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TRANSMITTAL/FAX MEMO

PROJECT: SHANNON ESTATES
7199 GRANVILLE STREET

NO: 8002-111
DATE: JULY 15, 2016

X	**BRITISH COLUMBIA UTILITIES COMMISSION** **ATTN: ERICA HAMILTON, COMMISSION SECRETARY (commission.secretary@bcuc.com)** **SIXTH FLOOR – 900 HOWE STREET, VANCOUVER, BC V6Z 2N3**	**FAX:** **PHONE:**	**604.660.4700** **604.660.1102**
CC	**SHANNON WALL CENTRE RENTAL APARTMENTS LIMITED PARTNERSHIP** **3502 – 1088 BURRARD STREET, VANCOUVER, BC V6Z 2R9**	**FAX:** **PHONE:**	

NO. OF PAGES INCLUDING THIS PAGE: AS NOTED

COMMENTS:

Please find enclosed via the online e-Filing system for the Shannon Estates Thermal Energy System Rate Application:

The final response to Intervenors.

Please note that Sterling Cooper Consultants Inc. (SCCI) is submitting on behalf of the applicant, Shannon Wall Centre Rental Apartments Limited Partnership.

Please direct questions to George Steeves (g.steeves@ndy.com), Joseph Chow (j.chow@ndy.com) and Chi Zhang (c.zhang@ndy.com).

PER: JOSEPH CHOW

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STERLING COOPER CONSULTANTS

July 15, 2016

BRITISH COLUMBIA UTILITIES COMMISSION
6TH FLOOR, 900 HOWE STREET
VANCOUVER, BC V6Z 2N3

ATTENTION: Ms. Laurel Ross, Acting Commission Secretary

Dear Ms. Ross,

RE: RESPONSE TO INTERVENOR'S FINAL SUBMISSIONS
SHANNON WALL CENTRE RENTAL APARTMENTS LIMITED PARTNERSHIP (SWCRA)
RATE APPLICATION FOR THE SHANNON ESTATES THERMAL ENERGY SYSTEM

In accordance with the British Columbia Utilities Commission (BCUC) Regulatory Timetable set in Commission Order G-77-16A, we provide our responses to the final Intervenor submissions for the Shannon Estates Thermal Energy System (SETES) Rate Application.

Responses are provided to the Fortis BC Alternative Energy Services (FAES) Final Submission dated July 11, 2016. Robert Peden registered as an Intervenor but no submissions have been provided.

FAES' claimed interest in this application is because it has "a strong interest in ensuring all applicants in this market are subject to the <u>same rigorous regulatory standards</u> as FAES"[1] (underlined added). They are however, complicating the regulatory process through their endeavors to apply their experience to our local neighborhood project. This leads to their recommendation to apply their experience of the regulatory process to SETES which contradicts the Utilities Commission Act (UCA) s75 "the commission must make its decision on the merits and justice of the case, and is not bound to follow its own decisions."

We offer additional information to support our rates application especially in response to the claims FAES has made of our adherence to sections 2.4.3 – 2.4.4 of the Thermal Energy System (TES) Regulatory Framework Guidelines[2] in setting rates. Our position remains that the rates applied for are fair, just, and reasonable and meet the criteria for acceptance per the UCA s59-61.

Our proposed rate-setting mechanism, pegging, sets a fixed limit upon which the Utility must improve its operation or it forgoes the opportunity for any return.

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[1] See BCUC Document 46725 SWCRA Rate Application FAES Final Submission dated July 11, 2016, Page 2
[2] See BCUC Order G-27-15 Thermal Energy Systems Framework Guidelines dated March 2, 2015, Appendix A p.22-23

The process BCUC brought to the SETES CPCN application and the Rates Application Information Request #1 are commendable for their fair and balanced treatment for a TES of our size and complexity and reflects an appropriate application of a scaled approach. Even within Stream B TES projects, a scaled approach is applicable to evaluate the complexity of each project on its own merits.

SETES PROVIDES AN EQUITABLE BALANCE OF RISK AND COST BETWEEN THE UTILITY AND THE RATEPAYERS

Rate Setting Principle 1 of the TES Framework is met by providing an equitable balance of risk and cost between the utility and the ratepayer. FAES assertion the principle has "not been adequately addressed by the proposed rates"[3] is not correct. Possibly, because they seem to have not fully reviewed the documents submitted nor do they seem to understand the risks which SETES has entailed in the development of the facility and in the context of SWCRA.

SWCRA has prudently provided to residents a reliable system for thermal service provision. Consequently, to the customers, their thermal energy connection is low-risk. SETES' can consistently provide thermal services without requiring significant alteration or reconstruction of customer terminals, distribution systems, and thermal generation / absorption systems due to technology failure. The main plant is remote from the end-user and has multiple equipment redundancies and back up possibilities. For instance, there are both redundant units as well as redundant capacity of the main heating and cooling equipment. We provide a level of redundancy which will provide ongoing thermal services at only a slightly reduced level if there is equipment failure or partial system failure. These are the commonalities shared with a high-rise building in Downtown Vancouver, as previously mentioned.[4]

The fuel risk analysis presented[5] verifies SETES' capability to ensure reliable delivery of thermal services with multiple energy sources. Should one energy source become unavailable due to external events or to rapid rise in price, we could prioritize thermal energy generation between gas-fired equipment, or electric heat pumps, or solar generation with minimal changes or costs. We designed and built this reliability as a service which ratepayers can depend on; especially for important space heating and domestic hot water needs.

The project is not low-risk in its capability to provide an economic coefficient-of-performance (COP), which is the ratio of sold thermal energy to utility purchases such as natural gas and electricity. As noted in our application, there are "<u>potential</u> coefficient-of-performance advantages" (underline added). Since SWCRA is normally unwilling to use technology which may not be capable of providing thermal services, we have taken a calculated risk of using the technology offered by Thermenex[6]. Since Thermenex has

[3] See BCUC Document 46725 SWCRA Rate Application FAES Final Submission dated July 11, 2016, p.4
[4] See BCUC Document 46402 Exhibit B-1 SWCRA Rates Application, Appendix B1, CPCN Application, p.30
[5] See BCUC Document 46402 Exhibit B-1 SWCRA Rates Application, Appendix B1, CPCN Application, p.31
[6] Thermenex is the technology which allows for the integration of multiple temperature sources, multiple energy sources for single delivery of space heating, domestic hot water, and space cooling to customers.

no proven application or published efficiency for a residential development in a heating-dominant climate.

Thermenex uses a single piping system to collect water from different heating and cooling sources and distributes the water to an area requiring a particular temperature water, all of which provides proven efficiencies for other occupancies. Consequently, those efficiencies are likely available in a residential occupancy, which represents a risk the DEU has accepted by paying an additional capital cost to construct a Thermenex piping system in this project. In addition, SETES's commitment to the City of Vancouver to provide heating energy at an aggressive low carbon target limits the SETE's ability to operate at the lowest cost energy source/heating technology.

FAES portrayal of our response about COP is not correct. By reducing our plant's natural gas usage, it will increase our dependence on electrical and solar energy. A TES for a development of this size is not able to purchase electricity from BC Hydro at energy-only rates and instead purchases on rate schedules which have energy and demand charges. The benefits of reduced energy charges, because of a higher overall COP which is due to solar and heat pump use, will be somewhat counteracted by higher demand charges for electricity. Higher energy COP of the system is not a full measure of economic COP.

FAES has quoted and misunderstood our response to the FAES IR of solar COP which originally was "Solar COP is infinite <u>without pumping energy</u>" (underline added). Their quotation may mislead others to think there is an infinite economic COP which is not the case. Because purchased pumping energy is still required. As noted in the Shannon Estates CPCN application response to IR-1 to reduce electric energy demand charges, the project has already used thermal storage to the extent it is economically and technologically feasible at Shannon Estates. [7]

Ratepayers are also further advantaged by the investments SWCRA made towards individual energy meters. The ratepayers are charged according to their usage, as opposed to the entire building being metered by the utility and without submeters for ratepayer usage, and have the ability to control their costs. The additional meters, which not all other regulated TES providers have, are a benefit ratepayers have by choosing to connect to SETES.

SWCRA entails additional risk for operation as it needs to establish a TES capital reserve rather than depend on a diversified aggregation of TES businesses. Recognition of this factor in determining the fair and just rate design and acceptance, which may not apply[8] to other utilities, is also applicable to support the development of a larger competitive utilities market and to not only entrench existing, established utilities.

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[7] See BCUC Document 46402 SWCRA Rates Application Exhibit B-1, Appendix B2, Response to IR-1, s2.1

[8] In FAES states, it is, "employing a portfolio approach to the capital reserve requirement…and due to its access to resources, FAES does not have a dedicated capital reserve fund" in respect to its Artemisia development. See BCUC Document 41898 FAES Rate Approvals TES Artemisia, Exhibit B-3, Response to IR-1, s10.3

The ratepayers are not only paying for an efficient plant; they are also paying for a low-carbon system. The low-carbon requirement was a development condition from the City of Vancouver (CoV)[9] and from which all system alternatives were required to meet. While the CoV regulatory requirements are distinct from BCUC regulatory requirements, it does not diminish the fact SWCRA had to bear the costs and then risks of developing such a system. As a result, the higher cost to meet another concurrent authority's requirement should be allowed as a factor in considering rate design and acceptance. We do not ask BCUC to condone or refute other authorities' requirements but without allowance of this consideration a rate may not accurately reflect the actual costs a utility incurs to deliver service.

In comparison to other projects regulated by the BCUC, a rate design where the occurrence of gains and losses due to a fixed rate accrue to the Utility and not to ratepayers is not unique. In FAES' project, Artemisia, FAES states they "will take the load forecast risk, which will not impact rates, and any over or under recovery of revenues will not be refunded to or recovered from customers except for variances incurred for fuel costs as noted above."[10] This rate application was allowed by BCUC.[11]

The benefits to ratepayers are reliable delivery of thermal services and reduced carbon emissions. The benefits to SWCRA are the capability to reliably delivery thermal services and a potential COP advantage. To the extent possible, SWCRA and the developer of the buildings connected to SWCRA have designed the project so electrical demand costs can be controlled. Because the rates are pegged as opposed to depending on the actual cost of operation, the technological risk of a low economic COP system, which could result in increased cost if the rate-structure was directly correlated to costs, is removed from the ratepayers.

Under the proposed rate structure, SWCRA is encouraged to increase efficiency, reduce costs, and enhance performance or it forgoes the opportunity for a reasonable return. Without doing any of the items in the last sentence, SWCRA will not have a reasonable return. For SWCRA to use a rate-setting mechanism which connects the operational cost to the rate, there is no further economic incentive to improve efficiency once the regulated rate of return is met.

In conclusion, SWCRA has equitably balanced the risk between ratepayer and utility for provision of thermal services, low-carbon system design, and variability in economic COP. The issue of comparative cost is addressed in the business-as-usual example below. In the context of SWCRA and SETES, the CoV requirement to design a low-carbon system and the need to establish a capital reserve without reliance on existing assets should be allowed as factors in evaluating the rate design and application.

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[9] See CoV Development Permit Staff Committee Report for DE415627 dated June 20, 2012, Appendix C, p.2-3 and CoV Development Permit Staff Committee Report for DE416823 dated July 31, 2013, Appendix B p.2-3
[10] See BCUC Document 41686 FAES Rate Approvals TES Artemisia CPCN, Exhibit B-1, Appendix D s1
[11] See BCUC Order C-9-14 Artemisia Development CPCN

PROPOSED RATE STRUCTURE RESTRICTS THE ABILITY OF THE UTILITY TO PASS CONTROLLABLE COSTS ONTO RATEPAYERS

SWCRA has disclosed Controllable Costs. Costs to operate SETES have been described in the SETES CPCN application in Section 9.6. FAES failure to observe this does not negate their existence.

Refer to the confidential filing for details of the forecast controllable costs.

Additionally, as the proposed rate-structure follows an externally set rate it is against SWCRA's own economic interest to not limit controllable costs as it immediately reduces its own return-on-equity. Passing on the costs through the rate-structure is also not possible. The rate-rider has a proposed means to regulate its use to maintaining the thermal energy service.[12]

In conclusion to the TES Framework Rate Setting Principle 3, controllable costs are limited to what are fair and reasonable and having any high controllable costs is counter to SWCRA's economic interests. The solution SWCRA would have to improve its own economic interest is to lower the controllable costs.

SWCRA AVOIDS RATE SHOCK (>10 PERCENT CHANGE IN RATES PER ANNUM IS GENERALLY CONSIDERED "RATE SHOCK") THROUGH APPROPRIATE REFERENCES FOR RATE FOLLOWING

SWCRA rate-design follows utilities which have documented rate forecasts. By this rate-setting mechanism, SETES ratepayers will not experience rate shock as BC Hydro and COV themselves have an intent to avoid rate shock.

The rate escalations intended by BC Hydro and the City of Vancouver (COV) South-East False Creek (SEFC) are provided below and are extracts of the documents referred to in the response to FAES.

[12] Refer to BCUC Document 46672 SWCRA Rates Application Exhibit B-2, Part E, p.13-18

Table 1: Forecast Rates for Benchmark Rate-Setting Utilities

Year-Over-Year Change from Previous Year			2016	2017	2018	2019	2020	2021
CoV SEFC[13]	Fixed Capacity Levy	[%]	+3.2% overall (2.5%[14] increase in Fixed Capacity Levy)	+3.2% overall	+3.2% overall	+2%	+2%	+2%
			F2016	F2017	F2018	F2019	F2020	F2021
BC Hydro[15]	Residential Rate	[%]	6%	4%	3.5%	3%	TBD 3%	TBD 3%

Note:

1 – CoV SEFC fixed capacity rate was set to be 2.5% of the overall rate increase for year 2016 with the energy rate set higher to achieve an overall 3.2% overall. CoV notes a 2% assumption in BC's CPI.

2 – BC Hydro rates for F2017 to F2019 are allowed to increase by the maximum of those figures. F2020 and F2021 are assumed to hold at F2019 values.

Based on publicly available information from SEFC and BC Hydro, the following rates are forecasted:

Table 2: SETES Forecast Rates for the initial 5-years

Rate	Unit	2016	2017	2018	2019	2020	2021
Space Cooling	[$/kWh]	0.0518	0.0539	0.0558	0.0574	0.0592	0.0609
Space Heating	[$/kWh]	0.1036	0.1077	0.1115	0.1149	0.1219	0.1293
Domestic Hot Water	[$/kWh]	0.1036	0.1077	0.1115	0.1149	0.1219	0.1293
Monthly Capacity Levy	[$/sqft-month]	0.0489	0.0501	0.0514	0.0527	0.0537	0.0548
Remainder of Fees and Charges	Various	As per submitted tariff					

FAES seems to have misread or misunderstood portions of our submissions and seems to have

[13] See CoV Administrative Report for Southeast False Creek Neighbourhood Energy Utility ("SEFC NEU") – Five-Year Review dated June 26, 2015, RTS No. 10804, VanRIMS No.: 08-2000-20, p.6

[14] See CoV Administrative Report for Southeast False Creek Neighbourhood Energy Utility ("SEFC NEU") 2016 Customer Rates dated November 12, 2015, RTS No. 11083, VanRIMS No.: 08-2000-20, p.1

[15] See Province of British Columbia Order in Council (OIC) No. 096, approved and ordered March 5, 2014, Direction No. 6 to the BCUC, Appendix B and Province of British Columbia OIC No. 097, approved and ordered March 5, 2014, Direction No. 7 to the BCUC s9

disregarded some of our accompanying notes and appendices which could have led to their invalid conclusion of a risk of rate shock to the SETES customers.

A rate-setting mechanism which correlated operational costs to rates would expose ratepayers to a higher probability of rate shock. As discussed in a prior section about Thermenex, the integrating technology has no prior precedent set for economic COP for residential applications. An alternate method to smooth out the rates and avoid rate shock is to select a higher rate, which could also be applied especially to earlier customers as the actual economic COP of the plant itself (i.e. energy sales versus utility purchases) and efficient operation is unknown. This could lead to unsatisfactory results for initial customers who conclude their ownership / tenancy at Shannon Estates while the economic COP is unknown if the economic COP is high as they would not receive any opportunity for refund.

A further variability to customers outside of these factors is the rate rider. A consistent rate rider would result in less opportunity for rate shock but may not necessarily result in lower rates. A rate rider applied as needed would increase the opportunity for rate shock but could result in lower rates. On this basis, SWCRA rate structure will favor a more consistent rate rider to limit the probability of rate shock.

In conclusion to the TES Framework Rate Setting Principle 5, a year-year rate change of less than 10% is forecast and is below the suggested threshold for rate shock.

SETES PROVIDES COMPARABLE RATES TO BUSINESS-AS-USUAL

A further element of rates comparison to a business-as-usual case is the inadequacy of comparing rates by assuming equal buildings. The new construction building envelopes ability to resist heat transfer is R-11.2 overall. This is 23% better than a code-minimum building envelope. Unlike more traditional utility scenarios, the design and development of customer infrastructure is within the boundaries of the utility's influence. As a result, the combination of improved insulation and a higher rate results in a net change to customers versus a code-minimum building of R-9.1 overall. The rate payers are receiving a fair and equitable exchange for having an energy saving of 20% from a conventional building they may have otherwise purchased from. The utility is also equitably compensated as the thermal energy demand is decreased compared to a development at code-minimum standards.

The SETE's decision to peg the heating rates at 50% at Step 1 Rate, 50% at Step 2 Rate of the BCH residential electricity rate is equal to the assumption the CoV makes[16] for BC Hydro effective rate calculation in a residence. This reasoning takes into account the conservation step must be shared amongst the baseload as well as the heating and cooling demands. The baseload is comprised mainly of lighting energy and household appliances. The baseload is expected to remain consistent month to month while the heating and cooling energies vary with seasonal conditions.

The monthly bills comparing SETES to a BC Hydro BAU heating system with a BAU building envelope are provided below, the rates for SETES can be seen to be comparable. The cost to own, operate, and

[16] See CoV Administrative Report for Southeast False Creek Neighbourhood Energy Utility ("SEFC NEU") 2016 Customer Rates dated November 12, 2015, RTS No. 11083, VanRIMS No.: 08-2000-20, Table 4, p.9

maintain thermal generation equipment is also excluded from the BAU case in this analysis but is included in the SETES case.

Table 3: SETES vs. BC Hydro (BAU) costs for Space Heating and Domestic Hot Water

Monthly		
	SETES	BC Hydro (BAU)
775 sq ft	$ 147	$ 132
2000 sq ft	$ 216	$ 180
Annual		
	SETES	BC Hydro (BAU)
775 sq ft	$ 1,763	$ 1,579
2000 sq ft	$ 2,595	$ 2,161

SETES is providing a comparable rate to the business as usual case as per the above analysis presented. The absence of the analysis of owning, operating, and maintaining thermal generation equipment while it is included in the SETES analysis but avoided in the BAU case and the advantages given to residents by an improvement in the building envelope over building code minimum performance requirements as a result of the integrated nature of the utility and the service area developer should be allowed factors in evaluating the cost-competiveness of SETES.

A working financial forecast model is included in the confidential portion of this filing to evaluate the fairness to customers and to the utility in the proposed rate-structure.

INACCURATE REPRESENTATION OF COMPARISON TO FAES RECONNECTION FEE

Our original response was “other BCUC-regulated utilities have charges in their terms and conditions where an equivalent to the disconnect and reconnect fees are isolated into the reconnection fee” in the context of comparing and contrasting what measures if any, other utilities are taking to the same situation.

SWCRA RATE APPLICATION IS IN ACCORDANCE WITH THE UTILITIES COMMISSION ACT S59 AND S60 AND THE RATE-SETTING REQUIREMENTS OF THE TES FRAMEWORK

The UCA s59-60 are complied with:

With respect to UCA s59(5)(a), SWCRA has brought additional analysis to support the conclusion ratepayers will be paying a comparable amount to a business as usual scenario which is fair and reasonable.

With respect to UCA s59(5)(c), SWCRA advises a rate-setting mechanism tied to the operational costs will increase the probability of rate shock to customers unless a higher rate is applied from which initial customers may not receive benefits.

With respect to UCA s60(1)(a), SWCRA responded to the Information Requests put forth by BCUC and Intervenor submissions and addressed the criteria in the TES Framework for a Stream B TES.

With respect to UCA s60(1)(b)(iii), the proposed rate-setting mechanism economically incentivizes SWCRA to increase efficiency, reduce costs, and enhance performance. It also naturally penalizes SWCRA if it does not achieve the above which encourages effective self-regulation and achievement of those factors.

CONCLUSION

In conclusion:

- SETES should be evaluated on its own merits consistent with UCA s75
- Development of the capital reserve solely from SETES rates rather than an aggregation of TES businesses results in higher rates but a fair, just, and equitable manner to ratepayers
- Meeting another concurrent authority's requirements resulted in higher capital costs results in higher rate requirements but in a fair, just, and equitable manner to ratepayers

FAES' line of questioning is seemingly leading and their recommendations do not appear to reduce regulatory burden, nor do they result in improved outcomes for ratepayers, whether measured by lowered rates, more predictable rates, or improved quality of service. FAES' recommendations should most likely be rejected.

SWCRA respectfully submits the information provided on the rate design and rates application meets the criteria for final rates approval.

Yours very truly,

George P. Steeves, BScE, MIS, P. Eng.
Principal
STERLING COOPER CONSULTANTS INC.
GPS/jc/ab

IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

THERMAL ENERGY SYSTEMS
REGULATORY FRAMEWORK GUIDELINES

DECISION

MARCH 2, 2015

Before:

D. M. Morton, Commissioner/Panel Chair
L. A. O'Hara, Commissioner
R. D. Revel, Commissioner

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1.0 INTRODUCTION

By Order G-127-14 dated August 28, 2014, the British Columbia Utilities Commission (Commission, BCUC) approved the Thermal Energy Systems (TES) Regulatory Framework (TES Framework) for immediate use. Among other provisions, the TES Framework laid out a characteristic of a Stream A system as having an AACE Class 3 capital cost estimate of equal to or greater than $500,000 and less than $15 million.

On August 1, 2014, in the FortisBC Alternative Energy Services (FAES) Application for a Certificate of Public Convenience and Necessity (CPCN) and Rate Approvals Established in Agreements for TES for the Artemisia Development proceeding (Artemisia proceeding), Ameresco Canada Inc. (Ameresco) raised the question of whether, in the case of a purchase of a TES, the purchase price should be the basis for the determination of the status of the TES for exemption or whether it should be the actual capital cost to construct the TES system.[1]

There was no determination on this issue requested by Ameresco in the FAES Artemisia proceeding. However, in response to Ameresco's question, on September 17, 2014, the Commission requested submissions from parties in the BCUC 2014 Proposed Regulatory Framework and Guide for TES Utilities proceeding, on the capital costs versus the purchase price and regulatory status. Specifically, parties were asked to address three scenarios laid out by the Panel, explaining views on exemption status, filing requirements and/or general standing of the TES. Parties were also invited to address any other topics that may be relevant to this issue.

Submissions on the three scenarios were provided by FAES, Ameresco, the BC Sustainable Energy Association and the Sierra Club of BC (BCSEA-SCBC) and the British Columbia Pensioners' and Seniors' Organization, Active Support Against Poverty, BC Coalition of People with Disabilities, Counsel of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO). Ameresco put forward what it calls Scenario 4: a system with an initial capital cost below the threshold amount is purchased for an amount above the guideline amount. Ameresco and FAES also provided submissions on the threshold between Stream A and Stream B TES. FAES and Ameresco provided submissions on aggregating multiple sites of a single customer. The Panel addresses each of these issues in the decision.

In addition, FAES provided a substantial submission on the Strata Exemption, in effect, requesting that the Commission reconsider its previous decision and remove the Strata Exemption. Other interveners also commented on this issue. The Panel will address this issue before considering the submissions on the issues requested by the Panel.

2.0 STRATA CORPORATIONS AND THE MICRO TES EXEMPTION

FAES submits that where the TES has a Strata Corporation as a customer, the TES should always be considered a Stream A TES regardless of the capital cost or the purchase price of the TES. It argues that "there is no material difference between a Strata Unit Owner in a Development with a TES System that has a capital cost below $500,000 or that FAES purchases for less than $500,000 and a Strata Unit Owner in a Development with a TES

[1] FAES Application for a Certificate of Public Convenience and Necessity and Rate Approvals Established in Agreements for TES for the Artemisia Development (FAES Artemisia proceeding), Exhibit D-1, p. 1.

System that has a capital cost above $500,000 or that FAES purchases for more than $500,000" and, accordingly, both TES should be regulated in the same way.[2]

In its view, the case of a Strata Corporation customer that has a number of residential units was never intended to be captured by the Micro TES Exemption. FAES argues that both the Panel in the AES Inquiry and Commission staff, in applying the Principles and Guidelines of the Alternate Energy Services (AES) Inquiry Report, "have always intended to treat strata properties as Stream A customers."[3] In support of its position, FAES cites the following from the Commission Report on the Proposed Micro Thermal Energy System Limit and Stream B Exemption Test:

> The Micro TES System exemption is intended to capture **the case of a homeowner or a small business** entering into an agreement with a TES provider. […] In the Panel's view, the Micro TES System exemption should be large enough to accommodate a project undertaken by or for a small group of homeowners or small businesses, such as a GSHP that may be shared by that group.
>
> The Panel find[s] the numerical example provided by Ameresco, relating to a **hypothetical group of five small businesses, properly captures the intent of the Panel**.[4]

FAES adds that in the case of the Artemisia Strata Corporation, "the 21 Strata Unit Owners are not the ones who entered into an agreement with FAES. In contrast, the Developer selected the thermal energy system based on its own objectives and, at a late stage, entered into agreement with FAES to provide thermal energy services to the Development."[5] In the Artemisia proceeding, FAES stated that "[t]he Developer selected the energy system to meet its goals with respect to reduction of greenhouse gas emissions and to enhance the marketability of the development. Prior to FAES' involvement in the Project, the Developer established the Strata Budget with respect to thermal energy and distributed that information to all the unit owners." As a result, FAES submits that "[t]herefore, to meet the Strata Budget requirement, the Developer and FAES have negotiated a purchase price for the energy system on the basis of what FAES would be prepared to invest in order to provide this service at the rates established by the Developer." On this basis, FAES will purchase the system from the Developer for $100,000, an amount that is less than the actual capital costs that the developer expects to incur for the construction and commissioning of the system.[6]

FAES also cites the following passage from the AES Inquiry:

> In the Panel's view there is a grey area as to what constitutes a Discrete Energy System as compared to a District Energy System. This, for example, could involve **the service to a single strata, but with multiple customers in the strata and a need to regulate to protect customer interests**.[7]

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[2] Exhibit C2-3, p. 6.
[3] Ibid., p. 4.
[4] Exhibit A-6, p. 7, emphasis added by FAES.
[5] Exhibit C2-3, pp. 3-5.
[6] FAES Artemisia proceeding, Exhibit B-1, p. 2.
[7] Report on the Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (AES Inquiry Report), p. 75, emphasis added by FAES.

FAES also cites passages from earlier versions of the TES Scaled Regulatory Framework that proposed an exemption for TES with one customer except in cases where that customer is a Strata Corporation.[8]

FAES further argues that strata customers of Exempt TES have no recourse under the *Strata Property Act* and therefore require the consumer protection afforded by the *Utilities Commission Act* (UCA). This is in contrast to the Strata Exemption, where the owner of a strata unit has recourse under the *Strata Property Act*.[9]

FASES submits a variant on Scenario 1, which it calls Scenario 1b, whereby the TES in Scenario 1 is originally owned and operated by a Strata Corporation. In Scenario 1b, the TES is initially exempt, by virtue of the Strata Exemption. FAES argues that if subsequent to the sale, the TES falls under the Micro TES Exemption, then Strata Unit Owners would no longer find recourse under the *Strata Property Act*, whereas they could do so before the sale. Accordingly, FAES submits that regardless of the selling price, the TES after the sale should always fall within Stream A.[10]

Ameresco disagrees with FAES. It submits that "[t]he premise that Micro TES Strata customers require or need BCUC protection that is afforded to Stream-A customers is misleading and is based on the dangerous assumption that the BCUC will protect Stream-A customers in terms of reviewing, approving and adjudicating the propriety of rates." It points out that under the TES Framework, the Commission will only intervene if there is an issue of disclosure or whether the original agreement is being applied, but not with respect to the propriety of the rate.[11]

With regard to consumer protection, Ameresco argues that a Strata Corporation that is a customer of an Exempt TES utility has recourse to the protection afforded by the *Real Estate Development Marketing Act* (REDMA). Ameresco states that any agreement that a strata owner/developer enters into is subject to the disclosure requirements of REDMA.[12]

BCOAPO agrees with FAES "that where a TES has a strata corporation among its customers, or as its only customer, that TES should never fall under the micro-exemption, regardless of the capital cost or the purchase price of the TES." In BCOAPO's view, "FAES has identified a regulatory gap where a utility owns and operates a TES that falls under the micro-exemption, and that utility sells thermal energy to the strata unit owners." BCOAPO submits that since these customers are not protected under the *Strata Property Act* because the Strata Corporation does not own the TES, it is important that these customers be protected under the UCA, "particularly since the strata unit owners would not have been party to the agreement with the utility."[13]

BCSEA-SCBC submits that the "regulatory gap" is a concern and "suggest[s] that consideration be given to setting the minimum threshold to zero."[14]

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[8] Exhibit C2-3, pp. 4-5.
[9] Ibid., p. 5.
[10] Ibid., p. 7.
[11] Exhibit C6-4, p. 2.
[12] Ibid., p. 3.
[13] Exhibit C5-4, p. 1.
[14] Exhibit C4-4, p. 1.

Commission determination

For the reasons set out in the following paragraphs, the Panel is not prepared to vary its original decision and remove the Micro TES Exemption for customers that are Strata Corporations.

FAES, along with BCSEA-SCBC and BCOAPO, provide a number of arguments to support their position that the Micro TES Exemption be varied with respect to strata customers, specifically:

1. Strata customers of Exempt TES have no recourse under the *Strata Property Act* and therefore require the consumer protection afforded by the UCA.
2. The Commission Report on the Proposed Micro Thermal Energy System Limit and Stream B Exemption Test demonstrates that the Commission never intended that a Strata Corporation to be captured by the Micro TES Exemption.
3. The Panel in the AES Inquiry and Commission staff, in applying the Principles and Guidelines of the AES Inquiry Report, have always intended to treat TES that provide service to one or more residential Strata Corporations as Stream A TES.

The Panel will examine each of these arguments below.

Recourse for Strata Customers

The Panel agrees with Ameresco that regarding rates for a Stream A TES, the Commission will only intervene if there is an issue of disclosure or whether the original agreement is being correctly applied, but not with respect to the propriety of the rate. Therefore, in regard to rate approval, Stream A customers are in a similar position to Micro TES Exempt customers. Neither customer will receive Commission approved rates.

The Panel does not agree with FAES that in the event of a sale of a strata-owned TES to a TES provider the TES should always be a Stream A, even if it would otherwise fall into the Micro TES Exempt category.

In the event the sale transaction is entered into by a developer on behalf of future Strata Unit Owners, REMDA sets out disclosure requirements. In the event that the transaction is entered into by a strata council, the strata council is subject to the *Strata Property Act*, which requires the transaction to be approved by a prescribed majority of owners voting in a meeting for which prescribed notice requirements have been met. If the TES that is sold is a Micro TES, the Strata Corporation, as its customer, will subsequently be subject to exactly the same terms to which any other Micro TES customer is subject. There is no evidence that a Strata Corporation requires any additional protection.

FAES emphasized that in the case of the Artemisia project, the Strata Unit Owners did not enter into the agreement and that the developer selected the TES based on its own objectives.[15] In the Panel's view, FAES appears to imply that because this is the case, Strata Unit Owners require additional protection. It has been the case with most greenfield TES applications brought before the Commission to date that the agreements with the TES utility are entered into by the developer on behalf of the Strata Corporation. In the Panel's view, this does not necessarily imply that there is no alignment of interest between the developer and the Strata Corporation. For the units to remain competitive, the developer must agree to rates that will ultimately be acceptable to the purchasers of the strata units. Similarly, any contribution provided to the TES utility that is recovered from the

[15] Exhibit C2-3, p. 5.

selling price of the units can only be recovered if the developer ensures that the selling price of the units remain competitive. It is precisely because of this competitive aspect that additional protection of rate regulation is not required.

The Commission Report

The Micro TES Exemption recognizes inherent differences in the dynamic of a small group of people, as opposed to a larger group, and that these differences support an exemption from regulation. The Panel considers small groups of people better able to ensure their collective self-interest than larger groups where members' individual self-interests may be diluted.

The Commission Report explicitly stated that the Micro TES Exemption is intended to capture the case of homeowners and/or small businesses, and should be large enough to incorporate a project undertaken by or for a small group of homeowners and or small businesses. The Commission did not distinguish between a group of people organized as a Strata Corporation or a group of people organized in any other way. There was no exclusion of a small group of people organized as a Strata Corporation.

Accordingly, the Panel finds no basis for the argument that a Micro TES Exemption that includes Strata Corporations is inconsistent with the previous Commission Report.

The AES Inquiry Report

The AES Inquiry Report laid out the following Key Principles and Guidelines:

Key Principles:

i) Where regulation is required use the least amount of regulation needed to protect the ratepayer.

ii) The benefits of regulation should outweigh the costs.

Guidelines:

The form of regulation should:

- provide adequate customer protection in a cost effective manner;
- consider administrative efficiency;
- consider the level of expenditure, the number of customers, the sophistication of the parties involved and the track record of the utility in undertaking similar projects; and
- require the provision of sufficient information to allow the Commission to assess the new business activity, and any rates to be set, against BC's Energy Objectives and the requirements of the *Utilities Commission Act* and the *Clean Energy Act*.[16]

In making its determination that a small group of customers should be exempt from regulation, the Panel recognized the key principles of the AES Inquiry Report. Exempting TES that supply small groups of customers reduces the amount of regulation while considering the level of expenditure and the number of customers.

[16] AES Inquiry Report, p. 18.

Accordingly, the Panel finds that including Strata Corporations in the Micro TES Exemption is consistent with the Key Principles outlined in the AES Inquiry Report.

3.0 THE BASIS FOR DETERMINATION OF THE STATUS OF A TES

This section presents the three scenarios and the positions of parties that commented and culminates with a number of Commission Panel determinations. A fourth scenario was proposed and addressed by Ameresco.

3.1 Scenario 1

Scenario 1 was laid out by the Panel as follows:

> The subsequent sale of a TES at a reduced price to reflect the effects of inflation and depreciation: Consider an example whereby "TES Provider A" constructs a TES, at a capital cost of $600,000, for which it is registered and granted a Stream A TES exemption. Several years later, TES Provider A sells the TES to TES Provider B for $450,000.[17]

All parties agree that if a system is registered as a Stream A system, a subsequent sale for less than the exemption amount does not change its Stream A status. Ameresco argues that as long as the rate agreements remain in place after the sale of the asset the TES should remain a Stream A TES and that this is because the original rates are based on the original capital cost, which was above the Micro TES threshold at the time of registration.[18]

FAES submits that the TES should remain in Stream A after the sale. In support of its position, it asserts that the TES customers had recourse to the Commission before the sale and there "is no principled reason why this TES' customers should lose [sic] protection from the Commission because of a change in TES providers *that occurred at a particular point in time.*" FAES further explained that if the transaction had occurred a few years before, the question may not have arisen because the book value of the TES may have been more than $500,000.[19]

BCSEA-SCBC submits that "the primary consideration should be achieving clarity (at a point in time) and certainty (over time). That would support defining the financial thresholds according to the initial construction cost." It therefor proposes that in the case of Scenario 1, the TES retain its status regardless of the amount for which it is sold.[20]

BCPSO submit that "the basis for determining the status of the TES for exemption in Scenario #1 should be initial capital cost, as this best reflects the size of the TES."[21]

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[17] Exhibit A-10, p. 1.
[18] Exhibit C6-3, p. 2.
[19] Exhibit B2-3, p. 7, emphasis in original.
[20] Exhibit C4-3, p. 1.
[21] Exhibit C5-3, p. 2.

3.2 Scenario 2

Scenario 2 was laid out by the Panel as follows:

> A developer provides a Contribution in Aid of Construction (CIAC) or otherwise agrees to sell the TES below its cost to construct: Consider an example whereby a developer builds a TES as part of the BCUC TES Regulatory Framework. The developer estimates the construction of the TES portion of the project is $1,000,000. However, the developer does not operate the TES, but sells the TES to a TES Provider for $400,000, thereby providing a *de facto* CIAC of $600,000. [22]

BCSEA-SCBC submits that the initial construction cost should be the determinant of the status of a TES. In BCOAPO's view, "the basis for determining the status of the TES for exemption should be initial capital cost, as this best reflects the size of the TES." Ameresco submits that the project should be granted a Micro TES Exemption because the rates the TES customers will pay are based upon this price.[23]

FAES submits that, provided the development does not have a residential component, it "sees no principled reasons why…..this TES [should] not fall under Stream A."[24] However, when commenting on the submission made by Ameresco in the FAES Artemisia proceeding, FAES agrees with Ameresco, stating that "the amount of capital that is included in the rate calculation (i.e. FAES' purchase price) should be the basis for determining the status of a TES project."[25]

3.3 Scenario 3

Scenario 3 was laid out by the Panel as follows:

> A change in the threshold amount: Consider a TES with an initial capital cost of $600,000. The builder and operator is a TES Provider who has applied for, and received Stream A exemption status for the TES. The micro exemption threshold is subsequently raised by the Commission to $650,000. Subsequent to the threshold being raised, the system is sold to TES Provider B for $550,000.[26]

Ameresco and FAES agree that the system should remain a Stream A system.[27] BCOAPO disagrees and submits that the system should be revaluated to determine if the initial capital costs meets the new criteria. BCSEA-SCBC submits that the Commission will need to decide at the time the exemption threshold is raised, whether the new threshold applies to existing systems. In its subsequent submission, after considering the submissions of other parties, BCSEA-SCBC accepts that "…in the interests of certainty it would be desirable for the Commission to state its current intention on the issue."[28]

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[22] Exhibit A-10, p. 1.
[23] Exhibit C4-3, p. 1; Exhibit C5-3, p. 2; Exhibit C6-3, p. 2.
[24] Exhibit C2-3, pp. 7-8.
[25] Ibid., p. 3.
[26] Exhibit A-10, p. 2.
[27] Exhibit C6-3, p. 2.
[28] Exhibit C4-3, p. 1; Exhibit C4-4, p. 2.

3.4 Scenario 4

Scenario 4 was proposed by Ameresco:

> A TES Project is developed by TES Provider A and is estimated to cost $450,000 and rate agreements are executed based on that cost. This is below the current TES Micro Threshold of $500,000 and, as such, this would be an Exempt TES project. However the project is sold to TES Provider B to operate for $550,000. (This sale could be prior to construction being completed or after construction.)[29]

In Ameresco's view, "this should still be an exempt project in this scenario even after the sale transaction. Parties should not be incented to pay a premium to obtain a greater amount of regulation than what is contemplated under the TES Regulatory Framework. That does not preclude the parties from a transaction at this price level but it should not impact the regulatory treatment of the project."[30]

BCSEA-SCBC agrees with Ameresco that "the regulatory status of the TES project should not change merely because of the size of the purchase price."[31]

FAES "believes that the regulatory treatment of a TES set out in the TES Guidelines should be based on the two key principles of the AES Inquiry Report….. This position applies to all cases, including those where a Micro TES may or may not transition into a Stream A TES and cases where a Stream A TES may or may not transition into a Stream B TES by virtue of differences between capital cost and purchase price of the TES."[32]

Commission determination
For the reasons set out below, the Panel finds that the initial construction cost should determine whether a TES is Stream A or an Exempt Micro TES.

As previously discussed, the Micro TES Exemption recognizes the inherent differences in the dynamic of a small group of people, as opposed to a larger group, and that these differences support an exemption from regulation. In doing so, it balances the need for regulation with due consideration of the costs of that regulation.

Further, as a proxy for the size of the group receiving service from the TES, the Panel chose the cost to construct the TES. The Panel accepted $500,000 as a proxy for the threshold between a group of people small enough to be better able to ensure their collective self-interests and a larger group whose members' self-interests may be diluted.

With regard to Scenario 3, where the Micro TES Exemption threshold amount changes subsequent to the commissioning of the TES, the Panel directs that the status of an Exempt TES or a TES registered as Stream A does not change. This approach recognizes that the exemption status is based on the proxy for system size as determined at the time of construction of the TES. Subsequent changes to the threshold do not change the size of the TES.

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[29] Exhibit A-10, p. 2.
[30] Exhibit C6-3, p. 3.
[31] Exhibit C4-4, p. 2.
[32] Exhibit C2-4, p. 7.

Ameresco argues that it is the purchase price that should be considered when determining whether a TES is over or under the threshold amount. The Panel disagrees. The purchase price may be affected by contributions in aid of construction (CIAC), grants or other factors. Consider the case where the utility receives a CIAC for a TES that would otherwise fall above the threshold and the effect of the CIAC results in a purchase price below the threshold. The CIAC hasn't changed the number of people served by, or any other physical characteristic of, the TES. In particular, in a case where the customer chooses to provide the CIAC, perhaps in order to reduce rates, the result should not be to reclassify the exemption status of the TES.

Further, Ameresco's argument concerning purchase price is premised on the fact that rates are determined by the purchase price. This premise also underlies the argument of other parties that submit the exemption status should be based on the capital costs recovered in rates. The Panel does not disagree that rates may be largely determined by purchase price. However, as Ameresco has correctly pointed out in other contexts, the Commission provides no oversight of rates for exempt Micro TES and Stream A TES. Accordingly, the Panel is of the view that purchase price is not relevant to the determination of whether a TES is exempt or is Stream A.

We therefore clarify that the exemption threshold is based on the cost to construct the TES and is not related in any way to the purchase price, whether that purchase price is below or above the cost to construct the TES. In cases where the purchased TES is an Exempt TES, it will remain exempt with no requirement to register, regardless of the purchase price. In cases where the purchased TES is Stream A, it will remain Stream A regardless of the purchase price, provided the system has not expanded to serve additional customers.

In making this determination, the Panel recognizes there may be ambiguities in a determination of the cost to construct. For example:

1. A piece of equipment may be purchased or leased. How should leased equipment be treated in the construction cost?
2. A charge for the land occupied by the equipment/control room may be levied on the utility. Should the value of this land be recognized in the construction cost?
3. How should construction costs for extant, unregistered TES be determined, especially if the construction cost records are no longer available.

In cases such as these, including cases where the original cost is not easily available, the Panel expects the utility to use its best efforts to determine the construction cost. The Panel considers that the construction cost should reflect the cost to acquire the physical components at the time the TES is constructed along with all costs that are incurred to install the components and ensure that they operate correctly at the time of commissioning.

4.0 TRANSITION FROM STREAM A TO STREAM B

Ameresco submits that although the scenarios contemplated involved the threshold between an exempt and Stream A TES, they also apply to the threshold between Stream A and Stream B TES. In its view, the same issues apply to both transitions.

Ameresco further submits that this is particularly true for Scenario 4: "In the event that a Stream A project is 'elevated' to Stream B, the TES Provider (the Acquirer) could apply to the Commission… to have rates regulated

with something approaching a cost of service model which could effectively raise rates to the TES customers." In Ameresco's view, this should only happen if there has been additional investment in the asset…. "[a]nd not merely because the system was resold for a value higher than what was used for the original application of the threshold."[33]

FAES agrees with Ameresco regarding the threshold between Stream A and Stream B, stating that "the purchase price of the asset should be the basis for determining the status of a TES project."[34]

BCSEA-SCBC submits that the transaction price alone should not be a reason to increase rates and that the Commission should state that a new owner of a Stream A TES should not expect approval of higher rates based merely on the transaction price being above the Stream A threshold. BCSEA-SCBC also questions whether the Commission should or even could completely preclude the possibility of a new TES owner from applying for a CPCN and rates."[35]

Commission determination

The Panel agrees with Ameresco that the scenarios contemplated with regard to the threshold between the Micro TES Exemption and Stream A also apply to the threshold between Stream A and Stream B. However, the Stream A/Stream B threshold is based, as is the Micro TES Exempt/Stream A threshold, on the size of the system and the number of customers served. **Accordingly, the Panel finds it appropriate that:**

i. **the initial construction cost of the TES determines whether it is a Stream A or a Stream B TES; and**

ii. **in the event of a subsequent purchase or sale of a Stream A TES for an amount greater than the threshold between Stream A and Stream B, the TES will remain a Stream A TES.**

In making this determination, the Panel acknowledges that any system extensions completed subsequent to the commissioning of the TES may contribute to the difference between the sale price and the initial construction cost. In that circumstance, the new owner may apply to the Commission for reclassification of the TES based on the costs to construct the TES along with any subsequent extensions to the TES. Further, if the extensions to the TES extend beyond the boundaries of the site on which the TES is located, the TES is reclassified as a Stream B TES, and a CPCN is required, along with rate review and approval.

With regard to BCSEA-SCBC's suggestion that the Commission may not be able to preclude the possibility of a new owner of a Stream A TES from applying for a CPCN and rates, the Panel agrees. Any utility is free, at any time, to make an application to the Commission. However, the TES Guidelines anticipate that Stream A TES providers will provide service based on long term contracts. The Panel expects that the contract will provide for the eventuality of the ownership of the TES changing hands. In the event that is not the case, it is expected that the new TES owner will negotiate a rate with its customers.

Scenario 3 can equally apply to a subsequent change to the threshold between Stream A and Stream B. In this circumstance, the status of a TES registered as either Stream A or Stream B does not change. This approach

[33] Exhibit C6-3, p. 3.
[34] Exhibit C2-4, p. 8.
[35] Exhibit C4-1, p. 2.

recognizes that the exemption status is based on the proxy for system size as determined at the time of construction of the TES. Subsequent changes to the threshold do not change the size of the TES.

5.0 THE AGGREGATION OF MULTIPLE SITES

FAES raises an issue related to the aggregation of multiple sites with a single owner. The TES Guidelines state that in this circumstance, each site[36] is treated as a separate TES. In the view of FAES, this could give rise to an impractical situation if one or more sites are TES Exempt and one or more are Stream A. FAES submits that the customer would only be able to submit a complaint to the Commission with regard to a Stream A TES, but not an Exempt TES. It cites as an example the Delta School District, a customer of FAES with 19 sites, four of which would be Micro TES Exempt had the Guidelines been in place when that customer began receiving service from FAES.[37]

BCOAPO agrees with FAES. However, Ameresco disagrees, claiming that FAES' proposal to bundle multiple, disconnected assets owned by the same customer "appears to be an attempt to achieve an regulatory outcome that does nothing to benefit the customer." In Ameresco's view, this creates a "possible inference that Stream-A projects are 'regulated' and therefore enjoy BCUC protection regarding rate review and approval (despite the required contractual acknowledgement to the contrary)" and that this "creates a moral hazard whereby potential customers could be more inclined to rely on non-existent rate protection from the BCUC than on their own due diligence." It also submits that "[t]he more customers that are categorized as Micro-TES, the less likely it will be that a customer enters into a TES agreement thinking they had BCUC rate protection only to find out later they do not. As for school districts, they <u>should</u> be sophisticated enough to do their own due diligence but having Micro-TES assets included in the mix of their overall agreement with a TES provider can only help to encourage them to exercise that due diligence."[38]

Commission determination

The Panel is not persuaded there is sufficient evidence to warrant a reconsideration of this particular aspect of the TES Guidelines. **Accordingly, the Panel makes no change to the TES Guidelines with respect to the aggregation of multiple sites.** FAES provides no specific evidence of any harm that could potentially be caused by not bundling the sites. Further, the Panel agrees with Ameresco that in the particular case of the Delta School District, it is reasonable to consider the customer to be sophisticated enough to do their own due diligence.

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[36] The TES Regulatory Framework Guidelines, at p. 3, define a site as a legal property of parcel with defined boundaries for which a municipal building permit is issued or pending approval.

[37] Exhibit C2-3, p. 9.

[38] Exhibit C5-4, p. 1; Exhibit C6-4, p. 4, emphasis in original.

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of March 2015.

Original Signed By:

_____

D. M. MORTON
PANEL CHAIR/COMMISSIONER

Original Signed By:

_____

L. A. O'HARA
COMMISSIONER

Original Signed By:

_____

R. D. REVEL
COMMISSIONER

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-27-15

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

and

Thermal Energy Systems Framework
Revisions to the Thermal Energy Systems Regulatory Framework Guidelines

BEFORE: D. M. Morton, Panel Chair/Commissioner
L. A. O'Hara, Commissioner March 2, 2015
R. D. Revel, Commissioner

O R D E R

WHEREAS:

A. On August 28, 2014, in Order G-127-14, the British Columbia Utilities Commission (Commission) approved and issued the Thermal Energy System (TES) Regulatory Framework Guidelines;

B. On August 1, 2014, in the FortisBC Alternative Energy Services (FAES) Application for Certificate of Public Convenience and Necessity (CPCN) and Rate Approvals Established in Agreements for TES for the Artemisia Development proceeding (Artemisia proceeding), Ameresco Canada Inc. (Ameresco) raised the question (Exhibit D-1 in the 2014 Artemisia proceeding) of whether, in the case of a purchase of a TES, the purchase price should be the basis for the determination of the status of the TES for exemption or whether it should be the actual capital cost to construct the TES;

C. On September 17, 2014 (Exhibit A-10 in the TES Regulatory Framework proceeding) the Commission requested submissions from participants on the question of capital costs versus the purchase price and regulatory status of a TES;

D. On October 3 and October 24, 2014, the Commission received submission from FAES, Ameresco, the BC Sustainable Energy Association and Sierra Club of BC (BCSEA-SCBC) and the British Columbia Pensioners' and Seniors Organisation, Active Support Against Poverty, BC Coalition of People with Disabilities, Counsel of Senior Citizens' Organisation of BC, and the Tenant Resource Advisory Centre (BCOAPO);

E. The Commission has considered the submissions made by interveners on the issue raised by Ameresco, as well as other issues raised by parties within their submissions, and finds that several clarifications and

housekeeping modifications to the Commission's Thermal Energy Systems Regulatory Framework Guidelines are warranted.

NOW THEREFORE pursuant to section 11 of the *Administrative Tribunals Act* and in accordance with the Decision issued concurrently with this Order, the Commission's Thermal Energy Systems Regulatory Framework Guidelines, attached as Appendix A to this Order, are in effect.

DATED at the City of Vancouver, in the Province of British Columbia, this 2nd day of March 2015.

BY ORDER

Original Signed By:

D. M. Morton
Panel Chair/Commissioner

Attachment

British Columbia Utilities Commission

Thermal Energy Systems
Regulatory Framework Guidelines

For further information, contact:

British Columbia Utilities Commission Attention: Commission Secretary Sixth Floor, 900 Howe Street Vancouver, BC V6Z 2N3	Telephone: (604) 660-4700 Toll Free: 1-800-663-1385 Facsimile: (604) 660-1102 Commission.Secretary@bcuc.com website: www.bcuc.com

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APPENDICES

1 INTRODUCTION

These Guidelines describe the regulatory framework for Thermal Energy Systems (TES). They are intended to inform persons (which may include an individual or a company) who own or operate TES (TES Providers) on the regulatory approval process and ongoing regulatory requirements to construct and operate a TES and charge rates to customers of those Thermal Energy Systems in British Columbia.

These Guidelines may be revised or updated from time to time in order to incorporate lessons learnt and adjust to evolving market circumstances and changes to the *Utilities Commission Act* (UCA).

1.1 To whom do these Guidelines apply?

These Guidelines are applicable to all TES Providers in the Province of British Columbia.

1.2 What is a Thermal Energy System?

A Thermal Energy System consists of equipment or facilities for the production, generation, storage, transmission, sale, delivery or provision of heat, hot water and/or cooling from one or more thermal energy sources and through a distribution system. Energy sources may include waste heat, renewable (solar, ground/water source or air source heat pumps, geothermal, biomass etc.) as well as non-renewable energy sources. A TES may include plant, equipment, distribution piping, apparatus, property and facilities employed by or in connection with the provision of thermal energy services.

1.3 What is a TES Provider?

A TES Provider is a person who owns and/or operates a Thermal Energy System.

1.4 Role of the British Columbia Utilities Commission

The British Columbia Utilities Commission (Commission) is responsible for general supervision of public utilities in British Columbia. The Commission's role is to ensure that public utility customers receive safe, reliable, non-discriminatory energy services at just and fair rates to ensure that the utility's shareholders have a reasonable opportunity to earn a fair return on their investment.

1.5 The Utilities Commission Act

The UCA sets out the Commission's duties and authority including regulation and general supervision of public utilities in British Columbia. Part 3 of the UCA lists the duties, responsibilities and restraints imposed upon a public utility.

Generally, if a person intends to purchase, construct or operate a public utility plant or system, or extend an existing public utility infrastructure, a Certificate of Public Convenience and Necessity (CPCN) is required. Approval of rates is also required before any customer can be billed for utility service.

The Commission has the authority to impose administrative penalties on utilities if they do not comply with the requirements of the UCA[1] or with Commission Orders. For more information on the Commission, please visit: www.bcuc.com.

1.6 UCA Definition of and Exclusions from the Definition of Public Utility

The UCA defines a public utility as a person owning or operating equipment or facilities in British Columbia for the provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation.

The UCA specifically excludes the following from the definition of public utility and therefore, exclusion from regulation by the Commission[2]:

- a municipality or regional district providing services within its own boundaries;
- a person not otherwise a public utility who provides the service or commodity only to the person or the person's employees or tenants, if the service or commodity is not resold to or used by others; and
- a person not otherwise a public utility who is engaged in the production of a geothermal resource, as defined in the *Geothermal Resources Act*.

The *Geothermal Resources Act* defines "geothermal resource" to mean the natural heat of the earth and all substances that derive an added value from it, including steam, water and water vapour heated by the natural heat of the earth and all substances dissolved in the steam, water or water vapour obtained from a well, but does not include water that has a temperature less than 80°C at the point where it reaches the surface[3].

Any exclusion from the definition of a Public Utility is with respect to a specific utility system. An example of this is the City of Nelson, who provides electrical energy to customers within its boundaries, and also to customers in the surrounding areas. As a municipality, the City of Nelson is excluded from the definition of a Public Utility with respect to energy sales within its own boundaries. However, the Commission does regulate the City of Nelson's sales with respect to customers in the surrounding area.

2 REGULATION OF THERMAL ENERGY SYSTEMS

2.1 Introduction

Under the *Utilities Commission Act*, a TES Provider is considered a public utility. However, by OIC 399, 400 and 401 and Commission Orders G-119-14, G-120-14 and G-121-14, certain TES Providers are exempt from certain provisions of the UCA. Together, these exemptions provide a scaled approach to the regulation of TES. This

[1] A copy of the UCA can be found at: www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_96473_01

[2] Please refer to the definition of public utility in the UCA for a complete description of those that are specifically not included and therefore excluded from the definition of public utility. If a TES Provider is unsure if it is excluded from the definition of a public utility, it should contact the Commission Secretary (information on inside cover page of this Guide) and/or seek legal advice.

[3] Given the definition of geothermal resource, most TES Providers utilizing ground source heat are not engaged in the production of a geothermal resource as defined in the *Geothermal Resources Act* due to the low temperatures involved in ground source heat exchange.

framework provides increased regulatory oversight as the size and scope of the TES increases. It consists of four categories of TES:

i. **Micro TES:** A TES with a capital cost of $500,000 or less is exempt from Part 3 of the UCA other than sections 42, 43 and 44.

ii. **Strata Corporation TES[4]:** A TES owned or operated by a Strata Corporation, or the Strata Corporation's lessee, trustee, receiver or liquidator, that supplies the Strata Corporation's owners, is exempt from Part 3 of the UCA other than sections 42, 43 and 44.

iii. **Stream A TES:** An On-Site TES with an Initial Capital Cost above $500,000 but less than $15,000,000 is exempt from sections 44.1, 45-46 and 59-61 of the UCA. TES Providers are required to register Stream A TES prior to building or otherwise acquiring the Stream A TES.

iv. **Stream B TES:** All other TES will be regulated similar to other Public Utility systems. An application for a CPCN[5] and a rate approval application are required.

Although TES described in (i) and (ii) above are not exempt from all sections of the UCA, they will be referred to as "Exempt TES" within this Guide.

In Order G-27-15 and the associated Reasons for Decision, the Commission clarified the term "capital cost" as it is used to define the threshold between a Micro TES and a Stream A TES and the threshold between a Stream A TES and a Stream B TES. The exemption threshold is based on the cost to construct the TES and is not related in any way to the purchase price, whether that purchase price is below or above the cost to construct the TES. In the decision, the Commission recognizes there may be ambiguities in a determination of the cost to construct. For example:

1. A piece of equipment may be purchased or leased. How should leased equipment be treated in the as built cost?
2. A charge for the land occupied by the equipment/control room may be levied on the utility. Should the value of this land be recognized in the as built cost?
3. How should as built costs for extant, unregistered TES be determined, especially if the construction cost records are no longer available.

In cases such as these, including cases where the original cost is not easily available, the utility is expected to use its best efforts to determine the construction cost. The construction cost should reflect the cost to acquire the physical components at the time the TES is constructed along with all costs that are incurred to install the components and ensure that they operate correctly at the time of commissioning.

The Decision also stated that in cases where a purchased TES is an exempt TES, it will remain exempt with no requirement to register, regardless of the purchase price. Further, in cases where the purchased TES is Stream A, it will remain Stream A regardless of the purchase price.

[4] As defined by the *Strata Property Act [SBC 1998].*

[5] Sections 45 and 46 of the UCA address CPCNs.

All TES that were in service before August 28, 2014 without a CPCN and/or where no previous exemption was granted are deemed to be Stream A systems that require registration upon issuance of these Guidelines.

A **site** is a legal property or parcel with defined boundaries for which a municipal building permit is issued or pending approval. A site is usually contained within the boundaries of a city block and is not a large multi-phase master development parcel which may be part of municipal re-zoning applications or multiple building permit processes into the future.

An **On-Site** TES consists of thermal energy generation and distribution equipment and fixtures that are physically located on the same site as the thermal load. It is designed to meet the energy demands of one or more customers on that site and doesn't share any generation or distribution facilities beyond the bounds of the site.

The characteristics of a Stream A TES are further described in section 2.3.1

A TES Provider could own and/or operate both regulated and exempted TES. An exemption is with respect to a specific TES - and does not necessarily apply to all of the TES Providers' TES.

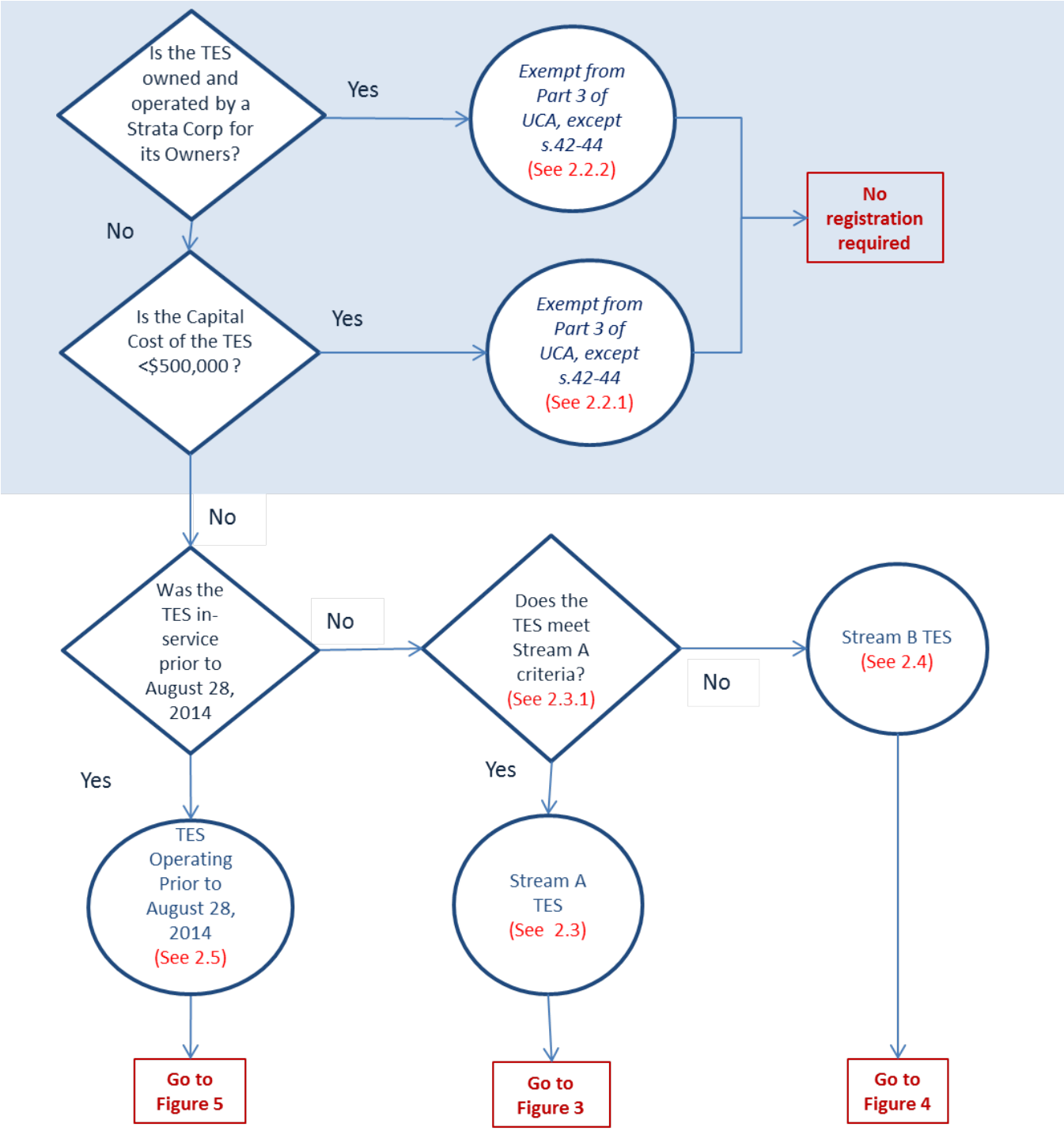
Figure 1 illustrates the dollar thresholds for each regulatory stream. TES operated by Strata Corporations are not subject to any upper limit.

Figure 1: The TES Regulatory Framework

TES Cost	On Site TES	Other TES
≤$500,000	Micro TES	Micro TES
≤$15 Million	Stream A Regulation	Stream B Regulation
No upper $ limit		

Figure 2 is designed to assist TES Providers in assessing which regulatory stream may be applicable for each Thermal Energy System. If the Applicant has questions on whether a particular TES is exempt, Stream A or Stream B TES, it should contact the Commission before submitting a registration or an application. The Commission ultimately decides the regulatory stream applicable to the particular TES and regulates accordingly.

Figure 2: Determination of the Appropriate Regulatory Stream



2.2 Exempt TES

2.2.1 Micro TES Exemption

A TES with an Initial Capital Cost that is less than $500,000 is considered a Micro TES and is exempt from active regulation, including the requirement for a CPCN and Commission oversight of rates. If subsequent capital additions result in a TES that has, in aggregate, a capital cost of over $500,000, registration under Stream A or Stream B, as applicable, will be required, unless the system meets the conditions of the Strata exemption described below.

A Micro TES Provider must be able to demonstrate that the capital cost of the system and any extensions, in aggregate, is less than $500,000, if requested by the Commission to qualify for this exemption.

2.2.2 Strata Exemption

A TES owned by a Strata Corporation that exclusively serves that Strata Corporation's Strata Unit Owners is exempt from active regulation by Commission Order G-120-14. A Strata Corporation that owns the TES and provides energy exclusively to its Strata Unit Owners[6] is subject to the *Strata Property Act*, which offers recourse and consumer protection to Strata Unit Owners. Accordingly, customers can find recourse under the *Strata Property Act*, and not through the Commission under the UCA. This exemption does not include a TES with a customer that is a Strata Corporation.

2.2.3 Registration and Reporting Requirements for Exempt TES

There are no registration or reporting requirements for persons owning or operating an exempt Thermal Energy System. However, if the same person also owns or operates a Stream A or Stream B TES, in addition to one or more exempt TES, then that person will be subject to registration and reporting requirements for the Stream A and/or Stream B TES, as the case may be.

There may be changes in circumstances which alter a Thermal Energy System's exemption status. Some examples are:

- Two or more Micro TES that were built and operated independently by the same person are subsequently combined for operational purposes, bringing the capital cost of the Micro TES above the threshold amount.
- A TES owned and operated by a strata that formerly exclusively served its own members, begins to sell thermal energy to customers who are not strata members.

In advance of a change of circumstance, a TES Provider is required to assess which regulatory stream is applicable to its TES and register or apply accordingly before proceeding.

[6] A Strata Unit Owner is an owner of a unit that is part of a Strata Corporation.

2.2.4 Complaints Concerning Exempt TES

Upon receipt of a complaint relating to an Exempt TES, the scope of the Commission's review will be limited to whether the TES meets the criteria to qualify for an exemption or whether the TES should be characterized as a Stream A or Stream B TES. The Commission will review whether the capital cost of the TES is, or likely is, greater than the maximum threshold for a Micro TES or the TES is owned by a Strata Corporation and is providing energy exclusively to its Strata Unit Owners. If that does appear to be the case, the Commission may take further action, such as requiring registration of the TES and further review of rates and contracts. The owner of the TES should be prepared to provide evidence concerning the costs, ownership of and/or the customers of the TES.

Accordingly, upon receiving a complaint concerning an exempt TES, any investigation the Commission may undertake will be limited to what is required to determine whether the TES meets the requirements for exemption. For this reason, sections 42, 43 and 44 of the UCA, which deal with a public utility's duty to obey Commission orders and to keep and provide information that the Commission requests, applies to exempt TES. **If, as a result of an investigation, the Commission determines that a TES does not meet the requirements for exemption, the customer's complaint will be investigated further.**

As per the Commission Complaint Guidelines (http://www.bcuc.com/Complaint.aspx), a complainant must submit evidence that supports their allegations.

2.3 Stream A TES

2.3.1 Stream A TES Characteristics

The following types of TES are considered by the Commission to be a Stream A Thermal Energy System:

- Any On-Site TES with the characteristics described in Table 1; and
- Any TES that does not meet the requirements of an Exempt TES or any TES without a CPCN or a CPCN exemption that has an in-service date prior to August 28, 2014.

Table 1 Stream A TES Characteristics

1. The thermal generation and distribution equipment and facilities are located on the same Site as the thermal load.
2. The TES is designed to meet the energy demands of a specific Site (one or more customers or buildings).
3. The Thermal Energy System serves one or more customers or buildings on a single Site but there are no shared or common thermal generation or distribution facilities beyond the boundaries of a single Site.
4. There is no, or very limited, use of public rights of way or public streets.
5. The TES provides thermal energy to an existing building(s) or to a new building(s) planned or approved under a municipal building permit process.
6. The TES has an AACE Class 3 capital cost estimate of equal to or greater than $500,000 and less than $15 million.

A person owning or operating a Stream A TES is exempt from CPCN requirements, regulation of rates and Long-Term Resource Planning (sections 44.1, 45-46 and 59-61 of the UCA) with respect to that Stream A TES. However, all other sections of the UCA apply.

The following examples are provided to further clarify what the Commission considers to be a Stream A TES:

Example 1:
In the case of two or more separate sites each of which has a TES, where those systems are not physically connected to each other, each site will be considered a separate TES. However, if the systems are related in some other way, the individual Stream A applications may be filed at the same time for convenience. This could be the case if, for example, there is a single customer such as a school district.

Example 2:
Two or more physically disconnected TES on a single site (single building permit), that are not physically connected to each other, will be considered a single TES (do not need to be physically connected).

Example 3:
Two or more separate sites where Stream A TES are physically connected where each TES is designed and maintained to meet the load for the site on which it is located. Each TES will be considered a separate Stream A TES (even though physically connected).

Example 4:
Two or more separate sites where Stream A TES are physically connected to another TES on a separate site and the TES at each site is NOT designed and maintained to meet the load for that site which it is located (i.e. thermal energy generation may be located at one site but dependant on sharing generation from another) will be considered to be a Stream B TES. In this example, the interconnection between two TES may occur after the in-service date. For example, a Stream A System could be approved and built in 2014 and in 2016, connected to a second TES on a separate site. If the second site TES is not designed to meet the load for that site (i.e. will share thermal energy generation with the original Stream A TES), then in that case a Stream B CPCN and rate approval application must be filed before the two systems can be interconnected. Please see section 2.4 for a further discussion of Stream B systems and CPCN applications.

2.3.2 Rates and Contracts for Stream A TES

A Stream A TES Provider must have a long-term contract(s) with its Customer(s) which set out the utility's fees/charges and terms of service. Given the TES Provider's ongoing obligation under the UCA to provide safe and reliable service, the Commission expects that the term of contract will be for as long as the Customer(s) continues to occupy the premises that are served by the Stream A TES.

The following are the minimum provisions that must be included in a long-term contract for Stream A TES in order to qualify for exemption(s) as a Stream A TES.

Attestation to these provisions must be included in the Stream A Registration Form

1. Schedule of all Fees and Charges for thermal energy service (shown as monthly, annual charges or sample bills at different energy consumption levels). Include the initial rate and any subsequent rate adjustments, if applicable.

2. Description of the minimum or maximum contract charges and/or volumes. If none exist, then this should be clearly stated.
3. Clear identification in dollar terms of any front-end or back-end Fees and Charges, and the term of applicability.
4. Clearly defined penalties/charges (if any) for early termination of contract. Clauses must clearly state what is to be paid at different stages of the contract life including any contract expiry/non-renewal fees or other such charges.
5. Description of the circumstances where disconnection of service may occur. Identify the parties and the required actions with reasonable notice in order for service reconnection to occur.
6. Identification of the energy services covered by the TES and the additional services/fees which are not covered under the TES Fees and Charges which will be at the Customers' own expense (e.g. electricity).
7. Telephone number or other means by which customers will be able to contact the utility, in the event of disputes and/or concerns with rates and services, but particularly regarding an emergency.
8. Description of facilities and trained personnel that will provide emergency response.
9. Information regarding complaint process to the Commission.

Because the Commission will not be reviewing rates or the contracts upon which those rates are based, any and all contracts that set out rates for Stream A TES must contain the following clause to inform parties of the role of the Commission:

> *The Customer acknowledges [TES Provider name] is a public utility as defined in the Utilities Commission Act (UCA). However, this Thermal Energy System has a limited exemption, granted by British Columbia Utilities Commission Order #, from direct oversight of rates. Accordingly, the British Columbia Utilities Commission has not reviewed this Agreement, nor has it approved the rates charged for thermal services. However, other provisions of the UCA apply, including the obligation to provide safe and reliable service. Any disputes between the Customer and the utility that are within the jurisdiction of the British Columbia Utilities Commission pursuant to the UCA, may be referred for determination to the British Columbia Utilities Commission.*

2.3.3 Complaint Process for Stream A TES

Complaints can be brought forward by any customer of a Stream A TES Provider. Where the customer is a Strata Corporation, only the Strata Corporation may bring forward a complaint on behalf of the strata members (the Strata Unit Owners). Individual Strata Unit Owners who bring forward a complaint to the Commission will be directed to raise the issue with their Strata Corporation Council.

The Commission will receive complaints concerning the following rates or service issues related to Stream A Thermal Energy Systems:

- **Service:**
  - **Safety:** The operation of the TES has caused, or has the potential to cause, harm or injury to persons, or material damage that impairs the value, condition or function of property.
  - **Reliability:** The TES is performing, or has a high probability of performing, in an unreliable manner such that service is not dependable or consistent.

- **Rates:**
  - **Accordance with Regulatory Requirements:** The rates were not disclosed up-front for the full life of the contract or plainly stated, and/or the fees and charges are not available for public inspection on the TES Provider's company website or the location of business (as per section 4.2.1).
  - **Accordance with Contract:** The rates charged are not consistent with the long-term contract(s) for service or disclosure statement(s).

With regard to complaints concerning rates, the Commission will not consider the propriety of rates that the TES Provider is charging as long as the rate is in accordance with a long-term contract.

Customers wishing to file a complaint are directed to view the Commission's Complaint Guidelines (found at http://www.bcuc.com/Complaint.aspx). As per the Complaint Guidelines, customers are encouraged to bring their complaint directly to their TES Provider first, to give them an opportunity to resolve the customer's issues or concerns before involving the Commission. A complaint to the Commission will only be considered if other forms of resolution are unsuccessful. As per the Complaint Guidelines, a complainant must submit evidence that supports their allegations.

Upon receiving a complaint about a TES Provider's rates or service, the Commission will review the complaint and the evidence submitted by the complainant in support of the complaint. If the Commission accepts the complaint, the Commission will provide the TES Provider an opportunity to resolve the complaint or respond with their own evidence. The Commission may ask the TES Provider to provide specific information and will consider all of the evidence in assessing the complaint.

If warranted, the Commission will initiate a more fulsome regulatory review, and may escalate the complaint to an adjudication process. Escalated review or adjudication may result in the Commission exercising its authority under the UCA, including, but not limited to, lifting the exemptions provided at registration, setting rates or ordering the Stream A TES Provider to improve service.

The onus is on the Stream A TES Provider to ensure it complies with the Stream A TES requirements. A Stream A TES Provider must retain documentation or evidence that it has complied with the Stream A requirements in the case of a regulatory review initiated by complaint.

2.3.4 Registration Requirements for Stream A TES

As shown in Figure 3 below, all Stream A TES with an in-service date after August 28, 2014 must file the Registration Form found in Appendix A. The Commission will review the Registration for completeness. If further information is required by the Commission, the Applicant will be contacted. When a complete application is received, the Commission will either:

1. confirm by Order that the TES is registered as a Stream A TES; or
2. notify the Applicant to reapply as a Stream B TES, as per section 2.4.

If further information is required by the Commission, the Applicant will be contacted.

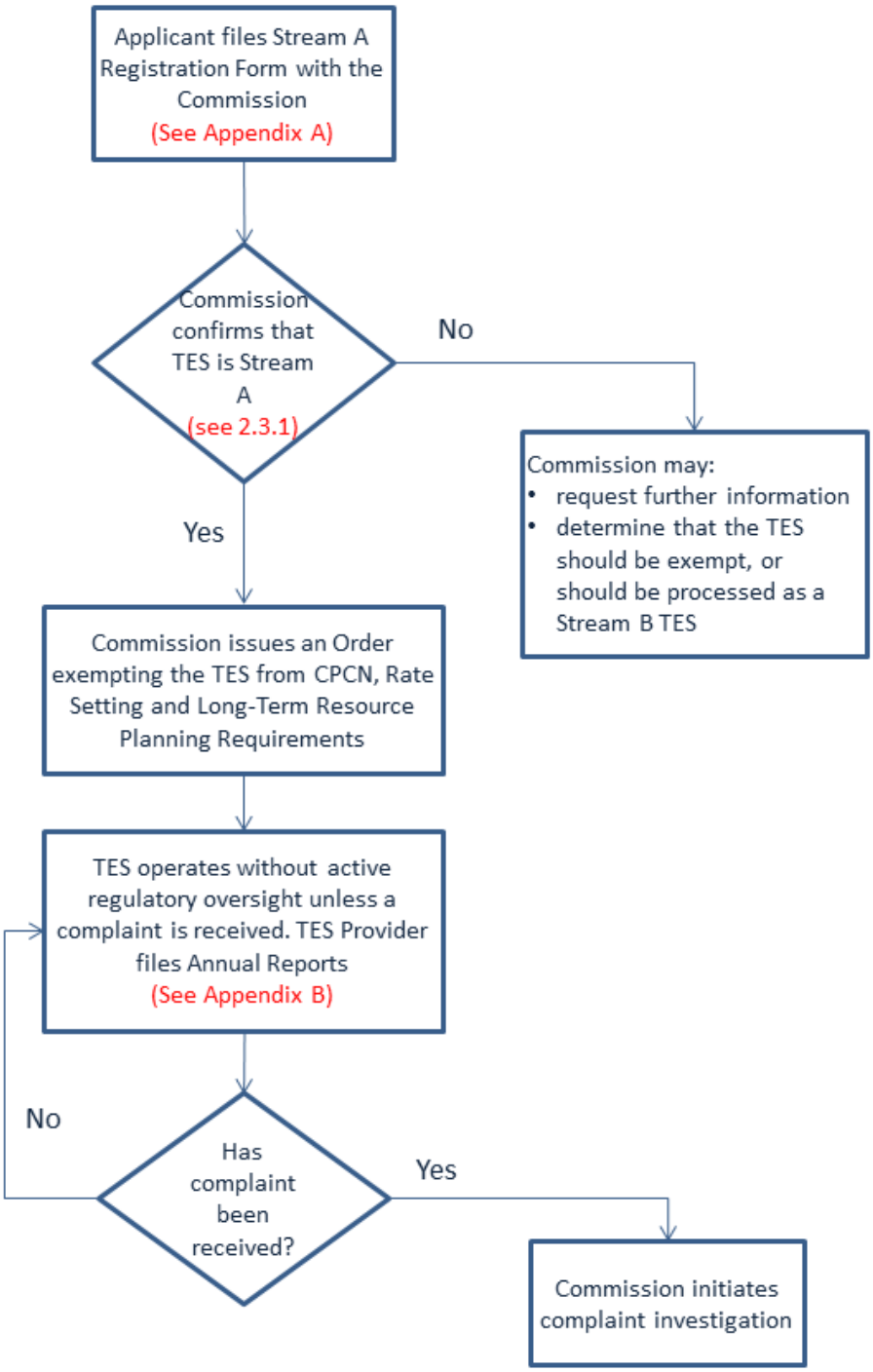
Once a TES is confirmed by the Commission to be a Stream A TES, the Commission will issue an Order to exempt the registrant from CPCN requirements, Rate Regulation and the requirement to file a Long-Term Resource Plan with respect to the registered Stream A System.

Applications that do not require further information are expected to be processed and an Order issued in as few as two weeks from receipt of the Application.

The Applicant must retain all background material related to the contents of the registration, for inspection and/or verification by the Commission, for as long as the TES is operational. It is important for the Applicant to ensure the information is clear, accurate and complete for the most efficient processing.

Prior to any transfer of ownership of a Stream A TES, an application must be made to the Commission for approval pursuant to section 52 of the UCA. The owner must provide the new owner with copies of the background material and the new owner must ensure they maintain that material. Appendix D sets out the information the new owner is required to provide to the Commission. Please contact the Commission Secretary if further information is required.

Figure 3: Stream A TES Operating After August 28, 2014



2.3.5 Extensions to Stream A TES

TES Providers must notify the Commission of any extension to a Stream A TES. An extension is any capital investment that is intended to increase the capacity of the TES. Provided the sum of the proposed extension and the initial system (plus any previous extensions) does not exceed $15 million, notification by way of a Stream A Application is sufficient. The Applicant should ensure that the Stream A Extension Application clearly identifies only those areas of the Thermal Energy System that the Applicant proposes to change.

If the sum of the proposed extension and the initial system, plus the cost of any previous extensions exceeds $15 million, the TES is considered a Stream B TES and a CPCN Application will be required. A CPCN application may also be required if an extension results in service to customers on a site different to the site on which the TES is located. Please see section 2.4.2 for more information on Stream B CPCN requirements.

2.3.6 Annual Reporting Requirements for Stream A TES

All Stream A TES Providers must submit to the Commission an Annual Report in accordance with the template attached as Appendix B to these Guidelines on or before February 15 of the most recent calendar year.

Information in this report is used for the Commission's Annual Report to the Legislature and in the assessment of the annual levy (see section 3). Both the Commission's Annual Report and the Commission Order that assesses the levy are public documents. Accordingly, the information provided in the Annual Report will not be held confidentially.

2.4 **Stream B TES**

A TES that does not meet the requirements for an exemption and does not meet the Stream A characteristics described in section 2.3.1 is by default considered a Stream B TES.

2.4.1 Stream B Regulatory Process

All Stream B TES Applicants must file a CPCN and Rates Application with the Commission. The CPCN and Rates Application may be filed simultaneously, or the Rates Application may be filed at a later date but not later than a customer is charged a fee for service. Construction of the TES cannot start until a CPCN is issued by the Commission. Upon determining that the Applicant's TES is to be considered under Stream B regulation, it is the Commission's sole discretion the process by which an Application will be reviewed.

After receiving approval for a CPCN authorizing the Applicant to construct and/or operate a Stream B TES, the TES Provider must:

1. File a TES Rates Application if it has not done so, according to the Guidelines set out in section 2.4.4. The Rates Application must include a Tariff[7] which outlines the schedule of proposed rates/fees and terms and conditions for all Customers. The TES Provider may not charge the customer a rate before it has filed the Rates Application for approval.

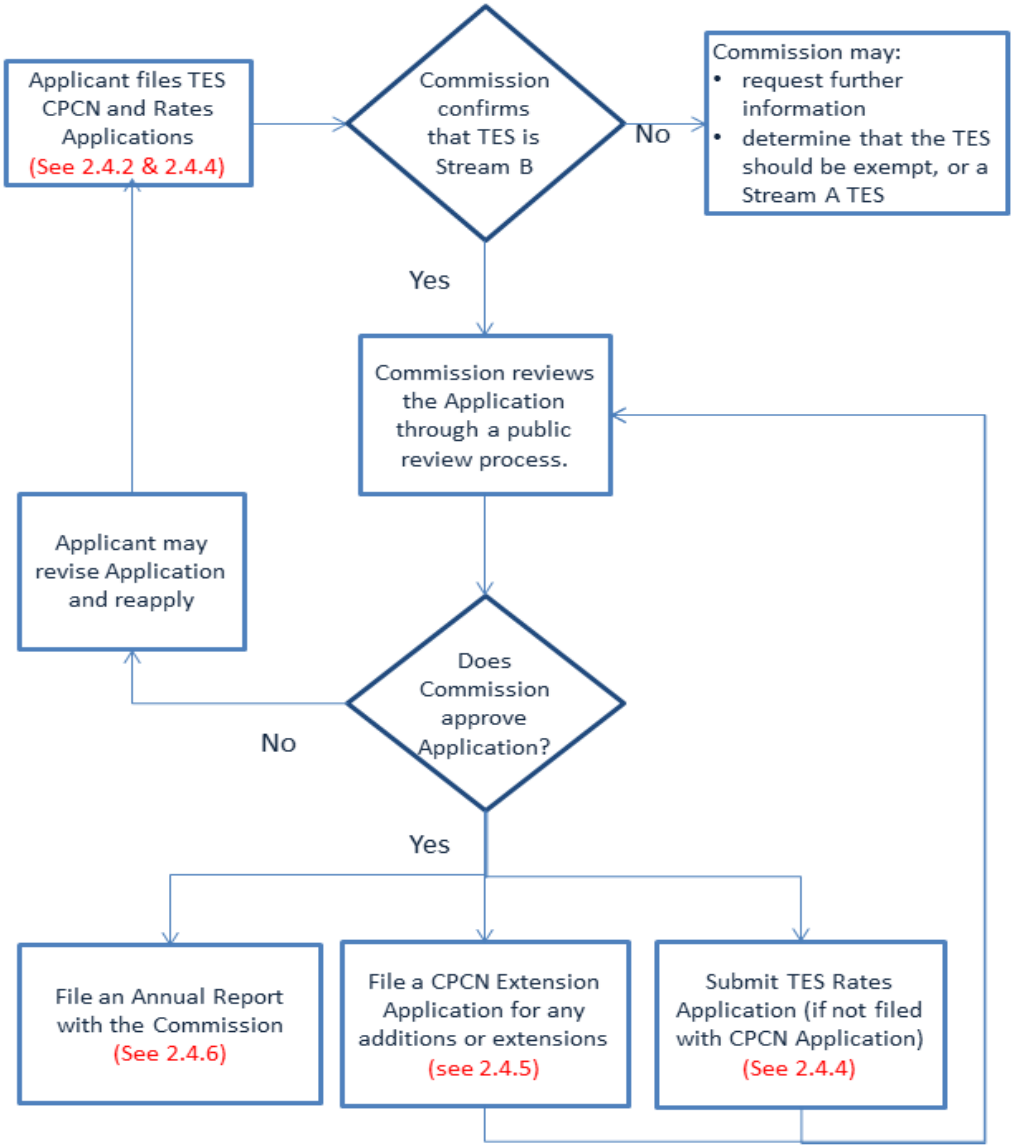
[7] A Tariff is a rate schedule, schedule of fees, terms and conditions, and definitions for the charging of rates that is approved by the Commission.

2. Submit an Annual Report within four months of each fiscal year according to the Guidelines set out in section 2.4.6.

Stream B TES Providers must file a TES Rates amendment Application in the event that it proposes to change the rate.

Figure 4 below illustrates the Regulatory Review Process for Stream B TES:

Figure 4: Stream B TES Operating After August 28, 2014



2.4.2 Stream B CPCN Application Requirements

The CPCN Guidelines can be found on the Commission website at:
http://www.bcuc.com/Documents/Guidelines/2010/DOC_25326_G-50-10_2010-CPCN-Application-Guidelines.pdf

These Guidelines are intended to be as general as possible with respect to the information required. If an Applicant is of the view that any guideline(s) are not applicable, the Applicant must provide explanations why it is considered not applicable.

In addition to addressing the CPCN Guidelines, Applicants should also address the following:

i. Evidence that the design energy capacity of the system has been appropriately determined and verified by a qualified person.

ii. Anticipated construction build-out and TES operation schedule.

iii. Load Analysis and Energy Demand Forecast for the Project:

   a. description of methodology used to forecast peak load and energy demand including key inputs and assumptions;

   b. forecast of floor area by building archetype (e.g., high rise, mid-rise, row house, retail, etc.) including data sources and assumptions;

   c. map of the TES Provider's service territory for the Project with identification of buildings connected;

   d. thermal energy end uses (e.g., space heat, domestic hot water, space cooling);

   e. energy use intensities (EUIs) by thermal energy end use for peak load (W/m^2) and energy demand (kWh/m^2), including data sources and assumptions;

   f. summary table of development schedule by year and building archetype or building including total sales (MWh) and peak (MW) for each year of the development schedule; and

   g. future expansion of the Project that is contemplated. Provide specifications concerning the size and location of the potential expansion.

iv. The amounts and sources of any contributions (developer), grants and other funding.

v. Forecast and treatment of Capital Reserve Fund balances and impacts.

vi. Annual operating budget specifying major cost components.

vii. A description of emergency repair fund sourcing, size rational and access protocol.

viii. A description of sustaining/replacement capital fund sourcing, size rational and access protocol.

ix. Any additional fees or liabilities of any kind.

x. Financial projections for various build-out scenarios to assess risk and required level of revenue requirements.

xi. Identify and evaluate risk factors, explain who bears the risk, and what actions are available to mitigate these risks. Some examples of risk factors may include:

a. technology risk;

b. fuel cost and availability;

c. customer base;

d. property development risk;

e. developer/customer connection risk;

f. load forecast uncertainty; and

g. financial risk.

In the event of a transfer of ownership of a Stream B TES, an application must be made to the Commission pursuant to section 52 of the UCA and the new owner must ensure they obtain a CPCN prior to the acquisition.

2.4.3 Stream B TES Rates

Approval of Stream B TES rates is governed by sections 59-61 of the UCA. Before setting rates, Applicants should ensure that they review these sections.

Applicants are also required to consider the Commission's rate setting principles, outlined below.

1. provide an equitable balance of risk and cost (such as forecast load and cost risk) between the utility and the ratepayer or generation of ratepayers;
2. use the least deferral mechanisms possible;
3. restrict the ability of the utility to pass controllable costs onto ratepayers;
4. use the least amount of regulatory oversight to protect the ratepayer (minimize the regulatory burden and costs on the utility, ratepayers and the Commission); and
5. avoid rate shock (>10 percent change in rates per annum is generally considered "Rate Shock").

2.4.4 Stream B TES Rates Application

A Stream B rate Application and calculations must include:

i. Description and details of the proposed rates (at minimum) for the initial five years for all rate classes. Include information on:

a. the rate design (i.e. fixed/variable component, single/multiple rate classes, etc.);

b. how rate increases will be determined; and

c. why the rate(s) and rate design is fair and reasonable.

ii. Options and terms for customers who enter into long-term contracts to opt out/cancelling the energy supply services.

iii. Information confirming the proposed rates will be competitive with other service options that are available to customers in the new service area (if appropriate).

iv. If the rate proposed is based on a regulated Cost of Service[8] rate-setting mechanism, this will be considered as a method of last resort. Therefore, the following must be provided:

a. analysis of alternative rate setting mechanisms for the Project;

b. justification as to why these alternatives are not preferable, making reference to:

1. the natural monopoly characteristics of the system;
2. the competitive market potential for the project;
3. the utility's obligation to serve new customers; and
4. rate setting mechanisms that encourage public utilities to increase efficiency, reduce costs and enhance performance.

A Stream B Rates Application must also include a proposed Tariff containing fees and terms and conditions of service. Include two copies of the tariff for endorsement by the Commission. The Commission must approve and endorse one copy of the tariff for the Applicant before it is deemed effective.

A sample tariff and tariffs for all utilities are available for viewing at the Commission's office. For further information, please contact the Commission Secretary.

If the Applicant files a Rates Application subsequent to a CPCN approval, the following additional information is required:

i. Name and address of Applicant;

ii. Name and address of Project;

iii. Commission Order granting a CPCN for the Project.

2.4.5 Extensions to a Stream B TES

Once a CPCN is granted for a Stream B TES, a new CPCN Application may be required if the TES Provider plans to construct or operate an extension to the TES. An extension is a capital addition to the system of a material dollar amount to provide additional capacity to meet increased demand. If the ratio of the capital costs of the planned extension to the initial capital cost of the TES, plus any previous extensions, exceeds one, a CPCN is required. A CPCN is also required if, as a result of the extension, rates for existing customers will increase by an amount greater than 10 percent. These criteria are summarized in the table below:

[8] A regulated Cost of Service rate-setting mechanism is a model that determines prices based on the costs of serving different customers and generally includes a regulated rate of return, which is deemed to be the fair return on investment.

EXTENSION COST	CPCN REQUIREMENTS
$\frac{\textit{Planned Extension Cost} + \textit{Cost of Any Previous Extensions}}{\textit{Initial TES Construction Cost}} > 1$ OR $\textit{Rate Impact as a result of Planned Extension} > 10\%$	CPCN REQUIRED
$\frac{\textit{Planned Extension Cost} + \textit{Cost of Any Previous Extensions}}{\textit{Initial TES Construction Cost}} \leq 1$ AND $\textit{Rate Impact as a result of Planned Extension} \leq 10\%$	CPCN NOT REQUIRED

In the event that a CPCN is not required, the TES Provider is required to file an application in the form set out in Appendix C.

A CPCN or the Stream A Application, as the case may be, must be granted prior to construction or operation of the extension. Please contact the Commission for further information if an extension is considered.

2.4.6 Annual Reporting Requirements for Stream B TES

Stream B TES Providers must file an Annual Report with the Commission **within four months of the TES Provider's fiscal year end**.

Although the Commission's annual reporting requirements may change from time to time, as of the date of this Guide, annual reporting requirements are set out in Commission Letters L-36-94 and L-14-95.

2.4.7 Complaint Process for Stream B TES

Customers wishing to file a complaint are directed to view the Commission's Complaint Guidelines (found at http://www.bcuc.com/Complaint.aspx) prior to filing a complaint. As per the Complaint Guidelines, customers are encouraged to bring their complaint directly to their TES Provider first, such that the TES Provider may have an opportunity to resolve the customer's issues or concerns before involving the Commission. A complaint to the Commission will only be considered if other forms of resolution are unsuccessful. As per the Complaint Guidelines, a complainant must submit evidence that supports their allegations.

2.5 TES Operating Prior to August 28, 2014

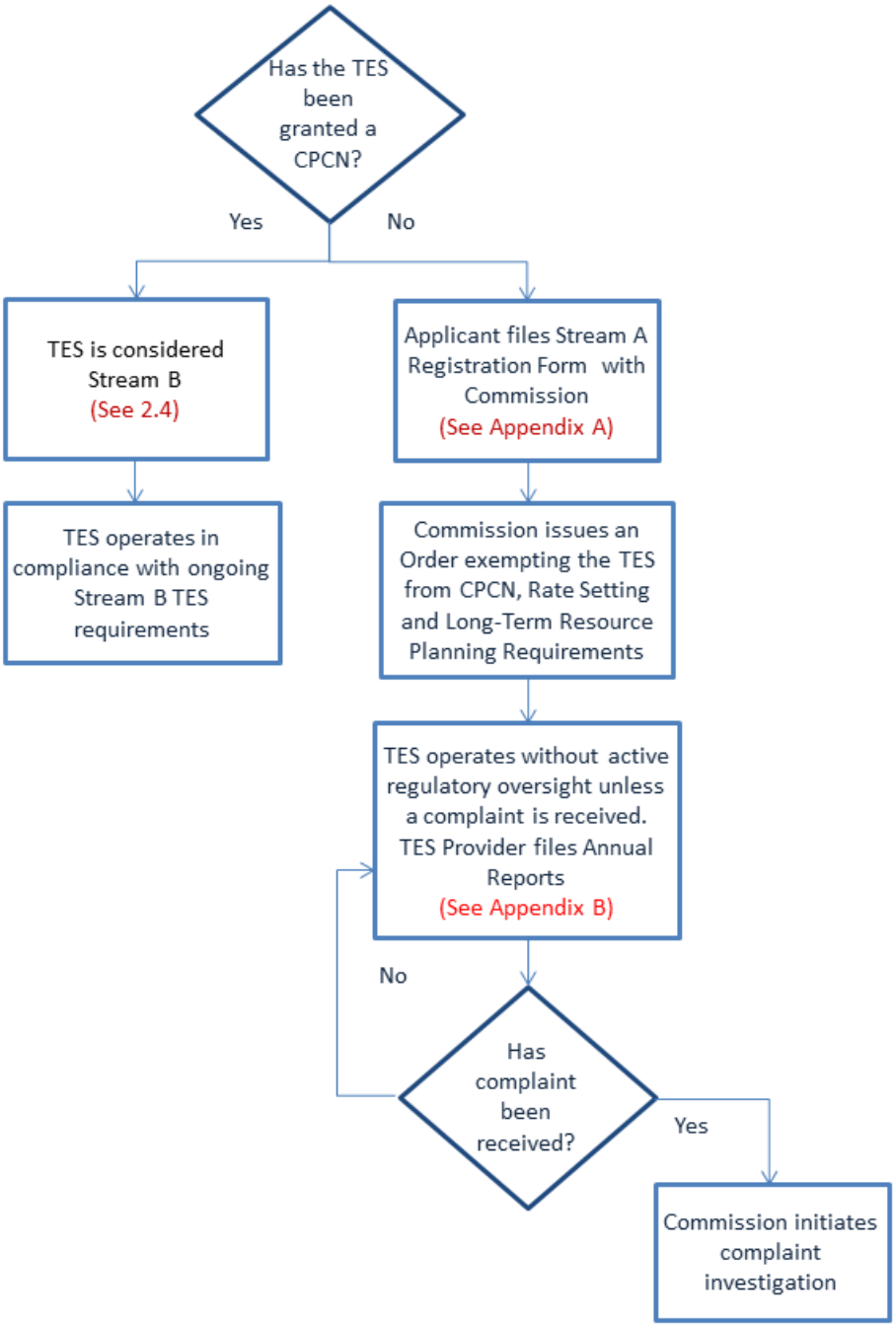
A TES that would not otherwise qualify for exemption as either a Micro TES or a Strata Corporation TES that was in-service before August 28, 2014, and for which no previous CPCN exemption was granted, must file a Stream A registration form with the Commission. Upon acceptance of the Stream A registration, the Commission will issue an order granting the TES Stream A exemption status. Going forward, section 2.3 of the Guidelines will apply to this TES.

Any TES that has previously been granted a CPCN will continue to operate under that CPCN and should not re-register the TES under this TES Guide. From August 28, 2014 that TES will be subject to the regulatory requirements of a Stream B TES, regardless of the size of the TES. The TES Provider is required to comply with the ongoing requirements for Stream B systems outlined in the Guidelines.

Any TES Provider that has a CPCN approval but no rates have been approved is required to contact the Commission Secretary.

Figure 5 below illustrates the regulatory process for TES operating prior to August 28, 2014.

Figure 5: Stream A TES Operating Prior to August 28, 2014



2.6 Capital Reserve Provisions

Owners and/or operators of Stream A and Stream B Thermal Energy Systems must have sufficient capital reserve provisions in place to ensure its ability to replace equipment essential to maintaining safe and reliable thermal energy service. The need for replacement may arise in situations where equipment either fails to operate prior to its end of life or as it comes to the end of its planned useful life.

Service interruption mitigation in the event of equipment failure must be considered in the design and set-up of the TES. Back-up energy service, redundancy, rapid deployment of temporary backup energy service through insurance etc. are some of the options that the TES Provider must have considered.

All TES Providers are required to assess, on an ongoing basis, their capital reserve requirements and ensure they have sufficient capital reserve in place. The TES Provider may use a portfolio approach in applying the capital reserve provisions where a single TES Provider owns and/or operates multiple TES. Only one capital reserve is required for a TES, regardless of whether owner and the operator are the same or different entities.

An Applicant requesting approval of a Stream A Thermal Energy System is required to attest that it has sufficient capital reserve provisions and must also attest, in its annual report that it continues to maintain adequate capital reserve provisions. Stream B providers are required to provide information about its capital reserve for review during a CPCN Approval process.

The Commission may, at any time, initiate a further review of a TES Provider's capital reserve provisions.

2.7 Filing Documents with the Commission

Stream A Registrations and Stream B Applications must be made to the Commission Secretary. All documents are to be filed with the Commission Secretary in accordance with the Commission's document filing protocols available on the Commission's website at: www.bcuc.com.

Documents will be made public, except where special circumstances require confidentiality. If an Applicant requires an application or certain sections of an application to be kept confidential, it must apply to do so and provide adequate justification to the Commission. Please refer to the Confidential Filings Practice Directive, available on the Commission's website at: www.bcuc.com.

3 TES REGULATION LEVY AND COMMISSION COST RECOVERY

3.1 TES Levy

The Commission recovers a portion of the costs associated with specific proceedings directly from the TES Provider involved. Other hearing costs and all overhead expenses are recovered from all regulated utilities through a levy authorized by the UCA. The levy is apportioned among regulated utilities on the basis of energy sold in a calendar year.

For calendar 2013, the amount of the levy was $0.012586 per GJ. The levy will be assessed on all Stream A and Stream B TES Providers. There will be no levy applied with respect to Exempt TES.

TES Providers will be also be assessed proceeding costs should a proceeding be required. A proceeding will typically be required for a Stream B CPCN Application and may be required as a result of a complaint against either a Stream A or a Stream B system. There are no additional fees assessed for a Stream A registration.

Depending on the outcome of the hearing of a complaint, the Commission may apportion the hearing costs between the TES Provider's owner/shareholders and the TES Provider's customer(s).

3.2 Collection of Information for the Levy

Currently, the Commission contacts all public utilities in February of each year to collect energy sales ($), sales volumes and number of customers. This information is collected from TES Providers on a TES basis.

Beginning on August 28, 2014, this information will be collected from Stream A TES Providers through the Annual Report (see section 2.4.6 and Appendix B). Stream B Providers will be contacted annually by the Commission in February for this information.

Information concerning energy sales, sales volumes and number of customers is used for the Commission's own Annual Report to the Legislature in addition to the assessment of the annual levy. Both the Commission's Annual Report and the Commission Order that assesses the levy are public documents. Accordingly, the information will not be held confidentially.

web site: http://www.bcuc.com

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

APPENDIX A REGISTRATION FORM FOR "STREAM A" THERMAL ENERGY SYSTEMS (TES)

By filing this Registration Form with the Commission, the Applicant attests that all information provided is true, accurate and complete.

Stream A TES Providers must retain documentation or evidence in support of the information provided as it may be required for future potential reviews initiated by complaint or as required by the Commission.

Stream A TES - Registration Form

Applicant Information	
Name of Applicant:	Company Name:
BC Business Registration No.:	Year Registered:
Full Address:	
Phone:	Email Contact:
Publicly or Privately held Business:	
Owner/CEO (name and address):	
Board Chair (name and address):	
Name of Parent Company if applicable and address:	
TES Specifics	
TES Location (address):	
Is this TES a: ❒ new construction ❒ retrofit ❒ purchase ❒ In service prior to 2014/08/24 ❒ Extension to an existing TES	In-Service date of the TES (YYYY/MM/DD):
Description of the construction phase-in or build-out period (in years):	
Service provided: ❒ space heating, ❒cooling, ❒ domestic hot water	
Primary thermal energy sources:	Heating: Cooling (if applicable):
Energy conversion technology used:	
Buildings served: ❒ single, or ❒ multiple, how many?	Total square meters served:
Municipal Building Permit Number:	
Location of TES facilities and description of site size. Include map or schematic diagram if possible.	

Description of TES including energy centre and distribution system (drawing, diagram or description of equipment, connections etc.)	
Describe system size and known energy demand.	
Description of whether system and or site is designed to be scalable and intended to connect to other systems, buildings or locations.	
Description of back up or alternative services available. Including information of provider.	
Any other information on service/energy provided and the scope of services and facilities.	
Description of the use of municipal or public rights of ways.	
Name the customer(s) involved in the selection or signing of contracts.	
Number of customers/end-users: • Initially; • In 5 years	
Type of customers: (e.g.) • residential/commercial/office; • individual tenants/strata corporation	
Is (are) the Customer(s) obligated or restricted to taking service from the TES? If so, how and why.	
What percent of the estimated TES cost was/will be competitively tendered?	How else is cost reasonableness for construction of the facility assured?
Load Forecast and Analysis	
❒ I/We confirm that the load analysis and energy demand forecast was/will be completed by the following qualified person(s): [Company name and qualifications]	

Information on peak loads (MW) and annual loads (MWh) by thermal energy end-use.

		Total
Peak Load (MW)	Heating	
	Cooling	
Annual Loads (MWh)	Heating	
	Cooling	

What is the method used to forecast the peak and annual loads? What are the key assumptions and design references used?

What is the peak design output (MW) of the TES (not including peaking/backup systems)?
What is the peak design output (MW) of the peaking/backup system?
Has the TES been designed to meet the full peak load for the site? If not, please explain other sources of peaking energy available to customers.
Cost Estimate

Estimated Capital Cost (AACE Class 3 minimum) (Applicant may add additional line items as appropriate)

Category	$, 000s	
Equipment		
Materials		
Engineering / Design		
Construction		
Financing		
Fees / Overhead		
Other 'soft' costs		
Total		

Describe methodology for estimating Overhead and Other 'soft' costs

Estimated Annual Operating Costs

Category	$, 000s	
Labour		
Consumables		
Sustainment Capital		
Admin/Taxes / Overhead		
Insurance		
Other (specify)		
Total		

Describe methodology for estimating sustainment capital and operating Admin/Overhead.

If the system is being purchased, what is the purchase price?

Attestation Requirements for Stream A TES	
Eligibility for Stream A TES Regulation:	❒ I/We certify that the proposed TES meets the description of an On-Site TES, as defined in the TES Regulatory Framework Guidelines. ❒ I/We certify that the proposed TES is associated with an approved single development/building permit. ❒ I/We certify that the proposed TES capital cost is $15 million or less.
Customer Disclosure:	❒ I/We certify that all customers or potential customers have signed or will sign a long-term contract as described in the TES Regulatory Framework Guidelines. (Not required for TES an in-service date preceeding 2014/08/28). ❒ I/We certify that the long-term contract include the minimum provisions included in section 2.3.2 of the TES Regulatory Framework Guidelines. (Not required for TES an in-service date preceeding 2014/08/28). ❒ I/We have provided a "Plain-language" explanation to all customers/potential customers of the TES, which includes the minimum provisions included in section 2.3.2 of the TES Regulatory Framework Guidelines. (Not required for TES an in-service date preceeding 2014/08/28). ❒ I/We will retain all records of customer disclosure in the event of a dispute.
Other Requirements:	❒ I/We have determined the Capital Reserve Requirement and will hold sufficient Capital Reserves. ❒ I/We ensure the design, construction and operation of the TES selected is the most cost effective alternative. ❒ I/We will retain all records and provide an Annual Report to the Commission by February 15 of each year.

_____

[Signing Officer]

APPENDIX B STREAM A ANNUAL REPORT GUIDELINES

Stream A TES– Annual Report

Applicant Information

Company Name:	BC Business Registration No.:
Contact Name:	Contact Email:
Contact Address:	
Contact Phone:	
Name of Parent Company, if applicable:	Jurisdiction of Incorporation:

Energy Delivered

Stream A Facility Name	# of Customers	Total Energy Delivered (GJ)					Sales ($)
		Heating	Cooling	DHW	Other	Total	

Attestations regarding Capital Reserve Provisions

❒ I/We have determined the Capital Reserve Requirement and I/We have sufficient Capital Reserve Provisions as required;
❒ I/We will continue to maintain all records in the event of a complaint and an audit by the Commission.

Demand Side Management

❒ I/We have taken demand-side measures during the period addressed by the report
If demand side measures have been taken during the period addressed by this report, describe *the effectiveness of those measures:*

_____

[Signing Officer]

APPENDIX C EXTENSION FORM FOR STREAM B TES

This Registration Form applies to system extensions planned for Stream B Thermal Energy Systems (TES) where the system extension capital cost, plus the capital cost of any previous extensions, is less than the initial capital cost of the Stream B TES.

By filing this Registration Form with the Commission, the Applicant attests that all information provided is true, accurate and complete.

Stream B TES – System Extension Form

Applicant Information	
Name of Applicant:	Company Name:
CPCN Number for TES:	
TES Specifics	
TES Location (address):	
Is this extension for: ❒ new distribution/new customers, ❒ expand or modify thermal energy generation, ❒ both Planned In-Service date of the extension (YY/MM/DD):	In-Service date of the TES (YY/MM/DD):
Description of TES extension including energy centre and distribution system (drawing, diagram or description of equipment, connections etc., thermal energy supply and demand before and after the planned extension)	

Cost Estimate

Estimated Capital Cost of the TES extension (AACE Class 3 minimum)

(Applicant may add additional line items as appropriate)

Category	$, 000s	
Equipment		
Materials		
Engineering / Design		
Construction		
Financing		
Fees / Overhead		
Other 'soft' costs		
Total		

Calculated ratio of TES extension capital cost (plus any previous extension capital)/initial TES capital cost.	(Must be less than 1.0 to use this Form. If greater than 1.0 a CPCN application is required.)
Does the TES Provider have a system extension policy? If so, please attach.	
Rate Impacts	
Please provide the impact to current rates including calculations and schedule showing current rates and forecast rates over time resulting from the proposed extension. Include a schedule of any deferral accounts that may be used as rate mitigation.	(Must be less than a 10% aggregate increase to use this form. If greater than 10% increase, a CPCN application is required.) When will the TES Provider file an updated rates application?

APPENDIX D REQUIREMENTS UPON TRANSFER OF TES OWNERSHIP

New Owner Attestation Requirements	
Eligibility for Stream A TES Regulation:	❒ I/We certify that the proposed TES meets the description of an On-Site TES, as defined in the TES Regulatory Framework Guidelines. ❒ I/We certify that the proposed TES is associated with an approved single development/building permit. ❒ I/We certify that the proposed TES capital cost is $15 million or less.
Customer Disclosure:	❒ I/We certify that all customers or potential customers have signed or will sign a long-term contract as described in the TES Regulatory Framework Guidelines. ❒ I/We certify that the long-term contract include the minimum provisions included in section 2.3.2 of the TES Regulatory Framework Guidelines. ❒ I/We have provided a “plain-language” explanation to all customers/potential customers of the TES, which includes the minimum provisions included in section 2.3.2 of the TES Regulatory Framework Guidelines. ❒ I/We will retain all records of customer disclosure in the event of a dispute.
Other Requirements:	❒ I/We have determined the Capital Reserve Requirement and will hold sufficient Capital Reserves. ❒ I/We will retain all records and provide an Annual Report to the Commission by February 15 of each year.

CITY OF VANCOUVER
COMMUNITY SERVICES GROUP

DEVELOPMENT PERMIT STAFF COMMITTEE REPORT
JUNE 20, 2012

FOR THE DEVELOPMENT PERMIT BOARD
JULY 16, 2012

7299 GRANVILLE STREET (COMPLETE APPLICATION)
DE415627 – ZONE CD-1

SDB/BM/DA/LH

DEVELOPMENT PERMIT STAFF COMMITTEE MEMBERS

Present:
J. Greer (Chair), Development Services
A. Law, Development Services
R. Thé, Engineering Services
L. Gayman, Real Estate Services
D. Naundorf, Social Infrastructure
T. Driessen, Park Board

Also Present:
S. Black, Urban Design & Development Planning
B. Mah, Development Services
D. Autiero, Development Services
M. D'Agostini, Heritage Group

APPLICANT:
Perkins + Will Architects
Attention: Rod Maas
1220 Homer Street
Vancouver, BC
V6B 2Y5

PROPERTY OWNER:
Wall Financial Corporation
3502 1088 Burrard Street
Vancouver, BC
V6Z 2R9

EXECUTIVE SUMMARY

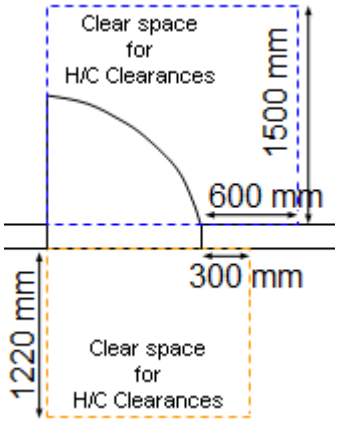
- **Proposal:** This application is for Phase One of the development at Shannon Mews. The project includes the construction of two multiple dwelling buildings and one mixed use building (commercial and residential) all over underground parking; together with a public park; the restoration of three designated heritage buildings, landscaping elements and the perimeter walls; and the development of a local energy system.

See Appendix A Standard Conditions
Appendix B Standard Notes and Conditions of Development Permit
Appendix C Processing Centre – Building comments
Appendix D Plans and Elevations
Appendix E Applicant's Design Rationale
Appendix F Applicant's Rezoning Response to the site wide conditions.
Appendix G Heritage Commission Resolution of June 4, 2012

- **Issues:**
  1. Vehicle movement through parkade to access Granville Street and 57th Avenue
  2. Design of new buildings as they relate to heritage buildings and landscape

- **Urban Design Panel: Support**

5. Use the following diagram for H/C clearances for doors into bicycle rooms, storage rooms in the parkade, doors to access the elevators from the H/C parking, etc.



* Items marked with an asterisk have been identified as serious non-conforming Building By-law issues.

Written confirmation that the applicant has read and has understood the implications of the above noted comments is required and shall be submitted as part of the "prior to" response.

The applicant may wish to retain the services of a qualified Building Code consultant in case of difficulty in comprehending the comments and their potential impact on the proposal. Failure to address these issues may jeopardize the ability to obtain a Building Permit or delay the issuance of a Building Permit for the proposal.

Engineering - NEU comments

The following comments have been provided by the Neighbourhood Energy Utility Projects (Engineering) and have identified requirements of the Rezoning Approval by Council at a Public Hearing on July 26, 2011, that will need to be satisfied as part of the Building Application process.

Prior to issuance of the Building Permit:

1. Where a geoexchange system is selected as the preferred low carbon energy approach, geoexchange site testing and detailed design shall be completed, summarized, and submitted at the time of building permit application and before issuance of building permit.

2. Detailed design of the Renewable Energy System, including low-carbon energy sources and any conventional heating and cooling infrastructure required to meet base load and peaking/backup energy demands, must be submitted to and approved by the General Manager of Engineering Services prior to issuance of building permit. Such as system shall supply at least 70% of annual heating requirements of the development through low-carbon sources(s) and reduce greenhouse gas emissions by at least 50% over a business as usual approach to heating and cooling.

3. Make arrangements, to the satisfaction of the General Manager of Engineering Services, for confirmation that the Renewable Energy System meets the required detailed design provisions. Such arrangements may include but are not limited to completion and certification by the design engineer of record, at the time of building permit application, of the City of Vancouver *Confirmation of Low Carbon Energy System Detailed Design Requirements* letter of assurance.

4. A proposed energy system *Performance Monitoring and Reporting Plan* shall be submitted at the time of building permit application and approved by the General Manager of Engineering Services prior to release of building permit. The Plan shall detail how system performance data will be collected and analyzed for the purpose of evaluating short- and long-term system performance, system efficiency, energy consumption, building energy demand, and opportunities for optimization of system operation and efficiency, and shall include a cost estimate for completion of all required monitoring and reporting works. The applicant shall refer to the City of Vancouver *Performance Monitoring and Reporting Requirements for Renewable Energy Systems* for further instructions on performance monitoring and reporting.

Prior to issuance of the Occupancy Permit:

5. Complete copies of all mechanical commissioning and testing reports shall be provided prior to issuance of occupancy permit, where energy system commissioning shall be completed under the supervision of a qualified registered professional. The ground loop portion of the Renewable Energy System, where applicable, shall be commissioned by a certified registered professional with expertise in the commissioning and inspection of closed-loop geoexchange systems.

6. For each building for which the owner is required to apply for an occupancy permit, the owner will include in its application a Confirmation of *Low Carbon Energy System Design, Installation, and Commissioning Requirements* letter of assurance, signed by the registered professional who is responsible for the design of the building mechanical system, stating that the building mechanical system is in compliance with the approved building permit application and the requirements of the Renewable Energy System, and that the building mechanical system is or will be fully capable of operating in accordance with the agreed-upon design and performance parameters.

CITY OF VANCOUVER
COMMUNITY SERVICES GROUP

DEVELOPMENT PERMIT STAFF COMMITTEE REPORT
JULY 31, 2013

FOR THE DEVELOPMENT PERMIT BOARD
AUGUST 26, 2013

7298 ADERA STREET (COMPLETE APPLICATION)
DE416823 – ZONE CD-1

SDB/AGM/BM/LK/LH

DEVELOPMENT PERMIT STAFF COMMITTEE MEMBERS

Present:
J. Greer (Chair), Development Services
P. Storer, Engineering Services
L. Gayman, Real Estate Services
D. Naundorf, Social Infrastructure

Also Present:
S. Black, Urban Design & Development Planning
A. Malczyk, Urban Design & Development Planning
A. Manness, Urban Design & Development Planning
B. Mah, Development Services
L. King, Development Services
M. D'Agostini, Heritage Group

APPLICANT:
Perkins And Will
Attention: Rod Maas
1220 Homer Street
Vancouver, BC
V6B 2Y5

PROPERTY OWNER:
Wall Financial Corporation
Shannon Mews Project
3502 - 1088 Burrard Street
Vancouver, BC
V6Z 2R9

EXECUTIVE SUMMARY

- **Proposal:** This application is for Phase 2 of the development at Shannon Mews. The project includes the development of four multiple dwelling buildings ranging from seven to nine storeys all over underground parking, restoration of the perimeter wall, landscaping elements and the development of a district energy system.

See Appendix A Standard Conditions
Appendix B Standard Notes and Conditions of Development Permit
Appendix C Plans and Elevations
Appendix D Applicant's Design Rationale
Appendix E Response to Site-wide Conditions
Appendix F Block G Section with Setbacks from Rear Property Line

- **Issues:**
  1. Privacy and overlook to nearby neighbour
  2. Vehicle movements around site

- **Urban Design Panel: SUPPORT (7-0)**

B.2 Conditions of Development Permit:

B.2.1 All approved off-street vehicle parking, loading and unloading spaces, and bicycle parking spaces shall be provided in accordance with the relevant requirements of the Parking By-law prior to the issuance of any required occupancy permit or any use or occupancy of the proposed development not requiring an occupancy permit and thereafter permanently maintained in good condition.

B.2.2 All landscaping and treatment of the open portions of the site shall be completed in accordance with the approved drawings prior to the issuance of any required occupancy permit or any use or occupancy of the proposed development not requiring an occupancy permit and thereafter permanently maintained in good condition.

B.2.3 All approved street trees shall be planted in accordance with the approved drawings within six (6) months of the date of issuance of any required occupancy permit, or any use or occupancy of the proposed development not requiring an occupancy permit, and thereafter permanently maintained in good condition.

B.2.4 All services, including telephone, television cables and electricity, shall be completely underground.

B.2.5 Amenity spaces of 9,086 ft.^{2}, excluded from the computation of floor space ratio, shall not be put to any other use, except as described in the approved application for the exclusion. Access and availability of the use of all amenity facilities located in this project shall be made to all residents and occupants of the building;

AND

Further, the amenity spaces and facilities approved as part of this Development Permit shall be provided and thereafter be permanently maintained for use by residents and users of this building complex.

B.2.6 Any phasing of the development, other than that specifically approved, that results in an interruption of continuous construction to completion of the development, will require application to amend the development to determine the interim treatment of the incomplete portions of the site to ensure that the phased development functions are as set out in the approved plans, all to the satisfaction of the Director of Planning.

B.2.7 The issuance of this permit does not warrant compliance with the relevant provisions of the Provincial Health and Community Care and Assisted Living Acts. The owner is responsible for obtaining any approvals required under the Health Acts. For more information on required approvals and how to obtain these, please contact Vancouver Coastal Health at 604-675-3800 or visit their offices located on the 12th floor of 601 West Broadway. Should compliance with the Health Acts necessitate changes to this permit and/or approved plans, the owner is responsible for obtaining approval for the changes prior to commencement of any work under this permit. Additional fees may be required to change the plans.

B.2.8 This site is affected by a Development Cost Levy By-law and levies will be required to be paid prior to issuance of Building Permits.

Engineering – NEU Comments

The following comments have been provided by the Neighbourhood Energy Utility Projects (Engineering) and have identified requirements of the Rezoning Approval by Council at Public Hearing on July 26, 2011, that will need to be satisfied as part of the Building Application process.

Prior to issuance of the Building Permit:

1. Detailed design of the Renewable Energy System, including low-carbon energy sources and any conventional heating and cooling infrastructure required to meet base load and peaking/backup energy demands, must be submitted to and approved by the General Manager of Engineering Services prior to issuance of building permit. Such as system shall supply at least 70% of annual heating requirements of the development through low-carbon sources(s) and reduce greenhouse gas emissions by at least 50% over a business as usual approach to heating and cooling.

2. Make arrangements, to the satisfaction of the General Manager of Engineering Services, for confirmation that the Renewable Energy System meets the required detailed design provisions. Such arrangements may include but are not limited to completion and certification by the design engineer of record, at the time of building permit application, of the City of Vancouver Confirmation of Low Carbon Energy System Detailed Design Requirements letter of assurance.

3. A proposed energy system Performance Monitoring and Reporting Plan shall be submitted at the time of building permit application and approved by the General Manager of Engineering Services prior to release of building permit. The Plan shall detail how system performance data will be collected and analyzed for the purpose of evaluating short- and long-term system performance, system efficiency, energy consumption, building energy demand, and opportunities for optimization of system operation and efficiency, and shall include a cost estimate for completion of all required monitoring and reporting works. The applicant shall refer to the City of Vancouver Performance Monitoring and Reporting Requirements for Renewable Energy Systems for further instructions on performance monitoring and reporting.

Prior to Issuance of Occupancy Permit:

1. Complete copies of all mechanical commissioning and testing reports shall be provided prior to issuance of occupancy permit, where energy system commissioning shall be completed under the supervision of a qualified registered professional. The ground loop portion of the Renewable Energy System, where applicable, shall be commissioned by a certified registered professional with expertise in the commissioning and inspection of closed-loop geoexchange systems.

2. For each building for which the owner is required to apply for an occupancy permit, the owner will include in its application a Confirmation of Low Carbon Energy System Design, Installation, and Commissioning Requirements letter of assurance, signed by the registered professional who is responsible for the design of the building mechanical system, stating that the building mechanical system is in compliance with the approved building permit application and the requirements of the Renewable Energy System, and that the building mechanical system is or will be fully capable of operating in accordance with the agreed-upon design and performance parameters.

FORTIS BC™
Alternative Energy Services

3700 2nd Avenue
Burnaby, BC V5C 6S4

June 24, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Alternative Energy Services Inc. (FAES)

Application for a Certificate of Public Convenience and Necessity (CPCN) and Rate Approvals Established in Agreements for Thermal Energy Services (TES) for the Artemisia Development (Development or Project) (the Application)

Approval Sought

On January 6, 2014, the British Columbia Utilities Commission (the Commission) issued Order G-231-13A and Reasons for Decision, in which it found that exemptions from certain provisions of the *Utilities Commission Act* (UCA) properly conserve the public interest. The Commission is now seeking approval for such exemptions from the Lieutenant Governor in Council (LGIC) pursuant to section 88(3) of the UCA. As of the date of this Application, the exemption order required to give effect to the Commission's Proposed TES Regulatory Framework has not been approved by Government.

In the absence of an approved TES Regulatory Framework, FAES applies to the Commission for approval, pursuant to sections 45-46 and sections 59 to 61 of the UCA, of a CPCN and of the rates, rate design and fuel deferral account established in the Agreement for Thermal Energy Services for the Artemisia Project.

As further explained below, the Development is the kind of project that should fall under the proposed "Stream A" regulatory model once the TES Regulatory Framework is implemented.

Therefore, FAES also seeks approval from the Commission to be exempted from long-term planning requirements under section 44.1 of the UCA and to be subject to ongoing regulatory oversight on a complaint basis, in a manner consistent with what the Commission approved for FAES' SOLO in Directive 1 of Order G-54-14, dated April 15, 2014.

The specific approvals sought are set out below and in the Draft Order attached to this Application as Appendix E.

Description of the Artemisia Development

Boffo Developments (Hornby) Ltd. (the Developer) has developed Artemisia, a boutique collection of 21 luxury condominium residences with a total floor area of 3,241 m^2 that will be located at 1102 Hornby Street in Vancouver, B.C.

The Development needs an energy distribution system to serve its future tenants. The Artemisia Thermal Energy System (ATES) consists of a geo-exchange system (GES) and a central natural gas boiler for peak heating located in the parkade of the Development that will provide heated water to a hydronic building loop. The hydronic building loop then connects to equipment owned by the Strata, namely distributed heat pumps located within each strata lot. The heat pumps will provide space heating and cooling to each strata lot. When the heat pumps are in cooling mode, excess heat will be removed from the building hydronic loop by way of rejection of heat to the GES loop field. FAES will not provide domestic hot water, which will be heated solely by electrical boilers owned by the Strata and located within each strata lot.

The ATES has been designed and is being built by the Developer and its consultant, AME Group Consulting Professional Engineers (AME). Construction of the ATES is substantially complete and occupancy is scheduled for April 2014. Upon successful commissioning, and subject to Commission approval, FAES will purchase, own and operate the ATES, and charge its customers the thermal energy rates for the service as set out in the Service Agreement (Appendix A to this Application).

The ATES will provide thermal energy to one (1) residential customer, which is a Strata Corporation that will be comprised of 21 Strata Unit Owners. The ATES is located entirely within the Development lands and is designed to only serve the Development currently under construction.

The Developer selected the energy system to meet its goals with respect to reduction of greenhouse gas emissions and to enhance the marketability of the development. Prior to FAES' involvement in the Project, the Developer established the Strata Budget with respect to thermal energy and distributed that information to all the unit owners. Therefore, to meet the Strata Budget requirement, the Developer and FAES have negotiated a purchase price for the energy system on the basis of what FAES would be prepared to invest in order to provide this service at the rates established by the Developer. On this basis, FAES will purchase the system from the Developer for $100,000, an amount that is less than the actual capital costs that the developer expects to incur for the construction and commissioning of

the system ($587,500). The selected energy system will advance British Columbia's energy objectives.

Regulatory Context of the Application

In the absence of an approved TES Regulatory Framework at this time, FAES applies to the Commission, pursuant to sections 45-46 and 59-61 of the UCA, for approval of a CPCN for the Artemisia Development and of the rates described in this Application. To increase regulatory efficiency, FAES respectfully submits that it is appropriate to request CPCN and Rates approval for the Development in the same manner as it successfully did for its SOLO District Development application (SOLO Application).

In Order C-3-14 and accompanying Reasons for Decision (SOLO Decision), the Commission stated that in granting a CPCN, the Commission must satisfy itself that there is a need for the project and that it is in the public interest. With respect to the information to be filed, the Commission quoted the CPCN Guidelines (Appendix A to Order G-50-10):

> *"They [the CPCN Guidelines] provide general guidance regarding the Commission's expectations of the information that should be included in CPCN applications while providing the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the project, and the issues that it raises. An applicant is expected to apply the guidelines in a flexible and reasonable manner. The Commission may issue further directions relating to the information to be included in specific CPCN applications and may require applicants to provide further information to supplement material in filed applications."*
> (Appendix A to Order C-3-14, page 3)

In support of the CPCN and Rates approvals sought in the SOLO Application, FAES provided the information required by the draft Registration Form for Stream A projects, submitting that the information filed was sufficient to grant the approvals sought given the relatively small size of the project.

In Order C-3-14, the Commission agreed and noted it was satisfied that the evidence provided by FAES in its SOLO Application, responses to information requests and Streamlined Review Process was adequate given the specific circumstances of the Application. Based on the information provided, the Commission found the SOLO Project to be both necessary and in the public interest and accordingly granted the CPCN under sections 45 and 46 of the UCA. With respect to rates, the Commission found that if FAES amended its Service Agreements to specifically address the issues raised in that Decision, the Commission would find the rates just and reasonable.

On March 27, 2014, FAES filed an application for the approval of the rates established in the amended Service Agreements for Thermal Energy Services for the SOLO Development to comply with Commission Order C-3-14. In Order G-54-14, the Commission approved the rates as just and reasonable under sections 59 to 61 of the UCA.

In light of the SOLO Decision and subsequent Commission Order G-54-14, FAES submits that the information provided in the draft Registration Form for Stream A projects is sufficient to grant the approvals sought in this Application, given the relatively small size of the Artemisia Development. Furthermore, FAES is proposing to use the same rate design for the Sovereign Development as the one the Commission approved for SOLO by Order G-54-14. FAES also submits that using this streamlined approach reflects the developments and regulatory approach found in Commission Order G-231-13A and the subsequent Report on the Proposed Micro Thermal Energy System Exemption Limit and Stream B Exemption Test issued on March 6, 2014 (the March 6 Report).

TES Regulatory Framework

As noted above, in FAES' view, the Development is the kind of project that should fall under the proposed "Stream A" regulatory model, and therefore, FAES seeks approval to treat this Project as a Stream A project for the following reasons:

1) As described in the Application, the total capital cost of the ATES stands at $587,500 and therefore exceeds the $500,000 threshold for the Micro TES Exemption. The fact that FAES and the Developer agreed that FAES would purchase the ATES from the Developer at $100,000 should have no bearing on the classification of the ATES as a Stream A project.

2) The ATES will supply space heating and cooling to a Strata Corporation comprised of 21 unit owners. FAES respectfully submits that the case of a strata corporation customer, that has a number of residential units, was never intended to be captured by the Micro TES Exemption as demonstrated in the following passages:

> "The Micro TES System exemption is intended to capture **the case of a homeowner or a small business** entering into an agreement with a TES provider. […] In the Panel's view, the Micro TES System exemption should be large enough to accommodate a project undertaken by or for a **small group of homeowners or small businesses**, such as a GSHP that may be shared by that group." (Emphasis added)[1]
>
> "The Panel find [sic] the numerical example provided by Ameresco, relating to a **hypothetical group of five small businesses, properly captures the intent of the Panel**." (Emphasis added)[2]

3) Furthermore, in the AES Inquiry Report, the Commission stated: "In the Panel's view there is a grey area as to what constitutes a Discrete Energy System as compared to a District Energy System. **This, for example, could involve the service to a single strata, but with multiple customers in the strata and a need to regulate to protect customer interests**."[3] (Emphasis added) The AES Inquiry Report tasked

[1] Appendix A to Order G-231-13A, page 31
[2] Commission Report on the Proposed Micro Thermal Energy System Limit and Stream B Exemption Test, March 6, 2014, page 7
[3] AES Inquiry Report, p. 75

Commission staff to develop a TES Scaled Regulatory Framework in accordance with the Principles and Guidelines of the AES Inquiry Report.

On May 9, 2013, the Commission initiated a public comment process on a Commission staff draft proposal for a streamlined regulatory approach for Thermal Energy System Utilities. On page 2 of this draft proposal, the first Commission staff proposal states:

> *"Commission staff propose a subsection 88(3) class exemption for On-site Thermal Energy Systems (Discrete Energy Systems) with one customer,* ***excluding circumstances where the one customer is a Strata Corporation,*** *unless the Strata Corporation owns the TES."*[4] (Emphasis added)

On August 28, 2013, the Commission established a Written Hearing for the review of the Proposed Thermal Energy Service Utility Regulatory Guide (Proposed Guide). The Proposed Guide states, at pages 11-12:

> *"The Commission proposes that in the event the TES Utility has a contract with a* ***single customer that is not a Strata Corporation****, the TES Utility does not warrant regulation. This is because this is a two-party transaction. In the Commission's view, in this situation, no public interest oversight is needed and just like a contracting for any competitive service, the parties should carefully review the terms of the contract before entering into a contractual relationship."*[5] (Emphasis added)
>
> *"****Stream A is intended to cover On-Site TES Utilities****, including those with more than one customer* ***and those selling to a Strata Corporation****."*[6] (Emphasis added)

4) On page 7 of Appendix A to Order G-231-13A, the Strata Exemption is described as follows:

> *"A TES System owned by a Strata Corporation that exclusively serves the Strata owners is exempt from regulation. A Strata Corporation that owns the TES System and provides energy exclusively to its Strata Unit Owners is subject to the Strata Property Act which offers some recourse and consumer protection to Strata Unit Owners who are dissatisfied with the manner in which the Strata Corporation operates. Thus, to prevent legislative overlap, it is proposed that Customers should find recourse under the Strata Property Act, and not through the Commission under the UCA"*

On page 6 of the final draft of the Thermal Energy Service Regulatory Framework Guidelines, issued by the Commission on June 12, 2014, the Strata Exemption is described as follows:

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4 http://www.bcuc.com/Documents/Proceedings/2013/DOC_34697_05-09-2013_TES-Regulatory-Framework-Strawman.pdf

5 http://www.bcuc.com/Documents/Proceedings/2013/DOC_35541_A-2_RegulatoryTimetable-HrgNotice_G-132-13.pdf

6 Ibid.

> *"A TES System owned by a Strata Corporation that exclusively serves the Strata Owners is exempt from active regulation by Commission Order G-XXX-XX. A Strata Corporation that owns the TES System and provides energy exclusively to its Strata Unit Owners is subject to the Strata Property Act, which offers recourse and consumer protection to Strata Unit Owners. Accordingly, Customers can find recourse under the Strata Property Act, and not through the Commission under the UCA."*

In contrast, when a utility, such as FAES, owns and operates the TES System of a Strata Corporation and sells thermal energy to the Strata Unit Owners, those Strata Units Owners will have no recourse under the *Strata Property Act*, since the Strata Corporation does not own the TES System. In such instance, it is necessary that the Strata Unit Owners have recourse to some form of consumer protection under the UCA, whether their TES System has a capital cost below or above the Micro TES threshold established at $500,000. FAES submits that there is no material difference between a Strata Unit Owner in a Development with a TES System that has a capital cost below $500,000 and a Strata Unit Owner in a Development with a TES System that has a capital cost above $500,000. FAES further submits that those two Strata Unit Owners should have the same access to the Commission in the event of a complaint. Accordingly, a Stream A classification should apply regardless of the capital cost of the TES System in a Strata Corporation.

5) The 21 unit owners of the Artemisia Strata Corporation are situated similarly to the SOLO, TELUS Garden or Marine Gateway Strata Corporations' unit owners, or any other unit owners of Strata Corporations that would fall under the Stream A regulatory framework, with respect to their thermal energy system.

   FAES thus believes that the Micro TES Exemption has the potential to create an artificial and unfair distinction between similarly situated residential unit holders based on the value of the thermal energy system in their respective developments, which could potentially be located across the street from each other. A distinction that would result in some unit owners having no recourse to the Commission if they are unsatisfied with the service provided.

6) In the future, once the TES Regulatory Framework is implemented, treating the ATES as a Stream A TES project will provide considerable benefits for the Strata Corporation customer and would have very little corresponding administrative burden.

7) As currently approved by the Commission but subject to advance approval from LGIC, Stream A thermal energy projects would be exempted from CPCN (section 45), rate setting (sections 59 to 61) and long-term planning (section 44.1) requirements of the UCA and would be subject to a form of complaint-based regulation.

   Characteristics that define a Stream A project are:

   - The thermal generation and distribution facilities are located on the same Site as the thermal load;

- The TES System is designed to meet the energy demands of a specific Site (one or more customers or buildings);
- The thermal generation or distribution facilities may serve one or more customers or buildings on a single Site but there are no shared or common thermal generation or distribution facilities beyond the boundaries of a single Site;
- There is no, or very limited, use of public rights of way or public streets; and
- The TES System has an AACE International Class 3 capital cost estimate of $15 million or less.

(Appendix A to Order G-231-13A, page 8)

As further described in the Application, FAES submits that the Artemisia Development meets these criteria.

FAES is providing all the information required by the draft Registration Form for Stream A projects, with necessary modifications to reflect the nature and history of the Project (Appendix B). As requested in the Registration Form, a schematic of the thermal energy system is attached in Appendix C and a plain language explanation of the Service Agreement is included as Appendix D. A Draft Order is included in Appendix E.

Accordingly, FAES submits that the enclosed completed Registration Form for Stream A projects, this cover letter, and the attached appendices supply the information necessary for the Commission to grant the approvals sought.

Timelines and Regulatory Review Process

Ideally, FAES would wait for the TES Regulatory Framework Proceeding to be completed before filing any more applications for CPCN and rate approval of TES projects. However, project timelines require approvals, and developments which advance British Columbia's energy objectives are moving forward. This application needs to be filed before the TES Regulatory Framework becomes effective.

FAES believes that a written review process with one round of information requests by the Commission and Interveners, followed by a Streamlined Review Process, is appropriate for this Application since the Commission and Interveners have had the opportunity to review several similar thermal energy projects brought forward by FAES, including the SOLO Development for which an identical rate design was approved by Order C-54-14.

With respect to the regulatory timetable, FAES is open to work with Commission Staff to establish a regulatory timetable that would work for both parties. FAES would only note that the occupancy permit was granted in April 2014, and unit owners have already started to move into this Development. In the case of this Project, FAES became involved at a very late stage, when construction of the energy system was almost complete. FAES will only go ahead with the purchase of the ATES once it is granted the CPCN.

Summary of Approvals Sought

FAES seeks:

- A CPCN to purchase, own and operate the Artemisia Thermal Energy System for the Development;
- Approval of the rates, rate design and fuel deferral account for thermal energy services established in the Thermal Energy System Service Agreement with Boffo Developments (Hornby) Ltd. (Residential Strata Parcel), attached as Appendix A; and
- Approval to be exempted from long-term planning requirements under section 44.1 of the UCA and to be subject to ongoing regulatory oversight on a complaint basis, in a manner consistent with what the Commission approved for FAES' SOLO in Directive 1 of Order G-54-14, dated April 15, 2014.

If you require further information or have any questions regarding this submission, please contact Grant Bierlmeier at (250) 896-3098.

Sincerely,

FORTISBC ALTERNATIVE ENERGY SERVICES INC.

Original signed:
Grant Bierlmeier

Attachments

Appendix A

SERVICE AGREEMENT

ARTEMISIA THERMAL ENERGY SYSTEM SERVICE AGREEMENT
PART I – BASIC TERMS

Customer Information and Billing Address		
Name or company name *(include business registration no. if applicable)* **The Owners, Strata Plan EPS1858**		
Mailing/billing address **c/o National Pacific Real Estate Services Inc.** **#210-1575 West Georgia Street, Vancouver BC, V6G 2V3**		
If company, contact name **Geoffrey Rosen**	**Telephone** **604-816-5572**	**Email:** **geoffrey@nationalpacific.ca**

Property/Service location address
1102 Hornby Street, Vancouver, BC Legally described as (at the execution date of this Agreement and subject to change upon subdivision/completion of construction): EPS1858

Term of Service		
Commencement Date To be determined	**Initial Term** (years) 20 years	**Renewal** Automatic five (5) year renewals

Energy Rate (per kWh)
The initial rate will be $ 0.095/kWh in Year 2014 escalated at 2% each year and adjusted every five (5) years by the Performance Ratio and will include the fuel Rate Rider which will be adjusted positively or negatively each year.

Thermal Energy Demand	
Annual Demand The initial Annual Demand will be 410,000 kWh, adjusted each year to equal the weather normalized average annual demand for the previous three years, once actual demand is available and reduced by the Utility to reflect expected demand side management projects where the Customer provides documentation satisfactory to the Utility.	**Design Capacity** The Design Capacity of the service will be: 159 kW heating; 138 kW cooling

Permitted Thermal Energy Use
Space heating and cooling

Supplemental Terms and Conditions:
(a) *Assignment to Strata Corporation* - The Utility hereby consents to the Customer assigning this Service Agreement to the Strata Corporation created upon deposit of the Strata Plan at the Land Title Office with respect to the Property, provided that the Customer shall continue to be responsible for any obligations arising under this Service Agreement prior to such assignment.

The Customer and Utility, by signing this Service Agreement, accept and agree to be bound by the terms and conditions herein contained. This Service Agreement, including Part I and Part II and any schedules or appendices attached hereto and any other agreements between the Customer and the Utility referenced herein, constitutes the entire agreement between the parties and supersedes all other agreements between the parties. This Service Agreement will not come into effect and does not bind the parties until the Utility has obtained the necessary approvals for this Service Agreement, or met the necessary requirements from, all regulatory or other applicable governmental authorities having jurisdiction, including the BCUC, on terms and conditions which are satisfactory to the Utility and the Customer.

CUSTOMER: The Owners, Strata Plan EPS1858		**FORTISBC ALTERNATIVE ENERGY SERVICES INC.**	
Signature	Date May 29, 2014	Signature	Date May 30, 2014
Name Ottavio Boffo	Title	Name Gareth Jones	Title

THERMAL ENERGY SYSTEM SERVICE AGREEMENT
PART II – TERMS AND CONDITIONS

SECTION A - DEFINITIONS

In this Service Agreement, in addition to the Basic Terms set out in Part I of this Service Agreement, the following definitions apply and unless the context otherwise requires the words and terms below shall mean as follows:

Affiliate: Has the meaning set out in the *Business Corporation Act*, S.B.C. 2002, c.57.

Annual Demand: The annual thermal energy demand as set out in Part 1 of this Service Agreement.

BCUC: British Columbia Utilities Commission.

Customer: The Person who entered into and receives Service pursuant to this Service Agreement.

Design Capacity: The design capacity of the Service to the Property as set out in Part 1 of this Service Agreement.

Energy Rate: The rate per kWh in Canadian dollars for the delivery of Thermal Energy set out in Part I of this Service Agreement, which rate may be amended from time to time as set out herein or through agreement between the Utility and the Customer.

Equipment: Facilities or equipment the Utility owns and operates for the production, generation, storage, transmission, measurement, delivery or provision of Thermal Energy to the Customer and any other customers.

Fuel Deferral Account: A record of the difference between forecast costs and actual costs of natural gas and electricity plus the recoveries or refunds associated with the Rate Rider. The forecast costs of natural gas and electricity are calculated by multiplying the applicable natural gas rate or electricity rate by the forecast natural gas and electricity consumption respectively (Appendix A). The forecast natural gas and electricity consumption is estimated based on the combination of the amount of estimated thermal energy delivery and the thermal efficiency of the heating and cooling equipment used to provide this thermal energy to the building. The estimation is done by a professional engineer using a combination of energy simulation software and industry standards.

Force Majeure: Any event or occurrence not within the control of the party claiming Force Majeure and which by the exercise of reasonable diligence such party (or those for whom it is responsible for at law) is unable to prevent or overcome, including any acts of God, including lightning, earthquakes, storms, washouts, landslides, avalanches, fires, epidemics and floods; strikes, lockouts or other industrial disturbances; acts of the Queen's or public enemies, sabotage, wars, blockades, insurrections, riots or civil disturbances, fires, explosions, breakages of or accidents to machinery or lines of pipe not preventable by maintenance properly carried out in the ordinary course; the inability to act due to acts or failures to act by any Laws, acts or restraints of any court or governmental authority. A party is deemed to have control over the actions or omissions of those persons to which it, its agents, contractors or employees, have delegated, assigned or subcontracted its obligations and responsibilities.

Heating Degree Day (HDD): Heating degree days for a given day are the number of degrees Celsius that the mean temperature is below 18°C.

kWh: Kilowatt hour.

kW: Kilowatt.

Meter: The device used for measuring Thermal Energy deliveries, and includes related equipment and appurtenances.

Minimum Annual Charge: The minimum amount to be paid by the Customer each calendar year for the Service calculated by multiplying the applicable Energy Rate by 80 per cent of the Annual Demand set out in Part I of this Service Agreement, provided that such Annual Demand will be:

(a) reduced by the Utility for any calendar year to the extent that such limit was not reached as a result of lack of availability of Thermal Energy from the Utility not resulting from any act or omission of the Customer, or an event of Force Majeure affecting the Customer's ability to use the Service; and

(b) prorated on *a per diem* basis where the commencement date or termination date of Service does not correspond with the first or last day of the calendar year, respectively.

Person: Includes an individual, partnership, corporation, organization, company or government agency.

Performance Ratio: The ratio of actual costs of providing the Service relative to the forecast costs of providing the Service (set out at the initiation of Service), as reasonably determined by the Utility, calculated in the fourth year of each Performance Term for the previous five years (four years for the first Performance Term). The individual cost components included in the calculation of the Performance Ratio are: a) natural gas costs, b) electricity costs, c) operations and maintenance, d) depreciation and amortization, e) taxes (property and income), and f) capital carrying costs, including initial investment, and replacement capital.

Performance Term: A five year period occurring in the years 1-5, 6-10, 11-15 and 16-20 of the Initial Term and for each subsequent renewal term.

Property: A building, a separate unit of a building, a strata property or any other property or land owned or occupied by the Customer as more particularly identified in Part I of this Service Agreement and receiving or to receive Thermal Energy pursuant to this Service Agreement.

Rate Rider: An amount per kWh in Canadian dollars for the recovery or refund of the Fuel Deferral Account set each year on a prospective basis by the Utility to achieve a zero balance in the Fuel Deferral Account by the end of the following year.

Rate Schedule: The schedule or schedules which lists the various fees and charges relating to services provided by the Utility.

Security Deposit Rate: The Prime Interest Rate minus 2% where "**Prime Interest Rate**" is the rate of interest declared from time to time by the Utility's lead bank as its "prime rate" for loans in Canadian dollars.

Service: The production, generation, storage, transmission, sale, delivery or provision of Thermal Energy by the Utility to the Customer in exchange for compensation.

Service Agreement: The agreement between the Utility and the Customer for the provision of Service and includes Part I and Part II of this Service Agreement and any Rate Schedules, as may be amended from time to time.

Term: The initial term of Service as set out in Part 1 of this Service Agreement, as renewed from time to time.

Thermal Energy: Energy that is transferrable from the Thermal Energy System to the Customer for the production of heat or cold.

Thermal Energy System: All of the Equipment associated with the provision of Thermal Energy to customers, including to the Customer.

UCA: The *Utilities Commission Act,* R.S.B.C. 1996, c. 473 as may be amended from time to time.

Utility: FortisBC Alternative Energy Services Inc. (FAES).

Weather Normalized Demand: The normal Heating Degree Days for the period, calculated as the average Heating Degree Days for the previous twenty years, divided by the actual Heating Degree Days for the same period, multiplied by the actual thermal energy demand for the period.

SECTION B – TERMS AND CONDITIONS

1. APPLICATION OF TERMS AND CONDITIONS

The Utility will provide Service in accordance with this Service Agreement. The Customer agrees to abide by the terms and conditions of this Service Agreement.

2. PROVISION OF SERVICE

(a) *Service to Multiple Properties or Businesses* – The Utility may, at its discretion, require a separate Service Agreement to be entered into for separate premises or separately operated business on the Property.

(b) *Refusal of Service* - The Utility may refuse to provide Service to, any Person if:

- (i) such Person, or an occupant of any Property owned by such Person has unpaid accounts with the Utility or any Affiliate for any service or purpose;
- (ii) conditions, other than standard conditions, are required by the Customer;
- (iii) facilities are not available to provide adequate Service;
- (iv) the Customer's facilities are not satisfactory to the Utility;
- (v) the Customer has provided false or misleading information to the Utility, including references, credit information, identification prior to or in order to induce the Utility to enter into a Service Agreement with the Customer;
- (vi) the Customer is not the owner or occupier of the Property;
- (vii) the Service requested is already supplied to the Property for another customer who does not consent to having the Service terminated;
- (viii) the Customer cannot or refuses to provide satisfactory security for payment as required by the Utility;
- (ix) the Customer is in receivership or bankruptcy, or operating under the protection of insolvency legislation; or
- (x) the Customer has breached any agreement or terms with the Utility.

(c) *Change of Customer* - The Customer shall not assign or transfer its rights and obligations to another Person without the prior consent of the Utility. When a change of Customer occurs, an application shall be submitted and the applicable application fee shall be paid by the new Customer with respect to each account transferred or created in such new Customer's name and the Utility may require the new Customer to provide a security deposit.

(d) *Re-Application for Service* – If, within 12 months of terminating this Service Agreement, the Customer re-applies for Service with respect to the same Property, in addition to payment of the applicable application fee, the Customer shall pay the Utility's estimated costs for restoring the Service.

3. USE OF SERVICE

(a) *Permitted Use/Prohibitions on Sale and Supply* - The Customer shall not sell or supply the Thermal Energy to other persons or premises, or use the thermal energy for any purpose, other than as identified in Part I of this Service Agreement or as otherwise permitted by the Utility in writing.

(b) *Excessive Use* - If the maximum thermal energy demand in kW exceeds the Design Capacity, the Utility may assess additional fees and charges to the Customer for usage exceeding such limits, provided that if usage exceeds such limits, the Utility reserves the right to temporarily suspend or limit Service to reduce the load on the Thermal Energy System.

(c) *Performance Reviews and Annual Rate Rider Changes* - The Utility will conduct a review of the Energy Rate prior to the commencement of each Performance Term and adjust the Energy Rate by the applicable Performance Ratio. In addition, each year the Utility will conduct a review of the prevailing rates for fuel such as natural gas and electricity and adjust the Rate Rider.

(d) *Fluctuations in Use* - If the Customer causes any undue or abnormal fluctuations on the Thermal Energy System that were not designed into the heating and cooling loads of the Thermal Energy System by the Utility, the Utility may require the Customer, at its own expense, to provide equipment which will reasonably limit such fluctuations or disturbances and may refuse to supply Thermal Energy or suspend the supply thereof until such equipment is provided.

(e) *Service Reactivation* - The Customer shall pay the Utility's costs for restoring or reconnecting Service which was disconnected for any of the following reasons:

(i) to permit the Customer to make alterations to or on the Property;
(ii) to permit a test of a Meter at the request of the Customer, and the Meter is later determined by the Utility to be accurate;
(iii) the Utility was ordered to disconnect the Service by the appropriate inspection authority; or
(iv) breach of this Service Agreement;

provided that such payment will not apply when the Service was disconnected for the reason of public safety or for the Utility's own service requirements.

4. EQUIPMENT AND ACCESS TO PROPERTY

(a) *Equipment Requirements, Ownership and Installation* –The Utility will own, supply and install the Equipment required to connect the Property to the Thermal Energy System and to measure energy usage for billing purposes, whether located inside or outside the Property, and will be responsible for the operation, maintenance, testing, repair, removal and replacement of the Equipment throughout the term of this Service Agreement, except as otherwise provided in this Service Agreement, in a manner consistent with industry standards. The Utility will install Equipment in such locations on the Property as determined appropriate by the Utility, as approved by the Customer acting reasonably.

(b) *Restriction re: Equipment* - No Equipment will be installed, connected, moved, replaced or disconnected, or any changes made to the Thermal Energy System by anyone except by the Utility's authorized employees, contractors or agents or by other persons authorized in writing by the Utility.

(c) *Protection of Equipment* - The Customer shall take reasonable care of and protect the Equipment located on the Property.

(d) *Damage to Equipment* - The Customer must advise the Utility promptly of any damage occurring to the Equipment of which the Customer is aware.

(e) *Rights of Way* - By applying for Service, the Customer agrees to grant to the Utility such rights-of-way, easements and any applicable permits on, over and under the Property as may be necessary for the construction, installation, operation, maintenance or removal of facilities. On request, the Customer, at their own expense, shall deliver to the Utility documents satisfactory to the Utility in registrable form granting the rights-of-way, easements and executed permits.

(f) *Access to Equipment and Property* - The Utility's agents, contractors and employees shall have, free access to the Equipment and the Property at all reasonable times to ascertain compliance with this Service Agreement, including the quantity or method of use of Service, as well as for the purpose of reading Meters, testing, examining, repairing or removing the Equipment, turning the Service on or off, conducting system leakage surveys and stopping leaks. In undertaking such access, the Utility shall act reasonably, comply, to the extent possible, with the Customer's security measures with respect to the Property and cause as little disturbance to the Property and the Customer as is possible in the circumstances.

(g) *Customer Equipment and Connections* - The Customer will consult with the Utility to ensure all Customer equipment and facilities used to connect to and downstream of the Thermal Energy System are compatible with the Thermal Energy System. The Customer shall ensure its equipment and facilities are installed in a manner satisfactory to the Utility and the local inspection authority. The Utility shall have the right, with reasonable notice to the Customer, to inspect the Customer's equipment and facilities to ensure compatibility with the Thermal Energy System and the Customer shall immediately remedy any defects identified by the Utility. In the event of an emergency, the Utility is not required to provide such notice, and shall have right to inspect the Customer's equipment and facilities without notice. The Utility is not responsible for any equipment or facilities on the Property not owned by the Utility.

(h) *No Obligation to Remove Equipment* - If this Service Agreement is terminated or expires, or Service to the Property is discontinued for any reason, the Utility is not required to remove the Equipment from the Property and the Equipment will at all times remain the property of the Utility as long as the Utility is still operating the Thermal Energy System.

(i) *Abandonment of Equipment* – Any Equipment which the Utility leaves on the Property after permanently ceasing to use or operate the Thermal Energy System will become part of the Property and the Utility will not be liable for any damage or claims related to any such Equipment.

5. BILLING AND PAYMENT

(a) *Billing* - Bills will be rendered as often as deemed necessary by the Utility, but generally on a monthly or bi-monthly basis, based on rates and charges set out in this Service Agreement plus applicable taxes thereon, and except as otherwise provided herein, based on Meter readings.

(b) *Minimum Annual Charge* – Where the amount billed to the Customer for the Service in any calendar year is less than the Minimum Annual Charge, the shortfall will be added to the next bill.

(c) *Payment Due Date* - The due date for payment is the first business day after:

(i) the twenty first (21st) calendar day following the billing date; or
(ii) Such other period as may be defined in this Service Agreement or agreed in writing between the Customer and the Utility.

(d) *Method of Payment* - Bills shall be paid electronically, regular mail, or as otherwise set out in the billing statement.

(e) *Taxes* - Any applicable taxes will be added to all rates and charges on each bill.

(f) *Late Payments* - The Utility may assess late payment charges on any overdue amounts owing to the Utility, which charge will accrue until the outstanding amount plus the late payment charge have been paid in full.

(g) *Returned Cheque Charge* - If the Customer's payment is returned by the Customer's financial institution for any reason, the Utility will add a handling charge to the amount due and payable by the Customer whether or not the Service has been disconnected.

(h) *Meter Readings Intervals* - The interval between Meter readings shall be at the sole discretion of the Utility. The Meter will normally be read at monthly intervals.

(i) *Consumption Estimates* – If a Meter reading cannot be obtained for any reason or a Meter fails to register or registers incorrectly, consumption may be estimated by the Utility and used for billing purposes and adjusted during a subsequent billing period to reflect the difference between estimated and actual use over the relevant period. Such adjustments do not require the back-billing provisions of section 6 to be applied. If the Customer terminates a Service Agreement, the Utility may estimate the final Meter reading for final billing.

(j) *Equal Payment Plan Billing* – If the Customer elects to participate in equal payment plan billing either upon commencement of this Service Agreement or at any time during the term, the Utility will estimate Thermal Energy use for the next 12 months and divide the total charges into 12 installments. Monthly billing will be based on the installment amount. Installment amounts will be reviewed every three (3) months and may be increased or reduced to reflect changes in usage or rates. The Utility will continue to conduct Meter readings. At the end of each billing year, the Utility will assess the difference between the installments paid and the cost of Thermal Energy actually used and charge or credit the Customer account accordingly. Such adjustments do not require the back-billing provisions of section 6 to be applied.

(k) *Meter Testing and Billing Adjustment* – If the Customer doubts the accuracy of a Meter, the Customer may request to have the Meter tested by a qualified independent meter testing company and pay the Utility for the actual cost of removing, replacing and testing the Meter. If the Meter is found to be inaccurate upon testing, the Utility will refund the inspection fee to the Customer and section 6 (Back Billing) will apply.

6. BACKBILLING

(a) *Right to Charge Additional Fees* - Pursuant to the *UCA*, these terms and conditions constitute the consent of the BCUC to allow the Utility in the circumstances specified herein, to charge, demand, collect or receive from the Customer in respect of a regulated service, a greater or lesser compensation than that specified in the subsisting schedules of the Utility applicable to that service.

(b) *Correction of Errors* - The Utility may re-bill the Customer for Service where the original billings or meter readings were discovered by either the Customer or the Utility to be inaccurate (either under-billed or over-billed) for any reason. In every case, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

(c) *Determination of Usage and Demand* - Where metering or billing errors occur, the consumption and demand will be based upon the records of the Utility for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, on reasonable and fair estimates may be made by the Utility.

(d) *Effect of Over-Billing* - In every case of over-billing, the Utility will credit all money incorrectly collected from the Customer for the duration of the error, subject to the applicable limitation period provided by law, plus simple interest, computed monthly at the short-term bank loan rate applicable to the Utility.

(e) *Effect of Under-Billing* - In every case of under-billing, the Utility will:

(i) back-bill the Customer for the shorter of: (i) the duration of the error; or (ii) one year; or (iii) the period as set out in a special or individually negotiated contract with the Utility; and

(ii) offer the Customer reasonable terms of repayment, including, if requested by the Customer, a repayment term equivalent in length to the back-billing period. The repayment will be interest free and in equal installments corresponding to the normal billing cycle. Late payment of such installments will be subject to late payment charges.

(f) *Disputed Amount* - If the Customer disputes a portion of a back-billing, the Utility will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer by the due date.

(g) *Change in Occupancy* - Where changes of occupancy have occurred with respect to the Property, the Utility will make a reasonable attempt to locate the former Customer. If, after a period of one year, the Customer cannot be located, any over-or under-billing applicable to such Customer will be cancelled.

(h) *Effect of Unauthorized Use* - If the Utility has reasonable grounds to believe the Customer has tampered with or otherwise used the Service in an unauthorized way, and including where evidence of fraud, theft or other criminal act exists, then, despite any other provisions of this section 6:

(i) the extent of back-billing will be for the duration of the unauthorized use, subject to the applicable limitation period provided by law;

(ii) the Customer is liable for the direct (unburdened) administrative costs and direct costs incurred by the Utility in the investigation of any such use and the repair, or replacement of the Equipment; and

(iii) any under-billing will incur a late payment charge calculated on the under-billed amount from the date of the original invoice until the amount under-billed is paid in full.

7. TERMINATION

(a) *Discontinuance of Service by Utility upon Notice* - The Utility may refuse to provide Service, or may discontinue Service and terminate this Service Agreement, **with 15 days written notice**, to the Customer if the Customer:

(i) has failed to fully pay for Services at any or all Property on or before the due date, regardless of whether the Customer has provided a security deposit to the Utility; or

(ii) has failed to pay any required security deposit, equivalent form of security, or post a guarantee or required increase in it, by the specified date; or

(iii) has failed to comply with the requirement of the Utility pursuant to section 10(b) (*Curtailment of Service);* or

(iv) is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to the Utility.

(b) *Discontinuance of Service by Utility without Notice* - The Utility may refuse to provide Service, or may discontinue Service and terminate this Service Agreement, **without notice**, to the Customer if the Customer:

(i) has breached the terms and conditions upon which Service is provided by the Utility or whose Service Agreement has been terminated for any reason; or

(ii) has defective pipes, appliances, or thermal energy fittings in the Property; or

(iii) uses Thermal Energy in such a manner, as in the opinion of the Utility, acting reasonably, may:

- lead to a dangerous situation; or
- cause undue or abnormal fluctuations in the temperature of the Thermal Energy System; or

(iv) fails to make modifications or additions to the Customer's equipment which have been reasonably required by the Utility in order to prevent the danger or control the fluctuations described in (iii) above; or

(v) fraudulently misrepresents to the Utility its use of Thermal Energy or the volume delivered.

(c) *No Liability for Loss* - The Utility shall not be liable for any loss, injury or damage suffered by the Customer by reason of the discontinuation of or refusal to provide service by the Utility as aforesaid.

(d) *Termination of Service by Customer*

(i) During the Initial Term, the Customer shall have the right to terminate this Service Agreement immediately upon the Customer giving written notice of such termination to the Utility if the Utility breaches any of the material terms and conditions of this Service Agreement and such breach shall continue for a period of thirty (30) days after written notice thereof has been given to the Utility or, if such default is not capable of being cured within such thirty (30) day notice period, fails to commence in good faith the curing of such default upon receipt of such written notice of default from the Customer and to continue to diligently pursue the curing of such default thereafter until cured.

(ii) After the Initial Term, the Customer may terminate this Service Agreement by giving the Utility at least 180 days' written notice of such termination.

(e) *Effect of Expiry or Termination of Service Agreement* – If this Service Agreement is not renewed or is terminated for any reason other than termination for default of the Utility pursuant to section 7(d)(i), in addition to any other amounts due and owing by the Customer to the Utility and despite any other remedies available at law or in equity, the Customer shall pay to the Utility, within 180 days of invoicing, the following amounts (plus applicable taxes thereon):

(i) If this Service Agreement is terminated during the Initial Term, the net book value of the Equipment associated with providing Service to the Property, plus any earnings foregone by the Utility to the remainder of the Initial Term as reasonably calculated by the Utility; and

(ii) If this Service Agreement is not renewed beyond the Initial Term or is terminated prior to the expiry of any renewal term, the net book value of the Equipment associated with providing the Service to the Property, as reasonably calculated by the Utility;

and despite any payment being made by the Customer to the Utility pursuant to this section 7(e) or not pursuant to section 7(d), the Equipment remains the property of the Utility.

(f) *Survival of Obligations* - Upon expiration or termination of this Service Agreement, the Customer shall not be released from any previously existing obligations to the Utility which arose prior to such expiration or termination.

(g) *Effect of Termination on Other Agreements with Customer* – The expiration or termination of this Service Agreement shall not affect or result in the expiry or termination of any other agreements made between the Utility and the Customer or any owner of the Property, including but not limited to any licenses, statutory rights of way or easements.

8. SECURITY FOR PAYMENT OF BILLS

(a) *Requirement for Security* - Customers who have not established or maintained creditworthiness to the satisfaction of the Utility or, in the reasonable opinion of the Utility, otherwise poses a credit risk, may be required to provide a security deposit or equivalent form of security, in an amount equal to the reasonable estimate of the Utility of the total bill for the two highest consecutive months' consumption of Thermal Energy by the Customer. A security deposit or equivalent form of security is not an advance payment. The Utility shall be entitled to monitor credit worthiness and assess the credit risk of the Customer at any time and from time to time.

(b) *Interest on Security Deposit* - The Utility will pay interest on a security deposit at the Security Deposit Rate. No interest is payable on any unclaimed deposit left with the Utility after the account for which it is security is closed, or on a deposit held by the Utility in a form other than cash.

(i) *Return of Security Deposit* - The Utility will refund any security deposit plus any accrued interest or cancel the equivalent form of security:upon twelve (12) consecutive months of prompt and full payment of invoices, provided that a security deposit or equivalent form of security may again be required by the Utility as a result of any subsequent delinquent payment; or

(ii) when the Customer pays the final bill, provided that if the Utility is unable to locate the Customer to whom a security deposit is payable and it remains unclaimed for 10 years, the security deposit then becomes the property of the Utility.

(c) *Use of Security Deposit* - The Utility may apply all or any part of the security deposit or equivalent form of security and any accrued interest towards payment of any outstanding bill, whereupon the Customer must immediately re-establish the security deposit or equivalent form of security before the Utility will reconnect or continue Service to the Customer.

9. TERM OF SERVICE AGREEMENT

(a) *Initial Term* -The initial term of this Service Agreement (the "**Initial Term**") will be for the period of time set out in Part I of this Service Agreement.

(b) *Renewal* - This Service Agreement automatically renews at the end of the Initial Term for a five (5) year term in each renewal unless Part I of this Service Agreement specifies otherwise. If the Customer does not wish to automatically renew this Agreement, the Customer must provide the Utility with at least 180 days prior written notice of such non-renewal prior to the expiry of the Initial Term or the applicable renewal term, as the case may be.

10. NO GUARANTEE OF SUPPLY AND CURTAILMENT OF SERVICE

(a) *No Guarantee of Supply or Service* - The Utility will endeavour to provide the constant delivery of Thermal Energy, the maintenance of unvaried temperatures and a regular and uninterrupted supply of Thermal Energy, but it does not guarantee a constant supply of Thermal Energy or the maintenance of unvaried temperatures. Service may be temporarily suspended to make repairs or improvements to the Thermal Energy System or in the event of fire, flood or other sudden emergency. The Utility will, whenever practicable, give prior notice of such suspension by email, fax, written notice, telephone, newspaper, flyer, radio or other acceptable announcement method and will restore service as soon as possible.

(b) *Curtailment of Service* - In the event of a breakdown or failure of the main supply or distributing plant or equipment, or to comply with the requirements of any law, the Utility shall have the right to require the Customer to discontinue the use or reduce consumption of Thermal Energy in any specified degree or quantity for any purpose or purposes until notice of termination of the requirement is given, or between specified hours. Any such requirement or termination of such requirement may be communicated by telephone, e-mail, newspaper, flyer, radio or other acceptable announcement method.

11. LIABILITY

(a) *Limitation of Liability* - The Utility, its employees, contractors or agents are not responsible or liable for any loss, injury (including death), damage or expense incurred by any Customer or any person claiming by or through the Customer, caused by or resulting from, directly or indirectly, any discontinuance, suspension, or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver, or transport Thermal Energy, or to provide Service, unless the loss, injury (including death), damage or expense is directly attributable to the gross negligence or willful misconduct of the Utility, its employees, contractors or agents provided, however, the Utility, its employees, contractors and agents are not responsible for any loss of profit, loss of revenues or other economic loss even if the loss is directly attributable to the gross negligence or willful misconduct of the Utility, its employees, contractors or agents.

(b) *Liability and Indemnity of Customer re: Thermal Energy* - The Customer is responsible for, and shall indemnify and save harmless the Utility from, all expense, risks and liability with respect to the use or presence of Thermal Energy: (i) after it passes through the Equipment, howsoever caused; and (ii) prior to it passing through the Equipment, if any loss or damage is directly caused by the act or omission of the Customer or a person for whom the Customer is responsible.

(c) *Liability of Customer re: Equipment* - The Customer is responsible for all, and shall indemnify and save harmless the Utility from, expense, risks and liability with respect to the Equipment, including the cost of any Equipment broken, missing or otherwise damaged, unless:

(i) the Customer can prove the loss or damage is directly attributable to the negligence or willful misconduct of the Utility, its employees, contractors or agents, or is caused by or resulting from a defect in the Equipment; or

(ii) the damaged Equipment was located in the mechanical room on the Property where access is restricted to the Utility and its employees, contractors or agents, unless the damage was directly attributable to any act or omission of the Customer or a person for whom the Customer is responsible, including unauthorized access to the mechanical room.

(d) *Indemnity* – In no way limiting subsections (b) or (c) above, the Customer will indemnify and hold harmless the Utility, its employees, contractors and agents from all claims, loss, damage, costs or injury (including death) suffered by the Utility or any person claiming by or through the Utility or any third party caused by or resulting from the use of the Service by the Customer or the presence of Thermal Energy in the Property, or from the Customer or Customer's employees, contractors or agents damaging the Equipment, except to the extent that any of the foregoing are directly attributable to the gross negligence or willful misconduct of the Utility, its employees, contractors or agents.

12. DISPUTES

Subject to section 19, where any dispute arises out of or in connection with this Service Agreement, including failure of the Customer and the Utility to reach agreement hereunder, either party may request the other party to appoint senior representatives to meet and attempt to resolve the dispute either by direct negotiations or mediation. Unresolved disputes may be submitted for final resolution by arbitration administered by the British Columbia International Commercial Arbitration Centre under its "Shorter Rules for Domestic Commercial Arbitration" in Vancouver, British Columbia, Canada. The language of that arbitration will be English. Alternatively, the Customer and Utility may agree, within 15 days of request by a party for final resolution, to submit that dispute for final resolution by arbitration in another manner. The parties shall continue to fulfill their respective obligations pursuant to this Agreement during the resolution of any dispute in accordance with this section.

13. AMENDMENTS

Except as set out in this Service Agreement, no amendment or variation of this Service Agreement shall be effective or binding unless such amendment or variation is set forth in writing and duly executed by the Customer and Utility and, where applicable, upon receipt of BCUC approval.

14. FURTHER ASSURANCES

The Customer and Utility will each execute and deliver any further agreement, document or instrument and do and perform any further act or things as may be reasonably required by the Customer or the Utility, as the case may be, from time to time in order to evidence or give full force and effect to the terms, conditions and intent of this Service Agreement.

15. AUTHORITY OF AGENTS OF THE UTILITY

No employee, contractor or agent of the Utility has authority to make any promise, agreement or representation not incorporated in these Terms and Conditions or otherwise in this Service Agreement, and any such unauthorized promise, agreement or representation is not binding on the Utility.

16. SURVIVAL

Upon expiry or earlier termination of this Service Agreement for any reason, all claims, causes of action or other outstanding obligations remaining or being unfulfilled as of the expiry or termination date and all of the provisions of this Service Agreement relating to the obligation or either the parties to account to or indemnify the other and to pay to the other any amounts owing as at the date of expiry or termination in connection with this Service Agreement will survive such expiry or termination.

17. GOVERNING LAW

This Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the laws of Canada. The parties hereby attorn to the jurisdiction of the courts of British Columbia and all courts competent to hear appeals therefrom.

18. ASSIGNMENT

The Utility may, upon written notice to the Customer, assign, transfer or sell its right, title and interest in this Agreement, or sell the majority of its shares or business or its material assets to, or amalgamate with, any of its Affiliates or another company, provided such Affiliate or other company agrees to be bound by the terms and conditions of this Agreement.

19. BCUC REVIEW

The Customer acknowledges FAES is a public utility as defined in the *UCA* and this Agreement, any rates and other amounts payable by the Customer hereunder and the terms and conditions contained herein are subject to BCUC oversight, review and approval. Any disputes between the Customer and the Utility which are within the jurisdiction of the BCUC pursuant to the *UCA*, shall be referred to and determined by the BCUC and the provisions of section 12 shall not apply to such disputes.

20. DISCLOSURE

(a) The Utility will calculate the Performance Ratio in the fourth year of each Performance Term for the previous five years (four years for the first Performance Term). At least six months prior to implementing a rate change under the Performance Ratio, the Utility will send an information package to its Customers to explain the calculation of the Performance Ratio, including the details of the forecast and actual costs used in this calculation. The information package will also include the weather normalized forecast consumption and actual consumption of natural gas and electricity, as well as the total thermal energy delivered, for each of the previous five years (four years for the first Performance Term).

(b) Within four (4) weeks of sending the information package to its Customers, the Utility will give notice to its Customers and convene a meeting to allow its Customers to ask questions on the Performance Ratio calculation, and the rates established in the subsequent term.

APPENDIX A

		2015	2016	2017	2018	2019
Cost of Natural Gas ($000's)		$ 10	$ 10	$ 10	$ 10	$ 10
Quantity of Natural Gas (MWh)		266	266	266	266	266
Average Price of Natural Gas ($/kWh)[a]		$0.039	$0.039	$0.039	$0.039	$0.039
Cost of Electricity ($000's)		$ 71	$ 74	$ 76	$ 78	$ 81
Quantity of Electricity (MWh)		834	834	834	834	834
Average Price of Electricity ($/kWh)[b]		$0.085	$0.088	$0.091	$0.094	$0.097

a - based on FortisBC Lower Mainland Rate 2 and $1.50 Carbon Tax;
escalations are based on GLJ Consultant Forecast http://www.gljpc.com/commodity-price-forecasts
b-rates and escalations based on BC Hydro Ten Year Plan released in 2013.
http://www.bchydro.com/news/conservation/2013/rates-investment.html

FAES notes that the above Cost of Natural Gas and Cost of Electricity for the period 2014 to 2018 is a forecast subject to change based on the actual quantity and price of natural gas and electricity for that period. Differences between forecast and actual costs of natural gas and electricity will be captured in the Fuel Deferral Account.

END OF DOCUMENT

Appendix B

STREAM A REGISTRATION FORM

APPENDIX A STREAM A REGISTRATION FORM

Thermal Energy System - Registration Form

Applicant Information

Name of Applicant: Company Name: FortisBC Alternative Energy Services Inc. (FAES)

BC Business Registration No.: BC0746680 **Year Registered:** January 24, 2006

Full Address:
FortisBC Alternative Energy Services Inc.
3700 – 2nd Avenue
Burnaby, BC V5C 6S4

Phone: Grant Bierlmeier (250) 896-3098 **Email Contact:** grant.bierlmeier@fortisbc.com

Public or Private Business: Private Business

Owner/CEO (name and address): President, Douglas Stout

Board Chair (name and address): Chairman, John Walker

Name of Parent Company if applicable and address:
FortisBC Holdings Inc.*
10th Floor, 1111 West Georgia St.
Vancouver, B.C. V6E 4M3

*Note: A wholly owned subsidiary of Fortis Inc.

TES System

Project Location (address)
Artemisia (Development or Artemisia)
1102 Hornby Street, Vancouver, BC

The developer of the project is:
Boffo Developments (Hornby) Ltd. (Boffo/Developer)
200—4580 Hastings Street
Burnaby, BC V5C 2K4

Tel 604 299 3443
Fax 604 291 2907
info@boffo.ca

Is this TES System a new construction, retrofit, purchase, or in-service priori to DATE or extension to an existing TES
The Artemisia Thermal Energy System (ATES) is a new construction. The construction for the Development is now completed with occupancy granted on April 23, 2014. The Development consists of a boutique collection of 21 luxury condominium residences with a floor area of 3,241 m^2 in Vancouver, BC.

In-Service date of the TES System (YY/MM?DD)?
The in-service date for the TES Utility was April 23, 2014.

Description of the construction phase-in or build-out period (years):
The construction started in July 2012 and was completed in April 2014. The Artemisia Thermal Energy System (ATES) is located entirely within the Development lands and is designed to only serve the Development so there will be no utilty facility phasing.

Service provided: space heating, cooling and/or domestic hot water
The ATES will provide space heating and cooling for the Development.

Primary Thermal energy sources

Heating:
Heating sources are: i) geo-exchange system, and ii) a natural gas boiler for peak heating.

Cooling (if applicable):
Cooling source is geo-exchange system.

Energy conversion technology used

The Artemisia Thermal Energy System consists of a geo-exchange system (GES) and a natural gas boiler for peak heating located in the parkade of the Development that will provide heated water to a hydronic building loop. The hydronic building loop connects to distributed heat pumps located within each strata lot. The heat pumps will provide space heating and cooling to each strata lot. When the heat pumps are in cooling mode, excess heat will be removed from the building hydronic loop by way of rejection of heat to the GES loop field. The Strata Corporation will own the heat pumps located within each strata lot, as well as the electrical boilers that will heat the domestic water (DHW), also located within each strata lot.

Buildings served: single or multiple. If multiple, how many?
Artemisia is a Development that consists of a single building with 21 residential units (strata lots).

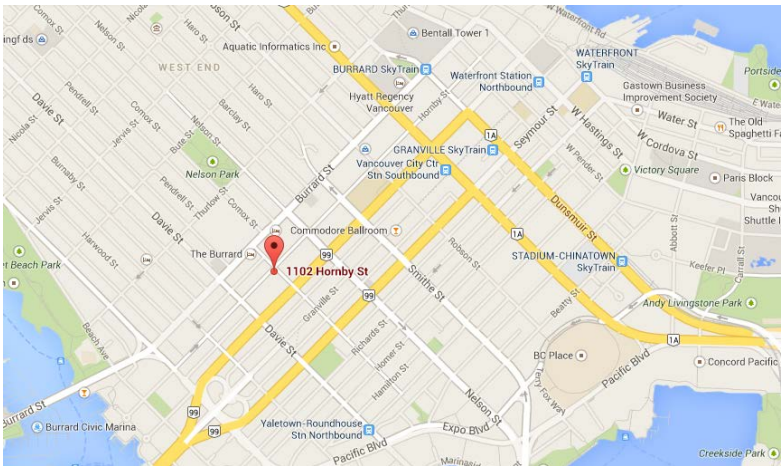
Total square meters served
3,241 m^2

Municipal Building Permit Number
Building Permit number: BU444083

TES System Information

Location of TES facilities and description of site size. Include a map or schematic diagram if possible.
Site Area=0.27 acres

The location of the facilities is shown in the map below:



Description of TES System including energy centre and distribution system (drawing, diagram or description of equipment, connections etc.)
The mechanical equipment that FAES will own consists of the following:

- High Efficiency Boiler B-1
- Gas make-up air unit MUA-1
- Heat exchanger HX-1
- Expansion tanks ET-1 & 2
- Loop field - 24 Boreholes @ 380' depth
- Glycol feeder GLY-1 & 2
- Pumps P-1 to 5 with VFDs for 4 pumps
- Piping in P2 Mechanical Room serving the heating and cooling system
- Controls and Digital meters

Mechanical equipment not owned nor maintained by FAES consists of:

- Heat Pumps (located in each strata lot)
- Electrical boilers for domestic hot water (located in each strata lot)

A schematic of the energy system is shown in Appendix C.

Describe system size and known energy demand

Please see Table-1 below.

Description of whether system and or site is designed to be scalable and intended to connect to other systems, buildings or locations.
The Artemisia Thermal Energy System is designed to serve the Development only.

Description of back-up or alternate energy services available. Include Information of provider.

Heating:
The natural gas boiler provides peak heating and partial back-up heating for energy supplied to the hydronic building loop. FAES is responsible for the acquisition of all natural gas and electricity required to operate the ATES.
The distributed heat pumps (owned by the customers) must be operable to transfer heat energy from the hydronic building loop to each strata lot. There are no back-up heating sources provided for the distributed heat pumps (in each strata lot) as is the case in most distributed heating applications.

Cooling:
No back-up or alternative cooling sources are provided as is the case in most space cooling applications.

No other alternate energy services from another TES provider are used at this Development.

Any other information on service/energy provided and the scope of services and facilities.
FAES will provide the thermal energy for heating and cooling required by the building hydronic loop. FAES will own the centralized thermal energy equipment . The customer will own the distributed heat pumps and the electric DHW boilers in each strata lot.

All energy inputs required for the FAES heating and cooling service above are the responsibility of FAES. FAES will also be responsible for the operation and maintenance for all FAES heating and cooling equipment.

The customer will be responsible for the energy inputs, operation and maintenance of the distributed heat pumps and DHW boilers.

Description of the use of municipal or public rights of ways.
The Artemisia Thermal Energy System is located within the Development lands and does not encroach on either municipal or public rights of ways.

Name the customer(s) involved in the selection or signing of contracts.
The Developer selected the energy system to meet its goals with respect to reduction of greenhouse gas emissions. Further, the Developer selected a system that would enhance the marketability of its Development.

Prospective strata lot owners have received information related to the energy system and FAES' role as the owner and operator of the system through the developer's Disclosure Statement.

The Developer is currently the sole customer of the Thermal Energy System Service Agreement that is appended to this Application (Appendix A). Once the Strata Corporation is created, the Service Agreement will be assigned from the Developer to the Strata Corporation.

Number of customers/end-users:
- **Initially;**
- **In 5 years**

FAES will provide thermal energy to one customer, the residential strata, which will be comprised of 21 strata lots. This arrangement is not expected to change.

Type of customers (eg.):
- **residential/commercial;**
- **individual tenants/strata corporation**

There will be one residential customer (one Service Agreement – Appendix A) in the form of a Strata Corporation that will consist of 21 strata lots.

Is (are) the Customer(s) obligated or restricted to taking service from the Utility? If so, how and why.
As the energy system is designed to optimally deliver thermal energy, there are no energy alternatives available to the customers. The Service Agreement obligates the customer to take or pay for a minimum annual amount of energy determined to be approximately 80 per cent of the expected annual demand. This provision (Minimum Annual Charge) is set out in Part II (Terms and Conditions) of the Service Agreement.

What percent of the estimated TES facility cost was/will be competitively tendered? How else is cost reasonableness for construction of the facility assured?
The design and construction of the Project was managed by the Developer. The total direct cost of the energy system owned by FAES is estimated to be $470,000 excluding soft costs. The total cost, including soft costs (consulting fees, contractor's overhead and profit, and the developers management fee, is estimated to be $587,500. A breakdown of costs, including soft costs, is shown below in the Cost Estimate section of the Application.

FAES and the Developer negotiated a thermal energy rate that would yield competitive and marketable strata fees for the unit owner and would maintain the estimated Strata Budget, as disclosed in the Original Disclosure Statement and as requested by the Developer. Based on this negotiated rate structure, financial parameters and expected thermal loads, the maximum purchase price FAES is able to pay for the energy system is $100,000. The purchase price of $100,000 is set out in the Construction and Purchase Agreement and results in the Developer absorbing approximately $487,500 of the energy system costs. The $100,000 purchase price agreed to between FAES and the Developer ensures that the Customer pays a competitive rate for thermal energy. The$487,500 difference between the total cost of the energy system and the purchase price will be treated as a non-refundable contribution in aid of construction (CIAC).

Load Forecast and Analysis

I/We confirm that the load analysis and energy demand forecast was/will be completed by the following qualified person(s): [Company name and qualifications)
Yes. The analysis was prepared by AME Group Consulting Professional Engineers (AME Group), reviewed and revised by FAES' Professional Engineer.

Information on peak loads (MW) and annual loads (MWh) by thermal energy end-use.

Table 1 - Peak and Annual Heating/Cooling Loads are:

Description	Residential	
	Peak MW	Annual MWh
Space Heating	0.159	335
Space Cooling	0.138	75
Total	-	410

What is the method used to forecast the peak and annual loads? What are the key assumptions and design references used.
Forecast peak and annual loads have been estimated based on consultation with AME Group (mechanical engineers for the project) and the use of Thermal Load Intensities (TLIs) from other similar projects. Similar to Energy Use Intensities, TLI is a unit of measurement that describes a building's thermal energy use. It represents the thermal energy delivered to a building relative to its size or square footage, and can be used to provide a benchmark to compare buildings. The average TLI is dependent on the type of building, also known as building archetype.

What is the peak design output (MW) of the TES System (not including peaking/backup systems)?
The peak design output of the TES Utility facility is 0.157 MW.

What is the peak design output (MW) of the peaking/backup system?
The peak design output of peaking system (i.e. natural gas boiler) is 0.082 MW.

Has the TES System been designed to meet the full peak load for the site? If not, please explain other sources of peaking energy available to customers.
Yes, the system is designed to meet the full peak heating load of the Development.

Cost Estimate

Estimated Capital Cost (AACE Class 3 minimum)
(applicant may add additional line items as appropriate)

The total capital cost of the thermal energy system is estimated to be $587,500 including soft costs. A breakdown of this cost is shown in the following table.

FAES' purchase price of the system is contractually set at $100,000 and will not change.

Description		$
Pumps & VFDs		$120,000
Heat exchanger		$30,000
Loop Field		$225,000
Gas fired Boiler		$25,000

Description		$
Gas fired Make-up air unit		$20,000
Piping in Mechanical Room		$25,000
Controls & Metering		$25,000
Subtotal - Equipment installed		$470,000
Consulting Fees	10%	$47,000
Conractor's O/H + Profit	10%	$47,000
Developer's Management Fee	5%	$23,500
Total		$587,500

The total capitalized amount that is reflected in the rate is $105,000, which is comprised of the purchase cost of $100,000 plus capitalized development costs incurred by FAES of $5,000.

Describe the methodology for estimating Overhead and Other 'soft' costs.
Actual project developent costs incurred are estimated to be $5 thousand. These costs relate to technical oversight/review and general administration.

Estimated Annual Operating Costs ($000)
The estimated annual operating costs for the energy system are provided in the following table:

Boffo Artemisia: Revenue Requirement
($000's), unless otherwise stated
Schedule 1

Line	Particulars	Reference	Forecast for PT2 Performance Ratio				Foreast for PT3 Performance Ratio				
			2014	2015	2016	2017	2018	2019	2020	2021	2022
1	**Revenue Requirement**										
2	Cost of Natural Gas	Schedule 2, Line	10	10	11	11	11	12	12	12	12
3	Cost of Electricity	Schedule 3, Line	3	4	4	4	4	4	4	4	4
4	Operation and Maintenance	Schedule 4, Line 11	14	14	14	14	15	15	15	15	16
5	Property Taxes	Schedule 4, Line 16	-	-	-	-	-	-	-	-	-
6	Depreciation Expense	Schedule 10, -(Line 21 + Line 46)	11	3	3	3	3	3	4	4	5
7	Amortization Expense	Schedule 11, Line 28	-	-	-	-	-	-	-	-	-
8	Income Taxes	Schedule 5, Line 21	-	-	-	-	-	-	-	-	-
9	Earned Return	Schedule 7, Line 24	6	6	6	6	5	6	6	7	7
10											
11	**Annual Revenue Requirement**	**Sum of Lines 2 through 9**	**45**	**37**	**37**	**38**	**38**	**40**	**41**	**43**	**44**

Forecast for PT4 Performance Ratio					Forecast for Renewal Period 1 Performance Ratio					
2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
13	13	13	13	13	14	14	14	14	15	15
5	5	5	5	5	5	5	6	6	6	6
16	16	17	17	17	18	18	18	19	19	20
-	-	-	-	-	-	-	-	-	-	-
5	5	6	6	7	7	6	6	7	7	8
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
8	9	9	10	10	11	11	12	12	13	14
46	**48**	**49**	**51**	**53**	**55**	**54**	**56**	**58**	**60**	**62**

Part II of the Service Agreement defines the Performace Ratio and the Performance Term as follows:

Performance Ratio: The ratio of actual costs of providing the Service relative to the forecast costs of providing the Service (set out at the initiation of Service), as reasonably determined by the Utility, calculated in the fourth year of each Performance Term for the previous five years (four years for the first Performance Term). The individual cost components included in the calculation of the Performance Ratio are: a) natural gas costs, b) electricity costs, c) operations and maintenance, d) depreciation and amortization, e) taxes (property and income), and f) capital carrying costs, including initial investment, and replacement capital.

Performance Term: A five year periodoccurring in the years 1-5, 6-10, 11-15 and 16-20 of the Initial Term and for each subsequent renewal term.

Describe the methodology for estimating sustainment capital and operating/administrative/overhead.

Based on discussions between the Developer's engineer, AME Group, and FAES's internal engineers, the annual amount for sustaining capital equal to approximately $11,000 per year commencing in the 6th year of operation, escalating at 2 per cent per year. The estimated operating and maintenance costs equal to approximately $14,000 per year escalated at 2 per cent each year over the contract term.

FAES has estimated its overhead related to this project to be $3,627 thousand per year as provided in the table below. This amount is included in the $14,000 of operating and maintenance costs noted in the table above and is not additive.

Description - Overheads (annual)	Amount
Contract Administration	$ 780
Billing	$ 492
Customer Service	$ 780
Insurance	$ 300
Corp OH	$ 275
TESDA	$ 1,000
Total	$ 3,627

Attestation Requirements for Stream A TES Systems (with in-service date after xx date)

Eligibility for Stream A TES Regulation:

☒ **I/We certify that the proposed TES System meets the description of an On-site TES System, as defined in the TES Guide.**

☒ **I/We certify that the proposed TES System is associated with an approved single development/building permit.**

☒ **I/We certify that the proposed TES System capital cost is less than $15 million.**

The Artemisia Thermal Energy System meets the above criteria.

Customer Disclosure:

☒ **I/We certify that all customers or potential customers have signed or will sign a long-term contract.**

i. Thermal Energy System Service Agreement (Residential Strata Parcel) between FAES and Boffo Development (Hornby) Ltd. dated May 29, 2014, attached under Appendix A.

☒ **I/We certify that the long-term contract include the minimum provisions included in Appendix C to the TES Guide.**

The Contract/Service Agreement Provisions listed in Appendix C of the TES Utility Regulatory Guide are listed below and accompanied by a description of how each provision is addressed in the Service Agreement. The information provided in the following sections is incorporated into the 'plain language' summary, attached as Appendix D to this Application.

1. **Rate(s) for service. The rate(s) must be set following the TES Rate Setting Guide (Appendix B). Include the first year rate and any rate escalator if appropriate.**
   The rate will start in 2014 at $0.095/kWh as negotiated with the Developer, and escalate at 2 per cent annually. The rate will be fixed at this escalation rate for the first five-year period and will only be subject to an annual adjustment for cost variances related to natural gas and electricity costs that are different from forecast for the first five years. In this Application, FAES is using the same rate design as it used for its SOLO Development, recently approved by the Commission by Order G-54-14.

   Revenue variances related to load consumption will be absorbed by FAES and will not impact rates. Any over or under recovery of revenues during this five-year period will not be refunded or recovered from the customer in future rates except for variances incurred for fuel costs, which will be recovered from or refunded to customers annually through a rate rider.

   After the initial four years of service (five years for any performance terms after the initial performance term), rates will be re-calculated, either up or down, based on the ratio of the actual cost of thermal energy ($/kWh) in the preceding four-year period (five-year period for any performance terms after the initial performance term) to the originally forecast cost of thermal energy ($/kWh) for the same period. Once this calculation is made, the rates for the next performance term will be reset to account for the actual performance in the immediately preceding performance term and then continue forward increasing at 2 per cent per year for the next five years.

   In section **"Follows the Rate Setting Guide (Appendix B) when setting rates"** towards the end of the Application FAES provides details on how the proposed rate adheres to the principles the Commission established under Appendix B of the TES Utility Regulatory Guide.

2. **Schedule of all fees to which Unit Owners/Other Ratepayers may be subject.**
   Section 7(e) of the Thermal Energy System Service Agreement Part II – Terms and Conditions describes the amounts payable should the customer terminate the Service Agreement either during the initial 20-year term or during a subsequent renewal term.

3. **Minimum or maximum contract amounts and/or volumes, if any.**
   Part II – Terms and Conditions of the Service Agreement defines the minimum annual charge to be paid by the Customer each calendar year as the amount calculated by multiplying the applicable Energy Rate by 80 per cent of the Annual Demand set out in Part I of the Service Agreement. The design capacity of the service is defined in Part I of the Service Agreement.

4. **Clear identification, in dollar terms, of any front-end or back-end costs for which the Customers/Other Ratepayers may be liable, in dollar terms.**
   There are no front end costs respecting the ATES. Charges related to termination or non-renewal of the Service Agreement, if applicable, are described in point 2 above.

5. **Clearly defined penalties for early termination of contract. Where payment is required at termination of contract or service, contract or service agreement clauses must clearly state what is to be paid at different stages of the contract life including any contract non-renewal fees or charges. Penalties / fees are subject to the same tests of just, reasonable and not unduly discriminatory and must consider inter-generational equity issues.**
   Termination can occur at any time subject to the payment provisions of Section 7(e) of the Thermal Energy System Service Agreement Part II – Terms and Conditions.

6. **Provision for the right to purchase and use assets, particularly in the event of TES Utility bankruptcy or other agreed grounds for termination.**
   The Service Agreement does not provide the Strata Corporation with the right to purchase the energy system in the event the contract is terminated or if FAES becomes insolvent. In the event that FAES becomes insolvent, any person (such as a receiver) who seizes the energy system would be subject to the Commission's jurisdiction.

7. **Recourse to the Commission in the event of disputes and/or concerns with rates and services.**
   Disputes related to the provision of TES are addressed under Article 12 (Disputes) and Article 19 (BCUC Review) of the Thermal Energy System Service Agreement Part II – Terms and Conditions of the Service Agreement.

8. **Telephone number or other means by which customers will be able to contact the utility, particularly regarding an emergency.**
   The established line of contact is between the property manager which represents the Strata Corporation and:
   Manager of Operations
   FortisBC Alternative Energy Services Inc.
   Phone: (250)-380-5738
   Cell: (250) 889-5782

9. **Description of facilities and trained personnel that will provide emergency response.**
   FAES has access to contracted qualified contractors in the Okanagan, Vancouver Island and Lower Mainland regions that are able to provide emergency response respecting the operation of all thermal energy systems.

☒ **I/We have provided a "Plain-language" explanation to all customers/potential customers of the TES System, which includes the minimum provisions included in Appendix C to the TES Guide.**

The ‘plain language’ summary is contained in Appendix D.

FAES have sent this document to the Developer on May 28, 2014 and the Developer confirmed on June 4, 2014 that it has provided a full copy of the Summary of Thermal Energy Service Agreement, as prepared by FAES, to all current owners as well as the purchasers who have yet to complete their sales transaction, by email and by mailing a hard copy to their current address.

☒ **I/We will retain all records of customer disclosure in the event of a dispute.**
Confirmed.

Other Requirements:
FAES complies with other requirements defined below .

☒ **I/We have determined the Capital Reserve Requirement and will hold sufficient Capital Reserves.**

According to Section 2.6 of the TES Guide, the purpose of the capital reserve fund is as follows:

> *“Owners and/or operators of Stream A and Stream B TES Systems must have sufficient capital reserve provisions (CRP) in place to ensure its ability to replace equipment essential to maintaining safe and reliable thermal energy service. The need for replacement may arise in situations where equipment either fails to operate prior to its end of life or as it comes to the end of its planned useful life.*
>
> *Service interruption mitigation in the event of equipment failure must be considered in the design and set-up of the TES System. Back-up energy service, redundancy, rapid deployment of temporary backup energy service through insurance etc. are some of the options that the TES System Provider must have considered.*
>
> *All TES Providers are required to assess, on an ongoing basis, their capital reserve requirements and ensure they have sufficient CRP in place. The TES Provider may use a portfolio approach in applying the capital reserve provisions where a single TES Provider owns and/or operates multiple TES Systems.*
>
> *An applicant requesting approval of a Stream A TES System is required to attest that it has sufficient capital reserve provisions and must also attest, in its annual report, that it continues to maintain adequate capital reserve provisions.”*

FAES currently has a portfolio of TES Utility Projects and includes replacement capital in the forecast cost of service for each TES Project.

Further, FAES’ parent company Fortis Inc. (Fortis) has combined assets approaching $18 billion with net earnings in 2013 of $353 million. Fortis has grown dramatically over the last decade, driven by the acquisition of regulated utilities in western Canada and ongoing capital investments. With the acquisition of UNS Energy, total Fortis assets will increase by approximately one-third to approach $24 billion.

For the fifth consecutive year, Fortis’ capital program surpassed $1 billion.

Fortis collectively serves three million utility customers and Fortis' substantial capital investments will ensure adequate financial capacity to continue to meet the growing energy needs of Fortis' existing and new customers.

Fortis is one of the highest-rated utility holding companies in North America with its corporate debt rated A- by Standard & Poor's and A(low) by DBRS, unchanged from 2012. The credit ratings were affirmed in 2013.

Since the beginning of 2013, Fortis has raised approximately $3.3 billion in the capital markets, which attests to investors' confidence in Fortis' business strategy. In addition to the $1.8 billion Debenture offering associated with the UNS Energy acquisition, major financing completed by Fortis included the $601 million in common equity associated with the CH Energy Group acquisition.

In July 2013 Fortis raised gross proceeds of $250 million from the issuance of 4% Fixed Rate Reset First Preference Shares, which were used to redeem all of the Corporation's 5.45% First Preference Shares for $125 million, to repay a portion of credit facility borrowings, and for other general corporate purposes. In October 2013 the Corporation closed a private placement of 10-year US$285 million unsecured notes at 3.84% and 30-year US$40 million unsecured notes at 5.08%. The proceeds were used to repay a portion of US dollar-denominated credit facility borrowings incurred to finance a portion of the CH Energy Group acquisition. In addition, the Corporation's regulated utilities issued over $300 million in long-term debt in 2013 to repay maturing debt and credit facility borrowings, to fund future capital expenditures and for general corporate purposes.

Accordingly, FAES has access to adequate resources to fund ongoing capital needs related to planned and unplanned replacement of assets. Therefore, FAES has no need for a Capital Reserve Fund.

☒ **I/We ensure the design, construction and operation of the TES System selected is the most cost effective alternative.**

Cost reasonableness is achieved through the application of the levelized rate design that is explained in the following section. The cost or the maximum price FAES will pay for the energy system is $100,000, which is $487,000 less than the total expected cost of the system. The two parameters that determine the purchase price of the system are the levelized rate, which conforms to the principles under Appendix B of the TES Utility Regulatory Guide, and the expected thermal load, which is described above in this Application.

FAES will ensure reasonableness of operation and maintenance costs by tendering and contracting to independent third parties at market rates.

☒ **I/We will retain all records in the calculations of the Capital Reserve Requirement, Provision and Annual Contribution to Capital Reserve Fund and provide to the Commission on an annual basis.**

Appendix C

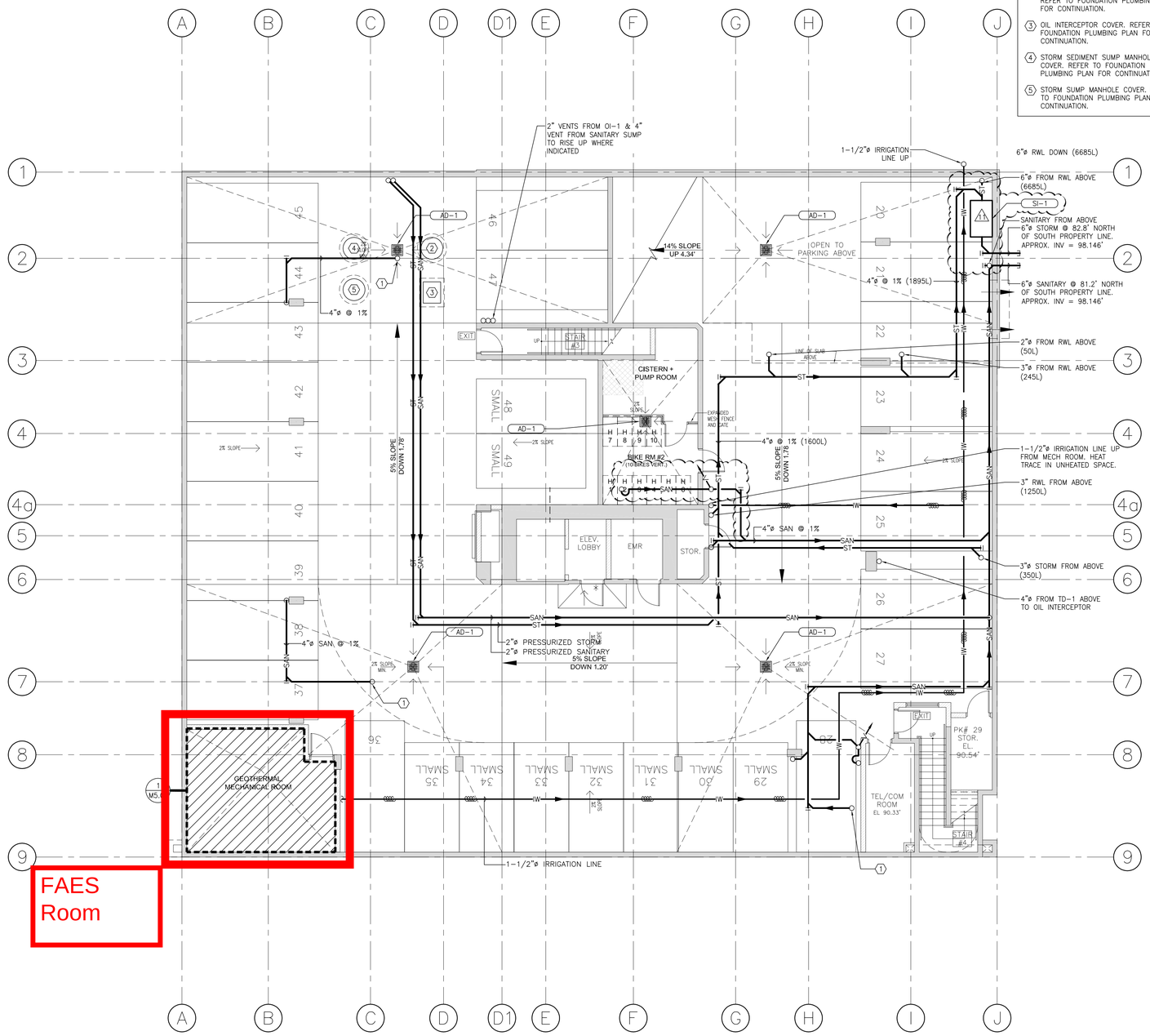
FACILITY DRAWINGS

GENERAL NOTES

1. ALL PIPING IN STAIRWELLS AND EXIT CORRIDORS TO BE ENCASED IN RATED ENCLOSURE AS INDICATED ON ARCHITECTURAL DRAWINGS.

DRAWING NOTES

1. 4"ø SAN FROM AD-1 ABOVE
2. SANITARY SUMP MANHOLE COVER. REFER TO FOUNDATION PLUMBING PLAN FOR CONTINUATION.
3. OIL INTERCEPTOR COVER. REFER TO FOUNDATION PLUMBING PLAN FOR CONTINUATION.
4. STORM SEDIMENT SUMP MANHOLE COVER. REFER TO FOUNDATION PLUMBING PLAN FOR CONTINUATION.
5. STORM SUMP MANHOLE COVER. REFER TO FOUNDATION PLUMBING PLAN FOR CONTINUATION.



1 M2.01 PARKADE LEVEL 2 PLUMBING PLAN
SCALE: 1/8" = 1'-0"

gBL
GBL ARCHITECTS INC.
140 - 2034 WEST 11TH AVENUE TELEPHONE 604 736 1156
VANCOUVER, BC CANADA V6J 2C9 FACSIMILE 604 731 5279

REVISIONS

NO.	DATE	DESCRIPTION
1	2009 JAN 16	ISSUED FOR COORDINATION
2	2009 JAN 29	ISSUED FOR ENGINEERING REVIEW
3	2009 FEB 12	ISSUED FOR CODE REVIEW & BP
4	2012 APR 13	RE-ISSUED FOR CODE REVIEW & BP
5	2012 APR 30	ISSUED FOR COORDINATION
6	2012 JUN 08	ISSUED FOR COORDINATION
7	2012 JUN 19	ISSUED FOR TENDER
8	2012 JUL 10	ISSUED FOR BUILDING PERMIT
9	2012 JUL 25	ISSUED FOR CONSTRUCTION - BELOW GRADE
10	2012 SEP 07	ISSUED FOR PLUMBING PERMIT
11	2012 NOV 13	RE-ISSUED FOR PLUMBING PERMIT
12	2012 DEC 07	ISSUED FOR CONSTRUCTION
13	2013 JAN 15	ISSUED FOR CONSTRUCTION

PROJECT NORTH

N

TRUE NORTH

GENERAL NOTES

AME Group
Consulting Professional Engineers

VANCOUVER
T. (604) 684-5995 F. (604) 684-5993
501 - 134 ABBOTT STREET
VANCOUVER, BC V6B 2K4

VICTORIA
T. (250) 382-5999 F. (250) 382-5998
721 JOHNSON STREET
VICTORIA, BC V8W 1M8

Boffo DEVELOPMENTS LTD

1102 HORNBY ST.
VANCOUVER, BC

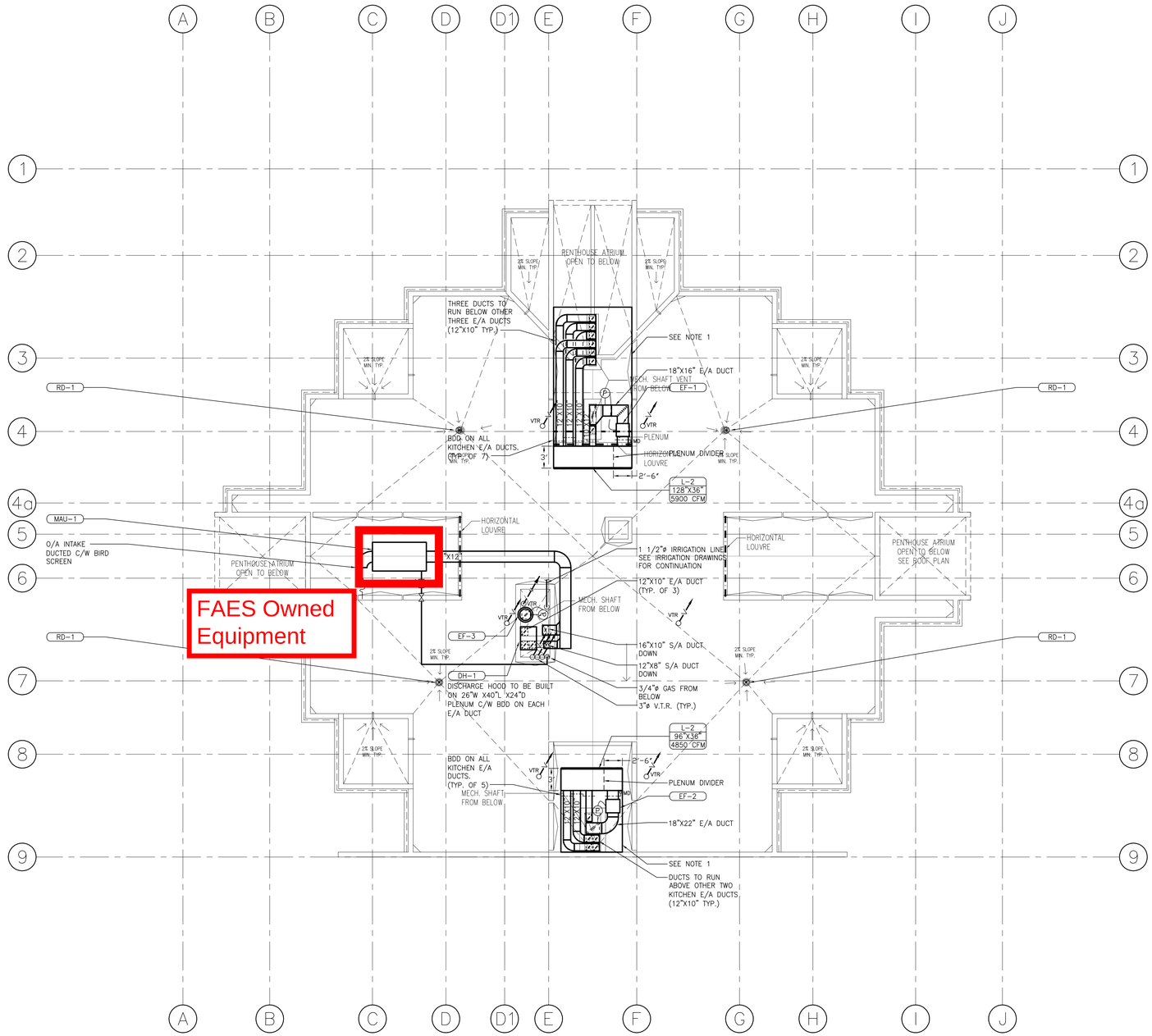
BU#: 444083
For: Boffo Developments Ltd. (Hornby)

PARKADE LEVEL 2
PLUMBING PLAN

DATE	JAN 15, 2013
DRAWN BY	JC/DJ
CHECKED BY	AO
SCALE	1/8" = 1'-0"
JOB NUMBER	B08-029-01

M2.01

GENERAL NOTES:
1. REFER TO ARCHITECTURAL DRAWINGS FOR PENTHOUSE DETAILS
2. BALANCING CONTRACTOR TO LOCATE BEST LOCATION FOR EXHAUST FAN PRESSURE SENSORS TO PROVIDE OPTIMAL PRESSURE READING



1 M3.09 MECHANICAL ROOF PLAN
SCALE: 1/8" = 1'-0"

gBL

GBL ARCHITECTS INC.
140 - 2034 WEST 11TH AVENUE TELEPHONE 604 736 1156
VANCOUVER, BC CANADA V6J 2C9 FACSIMILE 604 731 5279

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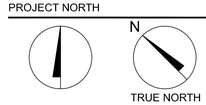
11	2013 JAN 15	ISSUED FOR CONSTRUCTION

PROJECT NORTH



GENERAL NOTES

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Consulting Professional Engineers

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VANCOUVER, BC

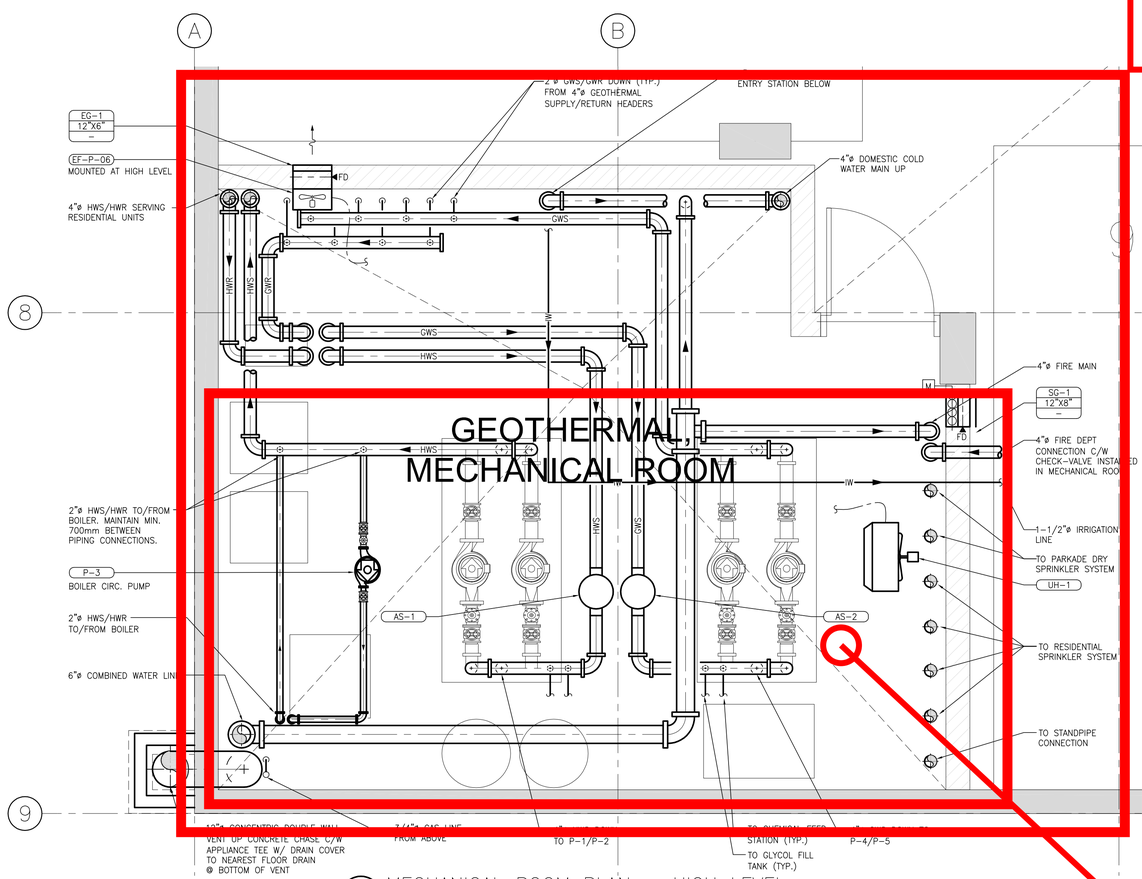
BU#: 444083
For: Boffo Developments Ltd. (Hornby)

MECHANICAL
ROOF PLAN

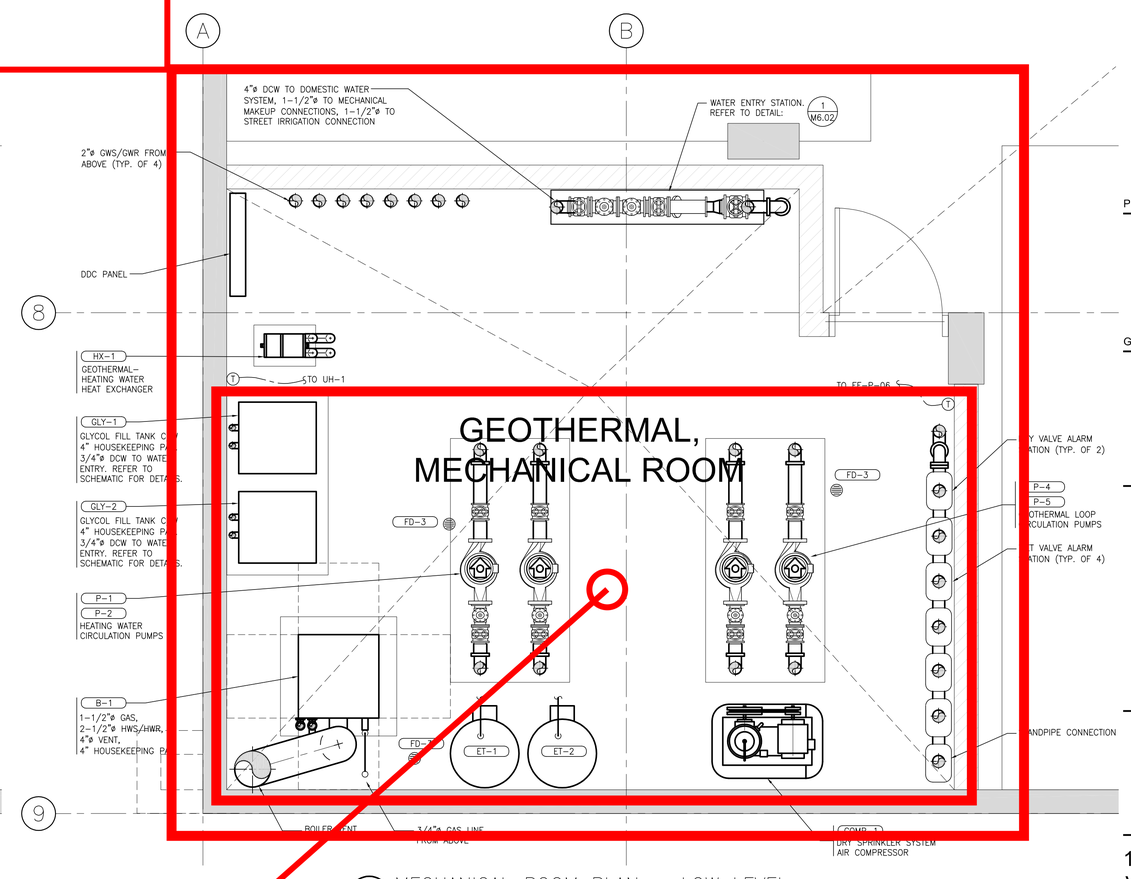
DATE	JAN 15, 2013
DRAWN BY	JC/DJ
CHECKED BY	AO
SCALE	1/8" = 1'-0"
JOB NUMBER	B08-029-01

M3.09

FAES Room



1 M5.01 MECHANICAL ROOM PLAN – HIGH LEVEL
SCALE: 1/2" = 1'-0"



2 M5.01 MECHANICAL ROOM PLAN – LOW LEVEL
SCALE: 1/2" = 1'-0"

FAES owned Equipment

gBL
GBL ARCHITECTS INC.
140 - 2034 WEST 11TH AVENUE TELEPHONE 604 736 1156
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12	2013 JAN 15	ISSUED FOR CONSTRUCTION

PROJECT NORTH

N

TRUE NORTH

GENERAL NOTES

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Boffo DEVELOPMENTS LTD

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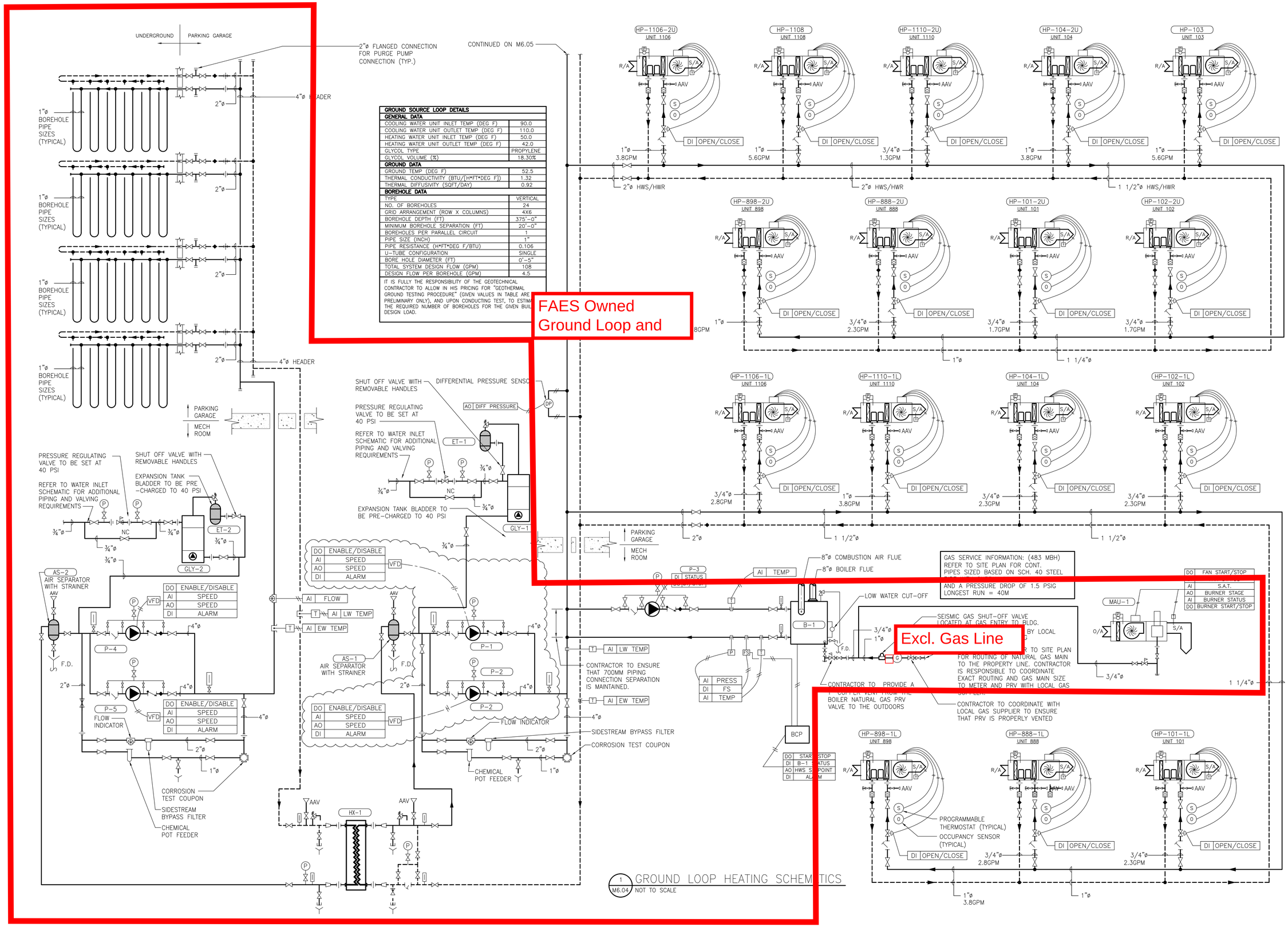
BU#: 444083
For: Boffo Developments Ltd. (Hornby)

MECHANICAL ROOM PLANS

DATE	JAN 15, 2013
DRAWN BY	JC/DJ
CHECKED BY	AO
SCALE	1/2" = 1'-0"
JOB NUMBER	B08-029-01

M5.01



GROUND SOURCE LOOP DETAILS	
GENERAL DATA	
COOLING WATER UNIT INLET TEMP (DEG F)	90.0
COOLING WATER UNIT OUTLET TEMP (DEG F)	110.0
HEATING WATER UNIT INLET TEMP (DEG F)	50.0
HEATING WATER UNIT OUTLET TEMP (DEG F)	42.0
GLYCOL TYPE	PROPYLENE
GLYCOL VOLUME (%)	18.30%
GROUND DATA	
GROUND TEMP (DEG F)	52.5
THERMAL CONDUCTIVITY (BTU/[H*FT*DEG F])	1.32
THERMAL DIFFUSIVITY (SQFT/DAY)	0.92
BOREHOLE DATA	
TYPE	VERTICAL
NO. OF BOREHOLES	24
GRID ARRANGEMENT (ROW X COLUMNS)	4X6
BOREHOLE DEPTH (FT)	375'-0"
MINIMUM BOREHOLE SEPARATION (FT)	20'-0"
BOREHOLES PER PARALLEL CIRCUIT	1
PIPE SIZE (INCH)	1"
PIPE RESISTANCE (H*FT*DEG F/BTU)	0.106
U-TUBE CONFIGURATION	SINGLE
BORE HOLE DIAMETER (FT)	0'-5"
TOTAL SYSTEM DESIGN FLOW (GPM)	108
DESIGN FLOW PER BOREHOLE (GPM)	4.5

IT IS FULLY THE RESPONSIBILITY OF THE GEOTECHNICAL CONTRACTOR TO ALLOW IN HIS PRICING FOR "GEOTHERMAL GROUND TESTING PROCEDURE" (GIVEN VALUES IN TABLE ARE PRELIMINARY ONLY), AND UPON CONDUCTING TEST, TO ESTIMA THE REQUIRED NUMBER OF BOREHOLES FOR THE GIVEN BUIL DESIGN LOAD.

FAES Owned Ground Loop and

Excl. Gas Line

1 / M6.04 GROUND LOOP HEATING SCHEMATICS
NOT TO SCALE

gBL
GBL ARCHITECTS INC.
140 - 2034 WEST 11TH AVENUE
VANCOUVER, BC CANADA V6J 2C9
TELEPHONE 604 736 1156
FACSIMILE 604 731 5279

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GENERAL NOTES

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Boffo DEVELOPMENTS LTD

1102 HORNBY ST.
VANCOUVER, BC

BU#: 444083
For: Boffo Developments Ltd. (Hornby)

MECHANICAL
HVAC SCHEMATICS

DATE	JAN 15, 2013
DRAWN BY	JC/DJ
CHECKED BY	AO
SCALE	NOT TO SCALE
JOB NUMBER	B08-029-01

M6.04

Appendix D

SERVICE AGREEMENT SUMMARY

Artemisia Development
Thermal Energy System Service Agreement

SUMMARY OF THERMAL ENERGY SERVICE AGREEMENT

➢ Overview of Energy System

The Artemisia Thermal Energy System consists of a geo-exchange system (GES) and a central natural gas boiler for peak heating that will provide heated water to a hydronic building loop. The hydronic building loop then connects to equipment owned by the Strata, namely distributed heat pumps located within each strata lot. The heat pumps will provide space heating and cooling to each strata lot. When the heat pumps are in cooling mode, excess heat will be removed from the building hydronic loop by way of rejection of heat to the GES loop field. FortisBC Alternative Energy Services (FAES) will not provide domestic hot water, which will be heated solely by electrical boilers owned by the Strata and located within each strata lot.

➢ Service Provisions

1. Thermal Energy Rate

The thermal energy rate is initially set at $0.095/kWh and, subject to BC Utilities Commission (BCUC) approval, will increase annually by approximately 2 per cent over the term of the Service Agreement. Details of how this rate has been determined are provided below under the heading "Rate Calculations".

For the first five-year period, the rate will be subject to adjustment only for cost variances that relate to natural gas and electricity costs that are different from the forecast cost used to set the rate. During the first five years, FAES will take the load forecast risk, which will not impact rates, and any over or under recovery of revenues will not be refunded to or recovered from customers except for variances incurred for fuel costs as noted above.

At the beginning of each subsequent five-year period, the rate will be re-calculated, either up or down, based on the actual cost of providing the service in the preceding five-year period relative to the forecast costs of providing the service, as set out at the initiation of the service. Once this calculation is made, the rate will again increase annually at 2 per cent per year for the next five-year period. The primary determinants that may result in rate changes are thermal energy consumption, operating and maintenance costs and debt costs.

2. No additional Fees

Other than applicable provincial and federal sales tax there are no other charges or fees added to the Rate. Also, there are no front end or back end costs that apply to the provision of thermal energy.

3. Annual Purchase Requirements

Part II – Terms and Conditions of the Service Agreement defines the minimum annual charge to be paid by the Customer each calendar year as the amount calculated by multiplying the applicable energy rate by 80 per cent of the Annual Demand set out in Part I of the Service Agreement.

Should the Strata Corporation customer – *i.e.,* all the strata lot owners - consume an amount of thermal energy over the course of a year that is less than 80 per cent of the Annual Demand, then the shortfall (in terms of kWh) would be multiplied by the applicable energy rate and the calculated amount would be added to the customer's first bill the following year. A sample bill is shown at the end of this document.

4. Contract Termination

If the Service Agreement is terminated due to default by the Strata Corporation during the initial 20-year term (Initial Term) of the contract, the Strata Corporation would be obligated to pay FAES an amount equal to the un-depreciated capital (Rate Base value) remaining on its balance sheet at the point of termination plus any earnings forgone by FAES for the remainder of the Initial Term. Upon such termination, the energy system would remain the property of FAES.

If the Service Agreement is terminated after the Initial Term of 20 years, the Strata Corporation would be obligated to pay only an amount equal to the un-depreciated capital that FAES has not yet recovered over the Initial Term. Upon such termination, the energy system would remain the property of FAES.

If the Service Agreement was terminated due to a default by FAES, the Strata Corporation would not be obligated to make any payment to FAES. Upon such termination the energy system would remain the property of FAES.

Below are estimated termination payments in respect of a default of contract due to the Strata Corporation. Actual values will be dependent upon total Rate Base value at that point in time.

	Year		
	10	15	20
Net Book Value ($000)	116	154	198
Pre-tax annual rate return	8.30%	8.30%	8.30%
Foregone Earnings ($000)	133	75	-
Termination Payment ($000)	**248**	**229**	**198**

5. What Happens if FAES Becomes Insolvent?

The Service Agreement does not provide the Strata Corporation with the right to purchase the energy system in the event the contract is terminated or if FAES becomes insolvent. In the event that FAES becomes insolvent, any person (such as a receiver) who seizes the energy system would be subject to the Commission's jurisdiction.

6. Dispute Resolution

Disputes related to the provision of service are addressed under Article 12 (Disputes) and Article 19 (BCUC Review) of the Thermal Energy System Service Agreement Part II – Terms and Conditions, which states:

> *"Subject to section 19, where any dispute arises out of or in connection with this Service Agreement, including failure of the Customer and the Utility to reach agreement hereunder, either party may request the other party to appoint senior representatives to meet and attempt to resolve the dispute either by direct negotiations or mediation. Unresolved disputes may be submitted for final resolution by arbitration administered by the British Columbia International Commercial Arbitration Centre under its "Shorter Rules for Domestic 13 Commercial Arbitration" in Vancouver, British Columbia, Canada…."*

Also, in the event of any disputes between the customer and FAES that are within the jurisdiction of the BCUC, a customer such as the Strata Corporation has recourse to the Commission through the provisions of the *Utilities Commission Act*.

7. Contact Information

FAES contact information:
Manager of Operations
FortisBC Alternative Energy Services Inc.
Phone: (250)-380-5738
Cell: (250) 889-5782

Rate Calculations

The thermal energy rate for the Artemisia Development of $0.095/kWh in the first year of service is based on the following financial parameters:

- Capital Cost of the energy system or "Rate Base": $ 86thousand.
- Debt cost based on financing 57.5% of the capital cost: 4.94%
- Return on equity based on an equity structure of approximately 42.5%: 9.50%
- Depreciation: depending on the asset class this rate is approximately 3.2%.
- Sustaining capital: $9 thousand per year commencing in the 6th year of the initial 20-year contract term.
- Operating costs and general administrative costs: $14 thousand per annum

The above financial parameters may change resulting from market influences over the service term.

Sample Energy Bills

A sample energy bill is shown in the following table and is representative of the last month of the annual billing cycle for the strata corporation.

For illustrative purposes, the sample bill assumes that the total annual consumption is 410 MWh. In this example, since the total annual consumption of 410 MWh exceeds 328 MWh, which is 80 per cent of the Annual Demand (410 MWh * 0.80 = 328 MWh), no bill adjustment for the subsequent period is required.

SAMPLE - RESIDENTIAL INVOICE (DECEMBER)			
FAES TES MONTHLY BILL			
Boffo Artemisia		**Cumulative Reading**	**Minimum Annual**
(Strata Corporation No. xxx)	**Current Reading**	**Year to Date**	**Consumption Limit**
	(MWh)	(MWh)	(MWh)
Total Thermal Energy Delivered	34	410	328
Rate (2014): $/kWh	$ 0.095		Annual consumption
			exceeds 80% of Annual Demand.
Amount Payable (excld. Taxes)	$ 3,254		No year-end adjustment
(plus applicable taxes)			required

In the event the "Cumulative Reading – Year to Date" for the last month of the year was less than 80 per cent of the Annual Demand (in MWh) set out in Part I of the Service Agreement, the difference would be multiplied by the Rate and added to the next bill.

➢ Services Covered by FortisBC Alternative Energy Services Inc. (FAES)

FAES will provide the thermal energy for heating and cooling required by the building hydronic loop. FAES will own the centralized thermal energy equipment. The customer will own the distributed heat pumps and the electric domestic hot water (DHW) boilers in each strata lot.

All energy inputs and other operating costs required for the FAES heating and cooling service above are the responsibility of FAES and these costs are included within the Rate. FAES provides 24-hour service 7 days a week and will be responsible for the operation and maintenance for all FAES heating and cooling equipment.

The customer will be responsible for the operating costs, operation and maintenance of the distributed heat pumps and DHW boilers.

Appendix E

DRAFT ORDER

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

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

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

DRAFT ORDER

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

and

An Application by FortisBC Alternative Energy Services Inc. (FAES)
for a Certificate of Public Convenience and Necessity and Rate Approvals
Established in Agreements for Thermal Energy Services for the Artemisia Development

BEFORE:

(Date)

WHEREAS:

A. On August 28, 2013, the British Columbia Utilities Commission (Commission) issued Order G-132-13 establishing a proceeding to review a Commission staff proposal for a streamlined regulatory framework and guide for Thermal Energy Systems (TES Regulatory Framework);

B. On January 6, 2014, the Commission issued Order G-231-13A and Reasons for Decision related to the TES Regulatory Framework, in which it found that exemptions from certain provisions of the *Utilities Commission Act* (Act) properly conserve the public interest. The Commission is now seeking approval for such exemptions from the Lieutenant Governor in Council (LGIC) pursuant to section 88(3) of the Act;

C. On June 24, 2014, in the absence of an approved TES Regulatory Framework at that time, FortisBC Alternative Energy Services Inc. (FAES) applied to the Commission for approval, pursuant to sections 45-46 of the Act, of a Certificate of Public Convenience and Necessity (CPCN) to purchase, own and operate the thermal energy system of the Artemisia Development (Development), and pursuant to sections 59-61 of the Act, of the rates established under the Thermal Energy System Service Agreement with Boffo Developments Ltd. (Application);

D. FAES also seeks approval from the Commission to be exempted from long-term planning requirements under section 44.1 of the Act and to be subject to ongoing regulatory oversight on a complaint basis, in a manner consistent with what the Commission approved for FAES' SOLO in Directive 1 of Order G-54-14, dated April 15, 2014.

E. FAES submits that the information provided in the draft Registration Form for Stream A projects is sufficient to grant the approvals sought in this Application, given the relatively small size of the Development and in light of the Commission's determinations in FAES' SOLO Development proceeding (Order C-3-14 and Order G-54-14); and

F. FAES also submits that using this proposed streamlined approach reflects the developments and regulatory approach found in Commission Order G-231-13A and the subsequent Report on the Proposed Micro Thermal Energy System Exemption Limit and Stream B Exemption Test issues on March 6, 2014.

NOW THEREFORE, pursuant to sections 44.1, 45-46 and 59-61 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to FAES to purchase, own and operate the thermal energy system component of the Artemisia Development as described in the Application.

2. The Artemisia Thermal Energy System will be exempted from long-term planning requirements.

3. The rates, rate design and fuel deferral account established by the Thermal Energy System Service Agreement filed with the Application are approved.

4. Ongoing regulatory oversight will be on a complaint basis.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2014.

BY ORDER

FORTIS BC™
Alternative Energy Services

3700 2nd Avenue
Burnaby, BC V5C 6S4

August 11, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Alternative Energy Services Inc. (FAES)

Application for a Certificate of Public Convenience and Necessity (CPCN) and Rate Approvals Established in Agreements for Thermal Energy Services (TES) for the Artemisia Development (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On June 24, 2014, FAES filed the Application as referenced above. In accordance with Commission Order G-95-14 setting out the Regulatory Timetable for the review of the Application, FAES respectfully submits the attached response to BCUC IR No. 1.

If you require further information or have any questions regarding this submission, please contact Grant Bierlmeier at (250) 896-3098.

Sincerely,

FORTISBC ALTERNATIVE ENERGY SERVICES INC.

Original signed:

Grant Bierlmeier

Attachments

cc (email only): Registered Parties

THERMAL ENERGY SYSTEM — CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN)

1.0 Reference: Thermal Energy System (TES)

Exhibit B-1, Appendix A, pp. 5, 6

Heating

FortisBC Alternative Energy Services Inc. (FAES) indicates that: "There are no back up heating sources provided for the distributed heat pumps."

FAES also indicates that there is no thermal energy alternative available to customers.

1.1 In the event of a Thermal Energy System outage or more serious failure, please explain how FAES envisage continuing to provide service in a long term and short term scenario?

Response:

To clarify, the term "source" in the preamble is in relation to fuel inputs. The energy sources that supply the Thermal Energy System in this Development are natural gas and electricity. As a result, where there is an outage of gas or electricity upstream of the system, end users in the development must wait until electricity and gas service are restored. If the outage is due to equipment failure, the equipment is repaired by FAES.

The FAES thermal energy service for Artemisia includes heating redundancy in the form of a boiler for the distributed heat pumps. In the event of geoexchange loop field failure, the boiler will provide necessary heat to the distributed heat pumps. However, there is no backup or redundancy for cooling.

In summary, Thermal Energy System outage could occur in the event of loss of natural gas or electricity service to the building or in the event of equipment failure, however, built in backup and equipment redundancy as described above should mitigate thermal service interruption as a result of equipment failure.

2.0 Reference: Thermal Energy System

Exhibit B-1, Appendix A, p. 5, para. 7

Selection of Energy System

2.1 Please state what alternative Thermal Energy Systems were considered during selection.

Response:

As described on pg. 2 of the Application and pg. 5 of Appendix B, the Developer selected the energy system to meet its goals with respect to reduction of greenhouse gas emissions and to enhance the marketability of the development. FAES was not part of the alternative analysis. Prior to FAES' involvement in the Project, the Developer established the Strata Budget with respect to thermal energy and distributed that information to all the unit owners. Therefore, to meet the Strata Budget requirement, the Developer and FAES have negotiated a purchase price for the energy system on the basis of what FAES would be prepared to invest in order to provide this service at the rates established by the Developer. On this basis, FAES will purchase the system from the Developer for an amount that is less than the actual capital costs that the developer expects to incur for the construction and commissioning of the system.

2.1.1 Please detail how cost reasonableness for the construction of the facility was assured?

Response:

As further described in the response to BCUC IR 1.2.1, the design and construction of the Project was managed by the Developer with the total costs estimated to be $587,500. FAES and the Developer negotiated a thermal energy rate that would yield competitive and marketable strata fees for the unit owner and would maintain the estimated Strata Budget, as disclosed in the Original Disclosure Statement and as requested by the Developer. Based on this negotiated rate structure, financial parameters and expected thermal loads, the maximum purchase price FAES is able to invest in the energy system is $100,000. As buyers in the area have other options, the parties had every incentive to ensure cost reasonableness. The ultimate validation of cost reasonableness for the construction of the facility will come from the sale of units.

3.0 Reference: Thermal Energy System

Exhibit B-1, Appendix A, p. 6

Obligation to Taking Service

On page 6 FAES states that the: "minimum annual amount of energy determined to be 80 percent of the expected annual demand."

3.1 Please explain in detail how the expected annual demand is determined.

Response:

The expected annual demand is determined by performing a standard building computer simulation based on the following assumptions:

- Climate (Vancouver BC)
- Building orientation
- Building configuration
- Glass to wall ratio
- Type of glazing
- Type of building materials and construction
- Internal and external shading
- Internal lighting types
- Heating and cooling loads
- Zone temperature set point
- Dry bulb temperature
- Wet bulb temperature
- Dew point temperature
- Wind speed and direction
- Solar radiation (direct and diffuses ones)
- Cloud cover

The actual energy demand may differ from the expected annual demand calculations due to a number of variables. These variables may include, but are not limited to, variations in occupancy, building operations schedules, weather, energy requirement for equipment not included in the simulations or not covered by the applicable energy code, changes in energy costs from the design of the building to occupancy, and the precision of the simulation and calculation tools/methods used.

The results of the simulation are also compared with typical load intensities (kWh/m2) for other projects to confirm the reasonableness of results.

3.2 Please explain why 80 percent is used to determine the minimum amount.

Response:

As further described in the FAES response to BCUC Panel IR 1.5.3 in the Kelowna DES Proceeding, the minimum consumption limit for this Project was set at 80 percent of the thermal energy requirement of each customer to ensure that customers use the system for their thermal energy needs. Given that the demand for thermal energy is fundamentally inelastic, the minimum consumption limits should have no effect on customers that are using the system to supply their thermal energy demand. However, if a customer switches fuels they will utilize less of the system which may have impacts on other customers and FAES. Therefore, the minimum consumption limit helps prevent fuel switching by ensuring that thermal demands are supplied by the system.

FAES has evaluated the climate patterns to establish an appropriate lower limit on consumption for customers that are supplying their thermal energy demands with the system. FAES uses the climate data because the correlation between weather and thermal energy demand is very high. Typically, one standard deviation of annual heating degree days in a BC community is approximately 6 percent.[1] Therefore, three standard deviations below normal, which would be an extreme case, equals 82 percent of normal consumption. Based on this, FAES believes that a minimum consumption limit of 80 percent is a level that customers using the system for their heating needs will not reach even in extreme weather conditions and is an appropriate minimum consumption limit to prevent fuel switching.

[1] The standard deviation in annual HDD for Vancouver International Airport is 5.4% for the period from 1992 through 2012.

ARTEMISIA THERMAL ENERGY SYSTEM — RATES REVIEW

4.0 Reference: Exhibit B-1, Part II - Terms and Conditions

TES Service Agreement

4.1 Please confirm that Part II — Terms and Conditions are identical to those that were amended and subsequently approved in the SOLO application.

Response:

Confirmed, except for the Appendix A to Part II, which is specific to this Application.

4.1.1 If there are any differences in wording to any section(s), please provide a side-by-side review for each section(s).

Response:

There is no difference in wording to any section.

5.0 Reference: Exhibit B-1, p. 2 and Appendix B

Purchase Price and Ratebase

Page 8 of Appendix B indicates that the: "total capitalized amount that is reflected in the rate is $105 thousand, which is comprised of the purchase cost of $100,000 plus capitalized development costs incurred by FAES of $5,000."

5.1 Please confirm that FAES will be recognizing $105 thousand in its gross ratebase (as opposed to including the capital cost of $587,500 then treating the difference as a Contribution in Aid of Construction.)

Response:

The rate base includes a net initial investment of $100 thousand. The $105 thousand was incorrectly stated in the Application and the following clarification on page 8 of Appendix B is required:

"total capitalized amount that is reflected in the rate is $100 thousand, which is comprised of the estimated cost of the system totaling at $593 thousand which includes the project development costs forecasted to be $5 thousand, and will be offset by a Contribution in Aid of Construction (CIAC) of $493 thousand. This will result in Net Plant in Service of $100 thousand in total. The Rate Base includes this Net Plant in Service amount of $100 thousand for recovery from customers in rates."

Please note that the presentation that shows the gross plant amount offset by the contribution in aid of construction provides additional information but does not affect the rate, which is calculated based on the rate base amount.

FAES would like to clarify the term "gross rate base" used in the question preamble. There is no such term as gross rate base; relevant terms are "Gross Plant in Service" and "Rate Base". Rate base includes Gross Plant in Service, less Accumulated Depreciation and CIAC as well as its amortization (all of which combined are referred to as Net Plant in Service). The Rate Base reflects the summation of the mid-year balance of net plant in service, the mid-year balance of deferred charges and an allowance for working capital. As such, the forecast Rate Base for 2014 reflects an amount of $86 thousand. Please also refer to the fully functional spreadsheet filed in Confidential Attachment 5.2, provided in the response to BCUC IR 1.5.2.

It is also important to note that FAES' purchase price of the system is contractually set at $100 thousand. The data inputs in the current financial model are based on best estimates. FAES will receive the actual cost of the system with invoices from the Developer upon successful commissioning and prior to completing the purchase.

Further, one additional correction is required to Appendix B page 6, where the CIAC was incorrectly stated at $487,500 when it should have been $493,000.

5.2 Please confirm that the rates developed the customer are designed to recover the $105 thousand investment. Please show and provide the rate design calculation or the NPV levelized rate calculation in a fully functioning excel spreadsheet.

Response:

The cost of service is based on the recovery of the net investment of $100 thousand as described in the response to BCUC IR 1.5.1. The investment will not be fully recovered in the 20 year analysis as each asset will be depreciated according to its asset life. FAES' intent is to provide thermal energy service to customers in perpetuity according to the *Utilities Commission Act* (UCA). FAES has included a confidential fully functional model for reference as Confidential Attachment 5.2. Please refer to Schedule 12 Rate Design for the NPV levelized rate calculation.

1

Boffo Artemisia: Rate Design

($000's), unless otherwise stated

Schedule 12

Line	Particulars	Reference	PV	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
1	Annual Volume for Billing (MWh)			410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410	410
2	Present Value		4,382	383	359	336	314	294	275	257	241	225	211	197	184	173	161	151	141	132	124	116	108
3												20-Year Levelization Period											
4	Cost of Service	Table on page 8 of Application		45	37	37	38	38	40	41	43	44	46	48	49	51	53	55	54	56	58	60	62
5	*Present Value*		*482*	*42*	*32*	*31*	*29*	*28*	*27*	*26*	*25*	*24*	*24*	*23*	*22*	*22*	*21*	*20*	*19*	*18*	*18*	*17*	*16*
6	Cost of Service Rate $/kWh	Line 4 / Line 1	$ 0.110	0.109	0.090	0.091	0.093	0.094	0.097	0.101	0.105	0.109	0.113	0.117	0.121	0.125	0.129	0.133	0.132	0.137	0.141	0.146	0.151
7																							
8				Initial Rate																			
9	Nominal Levelized Rates		0.110	**0.095**	0.096	0.098	0.100	0.102	0.104	0.106	0.109	0.111	0.113	0.115	0.118	0.120	0.122	0.125	0.127	0.130	0.132	0.135	0.138
10	Annual Revenue	Line 9 x Line 1		39	40	40	41	42	43	44	44	45	46	47	48	49	50	51	52	53	54	55	56
11	*Present Value*		*482*	*36.23*	*35*	*33*	*31*	*30*	*29*	*27*	*26*	*25*	*24*	*23*	*22*	*21*	*20*	*19*	*18*	*17*	*16*	*16*	*15*
		Line 11/Line 2	*$ 0.110*	0.095	0.096	0.098	0.100	0.102	0.104	0.106	0.109	0.111	0.113	0.115	0.118	0.120	0.122	0.125	0.127	0.130	0.132	0.135	0.138

2

6.0 Reference: Exhibit B-1, Appendix B, p. 8

Project Development Cost

FAES estimates project development costs totaling $5 thousand will be capitalized.

6.1 If the actual development costs are lower than the forecast $5 thousand, please explain whether rates will be adjusted downwards to reflect this lower capitalized cost?

Response:

Yes rates will be adjusted downwards, but this will not occur until after the 1st Performance Term. Actual costs that vary from forecast will affect the performance ratios in the future. In this example, the effect would be to reduce the total capital of the project, thereby reducing depreciation and financing costs relative to the forecast.

6.2 In this scenario, please discuss how this will impact the proposed Performance Ratio.

Response:

Please refer to the response to BCUC IR 1.6.1.

6.3 Please explain whether any component of the project development costs are related to transfers from the TES Deferral Account (TESDA).

Response:

All project development costs flow through the TESDA and as such, the actual development costs will be removed from the TESDA and charged to the Project.

7.0 Reference: Exhibit B-1, Appendix B, p. 8

Annual Revenue Requirement Table

On page 8 of Appendix B, FAES provides a table showing the annual revenue requirement for this project.

7.1 Please confirm that FAES' reference to "fuel costs" refer to the cost of natural gas and electricity only.

Response:

Confirmed.

On page 10 of Appendix B, FAES states that: "fuel costs… will be recovered from or refunded to customers annually through a rate rider."

7.2 Please confirm that recovery/refund of the annual fuel costs will be completed in each subsequent year (as opposed to the current year in which the costs incur).

Response:

Not confirmed. The annual forecast fuel costs will be collected in the current year (year 1) and the variance between forecast and actual will be recorded in the deferral account. Then in the subsequent year (year 2), the annual forecast fuel costs for year 2 will be collected along with a rider to recover the balance in the deferral account. As per the Service Agreement:

*"**Rate Rider:** An amount per kWh in Canadian dollars for the recovery or refund of the Fuel Deferral Account set each year on a prospective basis by the Utility to achieve a zero balance in the Fuel Deferral Account by the end of the following year.";*

where Fuel Deferral Account is defined as:

*"**Fuel Deferral Account:** A record of the difference between forecast costs and actual costs of natural gas and electricity plus the recoveries or refunds associated with the Rate Rider. The forecast costs of natural gas and electricity are calculated by multiplying the applicable natural gas rate or electricity rate by the forecast natural gas and electricity consumption respectively (Appendix A). The forecast natural gas and electricity consumption is estimated based on the combination of the amount of*

estimated thermal energy delivery and the thermal efficiency of the heating and cooling equipment used to provide this thermal energy to the building. The estimation is done by a professional engineer using a combination of energy simulation software and industry standards."

7.3 Please provide the 20-year levelized rate for this project, assuming the forecast revenue requirements according to the table provided.

Response:

The forecast 20-year levelized rate for this project is $0.110 per kWh. Please also refer to the response to BCUC IR 1.5.2.

For the annual revenue requirement table on page 9 of Appendix B, the last box titled "Forecast for Renewal Period 1 Performance Ratio" is shown for the years 2028–2032.

7.4 Please explain why the years 2028–2032 are not part of the 20-year initial term (which commenced at 2014).

Response:

Years 2028-2032 are part of the 20 year initial term as set out on Page 1 of Appendix A. The labeling for the five year period 2028-2032 on page 9 of Appendix B identifies that the contract will be expiring at the end of that five year term and thus the period 2028-2032 is the 5-year period on which the calculation of the Performance Ratio will be done to adjust rates for the first renewal period after the initial term.

8.0 Reference: Exhibit B-1, Appendix B, pp. 8, 9, 11, 14–16

Performance Ratio and Rate Design

On page 9 of Appendix B, FAES explains that: "The individual cost components included in the calculation of the Performance Ratio are: a) natural gas costs, b) electricity costs, c) operations and maintenance, d) depreciation and amortization, e) taxes (property and income), and f) capital carrying costs, including initial investment, and replacement capital."

8.1 Please explain why FAES refers to the terms "Performance Ratio" and "performance term". What performance guarantees or commitments is FAES obliged with according to the Service Agreement? Please make references to the Service Agreements where appropriate.

Response:

The reference to "Performance Ratio" and "performance term" immediately follows the revenue requirement table, which references the term "Performance Ratio". For clarity purposes, FAES had added the definition of the "Performance Ratio". As per the Service Agreement included in the Application, Performance Ratio is defined as:

> *"**Performance Ratio:** The ratio of actual costs of providing the Service relative to the forecast costs of providing the Service (set out at the initiation of Service), as reasonably determined by the Utility, calculated in the fourth year of each Performance Term for the previous five years (four years for the first Performance Term). The individual cost components included in the calculation of the Performance Ratio are: a) natural gas costs, b) electricity costs, c) operations and maintenance, d) depreciation and amortization, e) taxes (property and income), and f) capital carrying costs, including initial investment, and replacement capital."*

where Performance Term is defined as:

> *"**Performance Term:** A five year period occurring in the years 1-5, 6-10, 11-15 and 16-20 of the Initial Term and for each subsequent renewal term."*

Section 3c and Section 20 in the Service Agreement make reference to the above terms.

There are no performance guarantees or commitments in the Service Agreements. However, FAES and the customers are bound by the specific conditions in the terms and conditions of the agreements (Appendix A to the Application, Section B- Terms and Conditions).

8.2 [In reference to item a) and b) in the preamble] Given that the natural gas and electricity costs are captured in a deferral account subject to deferral account true-up, please confirm that FAES will not be faced with any forecast risk for these fuel costs.

Response:

Confirmed.

8.2.1 Please also confirm that these costs would not be flowed through the Performance Ratio adjustment.

Response:

The variance in fuel costs will not flow through the performance ratio because the variance in these costs is captured in the Fuel Deferral Account and recovered or refunded through the Rate Rider. However, the forecast fuel costs are included in the performance ratio to provide adequate weighting to other cost components (i.e. both the numerator and the denominator will have the same value for fuel costs in the performance ratio).

8.3 [In reference to item d) and f) in the preamble] Given that the purchase price of the system is contractually set at $100 thousand and will not change, please confirm that the carrying costs associated with this capital investment is also fixed and that FAES can forecast these costs with a great deal of accuracy year over year (assuming there is no change in the Commission allowed capital structure and cost of capital).

Response:

The carrying costs associated with the capital investment are not fixed. The project development costs allocated to capital may vary from the $5 thousand forecast, and the interest

rates, income tax rates, and capital structure/ROE will all likely vary over the 20 year period. These items can all cause a variance between forecast and actual costs.

8.4 [In reference to item e) in the preamble] Please confirm that FAES is able to forecast property taxes and income taxes with some degree of accuracy year over year.

Response:

FAES forecasts property taxes and income taxes based on the best available information and forecast property tax or enacted income tax rates. However, changes to property and income tax rates or policies may occur at any time and are driven by government policies over which FAES has no control.

8.5 Would it be reasonable to assume that the only three items that could impact the Performance Ratio are:

- Item c) in the preamble, operations and maintenance;
- Item d) and f) as it relates to actual sustainment capital; and
- Item f) Capital carrying costs, as it relates to any future Commission determinations on the allowed capital structure and cost of capital?

If not, please explain.

Response:

No, as discussed in the response to BCUC IR 1.8.2, 1.8.3 and 1.8.4, all of the cost components listed in items a) through e) are subject to fluctuation from forecast, with variances in the gas and electricity costs captured in a deferral account.

As discussed in the response to BCUC IR 1.8.2.1, the fuel cost variance will not affect the performance ratio calculation. Therefore, although forecast fuel costs are a component of the Performance Ratio to provide appropriate weighting to other cost items, variances in fuel costs do not impact the performance ratio.

In the Sovereign Development application, FAES proposed that the rate creates an incentive for FAES to find efficiencies in capital and operating costs including utilizing competitive markets for the supply of equipment and repair and maintenance services. FAES also indicates that it can benefit from competition amongst suppliers and maintenance contractors to minimize costs. (FAES Sovereign CPCN Application, Appendix B, p. 16)

8.6 This Application does not appear to discuss the incentives that FAES may find in reducing costs for customers. Do these incentives not apply for this development?

Response:

FAES uses the same Performance Ratio and Rate Design for both the Sovereign and Artemisia Developments. Therefore, the incentive for FAES to find efficiencies in capital and operating costs also applies to the Artemisia Project.

8.7 If so, why is there a need to employ the same rate design, utilizing the Performance Ratio and adjustments?

Response:

Please refer to the response to BCUC IR 1.8.6.

8.8 Please explain why the fixed rate design mechanism employed in the Tsawwassen Springs project, also a developer project purchased by FAES, would not be appropriate for this development?

Response:

There are two fundamental reasons why the rate design for Artemisia is different than the rate design used for Tsawwassen Springs.

First, in the Tsawwassen Springs project, FAES only owns the loopfield of the geo-exchange system and does not meter thermal energy. At Artemesia, FAES owns all of the mechanical equipment in addition to the geo-exchange system and is responsible for the fuel inputs and measurement of thermal energy deliveries. Consequently, the service is fundamentally different and a fixed rate design mechanism is not appropriate.

Second, the thermal energy business and regulatory environment in British Columbia has evolved significantly since the Tsawwassen Springs contracts were signed, as demonstrated by the AES Inquiry Report, the TES Regulatory Framework development, and applications by FAES for PCI Marine Gateway, TELUS Garden, SOLO Phase 1 Stratus, and the Kelowna District Energy System. Through this evolution, FAES has adapted the rates and contracts to reflect the directions and recommendations provided by the Commission as well as feedback from customers. Given the similarity between this service and the SOLO service, FAES is utilizing the identical rate design as the BCUC approved for SOLO in Order G-54-14.

8.9 Please discuss how the Commission can ensure that customer's rates, when adjusted by the proposed Performance Ration in subsequent periods, would still produce rates that are just and reasonable.

Response:

This rate design produces a levelized rate in real terms, over the entire initial term, set initially to be cost based (utilizing a 20-year forecast of costs) and then adjusted formulaically. This approach incents FAES to minimize short run costs, the benefit of which then gets passed on to the customers in the long run via the performance ratio, all else equal. Thus, adjustment of rates by the performance ratio brings the rates in line with the actual costs over time and in doing so, maintains rates that are just and reasonable.

The Artemesia rate design is the same rate design that the Commission has approved for the SOLO Application in Order G-54-14. Directive 1 of Order G-54-14 states that "The rates for thermal energy systems established in the two, 20-year term Amended Service Agreements including the Terms and Conditions for the SOLO Development are approved as just and reasonable and ongoing regulatory oversight will be on a complaint basis." FAES further confirms that the Terms and Conditions of the Artemesia Service Agreement are identical to the

Terms and Conditions for the SOLO Amended Service Agreement and both include the Performance Ratio mechanism.

Further, FAES notes that, in Order C-3-14, the Commission had stated under Directive 3: "The Panel finds that the rates would be just and reasonable if the amendments set out below and further described in the Reasons for Decision are made." FAES notes that the amendments that the Commission was seeking in relation to the "Performance Ratio" were to enhance the reporting to, disclosure to and avenues of communication with customers. Accordingly, FAES has made these amendments to the disclosure for this project as well.

9.0 Reference: Exhibit B-1, Appendix D, p. 1-2

Customer Communication

9.1 Please discuss the process by which FAES will communicate to customers regarding its performance, as it relates to forecast and actual expenses, and future rate adjustments.

Response:

FAES will make all rate schedules publically available and will post rates on its website.

Consistent with the SOLO TES approach and as directed in BCUC Order C-3-14, FAES will provide information in writing at least 6 months prior to implementing any change under the Performance Ratio. This process is further described in the Service Agreements included as Appendix A to the Application.

20. DISCLOSURE

The Utility will calculate the Performance Ratio in the fourth year of each Performance Term for the previous five years (four years for the first Performance Term). At least six months prior to implementing a rate change under the Performance Ratio, the Utility will send an information package to its Customers to explain the calculation of the Performance Ratio, including the details of the forecast and actual costs used in this calculation. The information package will also include the weather normalized forecast consumption and actual consumption of natural gas and electricity, as well as the total thermal energy delivered, for each of the previous five years (four years for the first Performance Term).

(b) Within four (4) weeks of sending the information package to its Customers, the Utility will give notice to its Customers and convene a meeting to allow its Customers to ask questions on the Performance Ratio calculation, and the rates established in the subsequent term.

9.2 If customers do not agree with such rate adjustment, please discuss what action FAES will take.

Response:

Customers can contact FAES using the contact information provided in Section 7 of the Service Agreement Summary attached as Appendix D of the Application. Should FAES fail to address the customers' concern adequately, this will then be subject to BCUC Review as per Section 19 of the Service Agreement:

> ***19. BCUC REVIEW***
>
> *The Customer acknowledges FAES is a public utility as defined in the UCA and this Agreement, any rates and other amounts payable by the Customer hereunder and the terms and conditions contained herein are subject to BCUC oversight, review and approval. Any disputes between the Customer and the Utility which are within the jurisdiction of the BCUC pursuant to the UCA, shall be referred to and determined by the BCUC and the provisions of section 12 shall not apply to such disputes.*

FAES will endeavor to provide fulsome details to customers to support the calculations of the performance ratio and the impact on rates, as per section 20 of the Service Agreement.

> ***20. DISCLOSURE***
>
> *(a) The Utility will calculate the Performance Ratio in the fourth year of each Performance Term for the previous five years (four years for the first Performance Term). At least six months prior to implementing a rate change under the Performance Ratio, the Utility will send an information package to its Customers to explain the calculation of the Performance Ratio, including the details of the forecast and actual costs used in this calculation. The information package will also include the weather normalized forecast consumption and actual consumption of natural gas and electricity, as well as the total thermal energy delivered, for each of the previous five years (four years for the first Performance Term).*
>
> *(b) Within four (4) weeks of sending the information package to its Customers, the Utility will give notice to its Customers and convene a meeting to allow its Customers to ask questions on the Performance Ratio calculation, and the rates established in the subsequent term.*

To the extent that FAES has complied with this requirement, there should not be any grounds for a complaint to the BCUC.

9.2.1 What recourse would customers have in this case?

Response:

Please refer to the response to BCUC IR 1.9.2.

In Appendix D, the service agreement summaries to the customers, FAES states: "The primary determinants that may result in rate changes are thermal energy consumption, operating and maintenance costs and debt costs." (p. 1)

9.3 Please explain whether the rate changes could result from future Commission determinations on cost of capital.

Response:

Yes; however, in the current Performance Term, there would be no changes to the rates. A change in the cost of capital would change the actual carrying cost of the debt and equity as compared to the forecast cost and will subsequently affect the performance ratio which will be applied to rates in the next Performance Term.

9.4 Please reconcile any differences between the statement provided in the above preamble with the statement in Appendix B that: "The individual cost components included in the calculation of the Performance Ratio are: a) natural gas costs, b) electricity costs, c) operations and maintenance, d) depreciation and amortization, e) taxes (property and income), and f) capital carrying costs, including initial investment, and replacement capital" (Appendix B, p. 9).

Response:

The two statements are consistent. The following items are all components of the calculation: a) natural gas costs, b) electricity costs, c) operations and maintenance, d) depreciation and amortization, e) taxes (property and income), and f) capital carrying costs, including initial investment, and replacement capital. However, the primary determinants or primary drivers of change that may result in rate changes are thermal energy consumption, operating and

maintenance costs and debt costs. As discussed in the response to BCUC IR 1.8.2.1, the forecast natural gas and electricity components are included to provide adequate weighting to the calculation since the rate which the Performance Ratio adjusts includes a forecast of fuel costs (natural gas and electricity).

9.4.1 Provide any corrections/revisions, if necessary.

Response:

No corrections are required. Please refer to the response to BCUC IR 1.9.4.

On page 2 of Appendix D, FAES explains to customers that they are: "obligated to pay FAES an amount equal to the un-depreciated capital (Rate Base value) remaining on its balance sheet at the point of termination plus any earnings forgone by FAES for the remainder of the Initial Term." [underline added]

Then, FAES provides a table showing the different payout costs at certain times during the initial term.

9.5 The first line of the table, reproduced below, identifies: "Net book value" while the statement above refers to "un-depreciated capital (Rate Base value)". Is there any difference in "un-depreciated capital (Rate Base value)" and "Net Book Value"?

Response:

FAES does not believe that a correction to Appendix D, page 2 is required as un-depreciated capital is clear and is synonymous with net book value. As a requirement under the TES Framework Regulatory Guidelines, Appendix D is a summary of the service agreements and is provided to end-users as a plain-language explanation of the elements within the service agreements. The service agreements themselves (Appendix A) contain the term Net Book Value, consistent with the table provided. FAES chose to use the term Net Book Value to provide clarity for customers because Rate Base is a term specific to regulated utilities and as such, is not as widely known. FAES notes that the end-users have received the Notice of Public

Hearing Process, which informs them that the FAES Application and supporting material, which includes the Service Agreements themselves, will be made available on the FortisBC website and on the Commission's website.

9.6 For clarity and consistency to customers, should consistent wording be used? Please explain why or why not?

	Year		
	10	15	20
Net Book Value ($000)	116	154	198
Pre-tax annual rate return	8.30%	8.30%	8.30%
Foregone Earnings ($000)	133	75	-
Termination Payment ($000)	**248**	**229**	**198**

Response:

Please refer to the response to BCUC IR 1.9.5.

9.7 According to the depreciation rate shown on page 3 of Appendix D, of 3.2 percent, the average service life of the assets is approximately 31 years. Please explain whether the assets in this development appear to be longer life assets than the Sovereign development.

Response:

Confirmed. The two developments use different thermal energy systems and as such, they will have different asset lives and different depreciation rates. Artemisia is a geo-exchange based thermal energy system whereas Sovereign is a water to water heat pump/water to air heat pump recovery system.

9.8 Please explain why after 20 years, the Net Book Value remaining is nearly double the initial capital investment of $105 thousand. Is this due to the continued sustainment capital that is being capitalized annually, commencing in the sixth year?

Response:

Correct. The forecast sustainment capital, that is being capitalized annually commencing in the sixth year, results in a net book value in year 20 that is greater than the initial capital investment.

10.0 Reference: Exhibit B-1, Appendix B, p. 9

Sustainment Capital

FAES estimates an annual amount for sustaining capital of $11 thousand commencing in the sixth year of operation.

10.1 Please provide a schedule showing the breakdown for this $11 thousand annual requirement for sustaining capital.

Response:

FAES' estimate of $11 thousand of annual sustaining capital (to replace equipment as necessary) was based on FAES' experience with systems it has, or is connected to, that are in operation currently and where appropriate, the manufacturer's equipment data. As such, a breakdown of the $11 thousand is not available.

10.1.1 Is this estimate based on forecast capital replacement? If so, is this replacement schedule according to manufacturer's estimates?

Response:

Please refer to the response to BCUC IR 1.10.1.

10.2 Please confirm that $11 thousand is added to this projects' ratebase each year and reflected in the annual revenue requirement table shown on page 8 of Appendix B.

Response:

Not confirmed. As specified on Page 9 of Appendix B, sustaining capital of $11 thousand per year commencing in the 6th year, and inflating at 2 percent per year, is embedded in the forecast revenue requirement.

10.3 Given that the recovery for sustaining capital is an annual fixed amount commencing in the sixth year, is FAES treating this collection as a type of capital reserve?

Response:

This response also addresses BCUC IR 1.10.5 and 1.10.8.

FAES is including a forecast of sustainment capital in the rates to ensure that they are adequate to cover the necessary capital replacements needed to maintain the assets and provide service to customers. On an individual project basis, to the extent that actual sustainment or replacement capital varies from forecast, this difference will affect the performance ratio. Thus, the sustainment capital forecast is not a capital reserve, rather it is a forecast cost by project where variances in actual cost will affect the rates for that project set in subsequent performance terms.

As explained in the Registration Form (Appendix B, Pages 12 and 13), FAES is employing a portfolio approach to the capital reserve requirement and includes replacement capital in the forecast cost of service for each TES Project. As such, and due to its access to resources, FAES does not have a dedicated capital reserve fund.

Page 12 of Appendix B: "FAES currently has a portfolio of TES Utility Projects and includes replacement capital in the forecast cost of service for each TES Project."

10.4 Is this statement referring to the "sustainment cost" item that is included in the revenue requirement?

Response:

Page 12 of Appendix B is in reference to the portfolio of FAES TES Utility Projects and not to this specific project. However, the statement on page 12 is consistent with the forecast of sustainment capital that is included in the Artemisia Project as identified on page 9 of Appendix B with sustaining capital of $11 thousand starting in Year 6th, escalated by 2% per year. Further the $9 thousand of sustaining capital stated in the Service Summary in Appendix D should be amended to $11 thousand.

10.5 Does this statement imply that there is a capital reserve held only for this project alone or as a portfolio within FAES together with its other TES projects?

Response:

Please refer to the response to BCUC IR 1.10.3.

10.6 At the end of each 4-5 year Performance Ratio term and in the event that actual sustaining capital spending is lower than forecast, please confirm that FAES will be adjusting this difference in the Performance Ratio mechanism. In other words, customer rates would be adjusted downwards in the following term if actual sustaining capital spending is less than the forecast all else being equal.

Response:

Confirmed. Please also refer to the response to BCUC IR 1.10.3.

10.7 In order to track such efficiencies, how does FAES plan to report these forecast and actual results to its customers, prior to the adjustment of their rates in subsequent terms?

Response:

Please refer to the response to BCUC IR 1.9.1.

10.8 If this sustainment cost is tracked cumulatively in FAES as a portfolio (not by project), how does FAES plan to treat any differences between forecast and actual sustaining capital requirements?

Response:

Please refer to the response to BCUC IR 1.10.3.

11.0 Reference: Exhibit B-1, Appendix B, p. 9

Operation and Maintenance (O&M) and Overhead

11.1 Please confirm that overhead is included in the O&M costs in Line 4 of the revenue requirement table shown on page 8 of Appendix B.

Response:

Confirmed. The O&M cost included in the table on page 8 of Appendix B (Line 4) includes forecast overhead of $3,627 as outlined in the table on page 9 of Appendix B.

11.2 Please confirm if overhead costs for the TES program (ie AES Inquiry costs, business development, etc.) are being recovered through rates and applied to the TESDA.

Response:

Confirmed. Please refer to the table on page 9 of Appendix B which shows the amount being recovered from the TESDA.

11.3 In the event that the Commission may make future determinations on the TESDA allocation from FortisBC Inc., how will this impact the TESDA forecast of $1 thousand that is included in the forecast annual overhead cost?

Response:

Note that the allocation is from FortisBC Energy Inc., not FortisBC Inc.

A change in the allocation of the TESDA from FortisBC Energy Inc. may affect the actual overhead cost but will not change the forecast overhead cost. To the extent that the actual cost changes, the performance ratio will be affected.

11.3.1 Will this flow through in the Performance Ratio calculation and get adjusted through rates in the subsequent Performance Ratio term?

Response:

FAES will be at risk for variances in each Performance Term, but to the extent that actuals differ from forecast they will affect the performance ratio and future rates.

12.0 Reference: Exhibit B-1, Appendix B, p. 13

Cost of Debt

Orders G-71-12 and G-88-12 for the Delta School District required FAES to use BBB-rated "distribution utilities" as a proxy debt rate for the TES class of service.

12.1 Please provide the source of this project's debt rate at 4.94 percent.

Response:

In order to establish this rate, FAES obtained BBB debt rate quotes from two Canadian Chartered banks, CIBC World Markets and RBC Capital Markets as of March 27, 2014.

Credit Spread	CIBC Interpolated BBB 20-year rate		1.91%
	RBC Interpolated BBB 20-year rate[1]		1.61%
	Average Rate		1.76%
GOC	CIBC Interpolated GOC Benchmark 20 - year		2.78%
	RBC Interpolated GOC Benchmark - 20 year[1]		2.87%
	Average Rate		2.83%
Issuance Fee Annualized			0.35%
Total Interest Rate			4.94%

Note:

[1] *Linear Interpolation*

The latest Delta School District debt rate has been re-calculated as 4.79% using "distribution utilities" rather than BBB rated entities, as per Order G-100-14. However, FAES notes that the Delta School District rate is a cost of service rate structure, with a rate change mechanism that is different than what is proposed for this Project. In addition, FAES has negotiated this rate for the Artemisia Development using the 4.94% rate for BBB-rated entities.

12.2 Please explain whether this forecast debt rate is subject to change during the initial term of 20 years. Otherwise, is this debt rate fixed for the term?

Response:

The forecast debt rate is fixed for the term. Actual debt costs will be calculated for each year as part of the Performance Ratio measurement which will compare the actual debt cost to this forecast.

Attachment 5.2

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

FILED CONFIDENTIALLY

(accessible by opening the Attachments Tab in Adobe)

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-9-14

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BC TOLL FREE: 1-800-663-1385
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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Alternative Energy Services Inc.
for a Certificate of Public Convenience and Necessity and Rate Approvals
Established in Agreements for Thermal Energy Services for the Artemisia Development

BEFORE: D.M. Morton, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
H. Harowitz, Commissioner

August 26, 2014

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On June 24, 2014, FortisBC Alternative Energy Services Inc. (FAES) applied to the Commission for approval, pursuant to sections 45-46 of the *Utilities Commission Act* (Act), of a Certificate of Public Convenience and Necessity (CPCN) to purchase, own and operate the thermal energy system of the Artemisia Development (Development), and pursuant to sections 59-61 of the Act, of the rates established under the Thermal Energy System Service Agreement with Boffo Developments Ltd. (Application);

B. FAES also seeks approval from the Commission to be exempted from long-term planning requirements under section 44.1 of the Act and to be subject to ongoing regulatory oversight on a complaint basis, in a manner consistent with what the Commission approved for FAES' SOLO in Directive 1 of Order G-54-14, dated April 15, 2014.

C. FAES requested that the Commission follow the SOLO approach for the Artemisia project, where the Commission approved the rates established in service agreements for that project by Order G-54-14. FAES believe this approach would be appropriate because the rate design and service agreement for the Artemisia project are identical to the ones employed for the SOLO project;

D. On July 15, 2014, by Order G-95-15, the Commission established a Regulatory Timetable to review the Application.

E. There were no registered Interveners. Ameresco Canada Inc. registered as an Interested Party, but provided no submissions related to the approvals requested.

F. A Streamlined Review Process was held in Vancouver on August 20, 2014.

G. The Commission has considered the Application and submissions in the proceeding and finds that FAES's requests are warranted and in the public interest.

NOW THEREFORE pursuant to sections 44.1, 45-46 and 59-61 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to FAES to purchase, own and operate the thermal energy system component of the Artemisia Development as described in the Application.

2. The Artemisia Thermal Energy System is exempt from long-term planning requirements.

3. The rates, rate design and fuel deferral account established by the Thermal Energy System Service Agreement filed with the Application are approved.

4. Ongoing regulatory oversight will be on a complaint basis.

DATED at the City of Vancouver, In the Province of British Columbia, this 26th day of August 2014.

BY ORDER

Original signed by:

D.M. Morton
Commissioner

CITY OF VANCOUVER

ADMINISTRATIVE REPORT

Report Date:	June 26, 2015
Contact:	Patrice Impey Brian Crowe
Contact No.:	604.873.7610 604.873.7313
RTS No.:	10804
VanRIMS No.:	08-2000-20
Meeting Date:	July 7, 2015

TO: Vancouver City Council

FROM: Director of Finance and General Manager of Engineering Services

SUBJECT: Southeast False Creek Neighbourhood Energy Utility ("SEFC NEU") – Five-Year Review

RECOMMENDATION

A. THAT Council adopt the key performance indicators ("KPIs") and targets as set out in this report to guide future rate setting for the SEFC NEU under the commercial utility rate model.

B. THAT Council authorize an increase to the previously approved internal financing from $8 million to $15 million to finance the accelerated loan amortization, to be repaid from future SEFC NEU revenues; source of funding to be the Capital Financing Fund.

REPORT SUMMARY

The purpose of this report is to present to Council the result of the comprehensive review of the SEFC NEU under the commercial utility rate model after five years of operation. The focus of the review was to determine i) the long-term financial viability of the NEU; ii) rate stability and competitiveness; iii) potential future expansion of sewage heat recovery capacity to optimize environmental and economic performance; and iv) City internal financing structure.

Based on the review, staff and the Neighbourhood Energy Expert Panel ("Expert Panel") have concluded that the SEFC NEU is financially viable, and the forecast rates are stable and competitive within the Council-approved rate setting framework. To provide greater clarity for future rate setting, staff recommend that a set of KPIs and targets be adopted as outlined in the report.

The review has also confirmed that the sewage heat recovery expansion is economically viable. Sewage heat recovery expansion will continue to be considered along with other potential low carbon energy sources to optimize the environmental and economic performance of the SEFC NEU as part of the City's overall Neighbourhood Energy Strategy.

When the SEFC NEU became operational, the financial model reflected financing of capital infrastructure costs through longer-term debt to match the useful life of assets (25-40 years). However, as longer-term debt is not always available for municipal debt issuers, the City issues primarily 10-year debt, and includes the SEFC NEU as part of the annual capital borrowing program. Shorter-term debt will result in significantly lower overall interest costs for the City (approximately $26 million) over the life of this project. As shorter-term debt requires higher principal payments upfront, staff recommend that Council authorize an increase to the previously approved internal financing from $8 million to $15 million to finance this accelerated loan amortization, to be repaid from future SEFC NEU revenues.

COUNCIL AUTHORITY/PREVIOUS DECISIONS

In December 2006, Council approved a set of governance and rate-setting principles for the SEFC NEU, including direction that the merits of continued ownership be reviewed before any significant expansion of the NEU, and, in any event, within three years of the commencement of commercial operations (Appendix B).

In March 2009, Council instructed staff to report back to Council annually on adjustments to the SEFC NEU rates, and to bring a comprehensive rate review to Council every five years.

In July 2010, Council approved the establishment of a third-party Expert Panel (referred to as the "Expert Panel" in this report) to advise staff and Council on future SEFC NEU rate adjustments. At this time, Council also approved the establishment of separate customer rate classes and rate formulas for residential and mixed-use residential buildings located outside SEFC, and for non-residential buildings both within and outside SEFC.

In July 2011, Council adopted the Greenest City Action Plan, which targets a 33% (1.1 million tonnes per year) City-wide reduction in carbon pollution by 2020 from 2007 levels. Low carbon neighbourhood energy systems represent 11%, or 120,000 tonnes per year, of this target.

In June 2012, Council approved the amendment of the Energy Utility System By-law to expand the SEFC NEU service area to include the Great Northern Way Campus Lands and adjacent lands in the False Creek Flats South Area.

In October 2012, Council approved the Vancouver Neighbourhood Energy Strategy and Energy Centre Guidelines, to address the Greenest City 2020 Action Plan objective of reducing 120,000 tonnes carbon dioxide per year through the conversion of existing steam heat systems to low carbon energy sources and the deployment of sustainable energy systems for high-density neighbourhoods.

In April 2014, Council approved a transition strategy to adjust the SEFC NEU rate structure to strengthen the energy conservation price signal while maintaining energy rates at the same level as projected under the commercial utility rate model.

CITY MANAGER'S/GENERAL MANAGER'S COMMENTS

The City Manager recommends approval of foregoing.

REPORT

Background/Context

The fundamental goal of the SEFC NEU is to reduce greenhouse gas ("GHG") emissions via a financially self-sustaining, commercially operated utility that delivers competitively priced low-carbon energy services. Through system efficiencies and the use of sewage heat recovery as its primary low carbon energy source, the NEU achieves substantial GHG reductions relative to traditional methods of providing heat and hot water. Upon system build-out, the NEU is expected to achieve a 60% GHG reduction, or 10,400 tonnes CO_2 per year, over a 25 year period.

Appendices A and B provide additional details on the SEFC NEU's services, technology, and its ownership, operating and governance model.

Strategic Analysis

Levelized Rate Structure

SEFC NEU rates are comprised of two components: a fixed Capacity Levy (related to the fixed capital and operating costs associated with the NEU) and a variable Energy Use Charge (related to customers' actual energy consumption).

To provide competitive and stable rates for the SEFC NEU customers, rates are established based on a levelized rate approach. As illustrated in Figure 1 below, rates are set to *under-recover* annual costs in the early years of the NEU's operation when the customer base is small, and to gradually recover past costs and a modest return on investment when the customer base is fully established. This approach ensures that infrastructure costs are more equitably distributed between the initial customers and those who connect in later years. If the levelized rate approach were not taken, customer rates would have to be set much higher in the early years of operation.

The levelized rate approach is commonly used by privately owned utilities regulated by the BC Utilities Commission ("BCUC"), including the SFU's UniverCity Energy system, the River District Energy system and the new UBC neighbourhood system.

Figure 1: Levelized Rate Approach

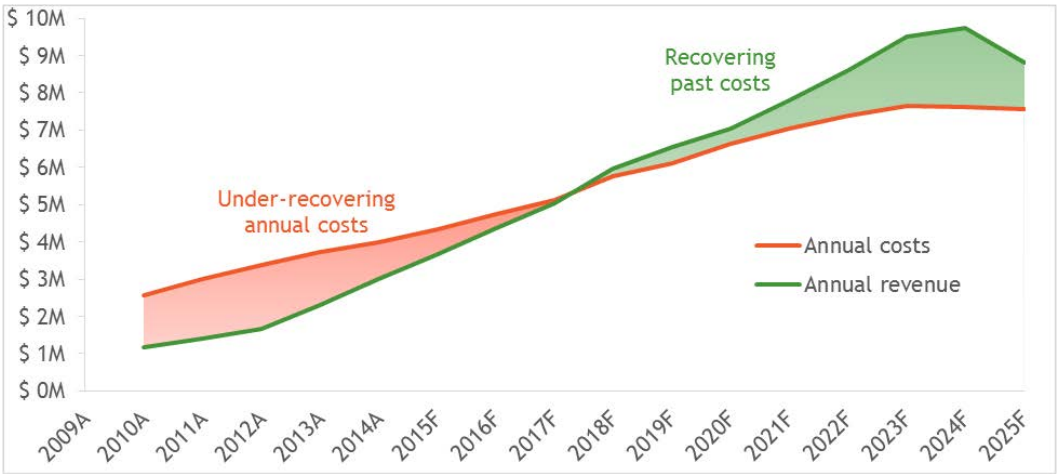
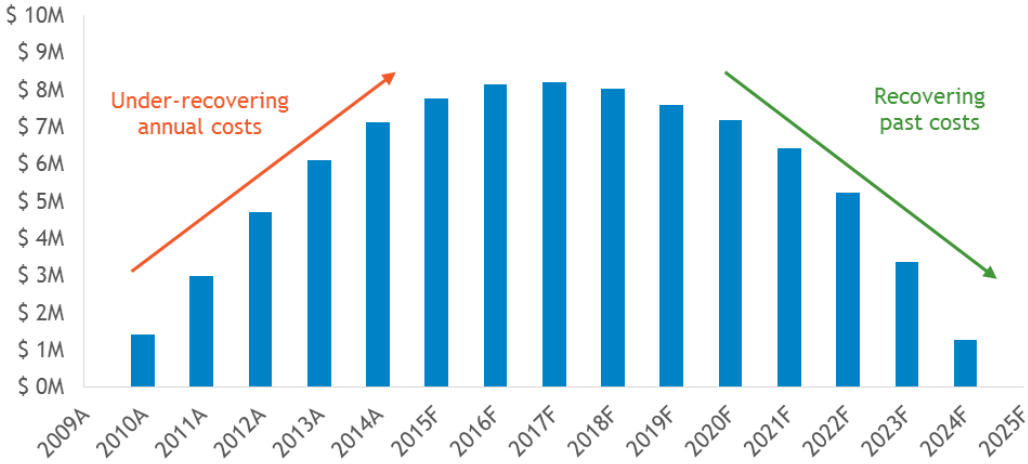


Figure 2: Cumulative Balance of Under-recovered Costs Under Levelized Rate Approach



To ensure that the cumulative balance of under-recovered costs (Figure 2) can be recovered within a reasonable timeframe without impacting the stability and competitiveness of the customer rates, the levelized rate approach contemplates annual rate increases that include two components: an inflationary increase and a Rate Escalation Factor.

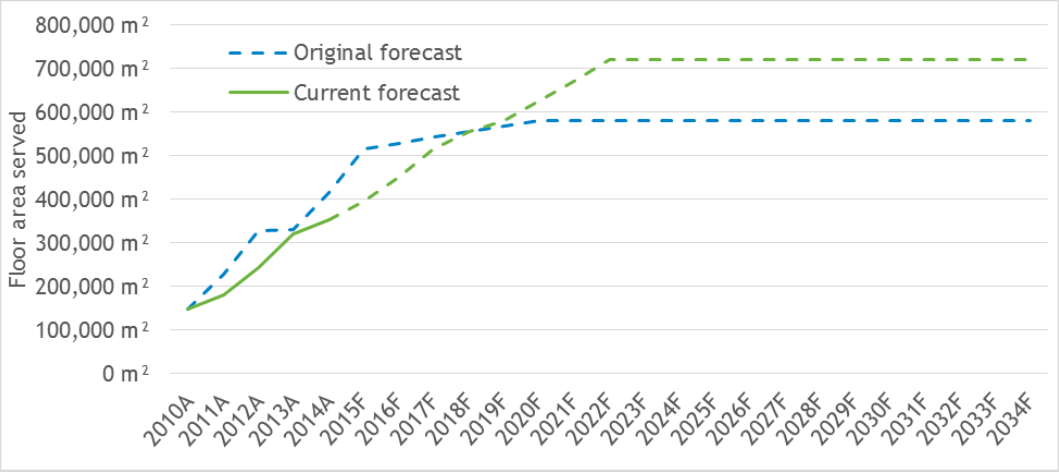
The Rate Escalation Factor is applied to customer rates above annual inflation to gradually increase rates over time to ensure all of the NEU's revenue requirements are met over the long-term. Using this approach enables the NEU to maintain rates that are stable, affordable and appropriate for new utilities with large upfront capital investments.

Long-term Financial Performance of SEFC NEU

Since beginning operation in 2010, the SEFC NEU has expanded to serve 358,000 square meters (3,850,000 square feet) of residential, commercial and institutional floor area as at the end of 2014. This is roughly 15% below the original business case projection, and is primarily due to the slow-down in the real estate market resulting from the 2008 economic downturn, which delayed private land developments in the SEFC service area.

Although development has been slower than the original forecast, the NEU will continue to expand over time to serve additional development density in SEFC and new service areas including the Great Northern Way Campus Lands. As illustrated in Figure 3 below, total build-out is currently forecast at 722,000 square metres (7,770,000 square feet) of floor area, which is about 25% higher than the original business case projection.

Figure 3: Floor Area Served



Given the slower pace of development and delayed occupancy for some buildings, energy sales in the first five years were 33% below the original forecast. As shown in Table 1 below, the impact of lower energy sales was partially offset by lower fuel costs and other operating cost savings.

Table 1: Five-year Review - Cumulative Results (2010-2014)

$ million	**Original forecast**	**Actual results**	**Change ($)**	**Change (%)**
Energy sales revenue	$14.4	$ 9.6	$ 4.8	(33%)
Recoverable costs	19.9	16.7	(3.2)	(16%)
Under-recovered costs	**5.5**	**7.1**	**1.6**	**29%**

Under the original forecast in 2009, the balance of under-recovered costs was projected to peak at $7.3 million and be fully repaid in 22 years. It also assumed that annual rate increases would include the Rate Escalation Factor over a 25-year period to ensure the NEU's revenue requirements be met under the levelized rate approach.

As illustrated in Figure 4 below, based on current projections, the balance of under-recovered costs is expected to peak in 2017 at $8.2 million, which is $0.9 million higher than the original forecast. As a result of the anticipated growth in future customer base as well as operating cost savings, the balance of under-recovered costs is expected to be fully repaid within 16 years, which is six years ahead of the original forecast. As well, the Rate Escalation Factor will no longer be required starting in 2019, when annual revenues are forecast to exceed annual costs.

Figure 4: Cumulative Balance of Under-recovered Costs
Original Forecast vs. Current Forecast

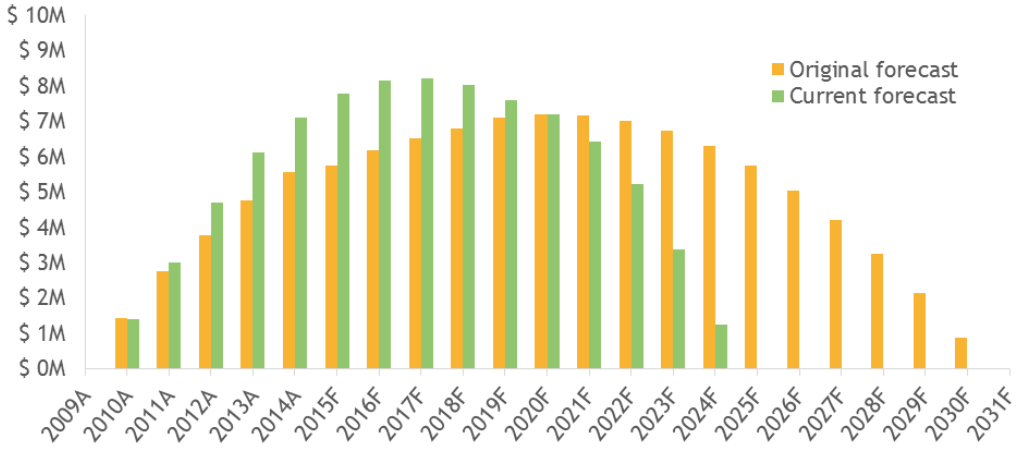


Table 2 below compares the key metrics associated with the levelized rate approach under the original forecast included in the 2010 rate report, the last forecast published as part of the 2014 rate report, and the current forecast.

Table 2: Five-year Review – Key Metrics

	Original forecast Feb '09	Last forecast Dec '13	Current forecast May '15
Maximum balance of unrecovered costs	$ 7.3 M	$ 8.0 M	$ 8.2 M
Recovery timeline (repaid in)	22 years (2031)	17 years (2026)	16 years (2025)
Escalated rate increases[1]	3.2% thru 2021[2]	3.2% thru 2015	3.2% thru 2018

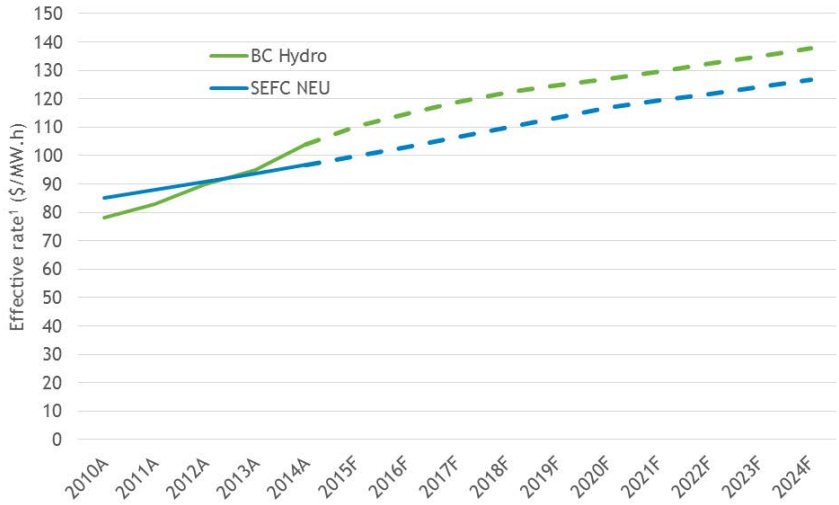
Notes to table

1- Includes projected 2% CPI

2- Original forecast maintained escalated rate increase over entire timeline, for comparative purposes 2021 is the year annual revenues exceed annual costs in original forecast

Figure 5 below shows the forecast NEU rates relative to the forecast effective electricity rates. Current projections indicate that NEU rates are expected to be lower than BC Hydro rates over the remainder of the levelized rate period.

Figure 5: Forecast Effective Rates ($/MW.h)



Note to figure:

1. Effective rate is based on a reference building with an annual energy demand of 109 KW.hr per m^2 of floor area. Actual effective rates for customers will vary due to differences in energy consumption
2. BC Hydro rates are projected to increase consistent with the increases published in BC Hydro's 10-year Rate Plan and at CPI thereafter

Key Performance Indicators & Targets (Recommendation A)

To provide greater clarity for future rate setting under the levelized rate approach, staff recommend that the following KPIs and targets be adopted:

KPI #1: Maximum balance of under-recovered costs – Staff recommend that the target for the maximum balance of under-recovered costs not exceed $9 million which allows for variation in the timing of development coming on stream. The current projection indicates that the balance would peak at $8.2 million in 2018, and gradually come down as annual revenues start to exceed annual costs.

KPI#2: Maximum timeline for recovery of all costs – Staff recommend that the target for recovery of all costs be within 25 years (2034) to match the original term of the levelized rate approach. The current projection indicates that all costs would be recovered in 2025, which is within 16 years from the start of NEU operations in 2010.

KPI#3: Application of Rate Escalation Factor – Staff recommend that the Rate Escalation Factor be applied until the year that annual revenues exceed annual costs. The current projection indicates that the Rate Escalation Factor will no longer be required starting 2019.

KPI#4: Competitive rates – Council policy requires that the NEU "*strives to establish and maintain customer rates that are competitive with the long-term capital and operating costs of other heating options available to customers.*" When the NEU started operation in 2010, a target was set to limit its rates to no greater than a 10% premium above the BC Hydro rate. Staff recommend no change to the target. The current NEU rate is 8% lower than the BC Hydro effective electricity rate.

Sensitivity Analysis

To understand risks to the long-term financial viability of the SEFC NEU under the levelized rate approach, staff have modelled the impact of a number of scenarios focusing on two key variables in the NEU proforma: fuels costs and customer energy consumption.

Table 3 below summarizes the impact of ±30% of fuel costs and customer energy consumption.

Table 3: Sensitivity Analysis

Sensitivity scenarios[1]	Max. balance of under-recovered costs	Timeline for recovery of all costs
(a) 30% lower fuel costs	$ 7.8 M	14 years (2023)
(b) 30% higher energy consumption	$ 8.0 M	16 years (2025)
(c) Combined a & b	$ 7.8 M	13 years (2022)
Base case (current forecast)	**$ 8.2 M**	**16 years (2025)**
(d) 30% lower energy consumption	$ 8.5 M	18 years (2027)
(e) 30% higher fuel costs	$ 9.6 M	19 years (2028)
(f) Combined d & e	$10.0 M	20 years (2029)

Note to table:

1- Scenarios model impact of an ongoing change in prices starting in 2015 without any adjustments to the current forecast SEFC NEU rates

Assuming a combination of high fuel costs and low energy consumption (Scenario F - worst case scenario), or a combination of low fuel costs and high energy consumption (Scenario C - best case scenario), the maximum balance of under-recovered costs would be in the range of $7.8-$10 million (recommended KPI#1 is a maximum balance of $9 million) while the timeline to recover all costs would range from 13-20 years (recommended KPI #2 is a maximum of 25 years).

Should fuel costs increase significantly from the current projections and additional cost saving measures cannot be identified, Council could consider one or more of the following approaches:

- passing on all or part of the fuel cost increase to customers
- adjusting the target for the maximum balance of under-recovered costs (KPI#1)
- adjusting the target for the maximum timeline to recover all costs (KPI#2)

NEU Expert Panel (Panel) Input

Staff conducted the five-year comprehensive review in consultation with the Expert Panel. Specifically, pursuant to the mandate of the Panel, input is sought for the following aspects that could have an impact on the SEFC NEU business case and current and future customers:

- long-term financial viability of the NEU
- rate stability and competitiveness
- potential future expansion of sewage heat recovery capacity to optimize environmental and economic performance.

The Expert Panel has provided a letter of endorsement for the recommended approach on these items (Appendix C).

Implications/Related Issues/Risk (if applicable)

Financial

City Internal Capital Financing Structure for SEFC NEU

NEU Operations - When the NEU became operational in 2010, Council approved a Rate Stabilization Reserve of up to $8 million to finance:

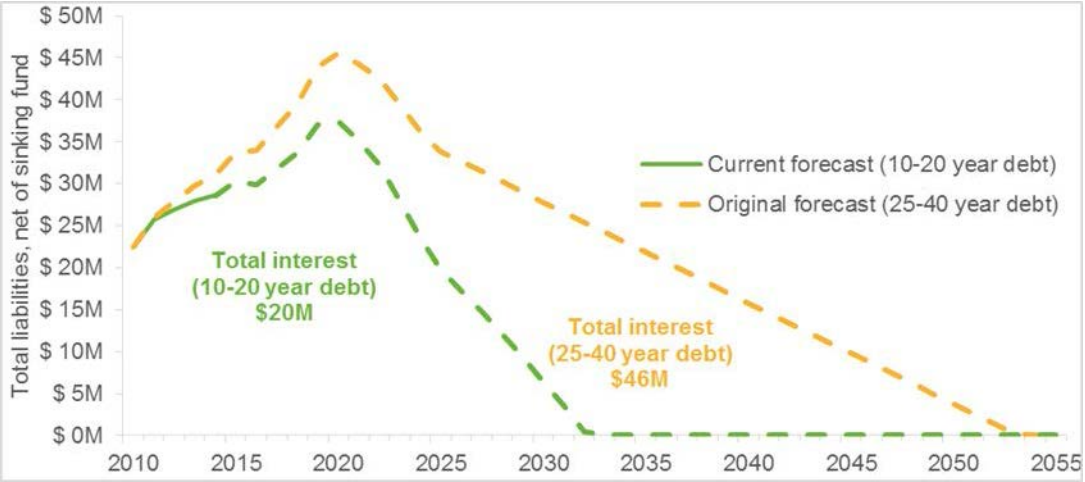
- the operating shortfall in the early years of operation resulting from the levelized rate approach; and
- small year-over-year fluctuations in revenues due to uncontrollable circumstances (e.g. weather) to ensure rate stability for customers.

The Rate Stabilization Reserve was financed through the Capital Financing Fund ("CFF") and the balance as of 2014 year end was just under $5 million.

NEU Capital Infrastructure - When the NEU became operational in 2010, it was contemplated that the capital infrastructure costs would be financed through longer term debt over a 25-40 year amortization to match the useful life of assets. This is a standard approach used by private utilities that are regulated by the BCUC. Subsequently, the City received a $5 million, 20-year low interest loan from the Federation of Canadian Municipalities. The remainder was financed through the City's regular capital borrowing program approved by Council as part of the Capital Plan and Budget process.

To reduce overall financing costs and align with the City's standard issuing term, the City has issued mostly 10-year debt. Shorter-term debt results in significantly lower overall interest costs. However, accelerating the loan amortization requires higher upfront annual principal payments.

Figure 6: Total Liabilities (net of Sinking Fund)



As illustrated in Figure 6 above, with shorter loan amortization, the City will benefit from long-term interest savings of approximately $26 million, and a lower long-term debt profile which is positive for credit rating agencies.

Incorporating the accelerated loan amortization, the current projection indicates that funding required would exceed the $8 million limit in 2018 and peak at $13 million in 2021. Staff therefore recommend that Council authorize an increase to the previously approved internal financing from $8 million to $15 million to finance the accelerated loan amortization, to be repaid from future SEFC NEU revenues; source of funding to be the Capital Financing Fund (Recommendation B).

Any changes to the future operating costs, timing of capital expansion and future debt financing costs may impact the maximum internal financing requirement and timing for full repayment. Staff will continue to monitor and update the SEFC NEU proforma as part of the annual rate setting process.

Environmental

GHG Reductions

The SEFC NEU derives most of its thermal energy production from a process that recovers waste heat from sewage, with the remaining energy supplied by high-efficiency natural gas boilers. It seeks to achieve a 60% GHG reduction compared to conventional heating systems. This target is based on 70% of the annual energy supply coming from the sewage heat recovery process. While the system has consistently achieved this target, for the years 2015 through 2018, it is anticipated that GHG emission reductions will be below this target.

This below-target performance has always been expected in the SEFC NEU business plan. This is a short-term situation which is the result of new customers being added to the system before expansion of the sewage heat recovery system is economical. Beginning in 2019, through growth in the customer base, revenues are expected to be sufficient to finance the expansion of the sewage heat recovery capacity at the False Creek Energy Centre, which will enable the NEU to achieve its long-term GHG reduction targets.

At the time of SEFC build-out, when the NEU is forecast to serve 720,000 square metres (7,770,000 square feet) of residential, commercial and institutional floor area, GHG emissions are forecast to be reduced by 10,400 tonnes CO_2 annually compared to Business-as-Usual[1]. This is a 37% improvement over the 2011 long-term forecast reduction of 7,600 tonnes CO_2 annually, and is due to expansion of the NEU service area, increases to SEFC floor area, and long-term capacity to source a greater proportion of energy from sewage heat recovery than was anticipated in prior years.

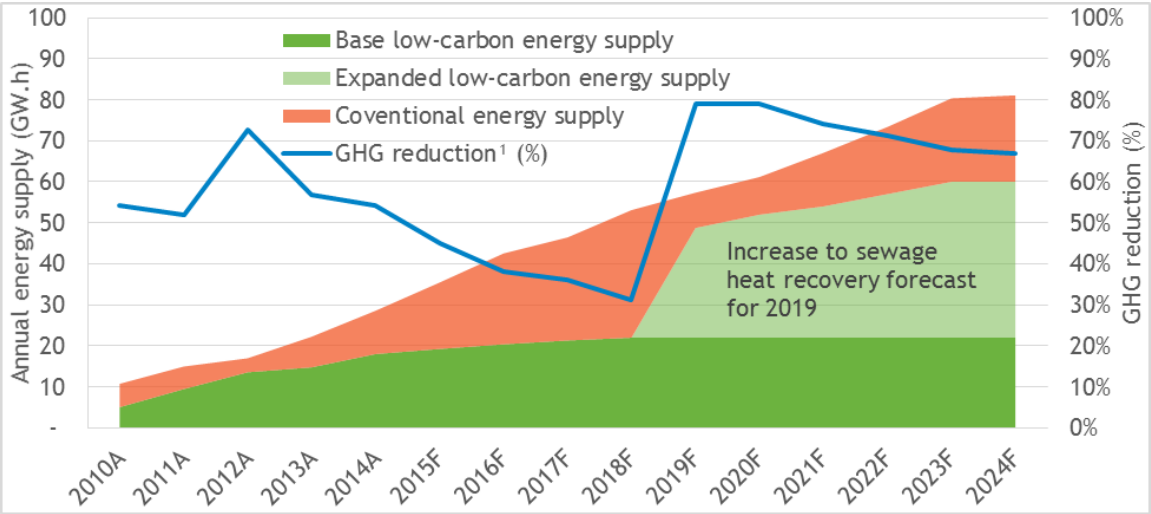
Future Expansion of Sewage Heat Recovery Capacity

The original forecast in 2009 projected that an expansion of the sewage heat recovery capacity would be required in 2015. As a result of the delay in development in the service area, the current projection indicates that additional sewage heat capacity will be required in 2019.

[1] Business-as-Usual is defined as the type of heating and domestic hot water system that would be installed in typical local construction in the absence of the NEU. It assumes electric baseboard heat for residential units and natural gas for ventilation air, domestic hot water and commercial/institutional spaces

Figure 7 below illustrates the forecast sources of energy supplied to meet customer loads and the projected annual GHG reduction.

Figure 7: SEFC NEU Energy Supply & GHG Reduction Forecast



[1] Represents CO2 reduction as compared to conventional heating approach

Staff have reviewed the timing of sewage heat expansion and have concluded that expansion could potentially be accelerated by one year to come online in 2018 without impacting customer rates. While sewage heat recovery expansion has been determined to be economically viable, staff will continue to monitor the timing for the expansion and evaluate other potential low carbon energy sources for the SEFC NEU to optimize its environmental and economic performance as part of the City's overall Neighbourhood Energy Strategy.

CONCLUSION

Based on the five-year comprehensive review, staff and the Expert Panel have concluded that the SEFC NEU is financially viable, and the forecast rates are stable and competitive within the Council-approved rate setting framework. Staff will continue to assess the timing and approach to future expansion of the sewage heat recovery capacity to optimize the environmental and economic performance of the SEFC NEU within the context of the City's Neighbourhood Energy Strategy.

* * * * *

Approved Ownership and Operating Model

On December 14, 2006, Council assessed various ownership and operating options for the NEU, and approved the continued ownership and operation of the NEU by the City, with the following conditions:

- That the NEU be integrated into the Engineering Services Department.
- That the ongoing governance, operational and financial responsibilities related to the NEU be shared by the General Manager of Engineering Services and the Director of Finance.
- That the merits of continued ownership be reviewed before any significant expansion of the NEU, and, in any event, within three years of the commencement of commercial operations.

Approved Governance Principles

At that same time, Council approved the following governance principles for the NEU:

1. That the NEU will seek to minimise greenhouse gas emissions, consistent with the directions established in the Community Climate Change Action Plan.
2. That the NEU will be operated to ensure long-term financial viability based on a commercial model.
3. That the NEU will strive to establish and maintain customer rates that are competitive with the long-term capital and operating costs of other heating options available to customers.
4. That the City, where feasible, will support the development and demonstration of flexible, innovative and local technologies through the NEU.
5. That the City will consider and evaluate the potential to expand the NEU to other neighbourhoods and developments, with the merits and feasibility of each expansion phase to be determined separately.

Approved Rate-Setting Principles

Council also adopted the following eight principles, to be applied to setting rates and terms of service for NEU customer:

1. That NEU rates are structured so as to recover the following costs incurred by the City, based on forecasted costs:
    i. all direct operating costs associated with the NEU,
    ii. all debt service and repayment costs associated with the NEU,

iii. the share of City administrative overheads that are attributable to the NEU,

iv. property taxes and/or payments-in-lieu of property taxes, as appropriate,

v. a reserve fund for NEU rate stabilization,

vi. an appropriate level of compensation for the risks and liabilities assumed by the City associated with the ownership and operation of the NEU, and

vii. credits for any benefits provided by the NEU to City taxpayers (e.g., contribution to corporate GHG reductions goals), as determined by Council.

2. That NEU rates fairly apportion the aforementioned costs among customers of the NEU.

3. That NEU rates be understandable to customers, practical and cost-effective to implement.

4. That at least two separate rate classes (commercial and residential) be established to distinguish different types of NEU customers, with rates reflecting each class's proportional contribution to total costs.

5. That, where feasible, NEU rates provide price signals that encourage energy conservation by NEU customers.

6. That the methodology for calculating NEU rates provide year-to-year rate stability for NEU customers to the greatest extent possible.

7. That the methodology for calculating NEU rates provide year-to-year revenue stability for the City to the greatest extent possible, and include the use of a rate stabilization reserve similar to that used by the City for other utility operations.

8. That rates be updated by Council annually based on forecasted costs, and adjusted to reflect any deviation from target levels of reserves, with annual rate changes requiring review and approval by Council followed by enactment of the necessary amendments to the NEU by-law.

On March 2, 2006, Council approved in principle the creation of the NEU to provide space heating and domestic hot water services to Southeast False Creek (SEFC) buildings. Council's decision was based on a business case that was developed with consulting support from experts in district energy and utility economics.

NEU Technology

The primary energy source for the NEU is sewage waste heat recovery, in which sewage waste heat is captured and used to heat water at the False Creek Energy Centre (referred to in this appendix as the Energy Centre). This facility, located under the south end of the Cambie Street Bridge, at 1890 Spyglass Place, also includes an integrated sewage pump station. While the Energy Centre derives most of its energy from sewage heat recovery, natural gas boilers are used for back-up purposes, and to provide supplemental energy on the coldest days of the year.

From the Energy Centre, a network of underground pipes delivers the heated water to SEFC buildings (termed the "Distribution Pipe System," or DPS). Energy Transfer Stations (ETS) located within each connected building control space heating and domestic hot water for distribution by the (customer owned) building mechanical system.

Metering is incorporated in the ETS's for energy measurement and billing purposes. Three of the ETS's also enable customer-generated solar thermal energy to be distributed to the wider neighbourhood.

In summary, there are four components to the NEU's infrastructure, illustrated in Figure 1 below.

- *False Creek Energy Centre*: Generates hot water through sewer waste heat recovery and natural gas boilers. Owned and operated by the NEU.

- *Distribution Pipe System* (DPS): A set of underground pipes that deliver hot water to connected buildings. Owned and operated by the NEU.

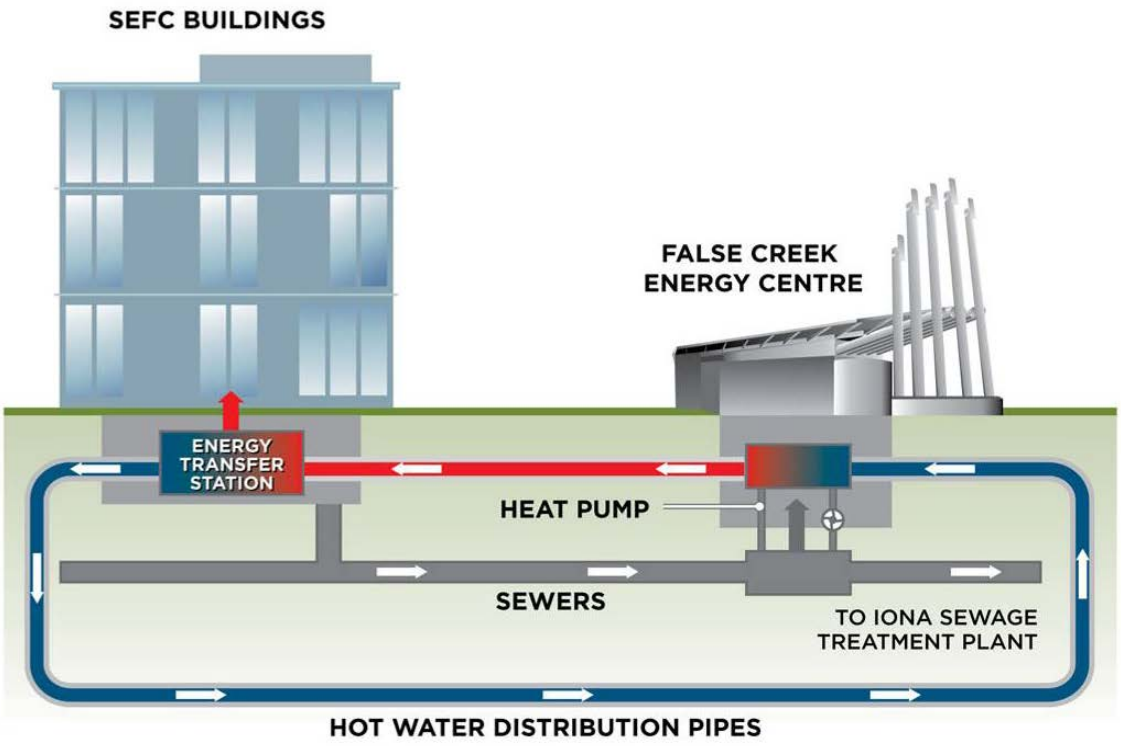
- *Energy Transfer Stations (ETS):* Heat exchangers within each connected building that use hot water delivered to the building via the DPS to generate heat and domestic hot water for individual consumers and building common spaces. Owned and operated by the NEU.

- *Building Mechanical Systems:* All infrastructures within a building (except for the ETS) that comprises the system that delivers heat and hot water to individual consumers and building common spaces. Owned and operated by the building owner(s).

It is noted that, for market residential buildings, the NEU bills strata corporations, and they in turn are responsible for allocating NEU costs among individual unit owners. It is up to each strata corporation to determine the basis for these allocations. Some buildings connected to the NEU have sub-metering systems installed that measure energy consumed by each unit.

NEU rates do not include any costs associated with sub-metering systems owned by strata corporations.

FIGURE 1. NEU CONCEPT DIAGRAM



Legislative Authority & Governance

The Province of British Columbia amended the Vancouver Charter in the spring of 2007 to provide the City with authority to provide energy utility services. Subsequent to this, the City enacted the *Energy Utility System By-law* ("By-law"). Beyond basic provisions required to regulate energy services, the By-law makes connection to the NEU mandatory for all new buildings within the SEFC Official Development Plan area (which is generally bounded by Cambie Street, Main Street, 2nd Avenue and the False Creek waterfront). In June 2012 this service area was expanded to also include the Great Northern Way Campus and Adjacent Lands in the False Creek Flats South area.

As with the City's water, sanitary sewer and solid waste utilities, City Council is the regulatory body for the NEU; municipal utilities are not regulated by the BCUC.

Energy Utility System By-law

On November 15, 2007, Council enacted the Energy Utility System Bylaw No. 9552. On March 5, 2009, Council approved amendments to the Bylaw, including the establishment of 2009 rates and fees for the NEU.

In June 2012, Council approved the amendment to the Bylaw to expand the SEFC NEU service area to include the Great Northern Way Campus Lands and adjacent lands in the False Creek Flats South Area.

Expansion in Southeast False Creek

Southeast False Creek is well suited to implementation of the NEU, because the size and density of the neighbourhood development provides an adequate customer base to make the system economically feasible.

The NEU's service area extends to all of the SEFC Official Development Plan area, the Great Northern Way Campus and adjacent lands in the False Creek Flats South area. At build-out, the system is forecast to serve 722,000 square metres (7,770,000 square feet) of floor area.

As with the Telus World of Science and Great Northern Way Campus, the City may extend the NEU system to serve properties outside of SEFC in cases where the new customer rate revenues are sufficient to fund the associated capital and operating costs

Mayor and Council
City of Vancouver
453 West 12th Avenue
Vancouver, B.C. V5Y 1V4

June 26, 2015

Re: Southeast False Creek Neighbourhood Energy Utility
Five Year Review
Expert Rate Review Panel Comments

Dear Mayor Robertson and Councilors,

The purpose of this letter is to advise Council of the Expert Rate Review Panel's views concerning the Five Year Review of the Southeast False Creek Neighbourhood Energy Utility (SEFC NEU) and recommendations flowing therefrom.

The Expert Review Panel met with City staff in April and June of 2015 to discuss the Five Year Review of the NEU's operations and its projections and recommendations to Council.

The Expert Review Panel's comments are restricted to matters relating to the rate structure and rates to be charged by the NEU, in accordance with its mandate. The Panel has not considered extraneous matters for Council's consideration, such as internal financing decisions.

The Panel concurs with staff's conclusions that the SEFC NEU is financially viable and that proposed rates going forward are relatively stable and appropriate for a new utility with a significant upfront capital investment.

The Panel approves of the levelized rate approach and considers this to be appropriate for a young utility. The Panel also approves the projected rate escalation, but assumes this will be considered each year in the context of actual inflation. The Panel also assumes that staff will continue to keep abreast of rates being charged by other neighbourhood energy utilities as well as those being charged by BC Hydro.

The Panel has reviewed and discussed the forecasted cost inputs, including the cost of capital, with City staff and is satisfied that these projections are well thought out and reasonable.

The Panel agrees with the Key Performance Indicators and Targets set out in Recommendation A. The Panel is of the view that the requested increased limits for the cumulative balance of Under-Recovered Costs and the 25 year time horizon for cost recovery will provide a reasonable degree of flexibility and yet serve as appropriate constraints.

The Panel appreciates the additional work of staff in terms of its Sensitivity Analysis and finds that this exercise provides additional assurance that the NEU is on track and financially viable.

The Panel encourages staff to continue to monitor factors relevant to the timing for potential expansion of the NEU.

Yours very truly,

Alison Rhodes
Chair,
NEU Expert Rate Review Panel

CITY OF VANCOUVER

ADMINISTRATIVE REPORT

Report Date:	November 12, 2015
Contact:	Chris Baber
Contact No.:	604.871.6127
RTS No.:	11083
VanRIMS No.:	08-2000-20
Meeting Date:	December 9, 2015

TO: Vancouver City Council

FROM: General Manager of Engineering Services

SUBJECT: Southeast False Creek Neighbourhood Energy Utility ("SEFC NEU") 2016 Customer Rates

RECOMMENDATION

A. THAT Council approve the amendments to the Energy Utility System By-law ("the By-law"), generally as set out in Appendix A, including the establishment of 2016 customer rates and fees, with a 3.2% increase over 2015 customer rates. In accordance with Council Policy to improve the energy conservation price signal, this 3.2% increase is to be achieved by increasing the Fixed Capacity Levy by 2.5% and the Variable Energy Charge by 4.0%.

B. THAT Council instruct the Director of Legal Services to bring the By-law amendment, generally as set out in Appendix A, forward for enactment.

REPORT SUMMARY

This report seeks Council approval of the recommended 2016 SEFC NEU customer rates, which incorporates a 3.2% net increase over 2015. This increase enables the NEU to recover its long-term costs under the commercial utility rate model, while providing stable and competitive energy rates for customers. This will result in a cost increase of ~$25 per year for a resident living in an average 75 square metre (800 square feet) suite.

In accordance with Council policy to improve the energy conservation price signal, this 3.2% net increase is to be achieved through a 2.5% increase to the Fixed Capacity Levy and a 4.0% increase to the Variable Energy Charge components of the SEFC NEU rate structure.

COUNCIL AUTHORITY/PREVIOUS DECISIONS

In December 2006, Council approved a set of governance and rate-setting principles for the SEFC NEU (Appendix C).

In March 2009, Council instructed staff to report back to Council annually on adjustments to the SEFC NEU rates, and to bring a comprehensive rate review to Council every five years.

In July 2010, Council approved the establishment of an independent Neighborhood Energy Expert Panel (referred to as the "Expert Panel" in this report) to advise staff and Council on future SEFC NEU rate adjustments. At this time, Council also approved the establishment of separate customer rate classes and rate formulas for residential and mixed-use residential buildings located outside SEFC, and for non-residential buildings both within and outside SEFC.

In July 2011, Council adopted the Greenest City Action Plan, which targets a 33% (1.1 million tonnes per year) City-wide reduction in carbon pollution by 2020 from 2007 levels. Low carbon neighbourhood energy systems represent 11%, or 120,000 tonnes per year, of this target.

In June 2012, Council approved the amendment of the *Energy Utility System By-law* to expand the SEFC NEU service area to include the Great Northern Way Campus Lands and adjacent lands in the False Creek Flats South Area.

In October 2012, Council approved the Vancouver Neighbourhood Energy Strategy and Energy Centre Guidelines, to address the Greenest City 2020 Action Plan objective of reducing 120,000 tonnes carbon dioxide per year through the conversion of existing steam heat systems to low carbon energy sources and the deployment of sustainable energy systems for high-density neighbourhoods.

In April 2014, Council approved a transition strategy to adjust the SEFC NEU rate structure to strengthen the energy conservation price signal while maintaining energy rates at the same level as projected under the commercial utility rate model.

In July 2015, based on the result of the comprehensive review of the SEFC NEU after five years of operation, Council adopted key performance indicators and targets to guide SEFC NEU rate setting under the commercial utility rate model.

REPORT

Background/Context

The fundamental goal of the SEFC NEU is to minimize GHG emissions via a financially self-sustaining, commercially operated utility that delivers competitively priced energy services. Through its system efficiencies and by using sewage heat recovery as its low carbon energy source, the NEU provides substantial greenhouse gas emission reductions relative to traditional methods of providing heat and hot water. At time of system build-out the NEU is forecast to reduce GHG emissions by 60%, or 10,400 tonnes CO2 per year.

The SEFC NEU began operation in January 2010, and since then has rapidly expanded to serve 395,000 square metres (4,250,000 square feet – slightly more that 70% of the original business case projection) of residential, commercial and institutional floor area. Over time, the NEU will continue to be extended to serve new developments in SEFC and Great Northern Way Campus Lands, with total build-out currently forecast at 725,000 square metres (7,770,000

square feet – approximately 25% greater than projected in the original business case) of floor area.

Appendices B and C provide additional details on the SEFC NEU's services, technology, and its ownership, operating and governance model.

Levelized Rate Structure

SEFC NEU customer rates are comprised of two components: a Fixed Capacity Levy (related to the fixed capital and operating costs associated with the NEU) and a Variable Energy Use Charge (related to customers' actual energy consumption). To ensure fair and appropriate rates, all annual rate changes are reviewed by the independent Expert Panel.

To provide competitive and stable rates for the SEFC NEU customers, rates are established based on a levelized rate approach. As illustrated in Figure 1 below, rates are set to *under-recover* annual costs in the early years of the NEU's operation when the customer base is small, and to gradually recover past costs and a modest return on investment when the customer base is fully established. This approach ensures that infrastructure costs are more equitably distributed between the initial customers and those who connect in later years. If the levelized rate approach were not taken, customer rates would have to be set much higher in the early years of operation.

The levelized rate approach is commonly used by privately owned utilities regulated by the BC Utilities Commission ("BCUC"), including the SFU's UniverCity Energy system, the River District Energy system and the new UBC neighbourhood system.

FIGURE 1: LEVELIZED RATE APPROACH

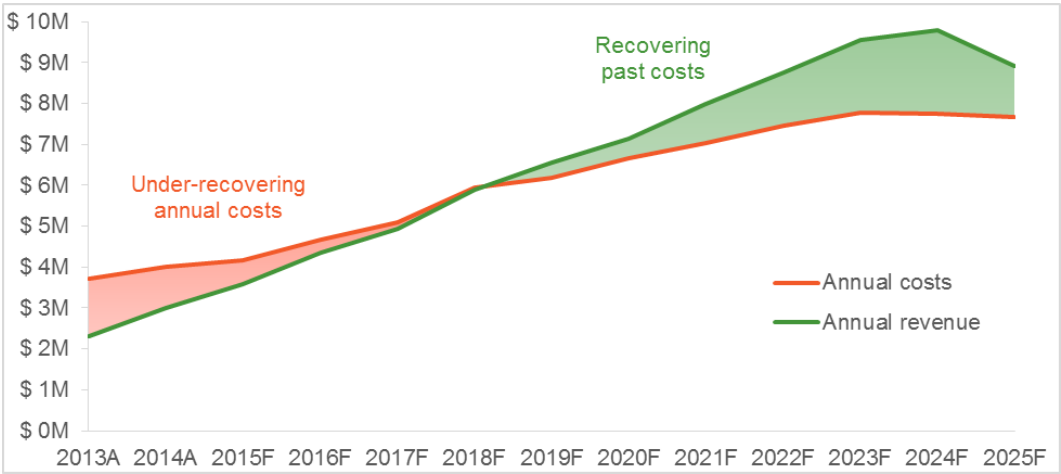
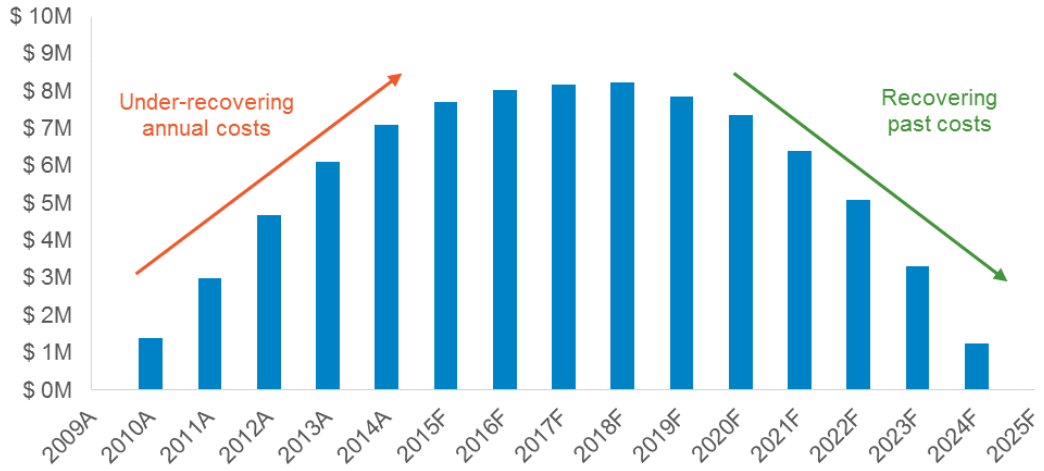


FIGURE 2: CUMULATIVE BALANCE OF UNDER-RECOVERED COSTS UNDER LEVELIZED RATE APPROACH



To ensure that the cumulative balance of under-recovered costs (Figure 2) can be recovered within a reasonable timeframe without impacting the stability and competitiveness of the customer rates, the levelized rate approach contemplates annual rate increases that include two components: an inflationary increase and a Rate Escalation Factor.

The Rate Escalation Factor is applied to customer rates above annual inflation to gradually increase rates over time to ensure all of the NEU's revenue requirements are met over the long-term. Using this approach enables the NEU to maintain rates that are stable, affordable and appropriate for new utilities with large upfront capital investments.

Strategic Analysis

2016 RECOMMENDED CUSTOMER RATES

The NEU recovers its costs using three different rate classes: (1) Residential and Mixed Use Residential Buildings within SEFC; (2) Residential and Mixed Use Residential buildings Outside of SEFC; and (3) Non-Residential Buildings. These separate rate classes were established to ensure that NEU costs are equitably distributed among different customers, based on a cost of service model.

Staff recommends that SEFC NEU customer rates for all three rate classes be increased by 3.2% over 2015 rates, as shown in Table 1. Consistent with Council policy to improve the energy conservation price signal, staff recommends that this 3.2% increase be achieved through a 2.5% increase to the Fixed Capacity Levy and a 4.0% increase to the Variable Energy Charge. This allocation is supported by the Expert Panel, and will improve the conservation price signal while maintaining energy rates at the same level as projected under the commercial utility rate model.

A 3.2% increase is equivalent to a 1.2% real rate increase to customers above a forecast mid-term average inflation rate of 2%. This 1.2% above inflation value is the Rate Escalation Factor, which enables the NEU to maintain rates that are stable and affordable, while keeping the NEU on track to recover its costs in accordance with the commercial utility rate model.

Applied as recommended by staff, this 3.2% increase will result in a cost increase of ~$25 per year for a resident living in an average 75 square metre (800 square feet) suite with an average energy demand of 8.2 megawatt hours per year.

TABLE 1. SEFC NEU 2015 AND RECOMMENDED 2016 CUSTOMER RATES[1]

	2015	2016 PROPOSED	% CHANGE 2016/2015
Class 1 (Residential and Mixed Use Residential within SEFC)			
Fixed Capacity Levy (per square meter per month)	$0.513	**$0.526**	2.5%
Variable Energy Use Charge (per MW.hr)	$43.652	**$45.398**	4.0%
Net Effective Rate[2] (per MW.hr)	**$100**	**$103**	**3.2%**
Class 2 (Residential and Mixed Use Residential Outside SEFC) and Class 3 (Non-Residential)			
Fixed Capacity Levy (per KW peak energy demand per month)	$7.705	**$7.905**	2.5%
Variable Energy Use Charge (per MW.hr)	$43.652	**$45.398**	4.0%
Net Effective Rate[2] (per MW.hr)	**$100**	**$103**	**3.2%**

NOTES TO TABLE

1. For the purposes of classifying buildings to apply these rate classes, the following definitions apply:
   - Residential: Residential uses comprise 100% of building net floor area.
   - Mixed-Use Residential: Residential uses comprise less than 100% and greater than or equal to 50% of net floor area.
   - Non-Residential: Building use is industrial, commercial or institutional, and, if residential uses are included, residential uses comprise less than 50% of the net floor areas.
2. Net effective rate is based on a reference building with an annual energy demand of 109 KW.hr per square metre of floor area. Actual effective rates for customers will vary due to differences in energy performance from building to building.

NEU EXPERT PANEL INPUT

The Expert Panel established by Council provides staff with invaluable advice on many elements of the business of the NEU. In their annual letter to Council, as attached in Appendix D, the Panel has endorsed the 2016 rate increase of 3.2%. In accordance with established policy to strengthen the conservation price signal, the Expert Panel also agrees that this 3.2% increase should be allocated by a 2.5% increase to the Fixed Capacity Levy and a 4.0% increase to the Variable Energy Charge components of the rate structure.

Staff would like to acknowledge the contributions of the Expert Panel. Their advice helps to ensure that the rate increases recommended in this report reflect an appropriate balance between the need to recover the City's costs for operating the NEU and the customer's need to receive fair and competitive rates for energy services delivered.

FINANCIAL PERFORMANCE UPDATE

This section provides an update on the financial performance of the SEFC NEU, based on the commercial utility rate model, as well as a comparison of the customer rates against various benchmark utilities.

In June 2015, Council adopted key financial performance indicators ("KPIs") and targets for the SEFC NEU. These KPIs are used to track long-term financial performance of the utility, and to guide future rate setting. Table 2 below compares the KPIs associated with the levelized rate approach under the original forecast included in the 2010 rate report, the last forecast published in the Rate Review Report in June 2015, and the current forecast. There have been no significant changes since May 2015, and the SEFC NEU is currently on target for all KPIs.

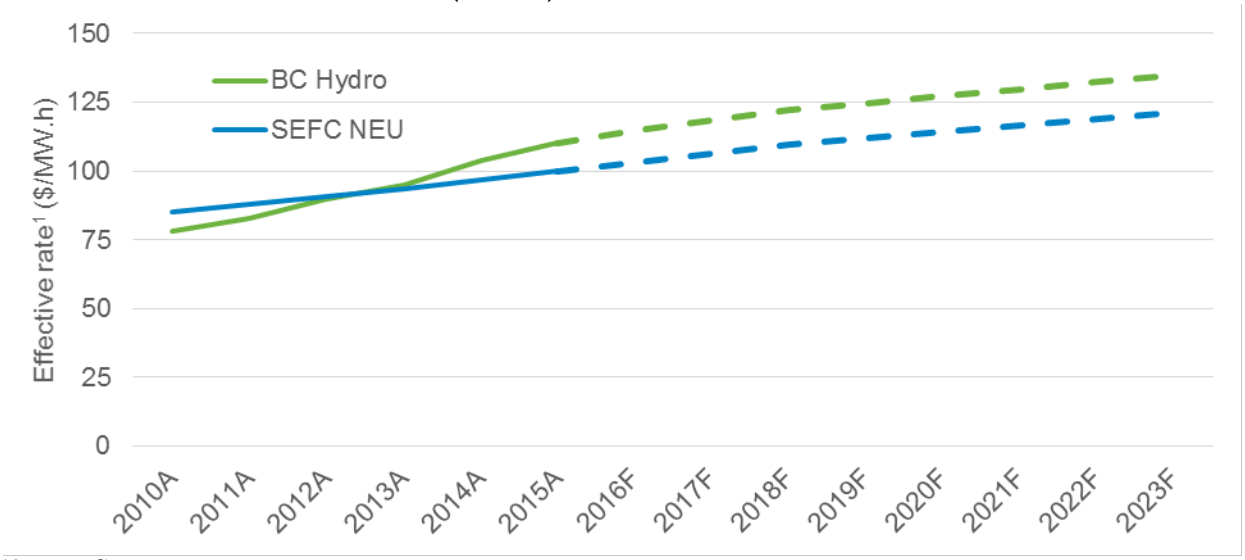
TABLE 2: SEFC NEU KPIs

	Original Forecast Feb '09	**Last Forecast June '15**	**Current Forecast**
Maximum balance of under-recovered costs *Target: not to exceed $9.0 M*	$ 7.3 M	$ 8.2 M	**$ 8.2 M**
Recovery timeline for under-recovered costs *Target: not to exceed 25 years*	22 years (2031)	16 years (2025)	**16 years (2025)**
Escalated rate increases[1] *Target: Rate Escalation Factor to be eliminated when annual revenues exceed annual costs*	3.2% thru 2021[2]	3.2% thru 2018	**3.2% thru 2018**

Notes to table
1. Includes mid-term average inflation of 2%
2. Original forecast maintained escalated rate increase over entire timeline, until 2035.

Figure 3 shows the forecast SEFC NEU rates relative to the forecast effective electricity rates. Current projections indicate that SEFC NEU rates will be lower than BC Hydro rates over the remainder of the levelized rate period.

FIGURE 3. FORECAST EFFECTIVE RATES ($/MW.H)



Note to figure:

1. Effective rate is based on a reference building with an annual energy demand of 109 KW.hr per m^2 of floor area. Actual effective rates for customers will vary due to differences in energy consumption.
2. BC Hydro rates are projected to increase consistent with the increases published in BC Hydro's 10-year Rate Plan, and at CPI thereafter.

Actual vs. Proforma 2015 Costs and Revenues

Table 3 compares 2015 revenues and expenses with the 2015 Operating and Capital Budgets. Offsetting variances in operating revenues and costs has resulted in a forecast operating budget shortfall that is 1% better than budget.

The main differences between 2015 budget and the 2015 actuals projected to year-end are as follows:

- **Energy Use Charge Revenues:** forecast to be 9%, or $142,000 below budget. This is due to abnormally warm weather experienced this year (February and March temperatures were 2.6 degrees Celsius warmer than average). This drop in revenues was more than offset by a reduction in fuel costs (see below).

- **Natural Gas, Electricity**: forecast to be 16%, or $176,000 lower than budget. This is primarily due to the warmer weather experienced this year.

- **Staffing, Maintenance, Overhead and Other**: forecast to be 9%, or $72,000 above budget. This is primarily due to a significant 5-year maintenance program for major equipment and higher than anticipated City water and sewer utility costs.

- **System Expansion Capital Costs**: forecast to be 8%, or $200,000 below budget, primarily due to the deferral of one new customer connection from 2015 to 2016.

TABLE 3. 2015 NEU REVENUES AND EXPENSES, BUDGET COMPARED TO YEAR-END FORECAST ($000s) BASED ON THE COMMERCIAL UTILITY RATE MODEL

$ 000	2015 BUDGET	2015 FORECAST	$ VARIANCE	% VARIANCE
Revenues				
Capacity Levies	2,182	2,215	33	2%
Energy Use Charges	1,501	1,359	(142)	(9%)
Total Revenues	**3,683**	**3,574**	**109**	**(3%)**
Operating Expenses				
Natural Gas & Electricity	1,131	955	(176)	(16%)
Staffing, Maintenance, Overhead & Other	815	887	72	9%
Total Operating Expenses	**1,946**	**1,842**	**(104)**	**(5%)**
Financing Expenses				
Interest Expense	699	695	(4)	(1%)
Return on Equity	998	992	(6)	(1%)
Depreciation	707	703	(4)	(1%)
Total Financing Expenses	**2,404**	**2,390**	**(14)**	**(1%)**
Total Expenses	**4,350**	**4,232**	**(118)**	**(3%)**
Operating Shortfall, resulting from levelized rates	**667**	**658**	**(7)**	**(1%)**
System Expansion Capital Costs	**2,595**	**2,395**	**(200)**	**(8%)**

Comparison of NEU Rates to Other Energy Providers

One of Council's approved governance principles is that *"... the utility will strive to establish and maintain customer rates that are competitive with the long-term capital and operating costs of other heating options available to customers."*

To assess the competitiveness of the NEU, staff examined what a typical NEU customer would pay compared with other energy providers. Table 4 includes comparisons with BC Hydro, FortisBC natural gas, and a range of district energy providers.

Because the rate structures and type of service of these energy providers vary, an "effective rate" is calculated for the purposes of comparison. This rate illustrates what customers will pay per megawatt-hour for heating. Based on the recommended rate increase of 3.2%, the proposed 2016 effective rate for the NEU is $103 per MW.h. This effective rate assumes an average residential customer would consume 109 kilowatt hours per square metre of floor area annually, regardless of what energy provider they use.

The 2016 NEU effective rate continues to be well within the target maximum 10% premium over electricity. The proposed 2016 NEU rate is 9% lower than the forecast 2016 BC Hydro effective rate.

The proposed 2016 NEU effective rate will be 17% higher than the cost of using high efficiency natural gas boilers. This is based on the current natural gas commodity price which is at a historical low and is subject to significant change from year to year. The NEU offers more stable and predictable rates compared to natural gas, and much lower GHG emissions.

TABLE 4. COMPARISON OF EFFECTIVE RATES, SEFC NEU WITH OTHER PROVIDERS

Energy Provider	GHG Emission Intensity (kg CO_2/MW.h)	Estimated Effective Rate [1] ($/MW.h)	Year of Effective Rate	Notes
SEFC NEU (Hot Water)	66	$103	Proposed 2016	The NEU bills strata corporations, not individual suites; any incremental strata sub-metering costs incurred by NEU consumers are not included here.
BC Hydro (Electricity)	24[2]	$109[2] $113[2]	2015 Proposed 2016	BC Hydro effective rate calculation is based on 50% of consumption at BC Hydro's Residential Step 1 Rate and 50% at Step 2, and includes a rate rider.
FortisBC (Natural Gas)	220[3]	$88[3]	2015	Fuel costs, based on FortisBC Lower Mainland Rate 3, with high efficiency boiler and factoring in conversion losses = $38 per MW.h. Installation and replacement of boiler equipment plus maintenance = $50 per MW.h. Total effective cost = $88 per MW.h
Creative Energy Ltd. (Steam)	300[3]	$64	2015	Actual effective rate for this Downtown steam system varies depending on size of building and building efficiency of converting steam to energy. Rates fluctuate with the commodity price of natural gas.
UBC Campus system (Steam)	208 173 (2018)	$98	2015	GHG intensity of UBC campus steam system reflects 15% of energy from biomass, and remainder from natural gas. UBC is converting from steam to a more efficient hot water system, which will further reduce GHG intensity. This institutional NES is not operated on a commercial basis.
SFU UniverCity Energy (Hot Water)	220 (Existing) 43 (2018)	$150[4]	2016	SFU UniverCity Energy operations began 2012, using a temporary natural gas boiler. This system will utilize a biomass facility for low carbon energy supply once customer base is sufficiently established (forecast 2018).

Energy Provider	GHG Emission Intensity (kg CO_2/MW.h)	Estimated Effective Rate [1] ($/MW.h)	Year of Effective Rate	Notes
River District Energy (Hot Water)	220 (Existing) 32 (Future at time of WTE connection)	$108[4]	2016	River District Energy operations began 2012, using a temporary natural gas boiler, and plans to use waste heat from the existing Metro Vancouver Waste to Energy Facility (Burnaby) once customer base is sufficiently established.
Richmond Oval Village District Energy (Hot Water)	220 (Existing) 23 (2026)	$86	2016	Oval Village District energy operations began 2015, using a natural gas boiler, and plans to use Sewer Heat Recovery once customer base is sufficiently established (forecast 2026)
Surrey City Energy (Hot Water)	220 (Existing) 53 (2024)	$105	2015	Surrey City Energy operations began in 2015, using temporary natural gas boilers. This system will use an undetermined proportion of renewable natural gas beginning in 2017, and plans to implement a wood waste fuelled energy centre in 2024.
PCI Marine Gateway (Heating & Cooling)	58	$115[4]	2016	The PCI Marine Gateway development will utilize a geo-exchange heating and cooling system, which will be provided by FortisBC Alternative Energy Services.

NOTES TO TABLE

1. Effective rate estimates are based on a reference building with an annual energy demand of 109 KW.hr per m^2 of floor area. Actual effective rates for customers will vary due to differences in energy performance from building to building.

2. Although B.C. Hydro's electricity is on-average a low carbon energy source, new electricity demand is largely served from high-carbon imported electricity, or new high-cost low carbon sources (e.g. proposed Peace River Site "C' project). Also, electric baseboard heat is generally used in conjunction with natural gas for ventilation air and hot water, and that natural gas typically supplies more than 50% of the building heat demand.

3. FortisBC, UBC Campus and Creative Energy Steam rates are largely dependent on the commodity cost of natural gas, which is currently at a historical low and subject to natural gas commodity price volatility. The GHG emission intensity as reported in Table 4 reflects provincial standard methods for calculating GHG emissions, and does not include upstream emissions associated with the extraction and transportation of natural gas.

4. Estimated effective rates sourced from BC Utilities Commission rate filings, which are based on modeled energy performance of buildings served by the reference systems. A high estimated effective rate does not necessarily imply that the customer's total cost of heating will be high, because some new developments consume significantly less energy than others.

Financial Implications

As noted above, staff recommends a 3.2% increase to the NEU customer rates for 2016 to be achieved by increasing the Fixed Capacity Levy by 2.5% and the Variable Energy Charge by 4.0%. This recommended increase is in accordance with the Council approved rate setting framework established in June 2015, and is also consistent with the rate forecasts from previous years.

Environmental Implications

The SEFC NEU derives most of its thermal energy production from a process that recovers waste heat from sewage, with the remaining energy supplied by high-efficiency natural gas boilers. It seeks to achieve a 60% GHG reduction compared to conventional heating systems. This target is based on 70% of the annual energy supply coming from the sewage heat recovery process. While the system has consistently achieved this target, for the year 2016 it is anticipated that GHG emission reductions will be 48% below conventional heating systems, which is 12 percentage points below the long-term target.

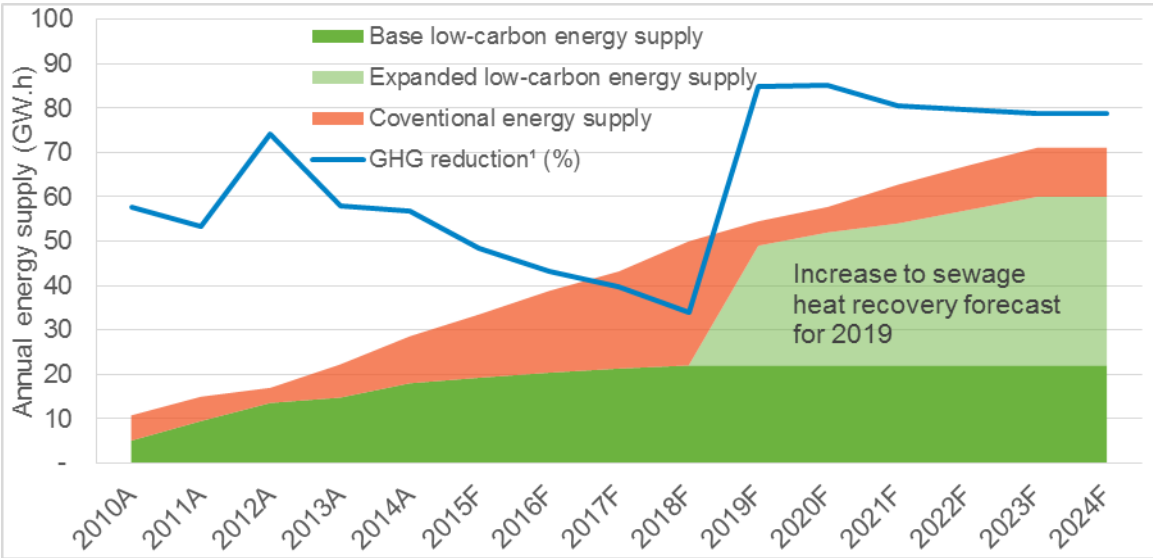
This below-target performance has always been expected in the SEFC NEU business plan. This is a short-term situation which is the result of new customers being added to the system before expansion of the sewage heat recovery system is economical. Beginning in 2018, through growth in the customer base, revenues are expected to be sufficient to finance the expansion of the sewage heat recovery capacity at the False Creek Energy Centre, which will enable the NEU to achieve its long-term GHG reduction targets. Staff will continue to monitor the timing for the expansion and evaluate other potential low carbon energy sources to optimize the environmental and economic performance of the utility.

At the time of SEFC build-out, when the NEU is forecast to serve 720,000 square metres (7,770,000 square feet) of residential, commercial and institutional floor area, GHG emissions are forecast to be reduced by 10,400 tonnes CO_2 annually compared to Business-as-Usual[1]. This is a 37% improvement over the 2011 long-term forecast reduction of 7,600 tonnes CO_2 annually, and is due to expansion of the NEU service area, increases to SEFC floor area, and long-term capacity to source a greater proportion of energy from sewage heat recovery than was anticipated in prior years.

Figure 4 below illustrates the forecast sources of energy supplied to meet customer loads and the projected annual GHG reduction.

[1] Business-as-Usual is defined as the type of heating and domestic hot water system that would be installed in typical local construction in the absence of the NEU. It assumes electric baseboard heat for residential units and natural gas for ventilation air, domestic hot water and commercial/institutional spaces

FIGURE 4: SEFC NEU ENERGY SUPPLY & GHG REDUCTION FORECAST



[1] Represents CO2 reduction as compared to conventional heating approach

CONCLUSION

This report recommends that SEFC NEU rates be increased by 3.2% in 2016. This proposed increase is consistent with Council's approved rate-setting principles and methodology, and enables the NEU to recover its long-term costs under the commercial utility rate model while providing stable and competitive energy rates for customers. This increase will be allocated to the Capacity Levy and the Energy Charge in a manner consistent with the conservation rate setting policy approved by Council in April 2014.

The NEU continues to be an important contributor to the City's work in achieving the Greenest City goals and carbon-reduction targets.

* * * * *

APPENDIX A
ENERGY UTILITY SYSTEM BY-LAW DRAFT AMENDMENT

BY-LAW NO. _____

A By-law to amend Energy Utility System By-law No. 9552
Regarding Updates to Levies and Charges

THE COUNCIL OF THE CITY OF VANCOUVER, in public meeting, enacts as follows:

1. This By-law amends the indicated provisions and schedule of the Energy Utility System By-law.

2. Council repeals Schedule C, and substitutes:

"SCHEDULE C

LEVIES AND CHARGES

PART 1 – Excess demand fee

Excess demand fee for each 1 W per m^2 of the aggregate of the estimated peak heat energy demand referred to in section 4.1(b) (i), (ii), and (iii) that exceeds 65 W per m^2	$1.50

PART 2 – Monthly levy

Class 1 - SEFC residential or mixed use residential building	$0.526 per m^2
Class 2 - Residential or mixed use residential building located outside SEFC	$7.905 per KW of peak heat energy demand
Class 3 - Non-residential building	$7.905 per KW of peak heat energy demand

PART 3 – Monthly charge

Monthly charge	$45.398 per MW per hour

PART 4 – Credit

Credit for heat energy returned to energy transfer station	$45.398 per each MW per hour multiplied by 50%

”

3. A decision by a court that any part of this By-law is illegal, void, or unenforceable severs that part from this By-law, and is not to affect the balance of this By-law.

4. This By-law is to come into force and take effect on January 1, 2016.

ENACTED by Council this day of , 2015

_____
Mayor

_____
City Clerk

EXPLANATION

A By-law to amend the Energy Utility System By-law
Re: Levies and Charges

On December 9, 2015, Council resolved to amend the Energy Utility System By-law to establish updated Levies and Charges effective January 1, 2016. Enactment of the attached By-law will implement Council's resolution.

Director of Legal Services
December 9, 2015

APPENDIX B
OVERVIEW OF THE CITY OF VANCOUVER'S SOUTHEAST FALSE CREEK NEIGHBOURHOOD ENERGY UTILITY

On March 2, 2006, Council approved in principle the creation of the NEU to provide space heating and domestic hot water services to Southeast False Creek (SEFC) buildings. Council's decision was based on a business case that was developed with consulting support from experts in district energy and utility economics.

The NEU Technology

The primary energy source for the NEU is sewage waste heat recovery, in which sewage waste heat is captured and used to heat water at the False Creek Energy Centre (referred to in this appendix as the Energy Centre). This facility, located under the south end of the Cambie Street Bridge, at 1890 Spyglass Place, also includes an integrated sewage pump station. While the Energy Centre derives most of its energy from sewage heat recovery, natural gas boilers are used for back-up purposes, and to provide supplemental energy on the coldest days of the year.

From the Energy Centre, a network of underground pipes delivers the heated water to SEFC buildings (termed the "Distribution Pipe System," or DPS). Energy Transfer Stations (ETS) located within each connected building control space heating and domestic hot water for distribution by the (customer owned) building mechanical system.

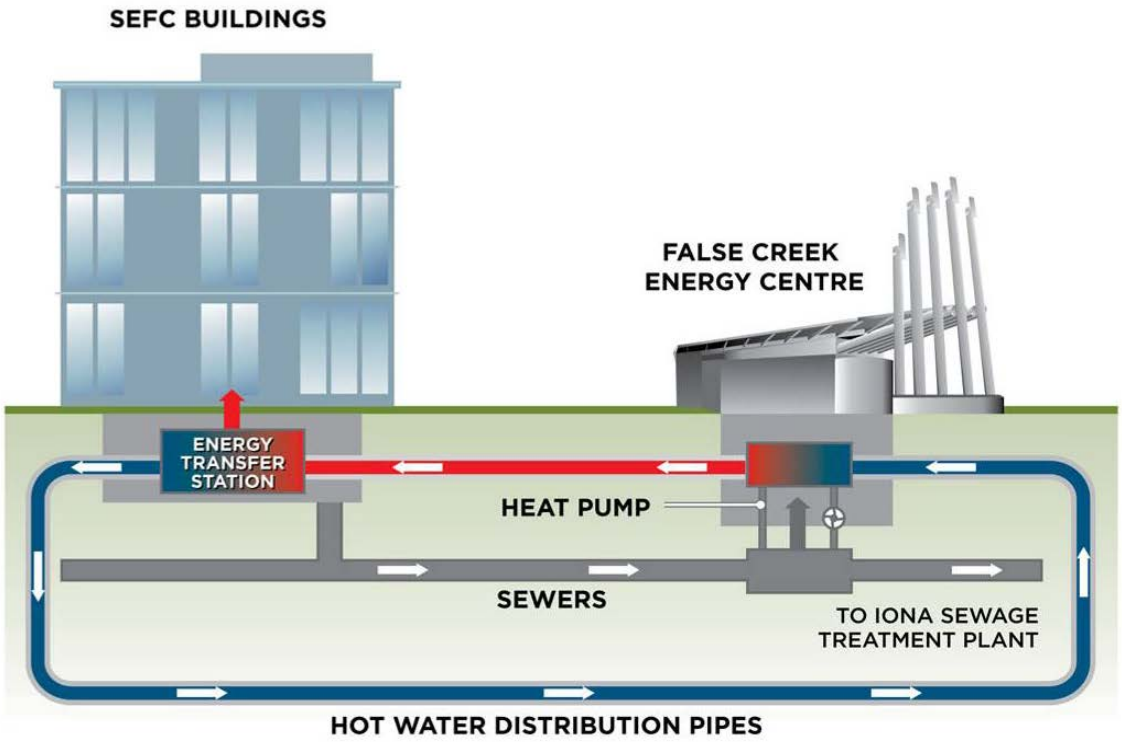
Metering is incorporated in the ETS's for energy measurement and billing purposes. Three of the ETS's also enable customer-generated solar thermal energy to be distributed to the wider neighbourhood.

In summary, there are four components to the NEU's infrastructure, illustrated in Figure 1 below.

- *False Creek Energy Centre*: Generates hot water through sewer waste heat recovery and natural gas boilers. Owned and operated by the NEU.
- *Distribution Pipe System* (DPS): A set of underground pipes that deliver hot water to connected buildings. Owned and operated by the NEU.
- *Energy Transfer Stations (ETS):* Heat exchangers within each connected building that use hot water delivered to the building via the DPS to generate heat and domestic hot water for individual consumers and building common spaces. Owned and operated by the NEU.
- *Building Mechanical Systems:* All infrastructure within a building (except for the ETS) that comprises the system that delivers heat and hot water to individual consumers and building common spaces. Owned and operated by the building owner(s).

It is noted that, for market residential buildings, the NEU bills strata corporations, and they in turn are responsible for allocating NEU costs among individual unit owners. It is up to each strata corporation to determine the basis for these allocations. Some buildings connected to the NEU have sub-metering systems installed that measure energy consumed by each unit. NEU rates do not include any costs associated with sub-metering systems owned by strata corporations.

FIGURE 1. NEU CONCEPT DIAGRAM



Legislative Authority & Governance

The Province of British Columbia amended the Vancouver Charter in the spring of 2007 to provide the City with authority to provide energy utility services. Subsequent to this, the City enacted the *Energy Utility System By-law* ("By-law"). Beyond basic provisions required to regulate energy services, the By-law makes connection to the NEU mandatory for all new buildings within the SEFC Official Development Plan area (which is generally bounded by Cambie Street, Main Street, 2nd Avenue and the False Creek waterfront). In June 2012 this service area was expanded to also include the Great Northern Way Campus and Adjacent Lands in the False Creek Flats South area.

As with the City's water, sanitary sewer and solid waste utilities, City Council is the regulatory body for the NEU; municipal utilities are not regulated by the BC Utilities Commission.

Energy Utility System Bylaw

On November 15, 2007, Council enacted the Energy Utility System Bylaw No. 9552. On March 5, 2009, Council approved amendments to the Bylaw, including the establishment of 2009 rates and fees for the NEU.

In June 2012, Council approved the amendment to the Bylaw to expand the SEFC NEU service area to include the Great Northern Way Campus Lands and adjacent lands in the False Creek Flats South Area.

Expansion in Southeast False Creek

Southeast False Creek is well suited to implementation of the NEU, because the size and density of the neighbourhood development provides an adequate customer base to make the system economically feasible.

The NEU's service area extends to all of the SEFC Official Development Plan area, the Great Northern Way Campus and adjacent lands in the False Creek Flats South area. At build-out, the system is forecast to serve 722,000 square metres (7,770,000 square feet) of floor area.

As with the Telus World of Science and Great Northern Way Campus, the City may extend the NEU system to serve properties outside of SEFC in cases where the new customer rate revenues are sufficient to fund the associated capital and operating costs.

APPENDIX C
SOUTHEAST FALSE CREEK NEIGHBOURHOOD ENERGY UTILITY OWNERSHIP MODEL, GOVERNANCE AND RATE-SETTING PRINCIPLES APPROVED BY CITY COUNCIL IN DECEMBER 2006

Approved Ownership and Operating Model

On December 14, 2006, Council assessed various ownership and operating options for the NEU, and approved the continued ownership and operation of the NEU by the City, with the following conditions:

- That the NEU be integrated into the Engineering Services Department.
- That the ongoing governance, operational and financial responsibilities related to the NEU be shared by the General Manager of Engineering Services and the Director of Finance.
- That the merits of continued ownership be reviewed before any significant expansion of the NEU, and, in any event, within three years of the commencement of commercial operations.

Approved Governance Principles

At that same time, Council approved the following governance principles for the NEU:

1. That the NEU will seek to minimise greenhouse gas emissions, consistent with the directions established in the Community Climate Change Action Plan.
2. That the NEU will be operated to ensure long-term financial viability based on a commercial model.
3. That the NEU will strive to establish and maintain customer rates that are competitive with the long-term capital and operating costs of other heating options available to customers.
4. That the City, where feasible, will support the development and demonstration of flexible, innovative and local technologies through the NEU.
5. That the City will consider and evaluate the potential to expand the NEU to other neighbourhoods and developments, with the merits and feasibility of each expansion phase to be determined separately.

Approved Rate-Setting Principles

Council also adopted the following eight principles, to be applied to setting rates and terms of service for NEU customer:

1. That NEU rates are structured so as to recover the following costs incurred by the City, based on forecasted costs:

i. all direct operating costs associated with the NEU,

ii. all debt service and repayment costs associated with the NEU,

iii. the share of City administrative overheads that are attributable to the NEU,

iv. property taxes and/or payments-in-lieu of property taxes, as appropriate,

v. a reserve fund for NEU rate stabilization,

vi. an appropriate level of compensation for the risks and liabilities assumed by the City associated with the ownership and operation of the NEU, and

vii. credits for any benefits provided by the NEU to City taxpayers (e.g., contribution to corporate GHG reductions goals), as determined by Council.

2. That NEU rates fairly apportion the aforementioned costs among customers of the NEU.

3. That NEU rates be understandable to customers, practical and cost-effective to implement.

4. That at least two separate rate classes (commercial and residential) be established to distinguish different types of NEU customers, with rates reflecting each class's proportional contribution to total costs.

5. That, where feasible, NEU rates provide price signals that encourage energy conservation by NEU customers.

6. That the methodology for calculating NEU rates provide year-to-year rate stability for NEU customers to the greatest extent possible.

7. That the methodology for calculating NEU rates provide year-to-year revenue stability for the City to the greatest extent possible, and include the use of a rate stabilization reserve similar to that used by the City for other utility operations.

8. That rates be updated by Council annually based on forecasted costs, and adjusted to reflect any deviation from target levels of reserves, with annual rate changes requiring review and approval by Council followed by enactment of the necessary amendments to the NEU by-law.

November 10, 2015

Mayor and Council
City of Vancouver
453 West 12th Avenue
Vancouver, B.C. V5Y 1V4

Re: Southeast False Creek Neighbourhood Energy Utility – 2016 Rates

Dear Mayor Robertson and Councilors,

The purpose of this letter is to advise Council of the opinion of the Expert Rate Review Panel on the proposed rates to be charged by the Southeast False Creek Neighbourhood Energy Utility (SEFC NEU) for calendar 2016.

The Expert Rate Review Panel met with City staff in April and June of 2015, concerning the Five Year Review of the operations of the NEU. The Five Year Review concluded that "the SEFC NEU is financially viable and that proposed rates going forward are relatively stable and appropriate for a new utility with significant upfront capital investment". The Panel also approved the levelized rate approach as being "appropriate for a young utility".

The Expert Rate Review Panel met again with City staff in October of 2015 to discuss the SEFC NEU's proposed rates for 2016 and to review updated forecasts and Key Performance Indicators. The Panel has also reviewed a draft "Administrative Report to Council" concerning the proposed 2016 customer rates.

Based on the information provided in the Report and discussions with City staff, the Panel supports the proposed rates for 2016, which incorporate a total rate increase of 3.2% above 2015 rates across all customer classes, including an inflationary adjustment of 2%. The Panel also supports the proposed allocation of this increase as between the fixed component (2.5%) and the variable component (4%). The Panel agrees that this allocation will provide an improved conservation price signal while ensuring appropriate cost recovery in accordance with the commercial utility rate model.

The Panel also notes the rates proposed for the SEFC NEU are not out of line with rates being charged by other neighbourhood energy utilities, as documented in the Report, and are expected to remain below those forecasted for BC Hydro over the remainder of the levelized rate period. In the Panel's view a total rate increase of 3.2% including inflation is a relatively modest increase, contributing to the objective of stable and predictable rates.

The Panel further notes that "the SEFC NEU is currently on target for all key financial performance indicators", including a reduction in the time period expected for the recovery of under-recovered early costs, while utilizing a reasonable and consistent rate increase assumption of 3.2% in the forecast.

The Panel would also like to take this opportunity to thank City staff for its assistance and cooperation throughout the review process.

Yours truly,

Alison Rhodes,

Chair, SEFC NEU Expert Rate Review Panel

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 096 *, Approved and Ordered* March 05, 2014

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction No. 6 to the British Columbia Utilities Commission is made.

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other: OIC 1123/2003; OIC 1125/2003

February 18, 2014 R/112/2014/27

DIRECTION NO. 6 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"amortization of capital additions" means the portion of the authority's annual amortization expense that is subject to the amortization of capital additions regulatory account;

"amortization of capital additions regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.7 of the reasons that accompany that order;

"arrow water divestiture costs regulatory account" means the regulatory account established under paragraph 1 of commission order G-90-11;

"arrow water provision regulatory account" means the regulatory account established under paragraph 2 of commission order G-90-11;

"asbestos remediation costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"asbestos remediation regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"deemed equity" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"electric tariff rates" means the rates in the schedules to the authority's electric tariff;

"F2014" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"F2015" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"F2016" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"first nations costs regulatory account" means the regulatory account established under commission order G-53-02;

"heritage payment obligation" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"home purchase option plan regulatory account" means the regulatory account established under commission order G-55-09;

"IFRS pension regulatory account" means the regulatory account established under paragraph 1 (xxii) of commission order G-77-12A;

"IFRS PP&E regulatory account" means the regulatory account established under paragraph 1 (xxi) of commission order G-77-12A;

"non-current pension costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"non-current pension costs regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"non-heritage cost of energy subject to deferral" means the portion of the authority's annual cost of energy that is subject to the non-heritage deferral account;

"non-heritage deferral account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"OATT rates" means the rates in schedules 00, 01 and 03 to the authority's open access transmission tariff;

"rate smoothing regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"real property gain/loss" means the net gain or net loss in a fiscal year incurred by the authority from the sale of its real property;

"related equipment" means the related equipment described in section 3 (b) of the Smart Meters and Smart Grid Regulation;

"Rock Bay costs" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"Rock Bay remediation regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"Site C regulatory account" means the regulatory account established under commission order G-143-06 and section 25 of Appendix A attached to that order;

"smart meter" has the same meaning as in section 17 of the *Clean Energy Act*;

"smart metering and infrastructure program" means the authority's program to install and operate smart meters and related equipment and the program referred to in section 17 (4) of the *Clean Energy Act*;

"SMI regulatory account" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission;

"storm restoration costs" means the costs that are subject to the storm restoration regulatory account;

"storm restoration regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.4 of the reasons that accompany that order;

"total finance charges" means the portion of the authority's annual finance charges that is subject to the total finance charges regulatory account;

"total finance charges regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.2 of the reasons that accompany that order;

"total rate revenue" means the portion of the authority's annual revenues that is subject to the non-heritage deferral account;

"trade income" has the same meaning as in Direction No. 7 to the British Columbia Utilities Commission.

Application

2 This direction is issued to the commission under section 3 of the Act.

Orders

3 Within 20 days of the date on which the authority files an application with the commission to request final orders in regard to the authority's F2014, F2015 and F2016 rates, the commission must issue final orders as follows:

(a) the commission must accept the schedule of expenditures in regard to demand-side measures for F2014, F2015 and F2016 as set out in Appendix A to this direction;

(b) the commission must confirm the authority's rates for F2014, set by commission order G-77-12A, as final and no longer subject to refund;

(c) the commission must set the electric tariff rates for F2015 and F2016 as set out in Appendix B to this direction;

(d) the commission must set the OATT rates for F2015 and F2016 as set out in Appendix C to this direction;

(e) the commission must approve the following forecasts and planned expenditures for F2015:

(i) heritage payment obligation: $353.2 million;

(ii) non-heritage cost of energy subject to deferral: $1 074.3 million;

(iii) total rate revenue: $4 168.3 million;

(iv) trade income: $110.0 million;

(v) non-current pension costs: $2.9 million;

(vi) storm restoration costs: $3.9 million;

(vii) total finance charges: $602.6 million;

(viii) amortization of capital additions: $34.7 million;

(ix) real property gain/loss: $10.0 million;

(x) asbestos remediation costs: $1.8 million;

(f) the commission must approve the following forecasts and planned expenditures for F2016:

(i) heritage payment obligation: $399.2 million;

(ii) non-heritage cost of energy subject to deferral: $1 032.2 million;

(iii) total rate revenue: $4 459.7 million;

(iv) trade income: $110.0 million;

(v) non-current pension costs: $0.1 million;

(vi) storm restoration costs: $3.9 million;

(vii) total finance charges: $725.2 million;

(viii) amortization of capital additions: $106.7 million;

(ix) real property gain/loss: $10.0 million;

(x) asbestos remediation costs: $0.9 million;

(g) the commission must order, in regard to the first nations costs regulatory account, that the authority amortize from that account $43.5 million and $43.3 million in F2015 and F2016, respectively;

(h) the commission must order, in regard to the Site C regulatory account, that the authority defer to that account operating costs it incurs in regard to the Site C project in F2015 and F2016;

(i) the commission must order, in regard to the storm restoration regulatory account, that the authority amortize from that account $1.4 million in each of F2015 and F2016;

(j) the commission must order, in regard to the amortization of capital additions regulatory account, that the authority amortize from that account $9.8 million and $9.4 million in F2015 and F2016, respectively;

(k) the commission must order, in regard to the total finance charges regulatory account, that the authority amortize from that account $25.5 million in each of F2015 and F2016;

(l) the commission must order, in regard to the SMI regulatory account, that

(i) the authority amortize from that account $30.5 million and $31.3 million in F2015 and F2016, respectively, and

(ii) the authority defer to that account net operating costs incurred in F2015 and F2016 arising from the smart metering and infrastructure program and net operating costs arising from commission order G-166-13;

(m) the commission must order, in regard to the home purchase option plan regulatory account, that the authority amortize from that account $11.8 million and $11.3 million in F2015 and F2016, respectively;

(n) the commission must order, in regard to the non-current pension costs regulatory account, that the authority amortize from that account $32.6 million and $15.5 million in F2015 and F2016, respectively;

(o) the commission must order, in regard to the Rock Bay remediation regulatory account, that the authority amortize from that account $51.5 million and $50.5 million in F2015 and F2016, respectively;

(p) the commission must order, in regard to the IFRS PP&E regulatory account, that

(i) the authority amortize from that account $15.9 million and $19.8 million in F2015 and F2016, respectively, and

(ii) the authority defer to that account $156.8 million and $134.4 million in F2015 and F2016, respectively;

(q) the commission must order, in regard to the IFRS pension regulatory account, that the authority amortize from that account $38.2 million in each of F2015 and F2016;

(r) the commission must order, in regard to the arrow water divestiture costs regulatory account, that the authority amortize from that account $4.7 million and $4.5 million in F2015 and F2016, respectively;

(s) the commission must order, in regard to the arrow water provision regulatory account, that the authority amortize from that account $0.3 million in each of F2015 and F2016;

(t) the commission must order, in regard to the asbestos remediation regulatory account, that the authority amortize from that account $12.1 million and $10.7 million in F2015 and F2016, respectively;

(u) the commission must order, in regard to the rate smoothing regulatory account, that the authority defer to that account $166.2 million and $121.2 million in F2015 and F2016, respectively;

(v) the commission must, despite section 5 of Direction No. 3 to the British Columbia Utilities Commission, direct the authority to defer to the non-heritage deferral account the amount that is determined by subtracting the amount in subparagraph (ii) from the amount in subparagraph (i)

(i) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year of 11.84%, and

(ii) the forecast return on deemed equity in F2014 calculated on the basis of an annual rate of return on deemed equity in that year that is greater than or less than 11.84% as a result of the commission's order arising from the generic cost of capital proceeding initiated by commission order G-20-12.

APPENDIX A

F2014 – F2016 DSM Expenditure Schedule

$ MILLION	F2014	F2015	F2016
Codes and Standards	2.4	4.0	4.2
Rate Structures	6.5	2.0	1.7
Programs			
Residential	30.4	17.7	18.9
Commercial	66.4	39.5	40.0
Industrial	101.9	64.3	42.9
Total Programs	198.7	121.5	101.8
Supporting Initiatives	28.7	20.6	20.3
Total Energy Efficiency Portfolio	236.3	148.0	128.0
Capacity Focused DSM	0.0	2.4	3.1
Total	236.3	150.5	131.1

APPENDIX B

Electric Tariff Rates – F2015 and F2016

Rate Class	Rate Schedule	Rate	F2015	F2016
Residential	1101/1121	Basic Charge($/day)	0.1664	0.1764
		Step 1 energy rate ($/kWh)	0.0752	0.0797
		Step 2 energy rate ($/kWh)	0.1127	0.1195
Residential	1105 (closed)	Energy rate ($/kWh)	0.0492	0.0522
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Residential Zone II	1107/1127	Basic Charge ($/day)	0.1775	0.1882
		Step 1 energy rate ($/kWh)	0.0901	0.0955
		Step 2 energy rate ($/kWh)	0.1548	0.1641
Residential	1148 (closed)	Basic Charge($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Residential	1151/1161	Basic Charge ($/day)	0.1775	0.1882
		Energy rate ($/kWh)	0.0901	0.0955
Exempt General Service	1200/1201/ 1210/1211	Basic Charge($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0	0
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55

Rate Class	Rate Schedule	Rate	F2015	F2016
		Energy Rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy Rate – Tier 2 ($/kWh)	0.0486	0.0515
General Service	1205/1206/ 1207	Energy rate – Tier 1 ($/kWh)	0.0492	0.0522
		Energy rate – Tier 2 ($/kWh)	0.0323	0.0342
		Energy rate during period of interruption ($/kWh)	0.2865	0.3037
Small General Service Zone II	1234	Basic Charge ($/day)	0.2129	0.2257
		Energy rate – Tier 1 ($/kWh)	0.1012	0.1073
		Energy rate – Tier 2 ($/kWh)	0.1686	0.1787
Distribution Service	1253	Monthly Minimum energy charge ($/month)	39.03	41.37
Distribution Service	1268	Energy charge ($/kWh)	0.00157	0.00166
Power Service	1278 (Closed)	$/kVA	2.526	2.678
		Energy charge ($/kWh)	0.06604	0.07
		Monthly minimum greater of $/kVA or ($)	4.93 9868.64	5.23 10460.76
Large General Service Zone II	1255/1256/ 1265/1266	Basic Charge ($/day)	0.2129	0.2257
		Energy charge – Tier 1 ($/kWh)	0.1012	0.1073
		Energy charge – Tier 2 ($/kWh)	0.1686	0.1787
Net Metering Service	1289	Energy rate ($/kWh)	0.0999	0.0999
Small General Service	1300/1301/ 1310/1311	Basic Charge ($/day)	0.2129	0.2257
		Energy Charge ($/kWh)	0.1012	0.1073
Irrigation	1401/1402	Irrigation season energy rate ($/kWh)	0.0487	0.0516
		Non-irrigation season energy charge – Tier 1 ($/kWh)	0.0487	0.0516
		Non-irrigation season energy rate Tier 2 ($/kWh)	0.3864	0.4096

Rate Class	Rate Schedule	Rate	F2015	F2016
		Minimum charge irrigation season ($/kW)	4.87	5.16
		Non-irrigation season if consumption >500 kWh ($per kW)	38.98	41.32
Medium General Service	1500/1501/ 1510/1511	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate – Tier 1 ($/kWh)	0.0934	0.0989
		Part 1 Energy Rate – Tier 2 ($/kWh)	0.0651	0.0690
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Rate ($/kWh)	0.0311	0.0330
Large General Service	1600/1601/ 1610/1611	Basic Charge ($/day)	0.2129	0.2257
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 1 Energy Rate Tier 1 ($/kWh)	0.1010	0.1066
		Part 1 Energy Rate– Tier 2 ($/kWh)	0.0486	0.0513
		Part 2 Energy Rate ($/kWh)	0.0971	0.0990
		Minimum Energy Charge ($/kWh)	0.0311	0.0330
Large General Service (150kW and over) for Distribution Utilities	2600/2601/ 2610/2611	Basic Charge ($/day)	0.2129	0.2257

Rate Class	Rate Schedule	Rate	F2015	F2016
		Demand rate – Step 1 ($/kW)	0.00	0.00
		Demand rate – Step 2 ($/kW)	5.19	5.50
		Demand rate – Step 3 ($/kW)	9.95	10.55
		Part 2 Energy Rate $/kWh (RS1600)	0.0971	0.0990
		Embedded Cost Rate $/kWh	0.0501	0.0531
		Discount ($/kWh)	-0.0037	-0.0039
Street Lighting	1701	100 SV fixture rate ($/month)	15.61	16.55
		150 SV fixture rate ($/month)	18.61	19.73
		200 SV fixture rate ($month)	21.49	22.78
		175 MV fixture rate ($/month)	17.15	18.18
		250 MV fixture rate ($/month)	19.76	20.95
		400 MV fixture rate ($/month)	25.48	27.01
Street Lighting	1702	Each Unmetered Fixture ($/watt per month)	0.03	0.0318
		Each Metered Fixture ($/kWh)	0.0901	0.0955
Street Lighting	1703	Energy rate ($/watt per month)	0.03	0.0318
		Contact rate ($/contact per month)	0.9057	0.96
Street Lighting	1704	Energy rate ($/kWh)	0.0901	0.0955
Street Lighting	1755 (closed)	1. Pole owned by Customer		
		175 MV or 100SV fixture charge ($ per month)	14.63	15.51
		400 MV or 150SV fixture charge ($ per month)	25.22	26.73
		2. Pole on public property		
		175 MV or 100SV fixture charge ($ per month)	15.54	16.47
		400 MV or 150SV fixture charge ($ per month)	26.13	27.70
		3. Pole paid by BC Hydro		
		175 MV or 100SV fixture charge ($ per month)	19.13	20.28
		400 MV or 150SV fixture charge ($ per month)	30.11	31.92

Rate Class	Rate Schedule	Rate	F2015	F2016
Transmission Service	1823	Demand rate ($/kVA)	6.925	7.341
		Energy rate A ($/kWh)	0.04059	0.04303
		Energy rate B Tier 1 ($/kWh)	0.03619	0.03836
		Energy rate B Tier 2 ($/kWh)	0.08022	0.08503
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1825	Demand rate ($/kVA)	6.925	7.341
		Winter HLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter HLH energy rate (above 90%) ($/kWh)	0.08952	0.09489
		Winter LLH energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Winter LLH energy rate (above 90%) ($/kWh)	0.08113	0.08600
		Spring energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Spring energy rate (above 90%) ($/kWh)	0.07226	0.07660
		Remaining energy rate (below 90%) ($/kWh)	0.03619	0.03836
		Remaining energy rate (above 90%) ($/kWh)	0.07923	0.08398
Transmission Service	1827	Demand rate ($/kVA)	6.925	7.341
		Energy rate ($/kWh)	0.04059	0.04303
		Minimum demand ($/kVA)	6.925	7.341
Transmission Service	1852	Excess demand rate ($/kVA)	6.925	7.341
Transmission Service	1853	Minimum Monthly Charge ($/month)	39.03	41.37
Transmission Service	1880	Administrative Charge per Period of Use ($)	150.00	150.00
		Energy charge ($/kWh)	0.08022	0.08503
Transmission Service FortisBC	3808	Demand Charge ($/kW)	6.925	7.341

Rate Class	Rate Schedule	Rate	F2015	F2016
		Energy rate ($/kWh)	4.059	4.303

APPENDIX C
BC Hydro OATT Rates – F2015 and F2016

Service	Rate Schedule in Authority's Open Access Transmission Tariff	F2015 Rate	F2016 Rate
Network Integration Transmission Service	00	$52.1 million/month	$62.1 million/month
Long-term Firm Point to Point Transmission Service	01	$53 698/MW/year	$64 968/MW/year
Monthly Short-term Firm and Non-firm Point to Point Transmission Service	01	$4 474.87/MW/month	$5 413.99/MW/month
Weekly Short-term Firm and Non-firm Point to Point Transmission Service	01	$1 032.66/MW/week	$1 249.38/MW/week
Daily Short-term Firm and Non-firm Point to Point Transmission Service	01	$147.12/MW/day	$177.99/MW/day
Hourly Short-term Firm and Non-firm Point to Point Transmission Service	01	$6.13/MW/hour	$7.42/MW/hour
Scheduling, System Control, and Dispatch Service Fee	03	$0.102/MWh	$0.099/MWh

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 097 , *Approved and Ordered* March 05, 2014

Judith D. Guichon
Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that

(a) the Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, B.C. Reg. 158/2005, is repealed, and

(b) the attached Direction No. 7 to the British Columbia Utilities Commission is made.

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3;
BC Hydro Public Power Legacy and Heritage Contract Act, S.B.C. 2003, c. 86, s. 4

Other: OIC 1123/2003

February 18, 2014 R/113/2014/27

DIRECTION NO. 7 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"asbestos remediation costs" means the costs that are subject to the asbestos remediation regulatory account;

"asbestos remediation regulatory account" means the regulatory account established under commission order G-7-13;

"base line rate change" means, for each of F2017, F2018 and F2019, the year-over-year increase in the authority's average rates that the commission determines it would have ordered but for section 9 (1) of this direction, expressed as a percentage;

"Burrard costs" means the costs incurred by the authority in F2014 or a later fiscal year arising from the decommissioning of those portions of Burrard Thermal that are not required for transmission support services, including, without limitation, employee retention costs incurred as a result of the decommissioning, costs incurred as penalties or damages that arise in consequence of the decommissioning, and the net increase in amortization expense in F2015 and F2016 arising from a commission order under section 15 of this direction;

"Burrard Thermal" has the same meaning as in the *Clean Energy Act*;

"California settlements" means the settlement of litigation between Powerex Corp. and various California parties arising from events and transactions in the

California power market during 2000 and 2001, as approved by the Federal Energy Regulatory Commission (US) on October 4, 2013;

"debt" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"deemed equity" means, for any fiscal year, the product obtained by multiplying the rate base relating to that year by 30%;

"deferral account rate rider" means the surcharge, expressed as a percentage, as set out in rate schedule 1901 of the authority;

"distributable surplus" has the same meaning as in Heritage Special Directive No. HC1 to the British Columbia Hydro and Power Authority;

"DSM regulatory account" means the regulatory account of the authority established under commission order G-55-95;

"F2014" means the authority's fiscal year commencing April 1, 2013 and ending March 31, 2014;

"F2015" means the authority's fiscal year commencing April 1, 2014 and ending March 31, 2015;

"F2016" means the authority's fiscal year commencing April 1, 2015 and ending March 31, 2016;

"F2017" means the authority's fiscal year commencing April 1, 2016 and ending March 31, 2017;

"F2018" means the authority's fiscal year commencing April 1, 2017 and ending March 31, 2018;

"F2019" means the authority's fiscal year commencing April 1, 2018 and ending March 31, 2019;

"First Nations settlements" means the settlement of litigation between the authority and the Tsay Keh Dene and Kwadacha First Nations, and the settlement of damages claims by the St'at'imc First Nation against the authority, as agreed to between the authority and the first nation on August 31, 2009, November 27, 2008 and May 10, 2011, respectively;

"government policy directive" means a directive in writing to the authority from the minister responsible for the administration of the *Hydro and Power Authority Act*;

"heritage contract" means the document attached as Appendix A to this direction;

"heritage deferral account" means the Heritage Payment Obligation Deferral Account established under commission order G-96-04 and the direction in section 4.5 of the reasons that accompany that order;

"heritage energy" has the same meaning as in the heritage contract;

"heritage payment obligation" has the same meaning as in the heritage contract;

"heritage resources" has the same meaning as in the heritage contract;

"non-current pension costs" means the costs that are subject to the non-current pension costs regulatory account;

"non-current pension costs regulatory account" means the regulatory account established under commission order G-16-09 and the direction in section 5.5.5 of the reasons that accompany that order;

"non-heritage deferral account" means the Non Heritage Deferral Account established under commission order G-96-04 and the direction in section 4.5 of the reasons that accompany that order;

"public awareness program" has the same meaning as in the Demand-Side Measures Regulation;

"rate base" means, in relation to a fiscal year of the authority, the amount determined in accordance with the following equation and notes:

$$RB = WCA + (A+B+C)/2 - (D + E + F)/2$$

where

RB =	rate base;
WCA =	working capital amount of $250 million;
A, B, D, E and F =	the sum of an amount the authority forecasts will be listed as follows in the authority's audited financial statements at the end of the previous fiscal year and the amount the authority forecasts will be similarly listed at the end of the applicable fiscal year:
A	is the amount listed as property, plant and equipment in service, less accumulated amortization;
B	is the amount listed as intangible assets in service, less accumulated amortization;
D	is the amount listed as contributions in aid of construction;
E	is the amount listed as contributions arising from the Columbia River Treaty;
F	is the amount listed as leased assets included in A, less accumulated amortization;
C =	the sum of the balance the authority forecasts for DSM regulatory account at the beginning of the fiscal year and the balance the authority forecasts for the same account at the end of the fiscal year.

Notes:

1 In determining rate base for a fiscal year, the amounts A, B and F must have subtracted from them any amount included in them that is an expenditure incurred by the authority on or after April 1, 2011, that the commission determines under the Act must not be recovered by the authority in rates.

2 In determining rate base for a fiscal year, the amount D must have subtracted from it any amount included in it that is related to an expenditure referred to in note 1;

"rate smoothing regulatory account" means the regulatory account the commission must allow the authority to establish under section 7 (h) (i) of this direction;

"real property sales regulatory account" means the regulatory account the commission must allow the authority to establish under section 7 (h) (ii) of this direction;

"retail access program" has the same meaning as in commission order G-39-12;

"Rock Bay costs" means the costs of the authority in F2014 or a later fiscal year subject to the Rock Bay remediation regulatory account;

"Rock Bay remediation regulatory account" means the regulatory account established under commission order G-75-11;

"Rock Bay settlement" means the settlement of litigation between the authority and the Attorney General of Canada as concluded through the issuance of a consent dismissal order in favour of the authority on June 1, 2012;

"SMI regulatory account" means the regulatory account established under commission order G-64-09;

"specified demand-side measure" has the same meaning as in the Demand-Side Measures Regulation;

"trade income" means,

(a) for all of the authority's fiscal years except F2014, the greater of the following:

(i) the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex Corp., less the amount that the authority's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between the authority and Powerex Corp;

(ii) zero, and

(b) for F2014, the amount that is equal to the authority's consolidated net income, less the authority's net income, less the net income of the authority's subsidiaries except Powerex Corp., less the amount that the authority's consolidated net income changes due to foreign currency transaction gains and losses on intercompany balances between the authority and Powerex Corp.;

"trade income deferral account" means the regulatory account established under commission order G-96-04 and the direction in section 4.6 of the reasons that accompany that order;

"transmission rate customers" means industrial or commercial customers of the authority who are eligible for service under rates designed by the commission under section 3 (1).

Application

2 This direction is issued to the commission under section 3 of the Act.

Consideration in designing rates for transmission rate customers

3 (1) In designing rates for the authority's transmission rate customers, the commission must ensure that those rates are consistent with recommendations #8

to #15 inclusive in the commission's report and recommendations to the Lieutenant Governor in Council dated October 17, 2003.

(2) Without limiting subsection (1), the commission must ensure the following:

(a) the rates for the authority's transmission rate customers are subject to

(i) the terms and conditions found in Supplements 5 and 6 to the authority's tariff, and

(ii) any other terms and conditions the commission considers appropriate for those rates;

(b) customers who own multiple plants under common ownership may engage in load aggregation for energy, if each plant

(i) is in operation, and

(ii) meets the requirements to be a transmission rate customer that are set out in the authority's electric tariff, or is otherwise authorized by the commission to be treated as a transmission rate customer.

Basis for establishing authority revenue requirements

4 Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to

(a) provide reliable electricity service,

(b) meet all of its debt service, tax and other financial obligations,

(c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and

(d) achieve an annual rate of return on deemed equity

(i) for F2015, F2016 and F2017, that is equal to 11.84%,

(ii) for F2018 and subsequent fiscal years the annual rate of return on deemed equity that would be necessary to yield a distributable surplus in the applicable fiscal year equal to the product of

(A) the distributable surplus in the immediately preceding fiscal year, and

(B) 100% plus the percentage change in the British Columbia consumer price index in the applicable fiscal year.

Determining the cost of energy

5 In setting the authority's rates, the commission

(a) must treat the heritage contract as if it were a legally binding agreement between 2 arms-length parties,

(b) must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract,

(c) may employ any mechanism, formula or other method authorized by section 60 (1) (b.1) of the Act, and

(d) unless a different mechanism, formula or method is employed under paragraph (c), must ensure that electricity used by the authority to meet its domestic service obligations is provided to customers on a cost-of-service basis.

Use of trade income in setting rates

6 In setting rates for the authority, the commission must include the net income of the authority's subsidiaries, assuming that the net income of Powerex Corp. equals trade income.

Regulatory accounts

7 When regulating and setting rates for the authority, the commission

(a) must allow the authority to continue to defer to the heritage deferral account the variances between the actual and forecast heritage payment obligation,

(b) must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income,

(c) must, in regard to the non-heritage deferral account, allow the authority to

(i) continue to defer to that account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load, and

(ii) defer to that account the Burrard costs,

(d) must, in regard to the DSM regulatory account, allow the authority to

(i) defer to that account the authority's costs arising from its development, implementation and administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs, and

(ii) amortize from that account in each fiscal year an amount equal to the sum of

(A) the amount amortized in the immediately preceding fiscal year less the amortization in that year associated with costs incurred more than 15 fiscal years prior to that year, and

(B) the product of the amount deferred to that account in the immediately preceding fiscal year and 1/15,

(e) must allow the authority to continue to defer to the Rock Bay remediation regulatory account the Rock Bay costs,

(f) must allow the authority to continue to defer to the asbestos remediation regulatory account the variances between actual and forecast asbestos remediation costs,

(g) must allow the authority to continue to defer to the non-current pension costs regulatory account the variances between actual and forecast non-current pension costs,

(h) must allow the authority to establish the following regulatory accounts:

(i) an account to defer for recovery in rates in future fiscal years of the authority those portions of the authority's allowed revenue requirement in a particular fiscal year that were not or are not to be recovered in rates in that particular fiscal year;

(ii) an account to defer the variances between the authority's actual and forecast real property gain/loss,

(i) must allow the following regulatory accounts to accrue interest in a fiscal year at the authority's weighted average cost of debt in that year:

(i) the first nations costs regulatory account;

(ii) the real property sales regulatory account,

(j) may allow the authority to establish one or more other regulatory accounts for other purposes, and

(k) subject to section 9 (1) of this direction, must set the authority's rates in such a way as to allow the regulatory accounts to be cleared from time to time and within a reasonable period.

Annual distributable surpluses allowed

8 When regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to allocate annual distributable surpluses in the manner specified by the Lieutenant Governor in Council under section 4 of the *BC Hydro Public Power Legacy and Heritage Contract Act* or section 35 of the *Hydro and Power Authority Act.*

F2017, F2018 and F2019 rates

9 (1) When regulating and setting rates for the authority for F2017, F2018 and F2019, under sections 4, 5, 6, 7, 9 (2), 10 (3) and 11 of this direction, the commission must not allow the rates to increase by more than 4% in F2017, 3.5% in F2018 and 3% in F2019, on average, compared to the rates of the authority immediately before the increase.

(2) If the base line rate change exceeds 4% in F2017, 3.5% in F2018 or 3% in F2019, the commission must order the authority to defer to the rate smoothing regulatory account the amount that is determined by subtracting the amount in paragraph (b) from the amount in paragraph (a)

(a) the forecast revenue that the authority would have earned under a base line rate change, and

(b) the forecast revenue that the authority is expected to earn under this direction.

Deferral account rate rider

10 (1) The commission must set the deferral account rate rider for F2015 and future fiscal years of the authority at 5%.

(2) The commission must not order any change to the deferral account rate rider, except on application by the authority.

(3) The commission must allow the authority, in regard to a fiscal year of the authority, to account for the forecast revenue from the deferral account rate rider as follows:

(i) a portion of the forecast revenue from the deferral account rate rider is to be accounted for as revenue in that fiscal year in accordance with equation 1 and the following table;

(ii) a portion of the forecast revenue from the deferral account rate rider is to be amortized from the forecast net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year in accordance with equation 2 and the following table:

Equation 1: DARR (Rev) = DARR – (X/5) x DARR

Equation 2: DARR(DA) = (X/5) x DARR

where

DARR (Rev) = the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is to be accounted for as revenue;

DARR(DA) = the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is to be amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year;

DARR = forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority;

X = the number in column X of the following table that corresponds to the forecast net balances of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year that is between the values shown in columns A and B of the following table:

Table		
A ($ million)	B ($ million)	X
< -500	-500	-5.0
-500	-450	-4.5
-450	-400	-4.0

Table		
A ($ million)	B ($ million)	X
-400	-350	-3.5
-350	-300	-3.0
-300	-250	-2.5
-250	-200	-2.0
-200	-150	-1.5
-150	-100	-1.0
-100	-50	-0.5
-50	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	> 500	5.0

(iii) the portion of forecast revenue from the deferral account rate rider in the applicable fiscal year of the authority that is amortized from the net balance of the heritage deferral account, the non-heritage deferral account and the trade income deferral account at the end of the immediately preceding fiscal year must be amortized from the respective balances of those accounts in proportion to the ratios of the balances of those accounts to the net balance of all 3.

Commission reviews

11 When setting rates for the authority under the Act, the commission must not disallow for any reason the recovery in rates of the costs that were incurred by the authority or Powerex Corp. in consequence of decisions of either with respect to

(a) the construction of extensions to the authority's plant or system that come into service before F2017,

(b) energy supply contracts entered into before F2017,

(c) the Rock Bay settlement,

(d) the First Nations settlements,

(e) the California settlements,

(f) the Burrard costs, and

(g) the costs deferred to the SMI regulatory account.

Expenditures for export

12 The commission must refrain from performing its duty under section 4 (5) of the *Clean Energy Act* when setting rates for the authority for F2014, F2015, F2016, F2017 and F2018.

Powerex Corp.

13 The commission may not exercise any power under Part 3 of the Act in regard to the gas and electricity trading activities of Powerex Corp.

Retail access

14 (1) By March 23, 2014, the commission must issue orders as follows:

(a) the commission must accept a withdrawal by the authority of any obligation to offer unbundled transmission services under the authority's open access transmission tariff to retail customers in British Columbia, and a withdrawal of any obligation to offer such services to those who supply such customers;

(b) the commission must order the cancellation of the retail access program.

(2) Except on application by the authority, the commission must not set rates for the authority that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.

Burrard Thermal

15 On application by the authority the commission must

(a) grant permission to the authority under section 41 of the Act to cease operating those portions of Burrard Thermal that are not required for transmission support services, and

(b) set depreciation rates for the classes of property, plant and equipment at Burrard Thermal as shown in Appendix B to this direction.

Rates

16 (1) The commission may not reconsider, vary or rescind the orders it issues under this direction or Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority.

(2) For F2014, F2015 and F2016, the commission must not issue any orders in regard to the authority's regulatory accounts, except on application by the authority.

(3) In setting the authority's rates for F2015, F2016, F2017, F2018 and F2019, the commission must exercise its powers and perform its duties consistently with the orders it issues under Direction No. 6 to the British Columbia Utilities Commission, except on application by the authority.

(4) Nothing in this section prevents the commission from making determinations on applications made by the authority respecting revenue-cost ratios, rate design and regulatory accounts, including interim rate orders in regard to one or more of the authority's customers.

APPENDIX A – HERITAGE CONTRACT

Definitions

1 In this Agreement:

"Agreement" means this Heritage Contract including Schedule A;

"Ancillary Service Requirements" means services necessary to deliver energy;

"BC Hydro" means the British Columbia Hydro and Power Authority;

"BCH Distribution" means BC Hydro's distribution line-of-business;

"BCH Generation" means BC Hydro's generation line-of-business;

"Commission" means the British Columbia Utilities Commission;

"heritage electricity" means the capacity, energy and ancillary services that BCH Generation is required to supply to BCH Distribution under this Agreement;

"heritage energy" means

(a) subject to paragraph (b), 49 000 GW.h per year less the energy generated for delivery under the Skagit Valley Treaty, or

(b) the quantity of energy determined by the Commission under section 8 of this Agreement to be heritage energy;

"heritage payment obligation" means

(a) subject to paragraph (b), the annual payment determined in accordance with the procedure set out in Schedule A to this Agreement, or

(b) the annual payment determined by the Commission under section 8 of this Agreement to be the heritage payment obligation;

"heritage resources" means the Electric Facilities and Thermal Facilities described in Schedule A to the Terms of Reference, together with

(a) the related civil works and plant, and

(b) potential future investments that increase the capacity, energy or ancillary service capability of such facilities, including potential future units 5 and 6 at Mica and potential future units 5 and 6 at Revelstoke;

"Order" means an order of the Commission;

"Terms of Reference" means Schedule A, Terms of Reference, to Order in Council 253/2003;

"Transfer Pricing Agreement" means the Transfer Pricing Agreement for Electricity and Gas dated April 1, 2003 between BC Hydro and Powerex Corp. as amended from time to time;

"Year" means fiscal year.

Electricity supply

2 BCH Generation must provide the full capacity of the heritage resources to BCH Distribution on a priority call basis.

Obligation to supply

3 BCH Generation must supply to BCH Distribution, in each Year, the heritage energy or such lesser amount of energy as may be required by BCH Distribution.

Obligation to deliver

4 BCH Generation will deliver the heritage energy to BCH Distribution at the various points of interconnection of the generating stations included in the heritage resources with the BC Hydro transmission grid or at points of interconnection with other utilities, as appropriate.

Responsibility for obtaining transmission services

5 BCH Distribution will be responsible for obtaining transmission services for energy provided to BCH Distribution.

Ancillary services

6 The parties may use the capacity available to them under section 2 to deliver energy to meet customer demand and to satisfy the parties' Ancillary Service Requirements, regardless of whether provision for self-supply is made under any tariff.

Payment

7 BCH Distribution must, on or before the end of each Year, pay to BCH Generation an amount equal to the heritage payment obligation.

Adjustment

8 The parties acknowledge that

(a) the Commission may, by Order, modify one or both of the definitions of "heritage energy" and "heritage payment obligation" if the Commission is satisfied that a change in circumstances has permanently affected

(i) the capability of the heritage resources to provide one or both of capacity and energy, or

(ii) the authority's cost of generating the heritage energy, and

(b) any such modification will automatically modify the heritage energy or the heritage payment obligation, as the case may be, without further action by the parties.

Information exchange and cooperation

9 Each party will continue to freely provide the other with any requested information to facilitate the coordinated and optimal operation of the BC Hydro system.

Dispute resolution

10 (1) The parties will make reasonable efforts to resolve disputes arising in relation to this Agreement at the staff level.

(2) As needed, issues may be dealt with by management levels within each party to achieve timely resolution.

(3) Issues that cannot be resolved in a timely manner at senior management levels may be referred by either party to the commission for resolution.

Term

11 This Agreement commenced on April 1, 2004.

SCHEDULE A TO APPENDIX A – HERITAGE PAYMENT OBLIGATION

1 The heritage payment obligation for any Year is the amount determined by

(a) adding those of the following costs incurred by BCH Generation in the Year that the Commission orders may be included in the heritage payment obligation:

(i) cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;

(ii) operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;

(iii) all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;

(iv) all costs or payments related to generation-related transmission access required by the heritage resources, and

(b) subtracting from the sum obtained under paragraph (a) any revenues BCH Generation receives from other services provided from the heritage resources, including, without limitation,

(i) revenues related to Skagit Valley Treaty obligations,

(ii) revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

(iii) revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

APPENDIX B – BURRARD DEPRECIATION RATES

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C12101 Tracks, Railway	100.0%	N/A
C12401 Drainage System Yard	9.1%	10.0%
C21901 Roofs	9.1%	10.0%
C22001 Plant Concrete Steel	15.8%	18.8%
C22002 Comm Concrete Steel	9.1%	10.0%
C22005 Building, Comp Pool	9.1%	10.0%
C22006 Equipment Shelter	19.0%	23.5%
C22009 Building-HVAC Sys&Cp	10.1%	11.1%
C22101 Off Trailer/Mob Home	9.3%	10.0%
C23801 Cranes	9.1%	10.0%
C24402 Ramp, Boat/Barge	85.7%	100.0%
C25101 Structure Supp Steel	9.1%	10.0%
C25301 Foundations	9.1%	10.0%
C25401 Ducts & Trenches	9.1%	10.0%
C25601 Barriers & Enclos	20.0%	25.0%
C30101 Casing, Boiler	50.0%	100.0%
C30102 Insulation, Boiler	14.3%	16.7%
C30103 Roof, Boiler	50.0%	100.0%
C30203 Superheater HighTemp	50.0%	100.0%
C30204 Superheater Low Temp	54.5%	100.0%
C30205 Reheater, Boiler	50.0%	100.0%
C30301 Header / Drum	50.3%	100.0%
C30401 Valves, Safety	14.5%	17.0%
C30501 Piping, High Press	33.4%	41.5%
C30601 Fan, Forced Draft	50.0%	100.0%
C30602 Breaching / Flue Sys	54.5%	100.0%
C30603 Stack, Flue Gases	50.0%	100.0%
C30605 Burner, Fuel	50.0%	100.0%
C30606 Instrument, Boiler	51.3%	98.6%
C30607 DNU - Asbe Abatement	9.1%	10.0%
C30611 Desuperheater System	50.0%	100.0%
C30612 Refractory, Boiler	54.5%	100.0%
C30613 Boiler, Package	54.5%	100.0%

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C30701 Equip, Water Treat	50.0%	100.0%
C30801 Transfer Sys Ammonia	92.3%	100.0%
C30802 Water Sys Ammonia	92.3%	100.0%
C30803 Vapouriser, Ammonia	92.3%	100.0%
C30804 Comp Vapour, Ammonia	92.3%	100.0%
C30805 Piping Sys, Ammonia	50.0%	100.0%
C30901 Monitor Equip, Cem	54.5%	100.0%
C30903 Deliver Sys, Ammonia	55.5%	100.0%
C31001 Water Intk/DisStruct	9.1%	10.0%
C31002 Protection, Cathodic	9.1%	10.0%
C31003 Gates, Inlet/Outlet	9.1%	10.0%
C31005 Conduit, Intake/Disc	9.1%	10.0%
C33001 Heat Exch, Shell Tube	50.0%	100.0%
C33002 Pump And Motor	50.0%	100.0%
C33004 Condenser, Boiler	50.0%	100.0%
C34004 Turbine, Comp Pool	22.2%	28.5%
C34005 Coils, Stator	9.3%	10.3%
C34006 Rotor, Generator	9.1%	10.0%
C34007 Generator, Comp Pool	28.6%	40.1%
C34008 Supervisory Sys Turb	70.9%	55.8%
C34009 Cooling Sys Hydrogen	15.8%	18.7%
C34015 Turbine Blades Sets	31.7%	46.4%
C42004 Major Maint.-Rewedge	25.3%	33.8%
C42102 Exciter, Static	42.7%	74.6%
C46701 Heat Exchanger	50.0%	100.0%
C47201 Turbine, Gas	50.0%	100.0%
C47202 Major Maint.-Gas Tur	80.0%	100.0%
C48003 Generator, Composite	29.7%	42.3%
C48004 Generator, Diesel	25.8%	34.8%
C49001 Pump	44.4%	77.8%
C49002 Motor	12.3%	14.1%
C51001 Condensor, SyncRotary	9.1%	10.0%
C52104 Transformer, <100Mva	50.0%	100.0%
C52105 Transformer, Stn Ser	10.5%	10.0%
C52302 Reactor, Dry Type	99.9%	100.0%
C52405 Transformer, Curr, Com	35.3%	54.6%

Class of Property, Plant and Equipment at Burrard Thermal	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)
C52504 Trans, Volt, Encaps.	9.1%	10.0%
C54101 Breaker, Air/Magnetic	9.1%	10.0%
C54201 Use Ind Disconnect	20.0%	25.0%
C55401 Buswork & StnConduct	9.1%	10.0%
C55501 Grounding Systems	9.1%	10.0%
C56001 Insulators	9.1%	10.0%
C59001 Power Supp Uninterr	39.4%	65.1%
C59101 Regulator FeederCirc	9.1%	10.0%
C59201 Charger System, Batt	13.3%	15.3%
C61001 Fencing	9.1%	10.0%
C61101 Alarm/Security Sys	9.1%	10.0%
C62001 Fire Protection Sys	12.0%	13.6%
C62501 Firefighting Equip	33.3%	50.0%
C65001 Panels/Cubicles, P&C	13.0%	14.9%
C67003 Contain Fac, Concret	9.1%	10.0%
C67005 Oil Spill Containmen	9.1%	10.0%
C68202 Term Unit, Rem(Slave)	23.1%	30.0%
C68204 Distributed Ctrl Sys	30.4%	42.9%
C68301 Radio, MW, Analog	9.1%	10.0%
C68901 Tele Equip, Pbx/Pax	100.0%	N/A
C70104 Instrumentation-Digi	9.1%	10.0%
C74001 Motor-Generator Sets	92.3%	100.0%
C75104 Compressor, Air	18.3%	21.3%
C75201 Tanks, Steel, Air/Fuel	9.1%	10.0%
C75202 Tank, Fibrglas, DblB	9.1%	10.0%
C75301 Water Supply System	9.1%	10.0%
C82504 Loader/Backhoe	8.3%	9.0%
C82513 Manlift	66.7%	100.0%
C82550 Tools/Work EquipMisc	12.3%	14.0%
C82551 DNU - Tools/Work Equ	21.7%	27.1%
C82601 Test/Calibration	43.9%	73.2%
C82603 Manufacturing/Test	24.4%	12.5%
C88002 Lab Equipment, Misc	30.8%	27.3%