yield⁴ over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.
- (ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield⁵ and the long-term GoC bond yield⁶ over the period October 1 to October 31 of each year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

7. The cost-of-capital parameters for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other proceedings should issues respecting ROE and deemed equity ratios arise for these utilities.

2 Background and procedural summary

8. On January 3, 2022, the Commission established a bifurcated process for this proceeding with the goal of determining ROE and deemed equity ratios. The first part of the proceeding (Stage 1) established the cost-of-capital parameters for 2023 and was completed on March 31, 2022, with the release of Decision 27084-D01-2022.⁷ This decision addresses the second part of the proceeding (Stage 2), establishes a formulaic approach for setting ROE in 2024 and each year

² The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.

³ A "naïve forecast" is a forecasting method that uses actual values from a previous period.

⁴ Bank of Canada CANSIM Series V39056.

⁵ Bloomberg Series C29530Y.

⁶ Bank of Canada CANSIM Series V39056.

⁷ Decision 27084-D01-2022: 2023 Generic Cost of Capital, Proceeding 27084, March 31, 2022.

thereafter, and sets the deemed equity ratios for the utilities. More specifically, the scope of Stage 2 comprised the following key objectives:

- Explore potential formula-based approaches for determining the ROE and identify a preferred formulaic method. This approach was intended to enhance transparency and predictability, ultimately saving both customers and Alberta utilities significant time, resources and costs associated with conducting fully litigated proceedings every one to three years.
- Establish the initial numerical variables required for the formula. This included defining an initial base, or notional ROE, that would form an integral part of the formula and serve as the basis for determining the ROE for the 2024 and future test years.
- Delineate the process for calculating the ROE in future test years while ensuring clarity and consistency in the methodology.
- Identify future processes or thresholds that would trigger a review of the formulaic approach and any necessary adjustments by the Commission, should such adjustments be deemed necessary.
- Evaluate whether the Commission should revise deemed equity ratios while employing a formulaic approach to determining the ROE.

9. By pursuing these objectives, the Commission aimed to provide a more structured and efficient framework for determining ROE and related parameters for 2024 and beyond.

10. Each of the utilities, except Lethbridge, Red Deer, TransAlta, KainaiLink L.P. and PiikaniLink L.P., actively participated in this proceeding. ATCO Electric and ATCO Gas (ATCO Utilities), Apex and Fortis co-sponsored the evidence of Dr. Bente Villadsen and Frank Graves. Apex also sponsored the stand-alone evidence of Michael Tolleth. AltaLink and EPCOR co-sponsored the evidence of Dylan D'Ascendis. ENMAX sponsored the evidence of Concentric Energy Advisors, Inc. (James Coyne and John Trogonoski) and Nicole Martin. Additionally, each of Apex, Fortis and the ATCO Utilities filed company-specific evidence.

11. The Consumers' Coalition of Alberta (CCA), the Office of the Utilities Consumer Advocate (UCA), and the Industrial Power Consumers Association of Alberta (IPCAA) (collectively, the interveners or customer groups) also actively participated in the proceeding. The CCA sponsored the evidence of Jan Thygesen; the UCA sponsored the evidence of Dr. Sean Cleary and Russ Bell; and IPCAA sponsored the evidence of Dustin Madsen.

12. To assist with the development of a comprehensive record and to prevent prolonged and unproductive debates among the parties regarding the suitability of various utility comparator groups used to construct models for estimating the fair ROE for Alberta utilities, the Commission took a proactive approach. At the outset of Stage 2 of the proceeding, on October 14, 2022, the Commission organized a technical conference for parties (involving participants from utilities and customer groups) with the primary purpose to discuss and formulate a comparator group of representative utilities that would inform the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE.

13. The outcome of the discussions during the technical conference was documented in appendixes A and B of the Commission's letter, dated October 24, 2022,⁸ which captured the consensus among parties regarding the Commission's proposed screening criteria for determining a comparator group. The appendixes also highlighted other areas where consensus was achieved or, in some instances, where consensus was not achieved. While agreement was reached on the majority of topics discussed at the technical conference, some matters still required further input from all parties. These additional submissions were subsequently received by the Commission on November 2, 2022.

14. On November 10, 2022, the Commission issued its determinations on the unresolved matters and, using the approved screening criteria, produced the list of comparator utilities. The Commission also circulated to parties a preliminary list of issues to be considered in this proceeding and provided parties the opportunity to highlight any material issues they believed the Commission should consider in Stage 2 of this proceeding that had not been identified in the list. Based on parties' feedback, a finalized issues list for Stage 2 of this proceeding was released on November 29, 2022, which parties used as a foundation for their evidentiary submissions.

15. In addition to having parties file evidence, the Commission's processes included information requests (IRs) and responses to evidence filed and/or sponsored by the utilities; IRs and responses to evidence sponsored by the interveners; concurrent rebuttal evidence filed by the utilities and interveners; and a one-week virtual oral hearing. The Commission also established a process for simultaneous written argument and reply argument. The Commission considers that the record of this proceeding closed with the filing of reply arguments on July 11, 2023.

16. The Commission reviewed the entire record in coming to this decision; lack of reference to a matter addressed in the evidence and submissions does not mean that the Commission did not consider it.

3 Fair return standard

17. The legislation that governs the Commission requires that it fix just and reasonable rates for the utilities it regulates.⁹ The Commission is guided in this task by well-developed case law on the meaning of just and reasonable rates, which includes determining a fair return on the equity component of invested capital, or the fair return standard. These concepts are set out in three seminal decisions: the Supreme Court of Canada's decision in *Northwestern Utilities v Edmonton (City)*,¹⁰ and two cases from the Supreme Court of the United States, *Bluefield*

⁸ Exhibit 27084-X0239.01.

⁹ See Section 89 of the *Public Utilities Act*; Section 36(a) of the *Gas Utilities Act*; and Section 121(2)(a) of the *Electric Utilities Act*. Note that the *Electric Utilities Act* also requires the Commission to provide an owner of an electric utility with a reasonable opportunity to recover a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)). The *Gas Utilities Act* and the *Public Utilities Act* requires the Commission to fix a fair return on the rate base (Section 37(1)). The Commission considers these statutory requirements to be the same.

¹⁰ *Northwestern Utilities v Edmonton (City)* [1929] SCR 186 (*Northwestern Utilities*).

Waterworks and Improvement Company v Public Service Commission of the State of West Virginia,¹¹ and *Federal Power Commission v Hope Natural Gas Company*.¹²

18. In *Northwestern Utilities*, the Supreme Court of Canada addressed whether a board had correctly set the rate for a utility. In enunciating the meaning of “fair return,” the court wrote:

By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company’s enterprise.¹³

19. A similar statement was made by the Supreme Court of the United States in *Bluefield*:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ...¹⁴

20. In *Hope*, the Supreme Court of the United States also spoke to comparable investments, as well as the importance of financial integrity and capital attraction:

The ratemaking process under the Act, *i.e.*, the fixing of “just and reasonable” rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the *Natural Gas Pipeline Co.* case that “regulation does not insure that the business shall produce net revenues.”... But, such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.¹⁵ [footnotes omitted]

21. The requirements of comparable investments, financial integrity, and capital attraction remain fundamental to setting a fair return. The Commission and its predecessors have employed

¹¹ *Bluefield Waterworks and Improvement Company v Public Service Commission of the State of West Virginia*, 262 US 679 (1923) (*Bluefield*).

¹² *Federal Power Commission v Hope Natural Gas Company*, 320 US 591 (1944) (*Hope*).

¹³ *Northwestern Utilities*, page 193.

¹⁴ *Bluefield*, page 692.

¹⁵ *Hope*, page 603.

these principles in setting rates of return,¹⁶ and other regulators also apply these principles.¹⁷ All three components must be satisfied to arrive at a fair return.

22. While satisfying these principles is fundamental to arriving at a fair return, the foundational cases also highlight the importance of ensuring that the interests of utilities are considered with those of consumers, in order to ensure that rates are just and reasonable. In *Northwestern Utilities*, the court wrote that the board had a duty to “to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested.”¹⁸ Similarly, in *Hope*, the court stated that “... the fixing of ‘just and reasonable rates’ involves a balancing of the investor and consumer interests.”¹⁹

23. The National Energy Board outlined the balancing exercise as follows:

To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline [natural gas transmission system] to recover its costs because it has understated the Mainline’s cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the Mainline’s point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline’s customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring that the Mainline’s costs are not overstated.²⁰

24. The Commission must therefore set a rate of return, and ensure that the fair return requirements of comparable investments, financial integrity, and capital attraction are satisfied, while also being mindful of the need to ensure that rates are just and reasonable for both the utilities and consumers. As noted by the Commission in the 2018 GCOC decision:

The Commission exercises its judgment in determining a total return for each utility to establish rates that provide the utility a reasonable opportunity to earn a fair return on invested capital while ensuring that rates are just and reasonable so that customers are not paying more than is required to maintain safe, reliable and economic service.²¹

25. The Commission must therefore review all evidence before it, in order to ensure that it achieves the three fundamental requirements in setting a fair return, while at the same time ensuring that the decision it arrives at results in rates that are just and reasonable for both utilities and consumers.

¹⁶ Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Application 1271597, July 2, 2004, page 13. See also Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571, November 12, 2009, which provided an extensive discussion of the fair return standard at paragraphs 82-109.

¹⁷ See National Energy Board Decision RH-2-2004, Reasons for Decision, TransCanada Pipelines Limited, Phase II, Released: April 2005.

¹⁸ *Northwestern Utilities*, pages 192-193.

¹⁹ *Hope*, page 603.

²⁰ *TransCanada Pipelines Limited v Canada (National Energy Board)*, 2004 FCA 149 (*TransCanada Pipelines*), paragraph 34.

²¹ Decision 22570-D01-2018, paragraph 37.

26. The Commission has significant discretion in addressing this complex task. In *Bluefield*, the court wrote that “(w)hat annual rate will constitute just compensation depends on many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts.”²² In a concurring judgment in the *Northwestern Utilities* case, Justice Smith noted that “[t]he question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board.”

27. There were 949 exhibits filed in this proceeding, and thousands of pages of evidence and submissions. There were significant matters of dispute between the parties and expert opinion that differed on critical points. The Commission must consider and weigh this evidence, and applying its judgment, make decisions that meet the fair return standard, and result in just and reasonable rates. As noted by Justice Rothstein of the Federal Court of Appeal:

... In cost of capital proceedings, the Board is entitled, on the basis of the evidence before it and the use of its own judgment, to choose a methodology for determining cost of capital and to estimate the cost of capital for a forthcoming year. Very often, the Board’s estimate will not reflect the precise estimates of one side or the other or of one witness or another. Having regard to all the evidence, the Board will determine its own estimate.²³

4 Relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision

28. In this section, the Commission considers changes in economic and market conditions, both global and domestic, since the 2018 GCOC decision. Macroeconomic conditions, such as economic growth and interest rates, factor into the Commission’s determination of an approved fair cost of capital because they are inputs in the models used to develop those costs.

29. In this proceeding, there was a general consensus among witnesses that the COVID-19 pandemic, and the varied responses to it in different countries, produced uncertain and volatile macroeconomic and capital market conditions not just in Canada or North America, but worldwide. This instability was compounded by government and central bank policies that, first, attempted to stabilize economic activity and then reacted to a quick economic rebound as the pandemic subsided. The U.S. and Canadian central banks lowered policy interest rates at the onset of the pandemic to promote economic activity while also purchasing bonds to stabilize debt markets (this asset-purchasing transaction is commonly referred to as quantitative easing). When the pandemic subsided in 2022, central banks increased interest rates in response to higher inflation and reduced their bond holdings (quantitative tightening). The Commission observes that economies and capital markets are still managing the residual fallout of the pandemic.

30. In the 2018 GCOC decision, the Commission concluded that global and Canadian economic conditions had improved since the 2016 GCOC proceeding.²⁴ The Commission made note of global and national economic growth, reduced market volatility, a modest increase in the 30-year GoC bond yield, and a compression in credit spreads. However, having regard to

²² *Bluefield*, page 692.

²³ *TransCanada Pipelines*, paragraph 58.

²⁴ Decision 22570-D01-2018, paragraph 192.

downward pressure from other factors, the Commission found that the approved ROE for 2018 should be set at or near that of the 2016 proceeding.²⁵

31. The evidence in this proceeding is that macroeconomic and capital market conditions are somewhat less favourable now than they were at the time the 2018 GCOC decision was issued. However, the Commission views the current conditions as transitional and likely to improve as inflation abates and the economy adjusts to higher interest rates than the abnormally low rates that prevailed in the relatively recent past.

32. The Commission agrees that higher inflation and higher interest rates since 2018 have created uncertainty in the broader economy, which is reflected in market volatility and in the Bank of Canada's (BoC) expectation for lower growth in 2023 and 2024. The credit spread between A-rated utilities and government bonds has also increased somewhat, demonstrating investors' concerns about the macroeconomic conditions for utilities. Capital market volatility, although having moderated recently, could flare up again until investors are once again confident that conditions have stabilized.

33. The Commission acknowledges the risk of a recession, but defers to the BoC's guidance as submitted by Dr. Cleary and Dr. Villadsen that economic growth will continue albeit at a slower pace. The Commission also notes that Alberta is resource dependent and agrees with Dr. Cleary's assessment that the anticipated economic slowdown in the rest of Canada will be less pronounced in Alberta as a result.

34. The Commission expects a normalization in macroeconomic conditions, including a sustained, if uneven, amelioration in the pace of inflation. As well, the Commission expects an eventual halt, then partial reversal, in the BoC's policy interest rate hikes at, or not much beyond, the level at which rates presently stand. Lower gross domestic product (GDP) growth is expected to reduce demand in the economy and, consequently, inflationary pressures as well. The Commission expects that the BoC will achieve its inflationary target; however, timelines for meeting that target remain unclear. As macroeconomic conditions stabilize, capital market conditions are expected to respond in kind with lower volatility and stabilizing bond yields. The Commission expects a higher interest rate environment for longer, which would be reflected in higher utility bond yields relative to 2018. However, the Commission agrees with J. Thygesen's contention that a slower growth environment or a recession may require the BoC or the Federal Reserve in the U.S. to reduce interest rates, which would put downward pressure on future utility bond yields, all else being equal.

35. Even accepting that there has been a deterioration in macroeconomic conditions since 2018, the Commission finds that many economic indicators (among them prolonged disruptions in global supply chains; pronounced volatility in prices for energy, grain and other foodstuffs; widespread workforce dislocations; health concerns; and pressures on medical systems, etc.) have begun stabilizing to a greater or lesser extent since the height of the pandemic and Russia's invasion of Ukraine. In addition, of the remaining post-pandemic economic shocks, including higher interest rates and inflation in excess of the BoC's target range, the Commission finds that

²⁵ Decision 22570-D01-2018, paragraph 206.

Alberta's regulatory framework has, to a significant extent, shielded Alberta utilities from much of the impact of these systematic risks.²⁶

36. The fact that a supportive regulatory environment can provide significant protection to utilities from rising costs occasioned by adverse macroeconomic changes is demonstrated by robust returns achieved by Alberta utilities during the pandemic years 2020 to 2022.²⁷ While many competitive industries were particularly hard hit by pandemic-related dislocations, Alberta regulated utilities appear to have avoided any significant harm and, indeed, experienced positive financial results throughout.

37. All parties provided evidence on relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision. Sections 4.1 to 4.4 that follow briefly summarize parties' submissions focusing on inflation, economic growth, bond yields and capital markets upon which the Commission has based its analysis and conclusions.

4.1 Inflation

38. Three utility witnesses (D. D'Ascendis, Dr. Villadsen and J. Coyne) identified high inflation as a primary risk to the economy in general, and to utility capital costs in particular. In their argument, ATCO-Fortis-Apex noted that inflation peaked in June 2022, at 8.1 per cent in Canada and remains above the BoC target range of one to three per cent.²⁸ The BoC, in response to higher inflation, increased its policy interest rate more than nine times since March 2022²⁹ and began quantitative tightening.³⁰ J. Coyne noted that while inflation has abated from its peak in 2022, inflationary pressures remain in the economy, which contributes to market instability.³¹ D. D'Ascendis concluded that increased inflation and BoC policy interest rates, among other factors, reflected a higher level of market risk compared to 2018.³² Dr. Villadsen noted that Moody's Investors Service revised its outlook for the U.S. regulatory utility sector to negative because higher inflation may limit a utility's ability to recover its costs absent regulatory support.³³ All utility witnesses viewed high inflation as a risk factor contributing to higher capital costs.

39. J. Thygesen stated in his evidence that he interpreted the BoC Governor Tiff Macklem's comments as foreshadowing a pause in the central bank's policy interest rate increases and that lower inflation was expected.³⁴ EPCOR challenged this claim by noting that policy interest rates

²⁶ See, for example, the oral testimony of D. Madsen for IPCAA on this point at Transcript, Volume 2, page 505. See also, Exhibit 27084-X0918, IPCAA argument, PDF page 18.

²⁷ Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

²⁸ Exhibit 27084-X0921, ATCO Electric Ltd. - The Utilities Argument, June 6, 2023, PDF page 5, paragraph 13.

²⁹ Exhibit 27084-X0921, ATCO Electric Ltd. - The Utilities Argument, June 6, 2023, PDF page 5, paragraph 13.

³⁰ The Commission notes that since the utilities submitted their argument on June 26, 2023, the BoC raised interest rates one additional time to 5.00% on July 12, 2023. Bank of Canada, <https://www.bankofcanada.ca/core-functions/monetary-policy/key-interest-rate/>

³¹ Exhibit 27084-X0743, ENMAX Power Corporation – Reply evidence Concentric, April 4, 2023, PDF page 18.

³² Exhibit 27084-X0390, AltaLink - EDTI evidence D'Ascendis written direct testimony, February 1, 2023, PDF page 120.

³³ Exhibit 27084-X0469.01, The Utilities Evidence – Villadsen, May 26, 2023, PDF page 24.

³⁴ Exhibit 27084-X0305, CCA evidence of Jan Thygesen, February 1, 2023, PDF page 10, paragraph 26.

had increased since J. Thygesen's evidence was submitted.³⁵ However, the Commission observes that inflation had, in fact, decreased in June 2023 from its June 2022 high.³⁶

40. Dr. Cleary acknowledged that inflation was high in 2022, but argued that it peaked and that the BoC's expectation is for a return to sub three per cent inflation going forward. He supported his contention by stating that higher central bank policy interest rates are reducing inflationary pressures and, consequently, that central banks are now in the later stages of their quantitative tightening cycle.³⁷

41. D. Madsen explained at the hearing that Alberta utilities are geographically and jurisdictionally constrained. Therefore, an Alberta-based utility's ability to recover its prudent costs is dependent on the regulator. His contention is that in a supportive regulatory environment, macroeconomic conditions do not materially affect a utility's ability to recover its costs and, therefore, a utility experiences no meaningful increase in risk due to inflation.³⁸

4.2 Economic growth

42. Slower economic growth, due in part to the actions of the central banks, was another key issue identified by witnesses. Generally, all witnesses agreed that lower economic growth is likely in Canada in 2023 and 2024, with a higher probability of a recession.

43. The utility witnesses contended that investors are concerned about a recession, based on the current macroeconomic conditions. J. Coyne noted that the U.S. already experienced a technical recession in 2022, which demonstrated weaker fundamentals in the economy and that the BoC is projecting lower growth in 2023 and 2024.³⁹ J. Coyne also referred to the inverted yield curve – higher short-term bond yields than long-term bond yields in the U.S. and Canada – as an indicator of investor concerns about a recession.⁴⁰ D. D'Ascendis stated that recessions create more inherent risk for investors because negative economic growth may put at risk a commensurate return.⁴¹ Dr. Villadsen cited the BoC's January 2023 Monetary Policy Report, which forecast Canada GDP growth of one per cent in 2023 and 1.8 per cent in 2024, which is lower than the 3.6 per cent growth experienced in 2022.⁴² All utility witnesses argued that the macroeconomic uncertainty due to inflation and monetary tightening increases the cost of capital because the market is riskier in that state.

44. J. Thygesen agreed that while there is an elevated expectation of a recession in the U.S., citing the Conference Board, Federal Reserve St. Louis and Federal Reserve New York, were a recession to occur, some or all of the associated risks would be offset by lower interest rates.⁴³

45. Dr. Cleary noted that Alberta's economic outlook was appreciably better than that of other provinces and, in fact, was unlikely to be recessionary. In support, he cited the Conference

³⁵ Exhibit 27084-X0928, AltaLink and EPCOR Final Argument, June 26, 2023, paragraph 35.

³⁶ Exhibit 27084-X0911, AltaLink and EPCOR Undertaking Appendix – Risk Measures Table Updated, June 8, 2023, worksheet 'Summary'.

³⁷ Exhibit 27084-X0320.02, Cleary evidence, PDF page 25. Transcript, Volume 3, page 645, lines 13-18.

³⁸ Transcript, Volume 2, page 505.

³⁹ Exhibit 27084-X0315, Concentric evidence, PDF pages 31-35.

⁴⁰ Exhibit 27084-X0585, Concentric Responses to UCA IRs, March 15, 2023, Concentric-UCA-2023FEB21-011.

⁴¹ Exhibit 27084-X0750, D'Ascendis rebuttal evidence PDF pages 18-19.

⁴² Exhibit 27084-X0469.01, Villadsen evidence, PDF page 22.

⁴³ Exhibit 27084-X0736, Thygesen rebuttal evidence, PDF pages 15-17, paragraphs 40-42.

Board of Canada's December 2022 Alberta outlook, which predicts higher positive growth compared to the rest of Canada due to continued strength in the oil and gas sector.⁴⁴

4.3 Bond yields

46. All witnesses agreed that as the BoC policy interest rate has increased, so too have bond yields – both corporate and government. There was also agreement among witnesses that the spread between A-rated utility bond yields and government bond yields (credit spread) has increased in the U.S. and Canada since 2018.

47. J. Coyne argued that the increased credit spread reflects investor concerns about the credit quality of utility bonds and general uncertainty about the broader economy.⁴⁵ Dr. Villadsen noted that the last time credit spreads were at this level or higher was in the spring of 2020 when the pandemic began riling financial markets, which is an indication of investor caution.⁴⁶ Dr. Cleary acknowledged that the credit spread is slightly higher than historical averages, measured since 2003.⁴⁷

4.4 Capital markets

48. Over the course of the pandemic and into the recovery from it, Canadian and U.S. capital markets experienced volatility and, at times, counterintuitive results.

49. The utility witnesses argued that capital market volatility underwent periods of extreme flux during and after the pandemic due to complex market conditions, which reflected a greater level of investor uncertainty. D. D'Ascendis compared the average VIXI and VIX (indices that measure the Canadian and U.S. stock market's expectation of volatility) between 2018 and 2022, and observed that the indices were higher in 2022, reflecting increased volatility.⁴⁸ Dr. Villadsen explained that market volatility peaked during the early stages of the pandemic, declined from its pandemic highs, and increased again once the economy reopened.⁴⁹

50. Dr. Cleary contended that in Canada the VIXI is currently below its normal range, while in the U.S. the VIX is slightly higher than usual.⁵⁰ He also pointed out that current corporate price earnings ratios and dividend yields are consistent with historical averages, suggesting that capital markets are healthy.⁵¹

5 Formulaic approach to determine ROE

5.1 The need for a formulaic approach to setting ROE

51. Over the past two decades, the Commission and its predecessors have employed various methodologies to set the approved ROE and deemed equity ratios. Prior to 2004, the

⁴⁴ Exhibit 27084-X0320.02, Cleary evidence, PDF page 33.

⁴⁵ Exhibit 27084-X0743, Concentric rebuttal evidence, PDF pages 22-23.

⁴⁶ Exhibit 27084-X0469.01, Villadsen evidence, PDF page 33.

⁴⁷ Exhibit 27084-X0320.02, Cleary evidence, PDF page 20.

⁴⁸ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 120.

⁴⁹ Exhibit 27084-X0469.01, Villadsen evidence, PDF page 35.

⁵⁰ Exhibit 27084-X0320.02, Cleary evidence, PDF page 23. Note that Dr. Cleary refers to the VIXI as the "Canadian VIX."

⁵¹ Exhibit 27084-X0320.02, Cleary evidence, PDF page 22.

Commission's predecessors determined these parameters individually for each utility on a case-by-case basis.

52. In 2004, the Alberta Energy and Utilities Board (EUB), predecessor to the Commission, established a uniform (generic) ROE rate for all utilities and introduced a formulaic approach to determine subsequent ROE values.⁵² This formulaic approach was used from 2005 to 2008. As a result of the global financial crisis in 2008-2009, in Decision 2009-216, the Commission discontinued the formulaic approach because it produced results that no longer accurately reflected changes in market circumstances. Specifically, the Commission observed that during the financial crisis, the traditional relationship between the risk-free rate and the required market return, on which the formulaic approach was based, did not hold.⁵³

53. From 2009 through 2020, the Commission determined the ROE and deemed equity ratios by relying on evidence presented by parties in the GCOC proceedings. In doing so, the Commission retained the practice established in 2004 of setting a generic ROE for all utilities and accounting for any differences in business risks among the utilities through the deemed equity ratios. These parameters were established through rigorous regulatory proceedings, which included extensive oral hearings, where parties submitted a wide spectrum of economic and financial evidence. For the period 2021 to 2023, the Commission did not have fully litigated GCOC proceedings. Rather, it maintained the ROE of 8.5 per cent and a deemed equity ratio of 37 per cent (39 per cent for Apex) in light of the uncertainty arising from the pandemic and the limited access to stable, reliable, current and forward-looking economic and market data at the time.

54. Even though the Commission discontinued the formula in Decision 2009-216, it indicated that, to reduce regulatory burden, it would not "preclude a return to some sort of formula-based adjustment mechanism in the future when relationships in the capital markets have stabilized and are once again considered reasonably predictable."⁵⁴ After the effects of the 2008 financial crisis had abated, the Commission revisited the idea of implementing an ROE formulaic approach in almost every subsequent GCOC proceeding. However, in each of those instances, the Commission determined that a return to an ROE formulaic approach was not warranted. In earlier GCOC proceedings, this was due to the remaining volatility in the markets⁵⁵ and abnormal risk-return relationship attributable to ultra-low interest rates.⁵⁶ In later GCOC proceedings, the key obstacle was the onset of the pandemic and its associated economic dislocations.⁵⁷ Nevertheless, in every GCOC decision the Commission expressed its continued interest in exploring the reinstatement of an ROE formulaic approach given its administrative efficiency.

55. The Commission initiated the current proceeding with the view that a formulaic approach could offer a substantial improvement in efficiency with no loss in rigour or objectivity in determining the ROE component of the utilities' fair return. The fact that many jurisdictions have already adopted such an approach supported the Commission's view. In its directions on

⁵² Decision 2004-052.

⁵³ Decision 2009-216, paragraph 417.

⁵⁴ Decision 2009-216, paragraph 422.

⁵⁵ Decision 2011-474, paragraph 165.

⁵⁶ Decision 2191-D01-2015, paragraph 411.

⁵⁷ Decision 24110-D01-2020: 2021 Generic Cost of Capital, Proceeding 24110, October 13, 2020, paragraphs 5, 7. Decision 26212-D01-2021: 2022 Generic Cost of Capital, Proceeding 26212, March 4, 2021, paragraph 18.

procedure letter,⁵⁸ the Commission asked whether ERP-based formulaic approaches, such as those adopted by the Ontario Energy Board (OEB) and the Commission's predecessor, the EUB, were an appropriate starting point for considering the reintroduction of an ROE formulaic approach in Alberta.

56. Most, if not all parties to this proceeding, were relatively unenthusiastic about, if not rather firmly opposed to, any Commission departure from holding periodic, fully litigated GCOC proceedings and moving instead towards adopting a formulaic approach for setting the ROE in 2024 and subsequent years. Nonetheless, over the course of this proceeding, parties were helpful to the Commission and provided their recommendations on specific parameters of a formulaic approach should the Commission ultimately decide to implement one, even though this was not their preference.

57. After considering various perspectives and parties' views, the Commission finds it will implement the formulaic approach for determining the ROE, starting in 2024. For the reasons set out below, the Commission is of the view that this approach offers a balanced and pragmatic solution to several pressing concerns.

58. Among the most important advantages of adopting a formulaic approach is the elimination of regulatory lag in establishing regulated rates. By setting the approved ROE on a prospective basis, the formulaic approach avoids delays, ensures that rates better reflect current economic conditions, offers greater regulatory certainty to utilities and customers alike, mitigates the risk of adverse credit rating actions, and reduces volatility in cash flows. Every one of these concerns has been raised by parties in past GCOC proceedings, including the most recent fully litigated one in 2018, as being among the negative consequences of regulatory lag.⁵⁹

59. Furthermore, the formulaic approach enhances transparency and predictability in the regulatory process. It streamlines decision making by providing a clear and objective mechanism for determining the approved ROE, while reducing the need for protracted, resource-intensive, and costly litigated proceedings.⁶⁰ By doing so, it not only saves significant time and resources for both customers and utilities, but also aligns with the Commission's broader goal of improving efficiency and reducing regulatory burden.

60. The Commission reaffirms its commitment to exercising regulatory judgment, addressing concerns expressed by many parties that there must be an opportunity to review the ROEs produced by the formulaic approach for reasonableness as a safety feature. Should any party determine that the formulaic approach no longer results in just and reasonable outcomes, Section 5.4 below outlines a mechanism by which parties can apply to the Commission for corrective action.

⁵⁸ Exhibit 27084-X0034, paragraph 9.

⁵⁹ Decision 22570-D01-2018, Section 9.3.2.4, Regulatory lag.

⁶⁰ For example, for the most recent fully contested GCOC proceeding in 2018, the Commission approved cost awards amounting to just over \$1.5 million. The Commission's scale of costs does not cover the full costs of most experts and legal counsel for proceedings, and the amounts claimed and awarded therefore do not reflect the real cost of participation. A review of actual invoices submitted in the 2018 GCOC costs proceeding indicates that parties to that proceeding spent a total of about \$4 million on external legal counsel and experts. This does not account for the significant costs incurred by the parties internally, nor the costs of other parties (such as the UCA) who do not submit cost claims to the Commission, nor the costs of the Commission itself and its processes (costs which are ultimately borne by customers).

61. The record in this proceeding is clear that a variety of formulaic approaches are used in other jurisdictions. Experience in these jurisdictions, notably Ontario, suggests that a properly calibrated formulaic approach can operate effectively over a sustained period of time, producing ROE results that meet the fair return standard, without the associated costs and complexities of a fully litigated process. If a formulaic approach produces reasonable outcomes and its adoption avoids one or two exhaustive fully litigated proceedings, thereby contributing to the reduction in regulatory burden and cost, this would be a significant advancement compared to the current approach of initiating litigated cases every two to three years.

5.2 ROE formulaic approach

62. As noted in the previous section, in its directions on procedure letter,⁶¹ the Commission put to parties the ERP-based formulaic approaches adopted by the EUB and the OEB as possible starting points for reintroducing an ROE formulaic approach.

63. In Decision 2004-052, the EUB adopted a single-factor formulaic approach for setting the generic ROE based on 75 per cent of the change in long-term GoC bond yield:

$$ROE_t = 9.60\% + 0.75 \times (YLD_t - 5.68\%)$$

64. The EUB established a generic ROE for the year 2004 at 9.60 per cent, which served as the initial or “base” ROE value in the above formula. An adjustment factor of 0.75 was determined through an assessment of the proposals submitted by the involved parties at the time. The final element of the formula encapsulated variation in forecast long-term Canada bond yield, calculated as the difference between the current year Consensus Forecasts⁶² (denoted as YLD_t in the formula above) and the “base” yield of 5.68 per cent that was set based on forecasts deemed reasonable in the 2004 decision.

65. In its Decision EB-2009-0084,⁶³ the OEB approved the following formula:

$$ROE_t = 9.75\% + 0.5 \times (LCBF_t - 4.25\%) + 0.5 \times (\text{UtilBondSpread}_t - 1.415\%)$$

66. The OEB’s formula established a “base” ROE of 9.75 per cent for the year 2010. The OEB approved an adjustment factor of 0.5 with respect to changes in long-term GoC bond yield, reducing it from the previously established value of 0.75. This change was made to decrease the formula’s sensitivity to changes in government bond yields, which could be influenced by monetary and fiscal conditions unrelated to shifts in the utility cost of equity. In addition, the OEB acknowledged the existence of a statistically significant correlation between corporate bond yields and the cost of equity, and incorporated an element related to utility bond yields with an adjustment factor of 0.5.

67. As discussed in the previous section, while no utility witnesses expressly supported the use of a formula to determine the ROE, they provided evidence on specifications for a formulaic

⁶¹ Exhibit 27084-X0034, paragraph 9.

⁶² Consensus Forecasts are published by Consensus Economics.

⁶³ Ontario Energy Board Decision EB-2009-0084: Report of the Board on the Cost of Capital for Ontario’s Regulated Utilities, December 11, 2009.

approach should the Commission decide to proceed with one. Such evidence was also provided by the customer groups to a certain degree.⁶⁴

68. Concentric indicated that, “If the AUC decides on an ERP approach, then the formula used in Ontario that includes both government bond yields and utility credit spreads is a reasonable compromise.”⁶⁵ D. Madsen⁶⁶ expressed a similar view. As well, Dr. Villadsen recommended that changes in the long GoC bond yield and changes in the utility bond yield spread be included in the formula, much as they are in the OEB’s methodology, as both factors influence the cost of equity.⁶⁷

69. D. D’Ascendis found an ERP-based approach to be a suitable starting point for developing a formula to adjust an appropriately derived “base” ROE. Of the two examples set forth by the Commission, he found the OEB’s two-factor adjustment formula to be superior to the one-factor adjustment formula used by the EUB, as it more closely reflects the relationship between interest rates and the ERP.⁶⁸ However, in his evidence, D. D’Ascendis recommended that the Commission broaden the basis of the ROE adjustment mechanism and use market data in the DCF model and capital asset pricing model (CAPM) for a group of risk comparable companies in lieu of a simple ERP model that is based on the change in bond yields.⁶⁹

70. In his evidence, Dr. Cleary, submitted that the ERP-based approach is the most suitable formulaic method for determining allowable ROEs. He asserted that this approach is widely adopted and, in his perspective, it stands as the sole viable option. Furthermore, Dr. Cleary underscored that the OEB formula can be viewed, in essence, as a modified version of two ERP models, namely the CAPM and bond yield plus risk premium, which are commonly relied upon in assessing the cost of equity, or the approved ROEs, during cost-of-capital hearings.⁷⁰

71. Based on the submissions of parties, the Commission adopts an ERP-based two-factor formulaic approach similar to the one utilized by the OEB. Specifically, the Commission approves the following two-factor formula to determine the ROE for 2024 and future test periods on an annual basis:

$$ROE_t = ROE_{base} + w_1(YLD_t - YLD_{base}) + w_2(SPRD_t - SPRD_{base})$$

where:

ROE_t is the approved ROE for the test year t

ROE_{base} is the “base” ROE, that is the approved notional ROE

w_1, w_2 are adjustment factors for changes in long-term GoC bond yield and utility bond yield spread, respectively (referred to on the record as VAR4 and VAR7)

⁶⁴ The CCA did not provide evidence regarding each variable of the two-factor formula.

⁶⁵ Exhibit 27084-X0315, PDF page 21.

⁶⁶ Exhibit 27084-X0292, PDF page 6.

⁶⁷ Exhibit 27084-X0469.01, PDF page 9.

⁶⁸ Exhibit 27084-X0047, PDF page 5.

⁶⁹ Exhibit 27084-X0057, PDF pages 9-10.

⁷⁰ Exhibit 27084-X0320.02, PDF pages 91-92.

YLD_t and YLD_{base} are long-term GoC bond yields for the test year and base period, respectively (VAR2 and VAR1)

$SPRD_t$ and $SPRD_{base}$ are utility bond yield spreads for the test year and base period, respectively (VAR6 and VAR5)

72. Based on the approvals in Section 6 of this decision, the generalized formulaic approach above can be specified as follows:

$$ROE_t = 9.0\% + 0.5 \times (YLD_t - 3.10\%) + 0.5 \times (SPRD_t - SPRD_{base})^{71}$$

73. In Decision 2011-474,⁷² the Commission noted that this type of a formula has advantages over the previously utilized single-factor formula, as it is likely to better reflect any fluctuations in capital market conditions.⁷³ Based on the record of this proceeding, the Commission maintains this view.

74. Parties in this proceeding highlighted that the introduction of the utility bond yield spread component was a major improvement to the OEB formula that contributed to its longevity and acceptance of the resulting ROEs. Dr. Villadsen stated academic literature supports the basic concept that changes in credit spreads serve as a meaningful directional indicator of relative changes in the prevailing market equity risk premium.⁷⁴ Concentric indicated that the OEB formula has generally provided a more reasonable return in most of the years since the utility bond yield spread component was introduced because it captures industry-specific changes in risk that are otherwise not captured by changes in the government or risk free bond yield.⁷⁵ N. Martin pointed out the only review that the OEB conducted since 2009 was completed in 2016 and did not result in any change.⁷⁶ The Commission agrees with all of these observations.

5.3 Annual process to determine the ROE through the formulaic approach

75. From 2005 to 2008 when the EUB used a formula, the EUB initiated a proceeding every year to calculate the approved ROE for the subsequent test year beginning January 1. The EUB relied on the forecast 10-year Canada bond yield for a test year published in the Consensus Forecasts issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.⁷⁷ The results of the update were made available to the public by way of an order released at or near the end of November each year.

76. A similar process is used by the OEB to update its two-factor formula adopted in EB 2009-0084. More specifically, the cost-of-capital parameters are based on the data for September of the preceding year (i.e., three months in advance of the January 1 effective date for

⁷¹ The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.

⁷² Decision 2011-474: 2011 Generic Cost of Capital, Proceeding 833, Application 1606549, December 8, 2011.

⁷³ Decision 2011-474, paragraphs 164-165.

⁷⁴ Exhibit 27084-X0469.01, PDF page 80.

⁷⁵ Exhibit 27084-X0315, PDF page 110.

⁷⁶ Exhibit 27084-X0316, PDF page 31.

⁷⁷ Decision 2004-052, PDF page 36.

rates), using the long-term GoC bond forecast and A-rated utility bond yield spread. The results of the update are made available to the public during the months of October to November.

77. In this proceeding, parties generally favoured the approach currently taken by the OEB⁷⁸ or the annual update process previously adopted by the EUB.⁷⁹ Overall, parties emphasized the need for transparency in the calculations with the results being made available to the public in advance of the ROE taking effect.

78. Given the preference of parties, and to reduce regulatory burden, the Commission will adopt a practice similar to the one it employed between 2005 and 2008. The Commission will initiate a proceeding in early November of each year, in which it will provide calculations of the upcoming year's ROE based on the October data for the forecast long-term GoC bond yield and prevailing utility bond yield spread in comparison to their base values. More specifically, as set out in Section 6.5:

- (i) The forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield⁸⁰ over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.
- (ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield⁸¹ and the long-term GoC bond yield⁸² over the period October 1 to October 31 of the year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

79. Parties will have the opportunity to comment on the Commission's ROE calculations and provide input on any identified discrepancies. The Commission will then issue a decision at the end of November with a final approved ROE for the upcoming year resulting from the formulaic approach approved in this decision.

80. The ROE calculated by the formulaic approach for each test year will come into effect on January 1 of that year.

5.4 Periodic reviews of formulaic approach

81. Employing a formulaic approach to determine annual changes in the ROE requires periodic evaluation to ensure that the ROE produced by the formula continues to be in alignment with the standards for achieving a fair return.

⁷⁸ Exhibit 27084-X0292, PDF pages 51-52. Exhibit 27084-X0315, PDF page 116. Exhibit 27084-X0320.02, PDF page 12, and Section 5, PDF pages 91-98.

⁷⁹ Exhibit 27084-X0469.01, PDF page 105. Exhibit 27084-X0390, PDF page 117.

⁸⁰ Bank of Canada CANSIM Series V39056.

⁸¹ Bloomberg Series C29530Y.

⁸² Bank of Canada CANSIM Series V39056.

82. The Commission solicited input on the process to assess whether the formulaic approach continues to generate a reasonable ROE. The Commission also sought parties' views, should questions arise as to the continued reasonableness of the results produced by the formulaic approach, on necessary remedial steps to be taken to ensure that an ROE satisfying the fair return standard is restored on a go-forward basis.

83. In their submissions, parties identified two main approaches to reviewing the reasonableness of the ROEs produced by the formulaic approach. The first approach involves a predetermined periodic review of the ROEs determined formulaically, every three to five years, regardless of economic conditions. The second approach contemplates mid-term reopeners initiated either by the Commission or upon application by any interested party (i.e., utility or intervener). In the case of mid-term review applications filed by interested parties, the burden of establishing that a full scale review of the reasonableness of the formula's results is warranted would reside with the applicant. As a variant of the second approach, some parties proposed proactively adopting measures such as deadbands, ceilings and floors around the ROE in order to accomplish the following ends: (i) automatically trigger reopeners when formulaic outcomes depart from the previous year's results by a specified margin; and (ii) limit potentially frivolous review applications for relatively minor changes in ROE results from one year to the next.⁸³ Other parties recommended that the Commission refrain from prescribing fixed thresholds for reviewing formula results and, instead, retain the discretion to review the ROEs resulting from the formulaic approach as and when required.⁸⁴

84. In the Commission's view, the two approaches are not mutually exclusive and elements of both can be employed to ensure that the formulaic approach continues to produce just and reasonable results.

85. The Commission has determined that a periodic review every five years strikes an optimal balance. This duration ensures the ongoing alignment of the formula-derived ROE with the established fair return standard, while maintaining the objectives of regulatory efficiency and certainty. The Commission emphasizes that this review process does not necessarily imply a fully litigated GCOC process resulting in a resetting of the formula's parameters, including base ROE. Rather, the Commission will initially seek input from parties on the preliminary assessment of the formula's continued capacity to generate a fair ROE. The Commission's decision on whether to undertake a comprehensive review of either the ROE in general, or the ROE formulaic approach in particular, will be informed by the feedback received on the preliminary matters. The Commission will retain full discretion in determining the process to be followed.

86. In line with this approach, the Commission expects to conduct its first assessment in 2028. Any modifications resulting from this evaluation will subsequently influence the ROE for the 2029 rate year and beyond.

87. In addition to providing for mandatory five-year reviews (without predetermining in advance the length, scope or complexity of the review process), the Commission also sees merit in allowing for mid-term reopeners either at its own initiative or upon application by interested parties if there are compelling grounds to believe that the ROE resulting from the formulaic

⁸³ Exhibit 27084-X0924, ENMAX argument, PDF page 31, paragraphs 141-142. Exhibit 27084-X0926, UCA argument, PDF page 34, paragraph 123.

⁸⁴ Exhibit 27084-X0928, AltaLink/EPCOR argument, PDF page 28, paragraph 73.

approach may no longer be just and reasonable. The Commission envisions mid-term reopeners initiated by parties would be subject to a two-stage review process. In order to move from Stage 1 to Stage 2 of the review process, applicants would bear the burden of establishing on a balance of probabilities that there exist one or more sufficiently compelling reasons for the Commission to question whether its formulaic approach to setting utility ROEs remains, and/or produces results that continue to be, just and reasonable. In the Commission's view, reliance on such a test is likely to quickly dispense with frivolous applications, while still allowing for a broad range of concerns that would justify a deeper examination of the continued reasonableness of the formulaic approach.

88. The Commission is not persuaded, however, that the potential benefits of establishing thresholds that would automatically trigger offramps for, or reasonableness reviews of, the formulaic approach outweigh the disadvantages of adopting such measures. As noted by AltaLink/EPCOR and Dr. Cleary, respectively: the "Commission should not attempt to predetermine and fix specific thresholds for reopeners or offramps"⁸⁵ and "given the difficulty capturing all scenarios where a review may be warranted, the need for a reopener may ultimately be best left to a matter of judgment."⁸⁶ In addition, the Commission notes that it has been almost 15 years since it last relied on a formulaic approach to set utility ROEs. The formulaic approach approved in this decision is also different from the last formula relied on by the Commission. As a result, the Commission considers it to be in the public interest – at least until it acquires greater familiarity with how the formula operates under a variety of different circumstances – that the Commission maintain the maximum degree of discretion in determining how and when the formulaic approach should be reviewed when a question arises as to its ability to meet the fair return standard both over time and in light of ever-changing market conditions.

89. Closely related, the Commission is concerned that any mechanical reliance upon predetermined ROE deadbands, ceilings and floors may inadvertently result in both false-positives (i.e., conducting unnecessary reviews) and false-negatives (i.e., failing to undertake necessary reviews).

5.5 Periodic reviews of deemed equity ratios

90. In order to meet the fair return standard, the Commission has to not only establish a fair ROE, but also determine which proportion of capital invested by the utilities should be financed through shareholder equity and which should be financed through debt. The proportion of capital to be financed by equity is referred to as the "deemed equity ratio." This represents that portion of total invested capital upon which a utility is allowed to earn its Commission-determined target rate of return. The Commission's findings on the approved deemed equity ratios for Alberta utilities are set out in Section 7 of this decision. In this section, the Commission addresses how often these approved ratios should undergo a reasonableness review.

91. The Commission solicited input from parties on whether it was necessary to update deemed equity ratios while a formulaic approach to determine ROE is in operation and, if so, how frequently and pursuant to what process.

⁸⁵ Exhibit 27084-X0928, AltaLink/EPCOR argument, PDF page 28, paragraph 73.

⁸⁶ Exhibit 27084-X0926, PDF page 34, paragraph 124.

92. Consistent with the timing recommended for mandatory reviews of the continued reasonableness of formulaically updated ROEs, experts for several parties (including J. Coyne,⁸⁷ D. D’Ascendis,⁸⁸ Dr. Villadsen⁸⁹ and Dr. Cleary⁹⁰) suggested that the reasonableness of deemed equity ratios also be reviewed at the same time (i.e., every three to five years). R. Bell, meanwhile, suggested that equity thickness be reviewed each year concurrently with the formulaic update to ROEs, while D. Madsen proposed several specific conditions for updating equity thickness ratios going forward.

93. The Commission acknowledges the importance of ensuring predictability of the approved level of the deemed equity ratios moving forward, particularly while utilizing a formulaic approach to determine ROE. Since the deemed equity ratio influences the financial structure of a utility and, therefore, the ROE calculation, the Commission agrees with those parties that advocated for a concurrent review of both elements.

94. The Commission does not consider an annual assessment of deemed equity ratios as proposed by R. Bell to be warranted or cost-justified. Similarly, the Commission does not find merit in imposing upon electric (and presumably, gas) utilities the many conditions D. Madsen⁹¹ recommended be satisfied before new equity ratios can be approved.

95. Instead, the Commission will institute a mandatory review of deemed equity ratios every five years consistent – and contemporaneous – with the approach outlined in Section 5.4 that the Commission will employ for the periodic evaluation of the formulaic approach. As with the latter, the length, scope and complexity of the equity thickness review process will not be predetermined but, rather, will depend on circumstances prevailing at that time.

96. Additionally, the Commission recognizes the value of permitting mid-term reopeners, either at its own discretion or upon application of interested parties, if compelling circumstances suggest that the deemed equity ratio is no longer reasonable. When initiated by parties other than the Commission, such mid-term reopeners will be subject to a two-stage review process similar to that for reviews of the formulaic approach.

6 Notional ROE and other formula variables

6.1 Overview

97. The Commission must determine a fair return for the utilities under its jurisdiction as part of fixing just and reasonable rates. In Section 5 of this decision, the Commission determines that it will adopt a formulaic approach to setting the ROE starting in 2024. As also set out in that section, the formula requires a notional ROE as a starting point. This notional ROE is determined with the same rigour and process used to determine ROE in prior fully litigated proceedings, and considers a variety of approaches, models and directional indices. However, this ROE will not be reflected in customer rates; rather, its sole purpose is to serve as an input to the approved

⁸⁷ Exhibit 27084-X0315, PDF page 7.

⁸⁸ Exhibit 27084-X0390, PDF page 118.

⁸⁹ Exhibit 27084-X0469, PDF pages 32-33.

⁹⁰ Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 13, lines 17-19.

⁹¹ Exhibit 27084-X0292, PDF page 65.

formula. The ROEs produced by the formula will be approved on a final basis effective January 1 of each test year.

98. This section is organized as follows. In Section 6.2, the Commission discusses the extent to which the market data for the comparator group of utilities can be used to inform the determination of cost-of-capital parameters for the Alberta utilities. Section 6.3 determines a risk-free rate as an input to the ERP models, such as the CAPM, and the formulaic approach adopted by the Commission in this decision. In Section 6.4, the Commission determines the notional ROE by analyzing results of various financial models that were presented by proceeding participants. Finally, in Section 6.5, the Commission determines the values for the first and second factors of the formulaic approach to account for changes in GoC bond yields and changes in utility bond yield spread.

6.2 Comparability of representative utilities

99. In past GCOC proceedings, the Commission has frequently expressed concern with the wide range of conflicting evidence and polarized opinions on how it should approach setting a fair return on capital for the utilities it regulates. Oftentimes there was prolonged debate on the degree to which various utility comparator groups that parties relied on to construct models to estimate the ROE were representative of the Alberta utilities. An example of this is the 2018 GCOC proceeding, where parties proposed at least 13 different proxy groups consisting of various subsets of North American utilities.⁹²

100. In order to address these concerns the Commission implemented a process to establish a comparator group of representative utilities that are similar to the Alberta utilities, for the purpose of informing the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE (the comparator group process).⁹³ The outcome of the comparator group process was that the parties reached a consensus on screening criteria and a comparator group of representative utilities resulting from the application of the screening criteria.⁹⁴

101. The weight to be assigned to the specific utilities within the comparator group was not determined in the comparator group process. Instead, the Commission acknowledged that the parties did not agree that all companies in the comparator group are truly comparable to the Alberta utilities, and confirmed that the comparability of and weight to be assigned to the specific companies in the comparator group remained an issue to be determined in the proceeding.⁹⁵ The Commission specifically noted that parties could present evidence that certain companies in the comparator group should not be given any weight at all.⁹⁶

102. The Commission is not persuaded by the argument that certain of the representative utilities in the comparator group lack comparability due to the involvement of their parent corporations in generation, retail or other unregulated business sectors. Concerns of this nature

⁹² Exhibit 27084-X0038, paragraph 8.

⁹³ Exhibit 27084-X0034, paragraph 8.

⁹⁴ Exhibit 27084-X0268.01, PDF page 4.

⁹⁵ Exhibit 27084-X0239.01, PDF page 1, paragraph 2; Exhibit 27084-X0255, PDF page 4, paragraph 12; Exhibit 27084-X0268.01, PDF page 4.

⁹⁶ Exhibit 27084-X0255, PDF page 4, paragraph 12.

were addressed by the screening criterion, which excluded utilities from the comparator group if less than 80 per cent of their assets are tied to rate-regulated activities.

103. While the Commission finds that the U.S. companies have higher business risks than the Alberta utilities, for the purpose of establishing the comparator group, the Commission accepts the utilities' evidence that it is appropriate to include U.S. utility holding companies. The reasons for this are: (i) the relatively limited number of publicly traded Canadian utility companies; (ii) the prevalence of U.S. business operations among many publicly traded Canadian utilities; and (iii) investors' tendency to consider utility investment opportunities in both the U.S. and Canada.⁹⁷ Further, the Commission remains of the view that it is reasonable to consider the U.S. market return data given the globalization of the world economy and integration of North American capital markets.⁹⁸ Notwithstanding these findings, none of the Alberta utilities raises capital directly in the equity market, or operates outside of Alberta unlike a number of companies in the comparator group, which are holding companies and can operate anywhere.

104. After considering the evidence presented in this proceeding, the Commission acknowledges the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in various financial models. However, and as set out in this section and Section 6.4.5, the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities. Accordingly, the Commission retains the view expressed in the 2018 GCOC decision that a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the ROE required by investors in the Alberta utilities.⁹⁹

6.3 Measure of the risk-free rate

105. The risk-free rate is an important component of ERP models, such as the CAPM, and the formulaic approach approved by the Commission in Section 5. ERP-based models are based on the fundamental assumption investors require higher returns for bearing higher risk; or, in other words, investors require a premium for bearing risk that exceeds the risk-free rate. The Commission has accepted in the past that there is an inverse relationship between the risk-free rate and the risk premium required by equity investors: as interest rates increase (decrease), risk premium decreases (increases).

106. Consequently, given these fundamental relationships inherent in ERP-based models, the risk-free rate of 3.10 per cent approved in this section is used for three purposes in this decision: (i) as a base forecast long-term GoC bond yield (YLD_{base}) against which future expected changes in risk-free rates are measured to adjust the ROE in accordance with the approved formula; (ii) as a factor to determine the base ERP underlying the approved formula; and (iii) a measure of the risk-free rate in the CAPM model used to estimate the notional ROE.

107. Consistent with past GCOC proceedings, parties uniformly submitted that yields on long-term government bonds are considered to be default free and therefore are an appropriate measure of the risk-free rate. There was general agreement the 30-year Canada bond yield be

⁹⁷ Exhibit 27084-X0937, Utilities reply argument, PDF page 12, paragraph 32.

⁹⁸ Decision 22570-D01-2018, paragraph 275; Decision 20622-D01-2016: 2016 Generic Cost of Capital, Proceeding 20622, October 7, 2016, paragraph 302; Decision 2009-216, paragraph 200.

⁹⁹ Decision 22570-D01-2018, paragraph 275.

used, as the 30-year term to maturity is consistent with the long-term character of the underlying utility assets.

108. Parties were also consistent in the view that the bond yield used to approximate the risk-free rate be forward-looking, in keeping with the forward-looking nature of a cost-of-capital determination. However, there were differences in how the forecast 30-year Canada bond yield should be determined and the data sources used. Submissions of parties as to the forecast long-term GoC bond yield, term to maturity, and source of data are summarized below in Table 1.

Table 1. Risk-free rate recommendations

Witness (sponsoring party)	Recommendation	Data source	Yield
Dr. Villadsen (ATCO/Apex/Fortis)	Use projection of the 10-year Canada bond yield plus the long-term average maturity premium between 10-year and 30-year Canadian bonds. ¹⁰⁰	Consensus Economics ¹⁰¹	3.85% as of November 7, 2022 ¹⁰²
Concentric (ENMAX)	Use 10-year bond yield forecast and add the average spread between 10- and 30-year government bond yields. ¹⁰³	Consensus Economics	3.59% ¹⁰⁴
D. D'Ascendis (AltaLink/EPCOR)	Use an average of three-month-out and 12-month-out forecasts of the 30-year Canada bond yield. ¹⁰⁵ ¹⁰⁶	RBC Financial Markets Monthly and TD Economics Forecast	2.89% as of December 31, 2022
D. Madsen (IPCAA)	Use current 30-year GoC bond yield as this point in time observation is consistent with a number of published forecasts of the 30-year Canada bond yield for 2023-2024. ¹⁰⁷	RBC Financial Markets Monthly, Kroll	2.95% as of January 13, 2023
Dr. Cleary (UCA)	Use the actual prevailing 30-year government bond yield at the time the initial (or base) ROE is set. ¹⁰⁸	-	2.85% as of January 19, 2023 ¹⁰⁹
J. Thygesen (CCA)	No submission made on the rate or approach to quantify this variable.	-	Maximum risk-free rate for 2024 be set at 3% ¹¹⁰

109. The Commission accepts the submissions of parties that the 30-year term to maturity best reflects the long-term character or useful life of the underlying utility assets. The Commission

¹⁰⁰ Exhibit 27084-X0469, PDF page 71.

¹⁰¹ Consensus Economics publishes long-term [10-year] interest rate projections twice a year, in April and in October. Transcript, Volume 2, page 114, lines 2-6.

¹⁰² Exhibit 27084-X0469, PDF page 41. 3.85% represents the average of yield on a 10-year Canadian government bond in February 2023 (3.5%) and November 2023 (3.4%) as reported by Consensus Forecasts on November 7, 2022, publication, adjusted upwards by Dr. Villadsen by 40 basis points to represent maturity premium for the 30-year over the 10-year Canadian government bond.

¹⁰³ Exhibit 27084-X0315, PDF page 101.

¹⁰⁴ Exhibit 27084-X0315, PDF page 61, Concentric evidence. While Concentric did not recommend a specific numerical value for the base forecast long-term GoC bond yield, it used an average of the Canadian (3.59%) and U.S. (3.87%) risk-free rates of 3.73% in its estimation of the notional ROE and implied ERP in its filed evidence.

¹⁰⁵ Exhibit 27084-X0390, PDF page 24.

¹⁰⁶ Exhibit 27084-X0610, AML_EPCOR-AUC-2023FEB21-001, PDF pages 1-3.

¹⁰⁷ Exhibit 27084-X0292, PDF page 14.

¹⁰⁸ Exhibit 27084-X0320.02, PDF pages 6-7.

¹⁰⁹ Exhibit 27084-X0605, UCA-AUC-2023FEB21-012, PDF page 31.

¹¹⁰ Exhibit 27084-X0713, paragraph 44.

notes that parties provided various empirical and capital markets resources that supported the rationale for matching the useful life of the asset and the term to maturity of the risk-free rate.¹¹¹

110. In keeping with the prospective or forward-looking nature of the determination of the cost of capital and prior Commission practice, it is appropriate to use a forecast of the 30-year Canada bond yield submitted on the record of this proceeding. The Commission finds that a direct forecast of the 30-year Canada bond yield from Canadian major banks is simpler and more transparent than the approach recommended by Dr. Villadsen and Concentric, which uses the Consensus Economics forecast 10-year GoC bond yield and adjusts it by adding the average spread between 10- and 30-year government bonds. The need for this adjustment arises from the fact that Consensus Economics, on which Dr. Villadsen and Concentric rely, does not publish a forecast for the 30-year Canada bond yield. Similar adjustments have been used by the OEB and EUB for their formulas because of reliance on Consensus Forecasts.

111. The 30-year Canada bond yield forecasts are published by large, reputable Canadian financial institutions such as “the Big Six” banks. In the Commission’s view, these forecasts are of comparable quality to the forecasts published by Consensus Economics. In fact, the Consensus Economics forecast is an average of estimates from various sources, including Canadian major banks. However, using direct forecasts of the 30-year Canada bond yield eliminates the need to make additional estimates and adjustments to the 10-year forecast for which there is no single, standardized approach. In addition, these forecasts are publicly available without cost. For simplicity, the Commission considers that averaging the forecasts from three banks, RBC, TD and Scotiabank, is sufficient. Should a forecast from one or more of these banks be unavailable, there are three additional major banks from which a forecast may be obtained as a substitute.

112. In addition to relying on bond yield forecasts published by the three banks, the Commission accepts in principle the approach of D. Madsen and Dr. Cleary to use a naïve forecast,¹¹² using the actual 30-year GoC bond yield to inform an estimate of the future 30-year GoC bond yield. The Commission has relied on this approach in past GCOC decisions to temper published forecasts because it accepted they tend to overestimate changes in interest rates. In this proceeding, representatives of customer groups made a similar point.¹¹³ However, the Commission considers it is better to use the average actual long-term GoC bond yields for an entire month rather than the yield that prevailed on any a single day in that month, as was done by Dr. Cleary and D. Madsen, to smooth out the daily volatility.

113. The Commission will use the bank forecasts published in February 2023 provided by D. D’Ascendis, as they were the most recent bank forecasts of long-term GoC bond yields provided on the record. For consistency, the Commission will use the average actual long-term GoC bond yield in February 2023 for the naïve forecast.

114. For the reasons above, the Commission finds it reasonable to set the forecast risk-free rate to be 3.10 per cent, equal to the average of the 30-year Canada bond yield estimates for the forecast period Q1 2023 to Q4 2023 of RBC at 2.90 per cent, TD at 3.08 per cent, and

¹¹¹ Exhibit 27084-X0390, D’Ascendis evidence, PDF pages 22-24.

¹¹² An estimating technique wherein the actual values from the previous period are employed as the forecast for the current period, without adjusting them or identifying causal factors.

¹¹³ Exhibit 27084-X0292, Evidence of Dustin Madsen, PDF page 14; Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 39.

Scotiabank at 3.26 per cent as of February 2023¹¹⁴ as well as a naïve forecast of 3.16 per cent representing the average actual long-term GoC bond yield for the period February 1 to February 28, 2023.¹¹⁵

6.4 Notional ROE

115. In this section, the Commission determines the notional ROE of 9.0 per cent using current market data and considering results of well-known and widely accepted empirical models to estimate the required return such as the CAPM, constant growth discounted cash flow (DCF), and multi-stage DCF.

116. Under the formulaic approach, the notional ROE serves as the base metric against which future adjustments arising from changes in forecast long-term Canada bond yields and utility bond yield spreads are made and captures the estimated forecast ERP that is commensurate with the base forecast long-term GoC bond yield.¹¹⁶ In turn, the notional ROE can be defined as the sum of the base forecast long GoC bond yield (YLD_{base} in the formula) and the base forecast ERP.

117. Parties recommended a notional ROE and estimated the ERP based on their respective risk-free-rate submissions. Table 2 sets out the notional ROE and ERP recommendations by party.

Table 2. Notional ROE and ERP recommendations by party

Witness (sponsoring party)	Notional ROE (%)	ERP ¹¹⁷ (%)	Empirical approaches used	Comments
Dr. Villadsen (ATCO/Apex/Fortis) ¹¹⁸	10.0	5.68	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommended range for notional ROE is 9.2% to 10.4%
Concentric (ENMAX)	9.50	5.67	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommendation reflects M-DCF and CAPM using historical MERP. ¹¹⁹
D. D'Ascendis (AltaLink/EPCOR)	10.30	6.44	CAPM/ECAPM, DCF, M-DCF, Predictive Risk Premium Model, Adjusted Total Market Approach	Recommended range for notional ROE is 9.80% to 10.80%. ¹²⁰
D. Madsen (IPCAA) ¹²¹	7.70	4.75	CAPM, DCF and M-DCF	Recommendation is simple average of CAPM and DCF models (7.51% and 7.90%)
Dr. Cleary (UCA)	6.75	3.90	CAPM, DCF, M-DCF and Utility Bond Risk Premium Analysis	-

¹¹⁴ Exhibit 27084-X0610, PDF page 2 with reference to Exhibit 27084-X0611 providing supporting data.

¹¹⁵ This is a Commission calculation using the Bank of Canada website provided in Exhibit 27084-X0613, UCA-UTILITIES-2023FEB21-008, PDF page 11.

<https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010013901>

¹¹⁶ Exhibit 27084-X0268.01, PDF page 3.

¹¹⁷ Includes 0.50% flotation allowance.

¹¹⁸ Exhibit 27084-X0921, PDF page 2. Recommendation also assumes 40% deemed equity for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, with additional equity thickness for ATCO Electric Transmission (42%), Apex (44%) and Fortis (43%). If deemed equity is set at 37%, then the ROE should be set 25 to 40 basis points above the recommendation for 40% equity or 10.25% to 10.40%. Recommended notional ROE and VAR3 include 20 basis point risk adder.

¹¹⁹ Exhibit 27084-X0315, PDF page 4. If deemed equity is set at 40%, then the ROE should be set at 10%.

¹²⁰ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 9.

¹²¹ Exhibit 27084-X0292, PDF page 6.

118. As was the case in past GCOC proceedings, parties in this proceeding presented the Commission with a wide range of recommendations for notional ROE and ERP. In addition, there is significant variability in the results obtained by applying each of the empirical models, all of which have been previously considered by the Commission.

119. In sections 6.4.1 to 6.4.4 the Commission briefly describes the empirical models, including the key variables that must be specified and associated measurement issues. In Section 6.4.5, the Commission considers the results of the models and exercises its judgment, having regard to all of the evidence in this proceeding, to determine the notional ROE and ERP. The Commission's conclusion on the notional ROE for the formula takes into account that the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities.

6.4.1 The CAPM

120. The CAPM is based on the relationship between the returns investors expect to receive on their investments in an asset and the systematic (or non-diversifiable) risk faced by that asset. The model is premised on a relationship where the required future return on the asset is proportional to that asset's risk relative to the market. This risk is measured by the asset's "beta."

121. The CAPM can be represented by the following formula:

$$R_s = R_f + \beta[R_m - R_f]$$

where:

R_s is the required return on the common stock;

R_f is the risk-free rate;

R_m is the return on the market portfolio;

$R_m - R_f$ is the market equity risk premium (MERP); and

β , or beta, is the risk measure for the common stock.

122. Each of the variables in the CAPM equation must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The CAPM recommendations of parties are summarized in the following table.

Table 3. CAPM recommendations by party

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
D. D'Ascendis (AltaLink/EPCOR) ¹²²	2.88	7.64	0.61	0.50	8.38 (Canadian utility group)
	4.03	7.80	0.79	0.50	10.88 (U.S. electric utility group)
	4.03	7.80	0.76	0.50	10.70 (U.S. gas utility group)
Dr. Villadsen (ATCO/Apex/Fortis) ¹²³	3.85	5.91-6.56	37% Raw: 0.6-1.72 37% Blume: 0.51-1.54	-	9.81-11.76 (full comparator group)

¹²² Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 86, 177-179. ROE results represent an average of CAPM and ECAPM models.

¹²³ Exhibit 27084-X0469.01 PDF pages 46-49; Exhibit 27084-X0460_C, BV-12(a) ROE Model - 40%; Exhibit 27084-X0461, BV-12(b) ROE Model - 37%; Exhibit 27084-X0689.01-C, ATCO/Apex/Fortis IR responses to the AUC, PDF pages 1-4. If deemed equity is set at 40%, Dr. Villadsen calculated betas ranging from 0.56 to 1.61.

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
			37% Hamada: 1.01-1.21		
Concentric (ENMAX) ¹²⁴	3.73	7.59	0.83-0.86	0.50	10.73 (full comparator group)
Dr. Cleary (UCA) ¹²⁵	2.85	5.00	0.45	0.50	5.7 (Canadian comparator group)
D. Madsen (IPCAA) ¹²⁶	2.95	6.08	0.669	0.50	7.51 (Canadian and U.S. electric utility group)

123. The Commission did not consider the empirical CAPM (ECAPM) approach to estimate the notional ROE or ERP, consistent with the Commission's previous approach.¹²⁷ The Commission accepts Dr. Cleary's concerns with the ECAPM¹²⁸ methodology, and that the assumptions and variables used in the approach were not subject to adequate testing in this proceeding.

6.4.1.2 CAPM inputs

Risk-free rate

124. In considering the parties' CAPM ROE results, the Commission took into account the extent to which parties' estimate of the risk-free rate differed from the 3.10 per cent rate that the Commission found reasonable in Section 6.3.

Beta

125. Beta captures the sensitivity of a stock's returns to the market's returns. It is a measure of systematic risk – general risk that cannot be diversified away. In effect, beta measures the contribution made by an individual stock to the risk of the diversified market portfolio.

126. Considerable academic and empirical evidence has been filed on the record of this proceeding to support the position taken by parties on how beta should be calculated. In general, witnesses for the utilities used betas that:

- were sourced from established fee-for-service data providers widely used by the investment community, in particular Value Line and Bloomberg;
- were based on weekly data on the premise that more frequent observations better capture the contribution made by each individual stock in the comparator group of equities to the

¹²⁴ Exhibit 27084-X0315, Concentric evidence, PDF pages 62, 64-65, 105. The betas used in Concentric's CAPM analyses for the entire comparator group are drawn from two sources: Value Line and Bloomberg. The MERP value of 7.59 represents an average of Canadian and U.S., historical and forward-looking values.

¹²⁵ Exhibit 27084-X0320.02, Cleary evidence, PDF page 61. Beta of 0.45% is raw/unadjusted. ROE of 5.7% includes an A-rated Canadian utility bond yield spread adjustment of 0.095%.

¹²⁶ Exhibit 27084-X0292, Madsen evidence, PDF pages 28-29.

¹²⁷ Decision 20622-D01-2016, paragraph 199.

¹²⁸ Exhibit 27084-X0759, Cleary evidence, PDF page 43-45.

risk of the diversified market portfolio over the measurement period. Selected measurement periods ranged from two¹²⁹ to five-years;¹³⁰

- incorporated the Blume adjustment on the basis that it addresses the tendency of raw betas to change gradually over time, transforms historical unadjusted or raw betas into an expectational value consistent with the forward-looking nature of the cost of capital, and partially corrects for the known deficiencies of the CAPM;¹³¹ and
- in the case of the evidence filed by Dr. Villadsen, used the Hamada adjustment to reflect a 40 per cent deemed equity component to standardize the capital structure of the comparable group of utilities and calculate beta¹³² on an equivalent basis, given the relationship between financial leverage and equity returns.

127. For the consumer groups, Dr. Cleary and D. Madsen used a different approach to calculate beta:

- Dr. Cleary used weekly and monthly raw (unadjusted) betas for both the U.S. and Canadian comparators data from Bloomberg to arrive at an estimated beta of 0.45. Dr. Cleary did not support the use of either the Blume or Hamada adjustments to calculate beta.¹³³
- D. Madsen used raw and adjusted betas in his analysis. He included Blume adjusted monthly betas on the basis that they are consistent with the forward-looking nature of a cost-of-capital determination. D. Madsen used five-year monthly data provided by YCharts and Yahoo Finance to determine an average adjusted beta of 0.669 for the combined Canadian and U.S. Electric Utility segments of the comparable group of utilities.¹³⁴ D. Madsen considered and then rejected the use of Blume adjusted, weekly Value Line betas.

128. In this proceeding, parties had much the same debates about beta as in past GCOC proceedings. Consistent with its views in past GCOC decisions, the Commission considers that there exists some room for legitimate differences of opinion among industry practitioners and academic experts on what constitutes a reasonable range for regulated utility betas.

129. For example, the Commission remains uncertain of the extent, if any, to which the Blume adjustment is warranted in determining betas for regulated utilities that face less risk than an average firm in the market. Indeed, there are ample reasons to question on what basis the

¹²⁹ Transcript, Volume 5, page 973, lines 8-11 and 15, D'Ascendis evidence. D. D'Ascendis uses Bloomberg's default setting of two years to calculate beta.

¹³⁰ Exhibit 27084-X0315, Concentric evidence, PDF page 62. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Concentric has computed Bloomberg betas using five years of weekly stock returns and using the S&P or the S&P/TSX Composite as the market index, in the case of U.S. or Canadian comparable equities, respectively.

¹³¹ Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 76-84; Exhibit 27084-X0315, Concentric evidence, PDF pages 62-64; Exhibit 27084-X0047, Villadsen evidence, PDF pages 7-8; and Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44.

¹³² Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44. Dr. Villadsen used weekly data from Bloomberg over a three-year measurement period. A similar analysis was performed assuming deemed equity of 37%.

¹³³ Exhibit 27084-X0320.02, Cleary evidence, PDF pages 49-60 and Exhibit 27084-X0333, Cleary evidence.

¹³⁴ Exhibit 27084-X0292, Madsen evidence, PDF pages 16-22.

systematic risks faced by regulated utilities might ever be expected to approach, much less exceed, those for the market as a whole, which is a central premise of the Blume adjustment.¹³⁵ Nevertheless, the Commission acknowledges that adjusted betas are widely used by finance professionals, as they provide useful information in certain circumstances.

130. As expressed in several past decisions, the Commission remains unpersuaded that adjusted betas are superior to raw betas in the context of regulated utilities. Rather, it finds that both raw and adjusted betas can provide useful information with respect to utility risk.¹³⁶ Similarly, the Commission continues to find that reliance on both weekly and monthly estimates of beta is reasonable.¹³⁷

131. J. Coyne estimated beta to be 0.83 to 0.86,¹³⁸ while Dr. Villadsen calculated raw, Blume and Hamada adjusted betas, producing betas ranging from 0.51 to 1.72. Within this range Dr. Villadsen recommended for the Commission's approval a range of Hamada betas from 1.01 to 1.21.¹³⁹ The Commission finds these are unreasonably high given its findings regarding the overall risk of the Alberta utilities. More generally, the Commission does not accept that betas are understated for the utilities in the absence of the Hamada adjustment.

132. The Commission concludes that utility stocks are appreciably less risky and volatile than equities in the broader market, and therefore considers a reasonable range of betas for regulated gas and electric utilities to be between 0.45 (representing Dr. Cleary's unadjusted long-term beta) and 0.75 (in the range of adjusted betas recommended by D. Madsen¹⁴⁰ and D. D'Ascendis¹⁴¹). The high end of Dr. Villadsen's¹⁴² beta estimates were well above this range.

Market equity risk premium

133. Parties to the proceeding used a variety of approaches to quantify the MERP.

134. D. Madsen's MERP of 6.08 per cent is an average of three MERP estimates: the implied MERP provided by Kroll of 6.0 per cent, Dr. Damodaran's implied MERP of 6.0 per cent as of January 1, 2023, and the implied MERP calculated by D. Madsen of 6.23 per cent by applying a Gordon Growth Model to the S&P500.¹⁴³

135. Dr. Cleary adopted a MERP of 5.0 per cent, equal to the average of a commonly used historical range of 4 to 6 per cent. Dr. Cleary relied on a series of surveys and reports from academics, investment management firms, and actuarial service providers to establish historical and forecast returns for the Canadian, U.S. and world developed markets.¹⁴⁴

136. Dr. Villadsen used the historical average premium of market returns over the long-term GoC bond yields, as per Duff & Phelps, for both Canada and the U.S. The MERP is expressed as

¹³⁵ For a discussion of the history of Blume's adjustment and its limitations in the context of the regulated utility industry, see paragraph 164 of Decision 20622-D01-2016.

¹³⁶ Decision 22570-D01-2018, paragraphs 345-346.

¹³⁷ Decision 22570-D01-2018, PDF page 80, paragraph 344.

¹³⁸ Exhibit 27084-X0315, Concentric evidence, PDF page 62.

¹³⁹ Exhibit 27084-X0469.01, Villadsen evidence at PDF pages 46-48.

¹⁴⁰ Exhibit 27084-X0292, Madsen evidence, PDF page 29.

¹⁴¹ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 80.

¹⁴² Exhibit 27084-X0469.01, PDF pages 46-49.

¹⁴³ Exhibit 27084-X0292, Madsen evidence, PDF pages 24-29.

¹⁴⁴ Exhibit 27094-X0320.02, Cleary evidence, PDF pages 39-49.

the arithmetic average and is 5.91 per cent for Canada (1935-2021) and 7.46 per cent for the U.S. (1926-2021). By adjusting Bloomberg forecast MERP for the spread between a 10-year and 30-year government bond yield, Dr. Villadsen also calculated a forecast MERP for Canada of 6.56 per cent and a lower number for the U.S. using proprietary data.¹⁴⁵

137. D. D'Ascendis calculated a prospective MERP for both Canada and the U.S. by applying a constant growth DCF model to the companies comprising each of the S&P/TSX and S&P 500. The resulting total return for each index was then reduced by the forecast Canadian or U.S. long-term government bond yield. This produced forecast MERPs for Canada and the U.S. of 9.92 per cent and 7.03 per cent, respectively. D. D'Ascendis also estimated historical MERPs by using a regression analysis in which the MERP is expressed as a function of the long-term government bond yield. The historical MERPs for Canada and the U.S. using this approach were 5.35 per cent and 8.57 per cent, respectively.¹⁴⁶ The Commission notes that overall, D. D'Ascendis recommended MERPs of 7.64 for Canada and 7.80 for the U.S. as summarized in Table 3 above.

138. Concentric used the MERP ex-post historical arithmetic average based on data from Kroll of 5.74 per cent for Canada (1919-2021), and 7.46 per cent for the U.S. (1926-2021). Concentric, used an approach similar to that of D. D'Ascendis, to forecast MERPs of 9.22 per cent for Canada and 7.93 per cent for the U.S.¹⁴⁷ Concentric's recommended MERP, as set out in Table 3, is 7.59.

139. Parties developed their MERP recommendations using three general approaches or a combination of them. The first approach was to examine historical MERPs; that is, the difference between historical long-term realized stock market returns and the risk-free rate (as measured by long-term GoC bond yields) in Canada and the U.S. The Commission agrees that this approach is informative as it captures a large number of economic and monetary cycles and minimizes the risk that calculated MERPs reflect anomalous or transitory market conditions. The historical MERP values were approximately 6.0 per cent for Canada and 7.50 per cent for the U.S.

140. The second approach was to estimate prospective or forward-looking MERPs by relying on available market return estimates of investment management professionals and actuarial service providers, as was done by Dr. Cleary to arrive at a 4 to 6 per cent estimate and by Dr. Villadsen to arrive at a 5.91 to 6.56 per cent recommended MERP estimate.

141. The Commission recognizes that there may be pitfalls to relying on available forecasts of market return. For example, these estimates may not be as robust as empirical studies, or be amenable to ready analysis or testing, and may be prepared for different purposes; however, this type of evidence does offer some indication of what market professionals believe the ROE may be in the future. This can, and potentially does, affect investor expectations and subsequent behaviour. That, in itself, can shed light on the limits or frontiers of the range of reasonable estimates of the required ROE.

142. Under the third approach, parties estimated prospective MERPs by calculating expected market return. To do so, Concentric and D. D'Ascendis employed forecast earnings growth rates in excess of 9 per cent, which resulted in estimates for expected market returns ranging from

¹⁴⁵ Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 42-43. Exhibit 27084-X0458-C, Appendix BV-7 Bond Yields & MERP, tab "MRP calculation."

¹⁴⁶ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 85.

¹⁴⁷ Exhibit 27084-X0315, Concentric evidence, PDF pages 64-65.

10.4 per cent to 12.8 per cent for Canada and from 11.0 per cent to 11.8 per cent for the U.S. This, in turn, produced MERP estimates in the order of 9 to 10 per cent. Consistent with the findings in the 2018 GCOC decision, the Commission considers these estimates excessive, as they are based on calculated expected market returns that reflect unrealistically high earnings growth assumptions.

143. Given the above observations, the Commission notes that when the MERP estimates in the order of 9 per cent calculated by Concentric and D. D'Ascendis are excluded, the remaining MERP recommendations of the parties fall into what the Commission considers is a reasonable range of 5.9 per cent to 7.5 per cent.

Flotation allowance

144. In past GCOC proceedings, the Commission has accepted a flotation allowance of 0.50 per cent in estimates of ROE obtained from the application of the various models, including CAPM. The flotation allowance is normally included in the approved return to account for administrative costs and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.¹⁴⁸ No party opposed the use of 0.50 per cent for the flotation allowance. The Commission finds this flotation allowance continues to be reasonable for use in the financial models.

6.4.2 Constant growth DCF model

145. The constant growth DCF model assumes that the market price of a stock is equal to the present value of the cash flows that the owners of the shares expect to receive. In general, expected future cash flows are represented by the dividends paid per share. This pricing relationship is generally expressed as:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty}$$

where:

P₀ represents the current stock price;

D₁ ... D_∞ represent expected future dividends; and

k (or K) is the discount rate or required ROE.¹⁴⁹

146. Each of the variables in the DCF approach must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The constant growth DCF recommendations by parties are summarized in Table 4.

¹⁴⁸ Decision 22570-D01-2018, PDF page 104.

¹⁴⁹ The expression can be simplified and rearranged into annual and quarterly compounding DCF equations: Exhibit 27084-X0292, Madsen evidence, PDF page 29.

Table 4. Constant growth DCF recommendation by party

Witness (sponsoring party)	ROE	Flotation allowance ¹⁵⁰	ROE including flotation allowance
	(%)		
D. D'Ascendis (AltaLink/EPCOR) ¹⁵¹	10.21 (Canadian utilities) 9.34 (U.S. electric utilities) 10.01 (U.S. natural gas utilities)	0.50	10.71 (Canadian utilities) 9.84 (U.S. electric utilities) 10.51 (U.S. natural gas utilities)
Dr. Villadsen (ATCO/Apex/Fortis) ¹⁵²	12.79 (Canadian utilities) 9.38 (U.S. electric utilities) 9.66% (U.S. gas utilities)	0.50	13.29 (Canadian utilities) 9.88 (U.S. electric utilities) 10.16 (U.S. gas utilities)
Concentric (ENMAX) ¹⁵³	9.88 (Canadian proxy group) 9.43 (U.S. electric proxy group) 9.84 (U.S. gas proxy group) 9.59 (N.A. combined proxy group)	0.50	10.38 (Canadian proxy group) 9.93 (U.S. electric proxy group) 10.34 (U.S. gas proxy group) 10.09 (N.A. combined proxy group)
Dr. Cleary (UCA) ¹⁵⁴	6.35	0.50	6.85
D. Madsen (IPCAA) ¹⁵⁵	7.31-9.14	0.50	7.81-9.64

6.4.2.1 Constant growth DCF inputs**Current stock price**

147. To estimate the current stock price input to the DCF model, most parties calculated the average closing price over a period ranging from 15 to 90 trading days ending between late December 2022 and late January 2023 to avoid biases that may arise over very short periods of time from anomalous or transitory events.¹⁵⁶

148. The Commission accepts the use of an averaging period to calculate the current stock price to mitigate the risk that a single date, point-in-time estimate may be biased by market conditions on the pricing date. The averaging period should not exceed 90 days, as a longer averaging period would likely violate the empirical assumption that the constant growth DCF approach uses current stock prices. In addition, the Commission will accept the adjustment of the current quarterly dividend by the chosen dividend growth rate, as submitted by D. D'Ascendis, Dr. Villadsen and Concentric. No party provided a contrary view that the adjustment was inappropriate.¹⁵⁷

¹⁵⁰ The constant growth DCF directly calculates ROE prior to the addition of the flotation allowance.

¹⁵¹ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 47. Average of the mean and median.

¹⁵² Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 54-55. Exhibit 27084-X0460-C, BV-12a, Villadsen evidence. ROE values are presented at 40% equity thickness.

¹⁵³ Exhibit 27084-X0315, Concentric evidence, PDF pages 53-57. Exhibit 27084-X0490, Concentric evidence, sheet JMC-3 Constant DCF. ROE results represent mean values. Of note, Concentric's recommended ROE of 9.50% is based on the average of the multi-stage DCF model (not the constant growth DCF model).

¹⁵⁴ Exhibit 27084-X0320.02, Cleary evidence, PDF page 71. Dr. Cleary used only the Canadian utilities in his recommendations.

¹⁵⁵ Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Attachment 1, Madsen evidence, Tab "DCF." D. Madsen does not use the U.S. Gas utility comparable equities in his constant growth analysis and excludes Algonquin Power & Utilities Corp. from his DCF calculations.

¹⁵⁶ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 42; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1, Exhibit 27084-X0292, Madsen evidence, PDF page 32.

¹⁵⁷ The Commission notes that the constant growth DCF formula set out at the beginning of the section is taken from D. Madsen's evidence and clearly shows the adjustment of the dividend by the growth rate (footnote 55).

Dividend

149. The experts adopted slightly different approaches to how they calculated dividends. Most took the annualized dividend at year-end 2022 for each utility and then increased it quarterly or semi-annually by a fixed percentage of the forecast growth rate.¹⁵⁸ Dr. Cleary's approach was to provide a number of dividend yield calculations, including trailing 12-month dividend yields from December 2022 and average five-year and seven-year dividend yield averages.¹⁵⁹

Dividend growth rate

150. Several of the experts relied on analysts' forecasts of company-specific dividend and earnings per share (EPS) growth rates.¹⁶⁰ D. Madsen also considered data from other sources and both he and Dr. Cleary¹⁶¹ considered historical data. There was debate on whether dividend growth rates in the constant growth DCF analysis can exceed the growth rate of the overall economy, as measured by the GDP growth rate. For example, D. Madsen said that, generally, dividend growth estimates should be below forecast growth in nominal GDP, while D. D'Ascendis did not agree with such limitation.

151. In past GCOC decisions the Commission rejected the use of dividend growth rates that exceeded estimates of the nominal long-term GDP growth rate. In this proceeding, Concentric filed evidence that earnings and dividend growth have exceeded GDP between 2007 and 2021 in support of the proposition that analyst estimates of growth rates above GDP are reasonable.¹⁶² D. D'Ascendis indicated that the compound annual utility industry EPS growth rate of 6.53 per cent exceeded the U.S. GDP growth rate over the 1947 to 2021 period.¹⁶³ While this supports the view that utility EPS growth can exceed nominal GDP growth, the Commission notes that D. Madsen provided evidence of the recent historical EPS growth rates of the Alberta utilities and concluded that average growth was generally lower than his forecast nominal GDP.¹⁶⁴ Further, he noted that the Alberta utilities have a "natural barrier to growth" due to their inability to expand into other jurisdictions.¹⁶⁵ On this point, the Commission notes that growth in dividends can come from higher earnings, and not only from the expansion of company operations.

152. Nevertheless, as in past decisions, the Commission remains concerned with the aggressive dividend growth rates and forecasts relied on by some experts for the utilities, both for utilities as a sector of the economy, and the economy as a whole. It notes Dr. Cleary's observation regarding high growth estimates put forward by experts for the utilities and for the economy as a whole:

¹⁵⁸ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 41; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0292, Madsen evidence, PDF page 32; Exhibit 27084-X0304, Madsen evidence, Sheet DCF.

¹⁵⁹ Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1.

¹⁶⁰ Exhibit 27084-X0391, D'Ascendis evidence, Sheets 2.2-2.4 CGDCF. EPS estimates were from Value Line, Zack's, and Yahoo! Finance; Exhibit 27084-X0469.01, Villadsen evidence, PDF page 51; Exhibit 27084-X0315, Concentric evidence, PDF page 54.

¹⁶¹ Exhibit 27084-X0320.02, Cleary evidence, PDF pages 64-65.

¹⁶² Exhibit 27084-X0315, Appendix 1, Evidence of Concentric Energy Advisors, PDF pages 56-57.

¹⁶³ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 159, Schedule 3, and Exhibit 27084-X0665.

¹⁶⁴ Exhibit 27084-X0292, Madsen evidence, PDF page 38.

¹⁶⁵ Exhibit 27084-X0292, Madsen evidence, PDF page 38.

The contradiction in these assumptions is obvious – i.e. if the economic environments are expected to experience high-risk and slow growth conditions, how is it reasonable to assume that corporate earnings and dividends (for the entire stock market of all publicly listed companies) can be expected to grow indefinitely at these abnormally high rates?¹⁶⁶

153. In the 2018 GCOC decision, with reference to Dr. Cleary’s evidence, the Commission recognized that the utilities are essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable.¹⁶⁷ Indeed, D. Madsen quoted in his evidence from a publication by Dr. Damodaran, who opined that it is questionable whether any firm is able to sustain high growth in the long term as it will eventually stop growing either due to limitations on size or to the effects of competition.¹⁶⁸

154. On the other hand, the sustainable growth rate Dr. Cleary used to estimate expected dividend growth rates relied on historical seven-year average dividend yields and payout ratios and used accounting data, rather than readily available, market-driven forecasts. The Commission notes that this approach produces growth estimates that are less than actual historical rates of dividend growth¹⁶⁹ and less than inflation, resulting in negative real growth. As a result, the Commission is concerned that Dr. Cleary’s sustainable growth rate produces results that understate dividend growth.

155. The Commission will generally continue to consider forecast long-term nominal GDP growth as a proxy for forecast dividend growth. Growth of the utilities will fluctuate over the years but, overall, considering the business profile of the utilities, the Commission does not expect the utilities will consistently achieve growth in dividends greater than the nominal GDP growth rate.

156. In this regard, the Commission finds it reasonable to use in the constant growth DCF model the minimum and mean analyst growth rates submitted in this proceeding; however, maximum EPS growth rates appear to be unreasonably high. Despite its general criticism of using high dividend growth rates, the Commission notes that analyst EPS growth estimates are widely used by the investment community, and concerns relating to analyst EPS optimism bias for large capitalization stocks like those in the comparator group may be overstated, at least relative to estimates for small to mid-cap stocks of which there are not many in the comparator group, in any event.¹⁷⁰ The use of analyst EPS estimates supplied by established data service providers, such as Value Line, Zack’s, Yahoo! Finance, SNL Financial, and Thomson First Call minimizes the opportunity for arbitrary adjustments and custom calculations for which there is no broad support among parties to the proceeding.

6.4.3 Multi-stage DCF model

157. The multi-stage DCF model reflects the premise that investors value an investment according to the present value of its expected cash flows over time.¹⁷¹ It is an extension of the constant growth DCF model, but the multi-stage DCF approach does not assume a single,

¹⁶⁶ Exhibit 27084-X0759, Dr. Cleary rebuttal evidence (redacted), PDF page 3.

¹⁶⁷ Decision 22570-D01-2018, paragraph 438.

¹⁶⁸ Exhibit 27084-X0292, D. Madsen evidence, PDF pages 34-35.

¹⁶⁹ Exhibit 27084-X0304, Madsen evidence, Tab DCF, column “Growth forecast past 5 years (per annum).”

¹⁷⁰ Transcript, Volume 3, pages 704-722.

¹⁷¹ Exhibit 27084-X0390, Concentric evidence, PDF page 53.

constant estimate of dividend growth in perpetuity.¹⁷² In general, the multi-stage DCF assumes that dividends grow at a constant rate over a short-term period, usually five years in length, transition to an assumed long-term constant growth rate over an interim period, also usually five years in length, and then grow in perpetuity at a growth rate usually equal to forecast nominal GDP.

158. The multi-stage DCF recommendations of parties are summarized in the following table.

Table 5. Multi-stage DCF recommendations of parties

Witness (sponsoring party)	ROE	Flotation allowance	ROE including flotation allowance
	(%)		
D. D'Ascendis (AltaLink/EPCOR) ¹⁷³	10.34 (Canadian utilities) 9.21 (U.S. electric utilities) 9.39 (U.S. natural gas)	0.50	10.84 (Canadian utilities) 9.71 (U.S. electric utilities) 9.89 (U.S. natural gas)
Dr. Villadsen ATCO/Apex/Fortis) ¹⁷⁴	11.81 (Canadian utilities) 7.88 (U.S. electric utilities) 7.62 (U.S. gas utilities)	0.50	12.31 (Canadian utilities) 8.38 (U.S. electric utilities) 8.12 (U.S. gas utilities)
Concentric (ENMAX) ¹⁷⁵	9.42 (Canadian proxy group) 8.28 (U.S. electric proxy group) 8.65 (U.S. Gas proxy group) 8.49 (N.A. combined proxy group)	0.50	9.92 (Canadian proxy group) 8.78 (U.S. electric proxy group) 9.15 (U.S. gas proxy group) 8.99 (N.A. combined proxy group)
Dr. Cleary (UCA) ¹⁷⁶	7.01	0.50	7.51
D. Madsen (IPCAA) ¹⁷⁷	7.38-8.46	0.50	7.88-8.96

6.4.3.1 Multi-stage DCF inputs

159. The variables that must be estimated in a multi-stage DCF equation are the same as those set out in Section 6.4.2, except the assumed short-term and long-term dividend growth rates and the length of the short-term and transition periods are expressed in years.

Dividend growth rate

160. Most of the experts calculated the multi-stage DCF in a similar manner, and many of the variables are calculated in the same way as for the constant growth DCF calculations, other than the dividend growth rate. As was the case for the constant growth DCF model, parties took different approaches to forecasting the growth rate.¹⁷⁸ In forecasting nominal GDP growth rates, parties used either the Canadian forecast, or a combination of the Canadian and U.S. forecast.

¹⁷² Exhibit 27084-X0390, Concentric evidence, PDF page 53.

¹⁷³ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 50. Recommended M-DCF reflects average of mean and median results.

¹⁷⁴ Exhibit 27084-X0469.02, Villadsen evidence, PDF pages 54-55. ROE values are presented at 40% equity thickness.

¹⁷⁵ Exhibit 27084-X0315, Concentric evidence, PDF page 59. Exhibit 27084-X0490, tab "JMC-4 Multi-Stage DCF."

¹⁷⁶ Exhibit 27084-X0320.02, Cleary evidence, PDF pages 70-71.

¹⁷⁷ Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Madsen evidence, Sheet DCF.

¹⁷⁸ Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 47-48. Exhibit 27084-X0391, D'Ascendis evidence, sheets 2.5-2.8, Exhibit 27084-X0469, Villadsen evidence, PDF pages 49-57. Exhibit 27084-X0471, Villadsen evidence, PDF pages 10-13, Exhibit 27084-X0315, Concentric evidence, PDF pages 57-58. Exhibit 27084-X0490, Sheet JMC-4 Multi-Stage DCF.

161. D. Madsen also calculated the multi-stage DCF using the approach used by the U.S. Federal Energy Regulatory Commission (FERC), applying it to several scenarios.¹⁷⁹ Using the FERC approach led to similar growth rates. Dr. Cleary took a slightly different approach and used a variation of the constant growth DCF called the H-Model. The approach assumes that growth in dividends moves in a linear manner from a short-term growth rate toward a long-term growth rate over a specified period of time, defined as the “half life.”

162. D. Madsen’s multi-stage DCF calculations included using current and one-year forecast EPS growth rates as a proxy for a five-year forecast EPS growth rate or a one-year EPS growth estimate in year one and the five-year EPS estimate in years two to five.¹⁸⁰ D. Madsen also used the FERC two-step DCF approach. He made adjustments to the FERC approach, including the weights used for short- and long-term growth, and used a simple average of the short-term and long-term growth estimates to adjust the dividend. These adjustments were criticized by Dr. Villadsen and D. D’Ascendis.¹⁸¹

163. The multi-stage DCF approach used by Dr. Villadsen¹⁸² models the first five years of dividends at a growth rate specific to the company she is estimating, then tapered the growth down towards that of the economy over the next five years. For year 10 onwards, Dr. Villadsen used the GDP growth rate as the perpetual growth rate for dividends.

164. Regarding the results of Dr. Cleary’s H-Model DCF approach, the Commission is persuaded by the concerns expressed by experts for the utilities who raised a number of empirical and qualitative issues with Dr. Cleary’s approach. These included the use of sustainable growth rates that are less than forecast inflation,¹⁸³ resulting in negative real utility growth, sustainable growth rates that are less than historical actuals,¹⁸⁴ and the need to consider growth arising from both internally generated funds and from issuances of equity.¹⁸⁵

6.4.4 Other risk premium models

165. In addition to relying on CAPM and DCF models, some parties used the following risk premium models to help inform their fair ROE estimates: (i) Concentric and Dr. Villadsen used the government bond yield risk premium model; (ii) Dr. Cleary and D. D’Ascendis relied on the utility bond risk yield premium model; and (iii) D. D’Ascendis used the predictive risk premium model. The Commission determines that it will not rely on any of these models for the purposes of the present decision.

¹⁷⁹ Exhibit 27084-X0292, Madsen evidence, PDF pages 42-44. Exhibit 27084-X0304, Madsen evidence.

¹⁸⁰ Exhibit 27084-X0304, Madsen evidence, Sheets DCF and Multi DCF Alt. FERC Scenario 1: nominal estimated GDP of 3.77% is used for both the short-term and long-term growth rate; FERC Scenario 2: short-term growth rate is the average of the current year forecast and next year’s growth rate and nominal estimated GDP of 3.77% is used as the long-term growth rate; FERC Scenario 3: short-term growth rate is equal to analyst five-year EPS growth rates and nominal estimated GDP of 3.77% is used as the long-term growth rate; and FERC Scenario 4: the average the short-term growth rate in scenarios 1 to 3 is used as the short-term growth rate and the long-term growth rate is nominal estimated GDP of 3.77%.

¹⁸¹ Exhibit 27084-X0761, Villadsen evidence, PDF pages 26-27, Exhibit 27084-X0750, D’Ascendis evidence, PDF pages 32-36.

¹⁸² Exhibit 27084-X0471, Villadsen evidence, PDF pages 9-10.

¹⁸³ Exhibit 27084-X0750, D’Ascendis evidence, PDF page 29.

¹⁸⁴ Exhibit 27084-X0743, Concentric evidence, PDF page 41.

¹⁸⁵ Exhibit 27084-X0761.02, Villadsen evidence, PDF page 61.

166. The government bond risk premium approach estimates the ROE as the sum of the ERP and the yield on the 30-year U.S. Treasury bond. The ERP was calculated as the difference between authorized returns from U.S. electric and gas utilities and the then-prevailing quarterly 30-year U.S. Treasury yield. Consistent with prior GCOC decisions,¹⁸⁶ the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model.

167. Under the utility bond risk premium approach, a required ROE is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D'Ascendis.

168. Dr. Cleary's recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment. D. D'Ascendis's risk premiums are estimated in a more rigorous manner; however, they have issues of their own. For one of his models, D. D'Ascendis used the authorized ROEs from litigated cases in other jurisdictions to estimate the utility bond ERP.¹⁸⁷ As stated earlier, the Commission prefers not to use authorized ROEs as a proxy for market data. For the other two models, D. D'Ascendis relied on market data; however, they require the Commission's determinations on a number of new variables such as the expected utility bond yields and expected returns for an index of U.S. utilities.¹⁸⁸ Variables and calculations in D. D'Ascendis's bond yield risk premium models were not explored in depth in this proceeding, and in the Commission's view, the merits of the utility bond risk premium approach do not outweigh the additional burden and empirical difficulties associated with measuring the ERP to utility bond yield, given the presence of the more widely accepted CAPM and DCF models.

169. Finally, the predictive risk premium model is based on the ARCH/GARCH¹⁸⁹ models that use historical volatility to predict future volatility, which can then be translated to a predicted ERP. The predictive risk premium model estimates the ERP directly, by predicting volatility or risk.¹⁹⁰ In the Commission's view, this analysis is similar in concept to the technical analysis of market data that relies only on historical time series data for a single indicator, for example, returns on a stock, to predict future returns for this stock. The Commission is not persuaded that this approach is superior to the CAPM and DCF models that use a variety of inputs to estimate the ERP and/or required return, especially as the predictive risk premium model approach is not used widely, if at all, by other regulators.

¹⁸⁶ Decision 22570-D01-2018, PDF pages 88-91.

¹⁸⁷ Exhibit 27084-X0390, D'Ascendis evidence, PDF page 64.

¹⁸⁸ In Exhibit 27084-X0390, PDF page 63, D'Ascendis explained, "As done for the S&P TSX Composite and the S&P 500, using dividend and EPS growth rate data from Bloomberg, I calculated projected total returns of the S&P/TSX Capped Utilities."

¹⁸⁹ The Autoregressive Conditional Heteroskedasticity (ARCH) and Generalized Autoregressive Conditional Heteroskedasticity (GARCH) models are based on the premise that the volatility of prices and returns clusters over time and is therefore highly predictable.

¹⁹⁰ Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 54-60.

6.4.5 Notional ROE and base forecast ERP

170. In this proceeding, the Commission was presented with a wide range of notional ROE and base ERP recommendations that were based on a variety of approaches, models and directional indices. The Commission rejected many of these approaches and instead focused on the results of the well-known and widely used models (CAPM, constant growth DCF, and multi-stage DCF) in GCOC proceedings. The Commission determines the notional ROE to be 9.00 per cent and the base forecast ERP to be 5.90 per cent.

171. Table 6 illustrates the ranges of notional ROE (including 0.50 flotation allowance) based on the results of the financial models submitted by the parties and reflects the resulting ERPs after subtracting the Commission's 3.10 per cent risk-free rate.

Table 6. Notional ROE and base forecast ERP from financial models

Financial model	ROE (%) range		Base forecast ERPs (%) range including flotation allowance (ROE less 3.10% risk-free rate)	
	Low	High	Low	High
CAPM	5.7	11.76	2.6	8.66
Constant growth DCF	6.85	13.29	3.75	10.19
Multi-stage DCF	7.51	12.31	4.41	9.21

172. It is obvious from the table above that the Commission was presented with a wide range of results from the experts using the CAPM, constant growth DCF, and multi-stage DCF models. The model results are subject to a high degree of variability given the range of data sources, forecasts and assumptions that parties choose to use, and the judgment and experience of the expert doing the modelling. These models provide some guidance to the Commission, but, as evidenced by the wide range of results, they do not produce a single correct number for the fair return that the Commission should choose.

173. In assessing the results of the models, the Commission is mindful of its concerns expressed in sections 6.4.1 to 6.4.3, including:

- CAPM results using a forecast risk-free rate that differs significantly from the 3.10 per cent rate the Commission found reasonable in Section 6.3.
- CAPM results using betas that were close to or exceeded one.
- CAPM results using MERPs based on excessively high earnings growth rates in estimating market return.
- Constant growth DCF results using dividend growth rates that are too high (e.g., exceed long-term nominal GDP growth) or too low (e.g., near or less than inflation).

174. The Commission has set the base forecast ERP and resulting notional ROE towards the lower end of the ROE ranges calculated in the financial models given its finding that the risk profile of the Alberta utilities is at the low end of the comparator group of companies.

175. D. D'Ascendis calculated a low CAPM ROE of 8.38 per cent, a constant growth DCF ROE of 9.84 to 10.71 per cent and a multi-stage DCF ROE of 9.71 to 10.84 per cent. Some of D. D'Ascendis's DCF ROE estimates are based on excessively high earnings growth rates, which

the Commission rejects. The notional ROE of 9.00 per cent is closer to the lower end of D. D'Ascendis's three calculations, namely the low 8.38 per cent CAPM ROE.

176. The low end of Dr. Villadsen's calculated ROEs was the 8.12 per cent for the multi-stage DCF. Dr. Villadsen's CAPM ROE of 9.81 to 11.76 per cent uses a high beta and high risk-free rate. Concentric's CAPM ROE of 10.73 uses a lower beta and risk-free rate than Dr. Villadsen; however, Concentric's risk-free rate is 3.73 per cent. The low end of Concentric's calculated ROEs is 8.78 per cent for the multi-stage DCF. Dr. Villadsen and Concentric's constant growth DCF ROEs range from 9.88 to 13.29 per cent, and 9.93 to 10.38 per cent, respectively. Some of Concentric's constant growth DCF estimates are based on excessively high earnings growth rates, which the Commission rejects.

177. The high end of Dr. Cleary's three ROE calculations was 7.51 per cent for the multi-stage DCF but even that high-end estimate is too low. It is approximately 100 basis points lower than the current approved ROE, and the Commission finds no compelling reason to decrease the currently approved ROE. D. Madsen calculated a CAPM ROE of 7.51 per cent, a constant growth DCF ROE range of 7.81 per cent to 9.64 per cent, and a multi-stage DCF ROE range of 7.88 per cent to 8.96 per cent. Given the Commission's finding that there is no compelling reason to decrease the currently approved ROE, the Commission considers the higher end of D. Madsen's constant growth DCF and multi-stage DCF ROEs to be more helpful. D. Madsen uses long-term nominal GDP growth rates in his DCF models. The notional ROE of 9.00 per cent is lower than D. Madsen's 9.64 per cent constant growth DCF ROE, and slightly higher than D. Madsen's 8.96 per cent multi-stage DCF ROE.

178. In addition to the various factors outlined above, the Commission's reasoning in setting the base forecast ROE and notional ROE on the lower end of the ROE ranges developed by parties in this proceeding includes the considerations set out below.

179. A great deal of evidence (and supporting argument) was filed in this proceeding by the utilities in an effort to persuade the Commission that the macroeconomic changes (and related systematic risks) confronting them compared to what they faced in 2018, together with other business, market, regulatory, competitive and related operating risks they deal with on a daily basis, warrant a significant increase in both their approved ROEs and deemed equity ratios commencing in 2024. After considering the full record of this proceeding, the Commission finds that, on balance, there are reasonable grounds for the notional ROE for Alberta utilities to be raised above the 8.5 per cent ROE approved for 2023, but not to set it as high as the utilities have been requesting.

180. Utilities are regulated monopolies. They supply essential, highly price-inelastic, services to captive customers, with few, if any, competitively available substitutes. Aside from fluctuations attributable to short-term extremes of weather, natural disasters, pandemics and the like, demand for their services is highly predictable from one season to the next, and one year to another.

181. In exchange for being cloaked with a legislative "duty to serve" or "supplier-of-last-resort" obligation as it is sometimes called, public utilities have long been the beneficiaries of a statutory guarantee, enforced by regulation and a century or more of appellate level jurisprudence, of a legal right to a reasonable opportunity to earn a fair return on their prudently invested capital. As leading credit rating agencies have noted on more than one occasion, utilities

under the Commission's jurisdiction face a favourable regulatory environment that excludes some or all of volumetric, counterparty and commodity price risks,¹⁹¹ and allows for the flowthrough to customers of most, if not all, cost increases that are outside the utility's direct control.

182. Alberta utilities are also the beneficiaries of a concerted effort in recent years to eliminate regulatory lag and to reduce unnecessary regulatory burden, plus numerous incentives to cut costs and earn supra-normal returns (i.e., earnings in excess of their approved rate of return) between rate cases under cost-of-service (COS) regulation for transmission utilities or performance-based regulation (PBR) terms for distribution utilities.¹⁹² Together, these conditions have the effect of significantly reducing the overall level of risk faced by Alberta utilities relative to the market as a whole. As noted in Section 4 above, while many competitive industries endured considerable economic and financial duress attributable to pandemic-related disruptions in the past few years, Alberta utilities appear not only to have avoided any lasting economic harm but have also exhibited, overall, very robust financial results throughout. Moreover, the fact that no evidence was presented by utilities attesting to undue hardship in raising new debt or equity capital on competitive terms at any time since the 2018 GCOC proceeding reinforces the overall conclusion that they operate in a lower risk and relatively more supportive regulatory environment than that of the comparator group.

6.5 Other variables of the formulaic approach

183. The approved notional ROE of 9.0 per cent will serve as a base ROE to which the approved formulaic approach will be applied each year:

$$ROE_t = 9.0\% + 0.5 \times (YLD_t - 3.10\%) + 0.5 \times (SPRD_t - SPRD_{base})$$

184. This section explains how the Commission arrived at each remaining variable to be used in the approved formulaic approach. Specifically, Section 6.5.1 deals with the adjustment factors for changes in GoC bond yield and utility bond yield spread. Section 6.5.2 deals with the base and test year values for long GoC bond yields. Section 6.5.3 deals with the base and test year values for utility bond yield spreads.

6.5.1 Adjustment factors for changes in GoC bond yield and utility bond yield spread

185. In future test years, risk-free rates (approximated by long-term GoC bond yield) and utility bond yield spreads will continue to vary as financial and economic conditions evolve. The approved formulaic approach accounts for fluctuations in both of these factors relative to their base values approved in this decision.

186. The adjustment factor for the 30-year GoC bond yield (denoted as w_1 in the formula) expresses the relationship between changes in the forecast long GoC bond yield and the ROE for the test year. The adjustment factor for utility bond yield spread (denoted as w_2 in the formula) expresses the relationship between changes in the utility bond yield spread and the ROE for the test year. The theoretical basis behind these adjustment factors is that the ROE (and underlying

¹⁹¹ Exhibit 27084-X0897, IPCAA-ATC-4, Extract from Proceeding 28174, Exhibit 28174-X0011, SP Rating Results for AltaLink, L.P., PDF pages 4 and 6.

¹⁹² The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR. Notwithstanding that, the Commission observes that some Alberta utilities under COS regulation do achieve returns over approved ROE.

ERP) do not change one-for-one with the change in risk-free rate and bond yield spread; rather, they change to some lesser degree in response to fluctuations in those variables.

187. Ideally, the values for these adjustment factors should be determined through an empirical exercise based on the strength of the relationship between interest rates and ERPs observed by analysing historical data. To that effect, the Commission asked parties to comment on the extent of the relationship between changes in the forecast long GoC bond yield and the forecast ERP, and whether this relationship is sustainable and statistically significant with a high coefficient of determination.

188. In the Commission's view, the results of the statistical analyses presented in this proceeding were not conclusive. Although there were some statistical analyses showing that the 0.5 adjustment factors for both w_1 and w_2 were in the range of reasonableness,¹⁹³ with the exception of Concentric, parties did not rely heavily on their statistical analyses and, instead, appeared to defer to the OEB adjustment factors of 0.5 for both w_1 and w_2 , the latter of which is also used by the California Public Utilities Commission (CPUC). This was the approach taken by Dr. Villadsen,¹⁹⁴ D. D'Ascendis¹⁹⁵ and D. Madsen.¹⁹⁶

189. Concentric's regressions showed a statistically significant, sustained relationship between changes in risk-free rates and authorized ROEs as well as between changes in utility bond yield spreads and authorized ROEs.¹⁹⁷ Based on these regressions, Concentric recommended the 0.5 adjustment for both factors in the formula.¹⁹⁸ However, the Commission will not rely on this analysis given its determination, expressed throughout this decision, not to use authorized ROEs as a proxy for market data.

190. An alternative to the adjustment factors used by the OEB was presented by Dr. Cleary who recommended adjustment factors of 0.75 for both w_1 and w_2 . The Commission is not persuaded that a 0.75 adjustment factor is warranted. Although of limited usefulness, the statistical analyses on the record of this proceeding (not including Concentric's) do provide general support for the 0.5 adjustment factors; at least more so than for the 0.75 adjustment factor. In addition, both the OEB and the EUB found that the 0.75 adjustment factor with respect to changes in GoC bond yield resulted in unduly heightened sensitivity to GoC bond yield, contributing to the demise of their formulas that were in place pre-2009.¹⁹⁹ The Commission agrees with the approach taken by the majority of parties that it is preferable to use the adjustment factors used by the OEB and CPUC whose formulas have been in place for a number of years.

¹⁹³ Exhibit 27084-X0900, Madsen undertaking No. 1. D'Ascendis: Exhibit 27084-X0399, Morin approach; Exhibit 27084-X0408, Harris approach; Exhibit 27084-X0411, Harris and Marston approach; Exhibit 27084-X0413, Brigham, Shome and Vinson approach; Exhibit 27084-X0440, Maddox, Pippert and Sullivan approach. Dr. Cleary: Exhibit 27084-X0605, UCA-AUC-2023FEB21-005, PDF pages 14-15.

¹⁹⁴ Exhibit 27084-X0469, Villadsen evidence, PDF page 79.

¹⁹⁵ Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 105, 112.

¹⁹⁶ Exhibit 27084-X0292, Madsen evidence, PDF page 50.

¹⁹⁷ Exhibit 27084-X0490, tabs "JMC-7.1 Risk Premium – Electric" and "JMC-7.2 Risk Premium – Gas."

¹⁹⁸ Exhibit 27084-X0315, Concentric evidence, PDF page 109. Exhibit 27084-X0743, Concentric reply evidence, PDF page 51.

¹⁹⁹ Exhibit 27084-X0678, EDTI-AML-CCA-2023FEB21-003 Attachment (OEB Report), PDF page 3.

191. The Commission approves a 0.5 adjustment factor for both changes in the 30-year GoC bond yield (w_1) and changes in the utility bond yield spread (w_2) in the formula.

6.5.2 Base and test year values for long-term GoC bond yield

192. As set out in Section 6.3, the risk-free rate of 3.10 per cent will serve as the base long-term GoC bond yield (YLD_{base}) in the formulaic approach. The updated risk-free rate forecast for each test year will be measured against this base value.

193. Regarding the 30-year GoC bond yield forecast for the prospective test year (YLD_t), parties recommended that methodologies be employed consistent with the methods they used to arrive at their respective base risk-free rate estimates (these methodologies are summarized in Table 1 from Section 6.3). Parties' choice of which forecast publication date to use was based on their assumptions as to when the Commission will calculate the ROE for the upcoming test year; on that basis parties presumed the Commission will rely on either September or October data.

194. The Commission agrees with parties that it is beneficial to maintain consistency in forecasting methods between base and test year values and therefore will use the same method for forecasting the risk-free rate. In Section 6.3, the Commission determined that it will base the calculations for a test year on the data from October of the preceding year. Consistent with these determinations, the Commission finds that forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield²⁰⁰ over the period October 1 to October 31 each year preceding the test year (0.25 weight).

6.5.3 Base and test year values for utility bond yield spread

195. In general terms, the utility bond yield spread is calculated as a difference between the utility bond yield and GoC bond yield of the same maturity.

196. Consistent with her recommendations to use the 30-year GoC bond yield for the forecast risk-free rate, Dr. Villadsen recommended calculating the spread against the yield on 30-year utility bonds. Dr. Villadsen also advised that the utility bond yield spread should be estimated using a bond index that measures the market-based yields on a broad portfolio of Canadian utility bonds. She recommended the 30-year A-rated Canadian Utility Bond Index from Bloomberg (Series C29530Y) for this purpose. The spread can then be calculated as the current yield on 30-year A-rated Canadian utility bonds minus the current yield on the 30-year GoC bond, as of the same valuation date that the other "base" inputs are established in the formula. Dr. Villadsen stated the Commission may consider using the average yield over a historical period (e.g., the prior 15 days) to account for any potential one-day pricing effects.²⁰¹ In her evidence, Dr. Villadsen noted that the base spread at the end of November 2022 was 1.63 per cent.²⁰²

197. Other parties generally followed the same methodology as Dr. Villadsen for calculating the base utility bond yield spread, but differed in certain aspects. In Concentric's view, the utility

²⁰⁰ Bank of Canada CANSIM Series V39056.

²⁰¹ Exhibit 27084-X0469.01, PDF page 82.

²⁰² Exhibit 27084-X0469.01, PDF page 33 at Figure 6, PDF page 80.

bond yield spread should consider both A-rated and Baa-rated utility bonds because not all of the Alberta utilities have an A rating. Further, Concentric suggested that if the A and Baa-rated bond yield spreads differ, the Commission could average them or differentiate the resulting ROE separately for the A and sub-A rated utilities. Concentric stated that the base utility bond spread should be calculated based on market data at the end of December 2022.²⁰³ D. D’Ascendis recommended setting the base spread using the average utility bond yield spread for the month of December 2022 in the amount of 1.64 per cent.²⁰⁴ Dr. Cleary recommended using the actual, prevailing A-rated 30-year utility bond yield spread at the time the base ROE is set. For example, Dr. Cleary observed that the 30-year GoC bond yield of 2.85 per cent as of January 19, 2023, implied an A-rated utility yield spread of 1.58 per cent versus the spread of 1.31 per cent as of January 2020, and the average spread of 1.39 per cent over the January 3, 2003, to January 19, 2023 period.²⁰⁵

198. Regarding the utility bond yield spread for the upcoming test year, parties preferred to use the same methodologies they recommended for calculating the base value of the spread. The only difference was to use data from either September or October, i.e., at the same time the Commission computes the other parameters of the formulaic approach.

199. The Commission agrees with the mechanics of the utility bond yield spread calculations as described by Dr. Villadsen and used by most parties. The Commission also agrees with the selection of the 30-year A-rated Canadian Utility Bond Index from Bloomberg given the Commission’s continued recognition of the importance of maintaining a target credit rating for the Alberta utilities in the A-range, as discussed in Section 7.3. As well, the Commission agrees with Dr. Villadsen that the base utility bond yield spread should be set based on data from the same time period that is used to establish the other “base” inputs in the formula. Therefore, the Commission will use the average utility bond yield spread for the month of February 2023 for the base value in the formula to be consistent with the time period selected for the data used to set the risk-free rate in Section 6.3.

200. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula.

201. Regarding the utility bond yield spread for the test year ($SPRD_t$), as was recommended by the majority of parties, the Commission will calculate the average difference between (i) the 30-year A-rated Canadian utility bond yield²⁰⁶ and (ii) the long-term GoC bond yield²⁰⁷ over the period October 1 to October 31 of the year preceding the test year.

²⁰³ Exhibit 27084-X0315, PDF page 111.

²⁰⁴ Exhibit 27084-X0390, PDF page 9.

²⁰⁵ Exhibit 27094-X0320.02, PDF page 20.

²⁰⁶ Bloomberg Series C29530Y.

²⁰⁷ Bank of Canada CANSIM Series V39056.

7 Capital structure

7.1 Overview, approved deemed equity ratios for 2024, and review timeframe

202. To satisfy the fair return standard, the Commission is required to determine a fair return on the deemed equity component of invested capital. In this section, the Commission will determine the deemed equity ratios (also referred to as capital structure) – that is, the approved deemed portion (percentage) of rate base, net of no-cost capital, supported by common equity, for each of the utilities.

203. In this decision, the Commission maintains its previous approach of setting a uniform approved ROE, and then adjusting for any differences in risk among each of the utilities by adjusting the deemed equity ratios. The Commission will make adjustments, if required, to recognize changes in relative risk for each utility from the deemed equity ratios approved for 2023 in Decision 27084-D01-2022.

204. The Commission finds that no change is required to the deemed equity ratios set out in the 2018 GCOC decision. The Commission has determined that a deemed equity ratio of 37 per cent for both distribution and transmission utilities (with the exception of Apex, whose deemed equity ratio will remain at 39 per cent), including those which pay income tax and those which currently are income tax exempt or do not currently pay income tax, satisfies the fair return standard when combined with a 9.0 per cent approved notional ROE, and will enable the utilities to target a credit rating in the A-range.

205. The Commission considers that the deemed equity ratios should be reviewed every five years, or whenever the ROE formula is reviewed, whichever happens first, and finds that this promotes regulatory efficiency. In the case of any material changes in business risk that occur before the scheduled review of the deemed equity ratios approved in this decision, parties can request that the Commission undertake an earlier review as further described in Section 5.5.

206. The section is organized as follows. In Section 7.2, the Commission briefly outlines the deemed equity ratios recommended by the parties. In Section 7.3, the Commission addresses the targeting of credit ratings in the A-range. In Section 7.4, the Commission discusses credit metrics required by a typical pure-play regulated utility in Canada in order to achieve an A-range credit rating. The Commission also evaluates the credit metrics of the utilities having regard to significant financial parameters observed in Rule 005 filings and other evidence on the record of this proceeding, including the embedded average debt rate, depreciation as a percentage of invested capital, the income tax rate and the mid-year construction work in progress (CWIP) as a percentage of invested capital.

207. The Commission's consideration of the other factors relevant to the determination of an approved deemed equity ratio for each utility is in Section 7.5 with a review of the evidence in relation to changes in business risk that impact all the utilities. The Commission addresses the submissions of Fortis and Apex regarding their deemed equity ratios in Section 7.6.

7.2 Requested deemed equity ratios

208. The currently approved deemed equity ratios and the ratios recommended by parties for 2024 are set out in the following table.

Table 7. Currently approved deemed equity ratios and the deemed equity ratios recommended for 2024

	Last approved ²⁰⁸	Recommended by Apex/ATCO Utilities/Fortis ²⁰⁹ Dr. Villadsen	Recommended by AltaLink/EPCOR ²¹⁰ D. D'Ascendis	Recommended by ENMAX ²¹¹ J. Coyne	Recommended by IPCAA ²¹² D. Madsen	Recommended by the UCA ²¹³ Dr. Cleary
Electricity and natural gas transmission						
AltaLink	37		40		35	37
ATCO Electric Transmission	37	42			35	37
ATCO Pipelines	37	40				37
ENMAX Transmission	37			40	35	37
EPCOR Transmission	37		40		35	37
KainaiLink L.P.	37					
Lethbridge	37					
PiikaniLink L.P.	37					
Red Deer	37					
TransAlta	37					
Electricity and natural gas distribution						
Apex	39	44				39
ATCO Electric Distribution	37	40			35	37
ATCO Gas	37	40				37
ENMAX Distribution	37			40	35	37
EPCOR Distribution	37		40		35	37
Fortis	37	43			35	37

209. Dr. Villadsen conducted a credit ratio analysis to determine at what approved ROE and equity ratio combination the ATCO Utilities, Fortis and Apex would meet standard credit metric benchmarks from credit rating agencies such as the earnings before interest and taxes (EBIT) coverage, funds from operations (FFO) coverage, and FFO to debt metric. She also looked at DBRS and Moody's stated debt to rate base benchmarks in recommending a deemed equity percentage of about 40 per cent for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, and Fortis. She noted that F. Graves further recommended an "about 300 [bps] of equity percentage" increase in the equity ratio of Fortis, and Dr. Villadsen adopted that recommendation. Dr. Villadsen noted that at a 10 per cent ROE, ATCO Electric Transmission only met the FFO coverage and FFO to debt metric at about 42.5 per cent equity, so she recommended a deemed equity ratio of about 42 per cent equity for ATCO Electric Transmission.

²⁰⁸ Decision 27084-D01-2022, paragraph 59.

²⁰⁹ Exhibit 27084-X0469.01, PDF pages 104-105. Dr. Villadsen concurred with M. Tolleth that the deemed equity ratio for Apex be at least 400 basis points higher than the other utilities. Exhibit 27084-X0921, PDF page 2. Exhibit 27084-X0925, PDF page 17. Exhibit 27084-X0930, PDF page 20.

²¹⁰ Exhibit 27084-X0390, PDF page 133. Exhibit 27084-X0928, PDF page 32.

²¹¹ Exhibit 27084-X0315, PDF page 19. Exhibit 27084-X0924, PDF page 32.

²¹² Exhibit 27084-X0292, PDF page 6. Exhibit 27084-X0918, PDF page 31.

²¹³ Exhibit 27084-X0320.02, PDF page 6. Exhibit 27084-X0926, PDF page 34.

For Apex, Dr. Villadsen recommended an equity percentage at least 400 basis points higher than the benchmark based on the business risk analysis by M. Tolleth.²¹⁴

210. Dr. Villadsen benchmarked her recommended deemed equity ratios against deemed equity ratios approved by other Canadian regulators, noting that the OEB approved a deemed equity ratio of 40 per cent for electric distributors and 36 to 40 per cent for gas distributors, while the British Columbia Utilities Commission has approved equity ratios of 38.5 per cent or more, and the Régie de l'énergie du Québec has approved equity ratios of between 38.5 and 46 per cent.²¹⁵ In the U.S., the average equity ratios in 2021-2022 for electric and gas distribution utilities were 50.2 and 51.1 per cent, respectively.²¹⁶

211. M. Tolleth concluded that in order to satisfy the fair return standard, Apex's deemed equity ratio should be set at a premium to that of the generic benchmark gas distribution utility, in recognition of the higher market cost of capital associated with its small size and correspondingly elevated risk. He further concluded that based on fundamental finance principles and market evidence, any partially countervailing reduction to Apex's deemed equity ratio for purposes of "balancing" the higher market cost of debt experienced by small utilities such as Apex would not be consistent with the fair return standard. M. Tolleth submitted that it would be appropriate for the Commission to set Apex's deemed equity ratio at least 400 basis points (bps) above that of the "generic" Alberta gas distribution utility.²¹⁷

212. F. Graves submitted that it is clear that the REA issue faced by Fortis presents a material financial risk, and can be offset by either allowing an ROE increase of 68 bps for Fortis, or an increase of about 300 bps in the deemed equity ratio of Fortis.²¹⁸

213. D. D'Ascendis recommended that the deemed equity ratio applicable to AltaLink and EPCOR should be 40 per cent, which he submitted reflects the substantial increase in market risk since the 2018 GCOC proceeding, and increased business risk faced by AltaLink and EPCOR over that same period.²¹⁹ D. D'Ascendis submitted that his 40 per cent recommendation is reasonable when viewed in light of the OEB's approved deemed equity ratio in its annual formula ROE.²²⁰

214. J. Coyne stated that his assessment showed that while Alberta regulated utilities generally have comparable business risk to companies in the North American proxy group, they have much higher financial risk. He added that the current deemed equity ratio for Alberta utilities is low by Canadian standards and very low when compared to U.S. utilities, and recommended that the Alberta deemed equity ratio be raised to at least 40 per cent. J. Coyne submitted that his recommended 40 per cent deemed equity ratio is the same as that currently allowed for Ontario's electric distribution companies, and equivalent to the Canadian average allowed equity ratio for investor-owned utilities. He commented that a 40 per cent deemed equity ratio is conservative for ENMAX, as it is a non-taxable entity that does not receive the benefit of including income taxes

²¹⁴ Exhibit 27084-X0469.01, PDF pages 7-8.

²¹⁵ Exhibit 27084-X0469.01, PDF page 101.

²¹⁶ Exhibit 27084-X0469.01, PDF page 89.

²¹⁷ Exhibit 27084-X0377, PDF pages 5-6.

²¹⁸ Exhibit 27084-X0479, PDF page 47.

²¹⁹ Exhibit 27084-X0390, PDF page 133.

²²⁰ Exhibit 27084-X0390, PDF page 10.

in its revenue requirement, thereby reducing its cash flow metrics as compared to taxable entities.²²¹

215. D. Madsen recommended a two per cent reduction to the equity thickness for the electric transmission and electric distribution utilities, from 37 per cent to 35 per cent. He submitted that the business and regulatory risk of the electric utilities has improved since the 2018 GCOC proceeding and that the financial risks and performance of the utilities remains strong. D. Madsen added that the growth rates of the utilities have slowed significantly in recent years which, all else being equal, reduces risk.²²²

216. Dr. Cleary commented that Alberta utilities have low risk as shown by their consistent “low business risk” ratings, low earnings volatility, and most importantly, the ability to generate earned ROEs above the approved ROEs for the last 17 years. Dr. Cleary recommended no change in the approved deemed equity ratios but, rather, emphasized the impetus for a reduction in the approved ROE, based on his belief that it continues to be “well above the actual cost of equity for Alberta utilities.” Dr. Cleary submitted that his recommendations are reasonable, and are supported by the credit metric analysis provided by R. Bell.²²³

217. R. Bell noted that if the achieved ROE increases, the level of the deemed equity ratio required to achieve the credit metric targets decreases. He recommended that if the approved ROE increases, the deemed equity ratio be decreased.²²⁴

7.3 Targeted credit ratings

218. The targeting of credit ratings in the A-range is one of the factors the Commission will continue to use as part of its determination of the deemed equity ratios for 2024 and beyond.

219. Credit ratings assess the credit worthiness of a firm as determined by a credit rating agency. A higher credit rating signals higher confidence in the firm’s ability to meet its interest payments and to repay debt principal, allowing the company to borrow at a lower interest rate.

220. Historically, the Commission has recognized the importance of maintaining a target credit rating for the utilities in Alberta in the A-range,²²⁵ and continues to do so. This target credit rating is especially important when interest rates rise. The use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction and comparability aspects of the fair return standard.

221. The Commission finds that, generally, most utilities in Alberta have had little difficulty raising debt and equity financing on satisfactory terms since the 2018 GCOC proceeding, all while maintaining the credit ratings from S&P that were in place during the 2018 GCOC proceeding. The one exception is ENMAX’s credit rating, which was decreased largely because of a debt-financed acquisition that was not associated with ENMAX’s Alberta operations.²²⁶

²²¹ Exhibit 27084-X0315, PDF pages 4-5.

²²² Exhibit 27084-X0292, PDF page 62.

²²³ Exhibit 27084-X0320.02, PDF pages 5-6.

²²⁴ Exhibit 27084-X0318, PDF page 20.

²²⁵ Decision 22570-D01-2018, PDF page 145, paragraph 689.

²²⁶ Exhibit 27084-X0926, PDF page 26, citing Transcript, Volume 2, page 294, line 4 to page 296, line 1.

7.4 Credit metrics

222. Dr. Villadsen,²²⁷ D. D’Ascendis,²²⁸ D. Madsen²²⁹ and Dr. Cleary²³⁰ each took the position that their respective recommended deemed equity ratios either considered credit metrics, or were supported by a credit metric analysis. In past GCOC decisions, the Commission has placed weight on credit metrics.

223. Credit metrics (or financial ratios) are an important, although not the only, component that credit rating agencies consider when assessing the risk of any particular company and assigning a credit rating. As noted in the 2018 GCOC decision, the Commission has historically assessed three principal credit metrics:²³¹

- **EBIT coverage:** This is referred to as an interest coverage ratio. In the Commission’s credit metric model, it is calculated by grossing up the net income by the statutory income tax rate, adding the return on debt amount, and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate.
- **FFO coverage:** This is also an interest coverage ratio. In the Commission’s credit metric model, it is calculated by adding the return on debt amount, the net income and the depreciation collected and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate. It is important to note that in the Commission’s credit model, the interest expense associated with the CWIP balance is not included in the numerator because it is based on the assumption that there is no CWIP included in rate base.
- **FFO/debt:** S&P compares this payback ratio against benchmarks to derive the preliminary cash flow/leverage assessment for a company. S&P notes that this ratio is also useful in determining the relative ranking of the financial risk of companies.²³² In the Commission’s credit metric model, it is calculated by adding the net income and the depreciation collected and dividing the resulting figure by the sum of the deemed mid-year debt for rate base and CWIP.

224. In the 2018 GCOC decision, the Commission observed that the credit rating metrics required for an Alberta utility to achieve a credit rating in the A-range had not changed since the 2016 GCOC decision. Those guidelines were EBIT coverage of 2.0, FFO coverage of 2.0 to 3.0, and an FFO/debt ratio range of 9.0 to 13.0.²³³ The Commission indicated that those guidelines assumed a credit rating assessment of “strong” for the Alberta regulatory environment. The Commission added that “the guidelines do not take into account potential adjustments to the

²²⁷ Exhibit 27084-X0469.01, PDF pages 5-6.

²²⁸ Exhibit 27084-X0390, PDF page 121.

²²⁹ Exhibit 27084-X0292, PDF page 62.

²³⁰ Exhibit 27084-X0320.02, PDF page 6.

²³¹ Decision 22570-D01-2018, PDF page 146, paragraph 698.

²³² Proceeding 20622, Exhibit 20622-X0089, PDF page 73.

²³³ Decision 22570-D01-2018, PDF page 164, paragraph 775. The guidelines were set out in Table 15 of the decision, on PDF page 165.

deemed equity ratios that may be necessary in the Commission's judgment to take account of the current trend of "negative" noted by credit rating agencies and in particular by S&P."²³⁴

225. Dr. Villadsen concurred with S&P that it is important to have credit metrics that are not marginally satisfactory.²³⁵ She submitted that to ensure sufficient cushion against negative occurrences, it is important to establish expected credit metrics that are not up against the lower bound, but instead near the middle.²³⁶

226. N. Martin indicated that under S&P's methodology, regulatory advantage is a key contributor to a utility's credit rating, and submitted that a lower assessment of the regulatory regime leads to higher business risk, and with higher business risk, stronger credit metrics are required to maintain the same rating.²³⁷ N. Martin stated that late in 2020, S&P lowered its assessment of the Alberta "regulatory advantage" from "strong" to "strong/adequate," citing low returns, regulatory lag and the risk of having to absorb undepreciated capital costs of stranded assets. She submitted that simply reducing regulatory lag by improving regulatory efficiency will not be sufficient to improve the regulatory advantage assessment back to "strong."²³⁸

227. N. Martin submitted that the Commission's sole reliance on ratio targets taken from S&P's low volatility table without also taking into account the medial volatility table is not prudent. She indicated that given Alberta's regulatory advantage is currently only strong/adequate, a utility rating will be based on the low volatility table only if S&P views the utility's business strategy as positive, thus moving the company-specific final regulatory advantage score to strong from strong/adequate.²³⁹

228. The Commission acknowledges that credit metric targets do not assure an A-range credit rating, but it is satisfied that credit metrics should be considered in the assessment of deemed equity ratios. The Commission recognizes that, among other things, the process of setting credit metrics required to maintain an A-range credit rating for the utilities in Alberta is a function of market dynamics and credit agency analysis of macro-economic trends, Canadian utility industry specific variables and future investor expectations, applied to an assessment of the relative risk of the utility sector, and perceptions of the regulatory environment.

229. Credit metrics reflect past market expectations as well as anticipated market expectations, given an assessment of current economic conditions, the information and assumptions employed in conducting the analysis, and judgment of relative risk. The element of judgment is reflected to some degree in the differing credit metrics employed and the breadth of ranges used by various credit rating agencies and market analysts. Further, the application of utility sector credit metrics to a particular Alberta utility involves a further element of judgment on factors such as the Alberta regulatory climate.

230. From a practical perspective, however, credit metrics affect investor risk perceptions and consequently may affect market behaviour. The Commission considers the credit metrics reflected in credit rating and market analyst reports to be generally reflective of future

²³⁴ Decision 22570-D01-2018, PDF page 164, paragraph 775.

²³⁵ Exhibit 27084-X0761.02, PDF page 76.

²³⁶ Exhibit 27084-X0761.02, PDF page 80.

²³⁷ Exhibit 27084-X0316, PDF page 7.

²³⁸ Exhibit 27084-X0316, PDF page 6.

²³⁹ Exhibit 27084-X0316, PDF page 25.

expectations of utility debt and of equity investors with respect to credit metric fundamentals. This observation is supported generally by a review of actual market behaviour.

231. In the 2016 GCOC decision and the 2018 GCOC decision, the Commission placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using the low volatility table. During the 2018 GCOC proceeding, the Alberta regulatory advantage was rated by S&P as "strong" with a trend of "negative." Evidence was submitted during the current proceeding that late in 2020, S&P lowered its assessment of the Alberta regulatory advantage from "strong" to "strong/adequate." AltaLink and EPCOR submitted that this made the use of the FFO/debt range from S&P's low volatility table inapplicable in this proceeding. J. Coyne submitted that a drop in the regulatory advantage can require stronger credit metrics to maintain a given credit rating. However, the Commission finds that this lower assessment of the Alberta regulatory advantage has not prevented S&P from assessing financial credit metrics for a number of the utilities in Alberta (AltaLink L.P., AltaLink Investments L.P., CU Inc. and Fortis) using the low volatility table.²⁴⁰

232. As explained by N. Martin, even with a regulatory advantage assessment of "strong/adequate," S&P's low volatility table will continue to be available, but only if S&P views the utility's business strategy as positive.²⁴¹ Given that S&P has viewed the business strategy of a number of the utilities in Alberta as positive, as evidenced by S&P's use of the low volatility table for these utilities, the Commission agrees with the UCA²⁴² that using the medial volatility table in establishing credit metric thresholds for an A-range rating is unnecessary, and would reward the utilities whose business strategy is not viewed as positive by S&P. The Commission finds that the continued use of the low volatility table is warranted in assessing the credit metrics.

233. The Commission agrees with Dr. Villadsen's submission that it is important to establish credit metrics that are not up against the lower bound, but are nearer to the mid-point of the range. The resulting EBIT coverage ratios at 37 per cent deemed equity are 2.2 for non-taxable utilities and 2.6 for taxable utilities. The DBRS range for EBIT coverage is 1.8 to 2.8, which places the non-taxable utilities just under the mid-point of the range, and places the taxable utilities towards the top of the range. The resulting FFO coverage ratios at 37 per cent deemed equity are 4.4 for the distribution utilities and 3.7 for the transmission utilities. Both of these exceed the 2.0 to 3.0 range of S&P's low volatility table and even exceed the lower bound of the 3.0 to 5.0 range of S&P's medial volatility table. S&P's low volatility table has a range of 9.0 per cent to 13.0 per cent for the FFO/debt ratio. The resulting FFO/debt ratios at 37 per cent deemed equity are 14.2 per cent for the distribution utilities and 11.5 per cent for the transmission utilities, both of which are well above the lower bound of 9.0 per cent, with the distribution utilities being within the range of the medial volatility table.

7.4.1 Equity ratios associated with credit metrics

234. In the 2018 GCOC decision (tables 11-14), the Commission provided a sensitivity analysis to illustrate the effect of a range of equity ratios on the three principal credit metrics for

²⁴⁰ Exhibit 27084-X0926, PDF page 26, citing Exhibit 27084-X0273, PDF pages 134 and 143 (for AltaLink L.P. and AltaLink Investments L.P.), citing Exhibit 27084-X0279, PDF page 66 (for CU Inc.), and citing Exhibit 27084-X0286, PDF page 6 (for Fortis).

²⁴¹ Exhibit 27084-X0316, PDF page 25.

²⁴² Exhibit 27084-X0926, PDF page 26, paragraph 92.

the distribution utilities and the transmission utilities, using income tax rates of 27 per cent and zero. The analysis was based on certain input parameters associated with the affected utilities. The Commission has prepared a similar analysis as part of this decision.

235. The parameter values used by the Commission in the 2018 GCOC decision, as well as the parameter values the Commission is using in this proceeding, are set out in Table 8 below. The Commission's reasons for selecting the updated parameter values follow.

Table 8. Parameters for calculating credit metrics

Parameter	Parameter values applied in this decision – taxable distribution utilities	Parameter values applied in this decision – taxable transmission utilities	Parameter values applied in 2018 GCOC decision – taxable distribution utilities	Parameter values applied in 2018 GCOC decision – taxable transmission utilities
	(%)			
Embedded average debt rate	4.20	4.20	4.70	4.70
ROE	9.00	9.00	8.50	8.50
Income tax rate	23.00	23.00	27.00	27.00
Depreciation	5.88	4.11	5.85	4.20
CWIP	2.89	3.10	3.21	5.00

236. In arriving at the updated parameters, the Commission reviewed the actual parameters from 2022 and 2021, as set out in the 2023 and 2022 Rule 005 filings that were submitted as part of this proceeding.

237. The ROE input parameter is common to all utilities, as is the income tax rate input parameter for those utilities that are not income tax exempt. The Commission has summarized the embedded average debt rates, depreciation rates and CWIP percentages for each utility in Table 9.

Table 9. Embedded average debt rates, depreciation rates and CWIP percentages by utility

Utility	Invested capital (\$000)	Debt cost (%)	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
ATCO Electric – distribution				
2023 Rule 005	2,670,900	4.43	5.14	4.47
2022 Rule 005	2,598,600	4.52	5.05	3.66
Fortis – distribution				
2023 Rule 005	3,929,400	4.44	6.36	1.78
2022 Rule 005	3,777,200	4.42	6.24	1.72
ENMAX – distribution				
2023 Rule 005	1,812,900	3.57	4.95	1.72
2022 Rule 005	1,672,700	3.48	4.93	2.21
EPCOR – distribution				
2023 Rule 005	1,652,300	4.11	4.20	1.45
2022 Rule 005	1,542,500	4.13	4.21	1.73
ATCO Gas – distribution				
2023 Rule 005	2,872,900	4.42	7.57	4.68
2022 Rule 005	2,855,900	4.48	7.24	3.50
Apex – distribution				
2023 Rule 005	452,800	4.27	5.21	1.80
2022 Rule 005	423,800	4.23	5.17	2.81
AltaLink – transmission				
2023 Rule 005	7,421,600	3.89	3.99	1.55
2022 Rule 005	7,469,200	3.86	3.91	1.49
ATCO Electric – transmission				
2023 Rule 005	4,841,400	4.53	4.31	4.84
2022 Rule 005	4,980,300	4.56	4.19	3.23
ENMAX – transmission				
2023 Rule 005	774,100	3.54	3.78	9.70
2022 Rule 005	750,600	3.49	3.67	5.83
EPCOR – transmission				
2023 Rule 005	761,000	4.53	3.64	5.48
2022 Rule 005	732,500	4.60	3.50	5.25
ATCO Pipelines – transmission				
2023 Rule 005	2,486,600	3.97	4.36	1.59
2022 Rule 005	2,344,600	4.06	4.33	2.14
Simple average				
2023 Rule 005		4.15	4.86	3.55
2022 Rule 005		4.17	4.77	3.05

238. In Table 10 below, the Commission presents additional calculations based on the information presented in Table 9. There is no simple average or weighted average for gas transmission utilities presented separately in Table 10 because there is only one gas transmission utility, i.e., ATCO Pipelines.

Table 10. Additional analysis of information included in Table 9

Utility	Debt cost (%)	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
Simple average – overall			
2023 Rule 005	4.15	4.86	3.55
2022 Rule 005	4.17	4.77	3.05
Weighted average - overall			
2023 Rule 005		4.91	3.01
2022 Rule 005		4.80	2.54
Simple average – distribution utilities			
2023 Rule 005	4.21	5.57	2.65
2022 Rule 005	4.21	5.47	2.60
Weighted average – distribution utilities			
2023 Rule 005		5.88	2.89
2022 Rule 005		5.77	2.61
Simple average – transmission utilities			
2023 Rule 005	4.09	4.01	4.63
2022 Rule 005	4.11	3.92	3.59
Weighted average – transmission utilities			
2023 Rule 005		4.11	3.10
2022 Rule 005		4.03	2.49
Simple average – electric distribution utilities			
2023 Rule 005	4.14	5.16	2.36
2022 Rule 005	4.14	5.11	2.33
Weighted average – electric distribution utilities			
2023 Rule 005		5.43	2.43
2022 Rule 005		5.36	2.33
Simple average – gas distribution utilities			
2023 Rule 005	4.35	6.39	3.24
2022 Rule 005	4.35	6.21	3.15
Weighted average – gas distribution utilities			
2023 Rule 005		7.25	4.29
2022 Rule 005		6.98	3.41
Simple average – electric transmission utilities			
2023 Rule 005	4.12	3.93	5.39
2022 Rule 005	4.13	3.82	3.95
Weighted average – electric transmission utilities			
2023 Rule 005		4.07	3.38
2022 Rule 005		3.98	2.55

239. In its credit metric calculations, the Commission adopted the following five parameters: ROE value, embedded average debt rate, income tax rate, depreciation as a percentage of invested capital, and mid-year CWIP as a percentage of invested capital.

ROE value

240. The Commission has applied the notional ROE value of 9.0 per cent in its credit metric calculations, consistent with its findings in Section 6.4.5.

Embedded average debt rate

241. The simple average of the embedded average debt rates is 4.17 per cent based on the 2022 Rule 005 reports, and 4.15 per cent based on the 2023 Rule 005 reports. The simple average of the distribution utilities based on both Rule 005 reports was 4.21 per cent. The simple

average of the transmission utilities was 4.11 per cent based on the 2022 Rule 005 reports, and 4.09 per cent based on the 2023 Rule 005 reports.

242. The Commission finds that the use of 4.20 per cent for the embedded average debt rate is reasonable. While this figure is higher than the overall simple average debt rate for all the utilities based on the 2023 Rule 005 reports, it errs on the conservative side, because it results in lower EBIT coverage and FFO coverage ratios.

Income tax rate

243. The Commission is analyzing credit metrics using both the current combined statutory income tax rate of 23 per cent, and a rate of zero. The income tax rate of zero accounts for the income-tax-exempt utilities, as well as those utilities that expect to have no taxable income.

Depreciation as a percentage of invested capital

244. The amount of depreciation collected through rates is included in the calculation of the FFO component of the FFO/debt and FFO coverage ratios.

245. The weighted average depreciation rate as a percentage of invested capital for the distribution utilities based on the 2023 Rule 005 reports is 5.88 per cent, and is 4.11 per cent for the transmission utilities, both as shown in Table 10. The Commission uses these figures in its credit metric calculations, because they represent the most recent data on the record of the proceeding.

Mid-year CWIP as a percentage of invested capital

246. The weighted average mid-year CWIP as a percentage of invested capital for the distribution utilities based on the 2023 Rule 005 reports is 2.89 per cent, and is 3.10 per cent for the transmission utilities, both as shown in Table 10. The Commission uses these figures in its credit metric calculations, because they represent the most recent data on the record of the proceeding.

247. Based on the credit metric parameters discussed above, the Commission has updated its credit metric calculations at various equity ratios from the calculations set out in the 2018 GCOC decision. As previously mentioned, to address the impact of zero income tax on credit metrics, the Commission has also provided credit metric calculations at various equity ratios, which reflect an income tax rate of zero. The revised calculations are set out in tables 11-14.

Table 11. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision)

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision
30	2.1	2.0	3.8	3.4	11.9	11.6
31	2.2	2.0	3.9	3.5	12.2	11.9
32	2.2	2.1	4.0	3.6	12.5	12.2
33	2.3	2.2	4.0	3.6	12.8	12.5
34	2.4	2.2	4.1	3.7	13.2	12.8
35	2.4	2.3	4.2	3.8	13.5	13.2
36	2.5	2.3	4.3	3.8	13.8	13.5
37	2.6	2.4	4.4	3.9	14.2	13.8
38	2.6	2.4	4.4	4.0	14.6	14.2
39	2.7	2.5	4.5	4.1	15.0	14.6
40	2.8	2.6	4.6	4.1	15.4	14.9
41	2.9	2.6	4.7	4.2	15.8	15.3
42	2.9	2.7	4.8	4.3	16.2	15.7
43	3.0	2.8	4.9	4.4	16.6	16.2
44	3.1	2.9	5.0	4.5	17.1	16.6
45	3.2	2.9	5.1	4.6	17.5	17.0

Table 12. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of zero

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable
30	1.9	1.7	3.8	3.4	11.9	11.6
31	1.9	1.8	3.9	3.5	12.2	11.9
32	2.0	1.8	4.0	3.6	12.5	12.2
33	2.0	1.8	4.0	3.6	12.8	12.5
34	2.0	1.9	4.1	3.7	13.2	12.8
35	2.1	1.9	4.2	3.8	13.5	13.2
36	2.1	2.0	4.3	3.8	13.8	13.5
37	2.2	2.0	4.4	3.9	14.2	13.8
38	2.2	2.0	4.4	4.0	14.6	14.2
39	2.3	2.1	4.5	4.1	15.0	14.6
40	2.4	2.1	4.6	4.1	15.4	14.9
41	2.4	2.2	4.7	4.2	15.8	15.3
42	2.5	2.2	4.8	4.3	16.2	15.7
43	2.5	2.3	4.9	4.4	16.6	16.2
44	2.6	2.3	5.0	4.5	17.1	16.6
45	2.7	2.4	5.1	4.6	17.5	17.0

Table 13. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision)

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision
30	2.1	2.0	3.2	2.9	9.4	9.2
31	2.2	2.0	3.3	3.0	9.7	9.4
32	2.2	2.1	3.3	3.0	10.0	9.7
33	2.3	2.1	3.4	3.1	10.2	10.0
34	2.4	2.2	3.5	3.1	10.5	10.2
35	2.4	2.2	3.5	3.2	10.8	10.5
36	2.5	2.3	3.6	3.3	11.1	10.8
37	2.6	2.3	3.7	3.3	11.5	11.1
38	2.6	2.4	3.8	3.4	11.8	11.4
39	2.7	2.5	3.9	3.4	12.1	11.7
40	2.8	2.5	3.9	3.5	12.5	12.1
41	2.8	2.6	4.0	3.6	12.8	12.4
42	2.9	2.7	4.1	3.7	13.2	12.8
43	3.0	2.7	4.2	3.7	13.6	13.1
44	3.1	2.8	4.3	3.8	14.0	13.5
45	3.2	2.9	4.4	3.9	14.4	13.9

Table 14. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of zero

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable
30	1.9	1.7	3.2	2.9	9.4	9.2
31	1.9	1.7	3.3	3.0	9.7	9.4
32	1.9	1.8	3.3	3.0	10.0	9.7
33	2.0	1.8	3.4	3.1	10.2	10.0
34	2.0	1.8	3.5	3.1	10.5	10.2
35	2.1	1.9	3.5	3.2	10.8	10.5
36	2.1	1.9	3.6	3.3	11.1	10.8
37	2.2	2.0	3.7	3.3	11.5	11.1
38	2.2	2.0	3.8	3.4	11.8	11.4
39	2.3	2.1	3.9	3.4	12.1	11.7
40	2.4	2.1	3.9	3.5	12.5	12.1
41	2.4	2.1	4.0	3.6	12.8	12.4
42	2.5	2.2	4.1	3.7	13.2	12.8
43	2.5	2.3	4.2	3.7	13.6	13.1
44	2.6	2.3	4.3	3.8	14.0	13.5
45	2.7	2.4	4.4	3.9	14.4	13.9

248. The Commission has undertaken the above calculations in light of the credit metric findings in Section 7.4. Table 15 sets out the guidelines established by the Commission in this section to achieve a credit rating in the A-range, which assumes S&P viewing the utility's business strategy as positive, which moves the utility's final regulatory advantage score to strong and enables the use of S&P's low volatility table.

249. Table 15 sets out the minimum equity ratio that would be required, in conjunction with an approved ROE of 9.0 per cent, for distribution and transmission utilities in Alberta with an income tax rate of 23 per cent, as well as distribution and transmission utilities in Alberta with an income tax rate of zero per cent, to meet the corresponding credit ratio threshold or range used by the Commission to establish a credit rating in the A-range. For example, as shown in Table 15, a distribution utility in the 2024 GCOC proceeding that has an income tax rate of zero per cent, would require a deemed equity ratio of 32 per cent to achieve an EBIT coverage ratio of 2.0. That same utility would require a deemed equity ratio somewhere below 30 per cent, in order to achieve an FFO coverage ratio of 2.0, and an FFO coverage ratio of 3.0. Finally, that same utility would require a deemed equity ratio below 30 per cent, in order to achieve an FFO/debt ratio of 9.0, while it would require a deemed equity ratio of 34 per cent to achieve an FFO/debt ratio of 13.0.

Table 15. Commission guidelines for equity ratios to achieve a credit rating in the A-range

Credit metric guideline	2.0 EBIT coverage	2.0 FFO coverage	3.0 FFO coverage	9.0 FFO/debt ratio	13.0 FFO/debt ratio
			(%)		
2023 distribution utilities – 23 per cent income tax rate	Below 30	Below 30	Below 30	Below 30	34
2018 distribution utilities – 27 per cent income tax rate	30	Below 30	Below 30	Below 30	35
2023 distribution utilities – zero per cent income tax rate	32	Below 30	Below 30	Below 30	34
2018 distribution utilities – zero per cent income tax rate	36	Below 30	Below 30	Below 30	35
2023 transmission utilities – 23 per cent income tax rate	Below 30	Below 30	Below 30	Below 30	42
2018 transmission utilities – 27 per cent income tax rate	30	Below 30	31	30	43
2023 transmission utilities – zero per cent income tax rate	33	Below 30	Below 30	Below 30	42
2018 transmission utilities – zero per cent income tax rate	37	Below 30	31	30	43

250. Based on the results of its credit metric calculations, the Commission continues to find, as it did in the 2016 and 2018 GCOC decisions, “that absent differences in business risk, the continued perpetuation of the historical gap in equity ratios between the higher equity ratio awarded to distribution utilities and the lower equity ratio awarded to transmission utilities is no longer warranted.”²⁴³ Using the credit metric inputs described previously, including the notional ROE of 9.00 per cent, and with the approved deemed equity ratio of 37 per cent, the distribution

²⁴³ Decision 22570-D01-2018, PDF page 165, paragraph 777. Decision 20622-D01-2016, PDF page 104, paragraph 433.

and transmission utilities meet the Commission's guidelines to achieve a credit rating in the A range.

7.5 Overall assessment of business risk

251. In this section of the decision, the Commission considers whether business risk factors impacting all the utilities, or a particular segment of the utilities, require the Commission to adjust the deemed equity ratios approved in the 2018 GCOC decision.

252. Utility company witnesses testified that business risk was an important factor underlying their recommended deemed equity ratios. They highlighted the increased business risk to utilities due to elevated cybersecurity concerns, the decarbonization policies of all levels of government along with the increased risk associated with macroeconomic factors of rising inflation, interest rates, and capital costs. More broadly, the Alberta utilities suggested that the overall utilities sector has seen a decline in credit ratings and that Alberta utilities are disadvantaged relative to other Canadian utilities and North American comparators that benefit from regulators approving higher ROEs and equity ratios. Two utilities, Fortis and Apex, argued that they warranted higher equity ratios than other Alberta utilities because of their company-specific business risks.

253. Contrary to the submissions of the utilities, interveners suggested that Alberta utilities operated in a low business risk environment and recommended that equity ratios be maintained at the levels set in the 2018 GCOC or decreased.

254. All parties provided their perspectives on the Alberta-specific utility asset disposition (UAD) related or stranded asset risk and the impact of a recent Court of Appeal decision,²⁴⁴ which dealt with recovery of costs of stranded assets destroyed by wildfires.

255. Based on the evidence on the record, the Commission identified (i) various macroeconomic factors; (ii) regulatory risk; (iii) UAD risk; and (iv) decarbonization risk as the main grounds offered by utilities for an upward adjustment to equity thickness for all utilities. A discussion of these issues is provided below, followed by a discussion of the utility-specific risks of Fortis and Apex.

7.5.1 Macroeconomic factors

256. While the Commission acknowledges that interest rates and inflation have increased since the 2018 GCOC, resulting in higher capital costs, it is not persuaded that these factors warrant an increase in approved ROEs or deemed equity ratios above those currently in place. In Alberta, the utilities are largely isolated from broader macroeconomic factors because utility regulation provides a reasonable opportunity to recover prudently incurred costs, including those directly and indirectly affected by higher interest and inflation rates.²⁴⁵ Specifically, PBR plans for Alberta distribution utilities include inflation as a direct input into the PBR formula, while cost-of-service (COS) regulation that applies to transmission utilities affords those utilities a reasonable opportunity to recover all reasonable forecast cost increases related to the safe, reliable and efficient provision of services to customers over the future test period.²⁴⁶

²⁴⁴ *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.

²⁴⁵ Exhibit 27084-X0918, PDF page 14, citing Transcript, Volume 2, pages 504-509.

²⁴⁶ Exhibit 27084-X0918, PDF page 14.

7.5.2 Regulatory risk

257. The utilities claim that regulatory risks in Alberta have increased since 2018. Among the risks they have identified are lower deemed equity ratios and lower approved ROEs than those awarded in other North American jurisdictions, regulatory lag, stranded asset risk, and one credit rating agency's lowering of its assessment of the Alberta regulatory advantage from "most credit supportive" (strong) to "highly credit supportive" (strong/adequate).²⁴⁷

258. The Commission finds these claims of higher regulatory risk in Alberta are without merit. Alberta utilities have low earnings volatility, low business risk ratings and, operate within a regulatory framework that encourages and rewards utility-driven initiatives, projects, and investments in cost reduction and efficiency improvement that can lead to earnings in excess of approved ROEs (that themselves have been determined to be just and reasonable independently of, and entirely without regard to, any additional profits arising from such cost-cutting initiatives) during each PBR term or COS test period.²⁴⁸ The Commission notes parenthetically in this regard, that, with very few exceptions, Alberta utilities have, on average, consistently earned returns above their approved ROE during the past 17 years by responding positively to existing incentives to drive costs lower and secure the benefit of savings thus generated until the next rate case or PBR term. Moreover, regulatory lag, regulatory costs, red tape and related aspects of regulatory burden have been significantly reduced in Alberta since the 2018 GCOC proceeding.²⁴⁹

259. On balance, the Commission finds that the regulatory environment for Alberta utilities is broadly supportive, and that the level of regulatory risk faced by the Alberta utilities is consistent with the level of regulatory risk they faced at the time of the 2018 GCOC proceeding, if not distinctly lower. The issue of stranded asset or UAD-related risk, meanwhile, is dealt with separately in the next section.

7.5.3 Utility asset disposition risk and the impact of the Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129

260. In a letter dated June 6, 2023,²⁵⁰ the Commission requested that parties provide submissions on the impact of the Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*²⁵¹ (the Wildfires Decision) on business risk related to the recovery of costs associated with assets that are stranded due to obsolescence.

261. Most parties submitted that it was premature to assess the impact of the Wildfires Decision – which dealt with the recovery of assets destroyed by a natural disaster – on the recovery of stranded assets made obsolete by technology or other causes. This is because the Court of Appeal sent the matter back to the Commission to determine, and the Commission has not yet rendered its decision. Until the Commission reconsiders its decision on the UAD framework, utilities argued that they were exposed to uncertainty and UAD-related cost disallowance. The CCA stated that the Wildfires Decision likely reduces the business risk of

²⁴⁷ Exhibit 27084-X0316, PDF pages 17-18; Exhibit 27084-X0390, PDF page 97.

²⁴⁸ As noted in footnote 192, The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR.

²⁴⁹ AUC website: <https://www.auc.ab.ca/auc-exceeds-government-of-alberta-target-with-48-per-cent-reduction-in-regulatory-red-tape-requirements/#hq=red%20tape%20reduction>

²⁵⁰ Exhibit 27084-X0906, AUC letter – Additional details regarding argument process.

²⁵¹ *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.

utilities as it appears to directionally increase the likelihood of recovery of costs from customers due to weather and natural disaster events.²⁵²

262. Apart from any impact the Commission's reconsideration of the Wildfires Decision may have, there is no compelling basis to suggest that UAD-related risk has changed since the decision in the 2018 GCOC. The Commission also finds that its 2016 GCOC decision²⁵³ is still applicable to the present proceeding. There, the Commission found that regulatory risk for investors in Alberta utilities had increased by some incremental but unquantifiable amount as a result of the Stores Block-Utility Asset Disposition line of decisions.²⁵⁴

7.5.4 Decarbonization

263. The Commission finds that while there are numerous legislative and other initiatives at all levels of government to reduce carbon emissions,²⁵⁵ the record of this proceeding does not establish that progress towards decarbonization that has taken place or is reasonably likely to take place in the foreseeable future, poses an immediate or imminent risk to Alberta utilities warranting an adjustment to their equity thickness.

264. The utilities argued that, generally, carbon reduction goals are more aggressive and difficult in Alberta than decarbonization policies in other jurisdictions. Examples include the current federal government's stated intention to decarbonize the electricity grid by 2035 and the transition to electric heating now overwhelmingly provided by natural gas. The utilities asserted that if decarbonization creates stranded assets (as it is designed to), the current recovery mechanism (the UAD line of cases) as applied by the Commission to date is much less supportive than in other jurisdictions, thus increasing the utilities' business risk.

265. Intervenors disagreed with this view, stating that absent actual evidence that decarbonization increases the risk to Alberta utilities, there should be no resulting adjustment to equity thickness.²⁵⁶ To the contrary, they submitted that decarbonization and net-zero policies would benefit electric utilities because in order to achieve these goals, additional investment in distribution infrastructure, for example, changes to accommodate wide penetration of electric vehicle charging would be required, thus increasing the utility's rate base and load. Intervenors did acknowledge that there may be impacts on natural gas utilities but that the actual impact was uncertain at this time given the present status of hydrogen injection into the natural gas distribution stream. They concluded that Alberta's overwhelming reliance on natural gas for space heating is not likely to change in the near term because of the very high cost of transitioning from natural gas to electricity.²⁵⁷

266. While the Commission appreciates that decarbonization is a potential risk to Alberta utilities, there is little or no evidence on the record of the current proceeding that shows that natural gas or electric utilities have experienced any significant increases in risk related to customers changing behaviour, a reduction in natural gas demand, complications related to electrification, or factors that might impact their operations. Absent any evidence that clearly shows the impact to the Alberta utilities' business risk from decarbonization, the Commission

²⁵² Exhibit 27084-X0919, PDF page 26, paragraph 82.

²⁵³ Decision 20622-D01-2016.

²⁵⁴ Decision 20622-D01-2016, PDF pages 120-121.

²⁵⁵ Exhibit 27084-X0479, PDF pages 29-31.

²⁵⁶ Exhibit 27084-X0934, PDF page 5.

²⁵⁷ Exhibit 27084-X0926, PDF pages 27-28.

finds that adjusting the deemed equity ratio for Alberta utilities to account for any such impact is unwarranted, or at a minimum, premature.

7.6 Utility-specific business risks

7.6.1 Determination of Commission-approved deemed equity ratio for Fortis

267. Fortis requested a 300 bps premium above the generic deemed equity ratio for an Alberta utility on the basis that it faces increased business and regulatory risk not experienced by other Alberta utilities. Specifically, Fortis argued that these risks arise from the increased competition for customers from rural electrification associations (REAs) and the removal from its recoverable revenue requirement of over \$10 million on an ongoing annual basis beginning in 2023. The removal of the \$10 million from revenue requirement resulted from a Commission decision²⁵⁸ which was subsequently upheld by the Court of Appeal of Alberta.²⁵⁹ Fortis estimated that this will reduce Fortis's earned ROE by approximately 68 bps and erode its cash flow credit metrics, which might result in a credit rating downgrade.²⁶⁰

268. The Commission is not persuaded that an increase in the equity thickness is required. As pointed out by the UCA, the threat of competition from REAs is negligible at present. A net total of just 35 sites has transferred to REAs since 2018, which the UCA calculated as 0.006 per cent of customers in Fortis's service territory.²⁶¹ The Commission is not persuaded that there is a serious threat of customer defections from Fortis to REAs. Further, the Commission finds that increasing Fortis's equity thickness to counter competition from REAs would place Fortis at a competitive disadvantage relative to REAs as an increase in equity thickness will result in an increased revenue requirement, and ultimately higher rates for Fortis's customers.

269. In addition, increasing the equity thickness by 300 bps in order to offset the removal of \$10 million from Fortis's revenue requirement is compensating Fortis indirectly for what the Commission does not have the authority to do directly, that is, to compensate Fortis for costs attributable to the REAs' use of Fortis's system from Fortis's own regulated customers.²⁶²

270. In upholding the Commission's decision to deny recovery of these costs from Fortis customers, the Court of Appeal in the EQUUS REA decision stated:²⁶³

[23] The Commission correctly determined that FortisAlberta cannot recover from its customers the difference between the costs FortisAlberta incurs when rural electrification associations use FortisAlberta's distribution system to provide electricity to its members and the costs rural electrification associations incur when FortisAlberta uses rural electrification associations' distribution systems to provide electricity to its customers. There is no sound reason why FortisAlberta's customers should subsidize the members of rural electrification associations.

²⁵⁸ Decision 25916-D01-2021: FortisAlberta Inc., 2022 Phase II Distribution Tariff Application, Proceeding 25916, July 8, 2021.

²⁵⁹ *Equus Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142.

²⁶⁰ Exhibit 27084-X0479, PDF page 47.

²⁶¹ Exhibit 27084-X0926, PDF page 31, paragraph 110.

²⁶² This point was also made by the UCA and IPCAA – see Exhibit 27084-X0926, PDF page 30, paragraph 108; Exhibit 27084-X0918, PDF pages 20-21, paragraph 64.

²⁶³ *Equus Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142.

271. Granting an increase in Fortis's deemed equity ratio would result in such subsidization, although in an indirect as opposed to direct way.

272. IPCAA further argued the Commission should not award higher returns to Fortis for an unregulated business risk.²⁶⁴ The CCA made a similar argument, submitting that the charges are not related to utility service and should, therefore, have no impact on the cost of capital.²⁶⁵

273. The Commission finds that the proper course for recovery of costs associated with intermingled service provided to REAs by Fortis is through negotiation and arbitration of integrated operating agreements under the *Roles, Relationships and Responsibilities Regulation*. While Fortis has not enjoyed success recently under that framework, it is the statutorily sanctioned mechanism and is available to Fortis as integrated operating agreements terminate and are renegotiated.

7.6.2 Determination of Commission-approved deemed equity ratio for Apex

274. Apex submitted that its deemed equity ratio should be 400 bps higher than the deemed equity ratio of the average distribution utility because it faces higher business and operational risks than other distribution utilities in Alberta. These risks, it argued, arise because of Apex's small size, geographically dispersed service territory in rural Alberta and gas supply risk.

275. The Commission accepts that these aspects of Apex's size, operations and service territory do create additional risks compared to other distribution companies but not to the extent of an additional 400 bps above the other utilities. The Commission acknowledges that for several years until 2018, it approved an additional 400 bps of equity thickness in excess of the other Alberta utilities to address these risks. The additional equity was intended to meet the business and operational risks that Apex faced. The extra equity thickness provided the utility with greater revenues than would otherwise be the case, in order to compensate for the inability to generate, for example, the cost savings and efficiencies that come from economies of scale that large, mostly urban utilities like ATCO Gas enjoy.

276. However, in the 2018 GCOC decision, the Commission reduced the equity thickness from 41 per cent to 39 per cent because, notwithstanding the additional 400 bps to AltaGas (now Apex), AltaGas's parent²⁶⁶ (which borrowed money in financial markets and passed it down to AltaGas) was unable to raise debt at an A-range credit rating resulting in customers paying for costs associated with additional equity thickness but without receiving the benefit of lower debt costs.²⁶⁷ The decision to reduce the equity thickness, the Commission stated, was in keeping with "... the Commission's duty to set a fair return for AltaGas as an element of the just and reasonable rates to be paid by its customers."²⁶⁸

277. In the current proceeding, the record shows that even with an extra 400 bps, Apex's current parent, TriSummit, would not achieve an A-rated credit rating because of its relatively small size.²⁶⁹ Apex argued that TriSummit, which continues to issue public debt instruments to fund Apex's operations and rate base, has a similar business risk profile to its own. For example,

²⁶⁴ Exhibit 27084-X0918, PDF page 20, paragraph 62.

²⁶⁵ Exhibit 27084-X0919, PDF page 26, paragraph 80.

²⁶⁶ Apex was previously known as AltaGas Utilities Inc., and its parent was AltaGas Ltd.

²⁶⁷ Decision 22570-D01-2018, PDF page 176, paragraph 840.

²⁶⁸ Decision 22570-D01-2018, PDF page 176, paragraph 837.

²⁶⁹ Exhibit 27084-X0377, PDF page 20.

80 per cent of TriSummit's assets are regulated utility operations with 95 per cent of its revenue earned from those operations. With this profile, TriSummit has a BBB high credit rating.

278. Apex argued that TriSummit's credit rating and borrowing cost represent an accurate proxy for the market cost of debt for Apex as a stand-alone entity, and that Apex requires an additional 400 bps above the generically deemed equity ratio to achieve the BBB high credit rating of its parent in order to maintain a fair ROE. Additional equity provides a utility with a better opportunity to achieve higher interest coverage ratios while reducing the financial risk to the utility.

279. The Commission finds that the focus in determining Apex's equity thickness should be on the risks identified in 2018 compared to the business risks that it currently faces. In the Commission's view, the risks resulting from Apex's small size, geographically dispersed service areas in mostly rural Alberta and its reliance on third party suppliers have not materially changed since then nor are expected to change in the near future. And there is little, if any, concrete evidence that Apex's financial integrity or its ability to attract investment has been unduly impaired at its current equity thickness of 39 per cent established in 2018.

280. The Commission notes, as interveners have argued, that the fact that the ownership of Apex's parent company has changed twice since the 2018 GCOC decision, most recently in 2020 when pension funds acquired all the outstanding shares of Apex's prior parent, AltaGas Canada Ltd. in a take-private transaction, demonstrates that equity financing is readily available.²⁷⁰ The Commission also finds that Apex's exposure to the abandonment of third-party laterals that it relies on to supply gas to its distribution network has also remained unchanged since 2018. Apex may well have to purchase or build new laterals itself, but there is little compelling evidence that these risks have increased or will increase, or that a 39 per cent equity thickness undermines Apex's ability respond to these contingencies.

281. In the Etzikom decision²⁷¹ referred to by Apex as an example of this risk, the Commission approved construction of a new lateral but denied recovery of these costs under the then PBR framework that governed access to additional capital. Essentially, the Commission found that sufficient funds had been approved in the going-in rates at the beginning of the 2018-2022 PBR term to meet the abandonment of third-party laterals. The Commission stated at paragraph 30:

The Commission has learned that the distribution utilities have considerable flexibility in dealing with the timing of their capital programs and are capable of accommodating many changes in circumstances without any immediate concerns about service quality and meeting their obligation to serve.

282. In summary, the Commission finds that Apex's risks have not materially changed since 2018 when a 39 per cent equity thickness was awarded to it. Apex has maintained financial integrity and has been able to attract capital on reasonable terms notwithstanding that it enjoyed a higher equity thickness prior to 2018. Further, as TriSummit has a better credit rating than Apex's previous parent, although still not A-rated, the Commission finds that a higher equity

²⁷⁰ Exhibit 27084-X0926, PDF pages 31-32, paragraph 113, Transcript, Volume 1, pages 249-250.

²⁷¹ Decision 25608-D01-2020: AltaGas Utilities Inc., Type 1 Capital Tracker True-Up – Etzikom Lateral Project, Proceeding 25608, October 16, 2020.

thickness is not warranted. The result is that the Commission approves a 39 per cent equity thickness, 200 bps above the generic equity thickness approved for the other utilities.

8 Order

283. It is hereby ordered that:

- (1) The final approved generic return on equity for Apex Utilities Inc. AltaLink Management Ltd. and its partners PiikaniLink L.P. and KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is to be set using the methods approved in this decision on an annual basis, beginning in 2024, until determined otherwise by the Commission.
- (2) The final approved deemed equity ratio for AltaLink Management Ltd., PiikaniLink L.P., KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is set at 37 per cent. The final approved deemed equity ratio for Apex Utilities Inc. is 39 per cent. These final approved deemed equity ratios are effective January 1, 2024, until determined otherwise by the Commission.

Dated on October 9, 2023.

Alberta Utilities Commission

(original signed by)

Douglas A. Larder, KC
Vice-Chair

(original signed by)

Renée Marx
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Direct Connect Consumers Association (ADC)
AltaLink Management Ltd. (AltaLink) Borden Ladner Gervais LLP ScottMadden, Inc.
Apex Utilities Inc. (Apex) MLT Aikins LLP The Brattle Group
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP The Brattle Group
ATCO Gas Bennett Jones LLP The Brattle Group
Capital Power Corporation (CPC) Dentons Canada LLP
Consumers' Coalition of Alberta (CCA)
ENMAX Power Corporation (ENMAX or EPC) Torys LLP Nicole Martin Concentric Energy Advisors, Inc. James Coyne
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden Ladner Gervais LLP ScottMadden, Inc.
FortisAlberta Inc. (Fortis or FAI) Fasken Martineau DuMoulin LLP The Brattle Group
Industrial Power Consumers Association of Alberta (IPCAA) Ackroyd LLP
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP Russ Bell & Associates Inc.

Alberta Utilities Commission

Commission panel

D.A. Larder, KC, Vice-Chair
R. Marx, Commission Member
B. Romaniuk, Acting Commission Member

Commission staff

L. Berg (Commission counsel)
A. Marshall (Commission counsel)
A. Jukov
D. Mitchell
M. McJannet
K. O'Neill
K. Taylor

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
AltaLink Management Ltd. (AltaLink) and EPCOR Distribution Inc. (EPCOR) J. Liteplo/J. Hulecki	D. D'Ascendis
Apex Utilities Inc. (Apex) R. Jeerakathil	B. Villadsen F. Graves M. Tolleth M. Stock D. Makarenko
ATCO Utilities (ATCO Electric Ltd. and ATCO Gas and Pipelines) T. Myers L. Smith	B. Villadsen F. Graves
FortisAlberta Inc.(Fortis) A. Sears	B. Villadsen F. Graves B. Hendersen
ENMAX Power Corporation (ENMAX) D. Wood/T. Campbell	J. Coyne J. Trogonoski N. Martin
Consumers' Coalition of Alberta (CCA) J.A. Wachowich	J. Thygesen
Industrial Power Consumers Association of Alberta (IPCAA) R. Secord	D. Madsen
Office of the Utilities Consumer Advocate (UCA) R. McCreary/B. Schwanak	R. Bell S. Cleary

Alberta Utilities Commission

Commission panel

D.A. Larder, KC, Vice-Chair
R. Marx, Commission Member
B. Romaniuk, Acting Commission Member

Commission staff

L. Berg (Commission counsel)
A. Marshall (Commission counsel)
A. Jukov
D. Mitchell
M. McJannet

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula. paragraph 200