# Neighbourhood District Energy System for UBC Expansion Areas

## Business Case Report

**Prepared for**

The University of British Columbia
With funding support from BC Hydro

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## Executive Summary

In June 2011, Stantec and earthvoice strategies completed a pre-feasibility study of a District Energy (DE) system for Wesbrook Place for the University of British Columbia (UBC), with funding support from BC Hydro. The study was undertaken to support UBC's sustainability goals and greenhouse gas (GHG) emissions reduction targets. Using preliminary, screening-level assumptions, the pre-feasibility study results suggested a Neighbourhood District Energy System (NDES) using waste heat capture from TRIUMF (Canada's national laboratory for particle and nuclear physic) was technically and potentially economically viable. Stantec recommended a full feasibility study be conducted.

In December 2011, UBC, with financial support from BC Hydro, commissioned FVB and Compass Resource Management to prepare a full feasibility study to assess the potential for a NDES serving Wesbrook Place, as well as the Stadium, Acadia West, Acadia East, East Campus, and Block F (Musqueam lands) Development Areas.

The full feasibility was separated into two components: a) a technical study; and b) the business case. The technical analysis was completed by FVB. The business case was completed by Compass. This report summarized the business case, which draws on technical inputs provided by FVB.

Some key conclusions and recommended next steps from the detailed feasibility study are as follows:

- District energy is one of the most common approaches worldwide for heating university, medical, and military campuses with single owners. District energy is also an established and growing strategy for heating high-density, mixed use, multi-owner urban developments. District energy provides a flexible platform for integrating alternative technologies not available, appropriate or economic at a building scale. District energy is increasingly seen as one of the key tools to provide deep GHG reductions in dense urban areas, while providing other community benefits such as energy security, economic development, and more productive use of various waste streams.

- There are large existing commercial DE systems in the Lower Mainland (e.g., Central Heat in downtown Vancouver) and virtually all significant master planned developments in the region are considering or have installed district energy systems to meet economic, environmental and social objectives, including major developments in Vancouver, North Vancouver, Richmond, Surrey, and Coquitlam. A system is currently being installed by Corix Utilities

to serve Phases 3 and 4 of UniverCity (initiated and facilitated by the SFU Property Trust).

- A NDES serving UBC's Wesbrook, Stadium, Acadia and Block F Development Areas and using waste heat from TRIUMF and/or biomass is technically feasible. Waste heat will be captured from TRIUMF's cooling towers. Heat recovery from cooling towers is a very common practice.

- The NDES will provide significant reductions in natural gas use and GHG emissions and moderate reductions in electricity use (at build out), both to the target Development Areas and to the Academic Campus. The NDES supports UBC's near-term GHG reduction targets. It also facilitates access to more distant alternative energy sources to meet more aggressive significant long-term reduction targets. The system supports UBC's vision for a sustainable community with seamless integration to surrounding academic uses. There are also many teaching, research, and demonstration opportunities associated with the NDES (both in terms of technical and socio-economic aspects), which is consistent with UBC's vision of a living lab.

- Waste heat from TRIUMF is the preferable starting technology, but biomass offers an economically viable alternative to TRIUMF if agreements cannot be reached with TRIUMF to access waste heat and optimize system design. Biomass also offers a source of supplemental alternative energy in future phases of development.

- The integration of the NDES and Academic District Energy System (ADES) provides significant benefits to both the NDES and ADES. The campus loads support the early installation of significant infrastructure, including the waste heat recovery system and help to reduce the system cost to residents. The ADES, in turn, will benefit from the ability to secure low-carbon energy to meet 2020 targets at a competitive cost with other alternatives. The NDES will also enable the ADES to more easily and cheaply access other alternative energy sources in the future within the South Campus and beyond. In addition to avoided gas and offset costs, there may be additional opportunities to avoid or defer certain capital costs within the ADES (e.g., additional peaking capacity). These opportunities can be explored more fully during detailed phases of system design and contract negotiations.

- The integration of the NDES and ADES can be achieved through an indirect connection, permitting separate ownership of NDES and ADES assets.

Transfers of energy between systems can be governed by an explicit internal transfer pricing system (if the NDES is owned by UBC) or through contract with a third party owner.

- The NDES is likely to be regulated by the BCUC, regardless of ownership. Even if exempted under UBC ownership (which is not guaranteed based on an initial review of the *Utilities Commission Act*), UBC may wish to submit to voluntary regulation of retail rates to ensure transparency and minimize potential disputes. Integration of the NDES and ADES is not likely to trigger BCUC oversight of the ADES, although the BCUC would likely review any contract or transfer pricing provisions between the NDES and ADES to ensure fairness to residents. BCUC oversight of a third party owner of the NDES would also provide additional (ongoing) oversight of the cost inputs, price, terms and conditions of any energy purchase agreement by UBC.

- Under a set of conservative but realistic Reference Case assumptions and a variety of ownership scenarios, the NDES cost to residents would be equal to or lower than the benchmark cost for 100% electric heat. This benchmark of 100% electric heat has been used to evaluate the cost-effectiveness of other low-carbon district energy systems throughout the Lower Mainland, and has also been accepted by the BCUC as one of benchmarks for determining whether systems are in the public interest. Under low expected natural gas prices, the cost of the NDES cost is slightly higher than a benchmark of a mix of electricity and natural gas (including additional capital replacement costs and operations associated with gas-fired equipment), but there is also higher uncertainty over future gas prices and GHG costs. The mixed gas/electric benchmark also has much higher GHG emissions than 100% electric. The projected NDES cost is within the range of heating costs for both existing and new buildings in the Lower Mainland reflecting a wide range of energy use intensities and energy sources.

- Assuming a fully allocated cost model and comparable cost of capital for UBC and private owners, there are minimal differences in the cost to customers under different ownership models. UBC ownership offers slight advantages in terms of income and property tax treatment, and some potential staffing synergies with the existing ADES. The latter synergies could potentially be captured under private ownership through a service contract between the NDES owner and UBC. Greater leverage and/or lower debt costs would also increase the net benefits to customers.

- Key downside risks (risks that would result in higher rates to residents and/or reduced returns or forgone non-cash costs) include slower development, persistently low natural gas prices (which lower the NDES gas costs but also the value of waste heat all things being equal), lower energy consumption (from higher than expected improvements in energy efficiency), and higher capital costs. Heat pump performance is important but has less impact than other uncertainties. Under a regulated model, these risks are borne largely by ratepayers in terms of higher potential rates. Under most scenarios tested, NDES rates remain within an acceptable range. There are also project optimizations and risk management strategies to reduce or eliminate the impact of certain uncertainties.

- There are also several opportunities for optimizing the system including:

    - Altering the annual shutdown at TRIUMF.

    - Sharing peaking capacity between the NDES and ADES.

    - Further monetization of GHG reduction benefits in the NDES.

    - Securing grants and low cost financing.

    - Additional optimization of the sizing and phasing of capital equipment, including use of temporary gas plants to optimize installation of distribution infrastructure and connection of Acadia / Block F Development Areas to the ADES (vs. direct connection to Wesbrook).

    - Reducing staffing requirements through reduced requirements for full time supervision and/or additional staffing synergies with the ADES.

    - Bulk purchasing of distribution piping in conjunction with the hot water conversion of the ADES.

    - Securing additional loads (e.g., Centre for Comparative Medicine located south of TRIUMF).

- The project has additional upside under certain scenarios (e.g., higher carbon taxes, rapid growth, higher energy demands, higher gas prices, deferral or

redeployment of Academic system capacity, marketing or other community development benefits).

- Discussions with TRIUMF suggest the facility will continue to operate for some time. Additional due diligence will be required regarding the actual quantity of waste heat available from TRIUMF and the best method of interfacing with the facility's cooling water system. This can be investigated during the next phase of development, in advance of formal investment. Ideally, these investigations would be undertaken by or in partnership with the ultimate NDES owner.

- Regardless of system ownership, as the master developer of the target development areas and as a major purchaser of energy in the near-term UBC has considerable influence over system development and business risk. UBC also has the ability to reduce or defer certain non-cash costs in the near-term in order to enhance competitiveness and mitigate development risks.

- For UBC, the main concerns with ownership of the NDES are available capital and complexities associated with governing a commercial (and potentially regulated) service to non-academic users. UBC is facing considerable constraints on future capital available for core academic purposes. At the same time, the NDES provides financial and strategic benefits to UBC.

- Given the strategic alignment of the NDES with UBC's academic and community visions, goals and strategies we recommend UBC proceed to the next steps of facilitating development of the NDES with a connection to the ADES and initially utilizing waste heat from TIRIUMF. Some key next steps include:

    - Require buildings to be DE ready and to connect to the NDES as condition of their ground lease (this requirement will reduce DE development risk and financing costs).

    - Explore other policy support for the NDES including access to rights of way for NDES infrastructure and principles for cost allocation.

    - Commence discussions with Musqueam Nation regarding the inclusion of Block F in a future system and potential partnership or employment opportunities for Musqueam.

- Pursue any available grants for the NDES. In the case of the hybrid ownership options, there may be funds available through P3 Canada.
- Ensure building mechanical systems are compatible and designed to maximize reliance on NDES and efficiency of NDES. This means creating a design document and design review to ensure compatible and optimized buildings systems similar to the design documents created by the Cities of North Vancouver and Vancouver. In the case of the City of North Vancouver, they have included a requirement for a security deposit to be returned when the building meets design and commissioning requirements for connection.[1]
- Commence formal discussions with TRIUMF regarding the terms and conditions of waste heat recovery (access, conditions, governance, etc.), including discussions regarding the annual shutdown period. Ideally this would result in a formal term sheet. This should involve the ultimate NDES owner but in the absence of an identified party, UBC should commence preliminary discussions to maintain viability and meet project schedules.
- Consider further optimization of sizing and configuration of the NDES Energy Centre and distribution system during detailed design phase, in particular options for optimizing phasing of distribution system and Energy Centre (e.g., through the possible use of temporary plants) and the possibility of sharing peaking services between the NDES and ADES.
- Given the capital constraints facing UBC and concerns about governance and providing a commercial service for non-academic users, seek a possible private sector partner to design, develop, own and operate the NDES. The first step in this process would be to issue a Request for Qualifications, similar to the process used for UniverCity among others.
- We recommend deferring the decision on the form of agreement with the successful RFQ proponent. There are several options ranging from no UBC partnership to partial ownership by UBC. In the case of partial ownership, we recommend a split assets model with UBC owning or partly owning the TRIUMF Energy Centre given UBC's expected use of

[1] UBC has created hydronic system requirements for new development but recent projects are not optimized for utilization of district energy.

the Energy Centre and the closer alignment with UBC's core competencies in energy production. Even if UBC does not participate in ownership of the NDES, there may be opportunities for strategic agreements to support and guide the development of the NDES, including an energy purchase agreement (for surplus heat in early years), an energy sales agreement (in the event the ADES provides peaking support), a franchise agreement (including exclusivity and possible franchise fees), various shared services agreements (to secure operating synergies between systems), environmental targets/commitments, and joint development opportunities for additional green energy sources.

- Establish tentative transfer pricing policy for purchases / sales by Academic Campus from / to NDES (in event of UBC ownership or to guide contract discussions with a third party).
- Regardless of the ownership model, pursue a fully-allocated pricing policy for the use of all UBC land and services by the NDES.

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# 1 Introduction

In June 2011, Stantec and earthvoice strategies completed a pre-feasibility study of a District Energy (DE) system for Wesbrook Place for the University of British Columbia (UBC), with funding support from BC Hydro. The study was undertaken to support UBC's sustainability goals and greenhouse gas (GHG) emissions reduction targets. The pre-feasibility study included:

- A quantitative and qualitative description of the study area;
- A phased service plan for the core area, which includes a renewable energy phase;
- An estimate of the GHG and electrical load reduction compared to business-as-usual;
- An economic, environmental and social analysis for the full build-out of the system;
- Analysis of the governance options, and;
- A summary of the major obstacles to successful implementation.

Using preliminary, screening-level assumptions, the pre-feasibility study results suggested a Neighbourhood District Energy System (NDES) using waste heat capture from TRIUMF (Canada's national laboratory for particle and nuclear physic) was technically viable and marginally viable from an economic standpoint. Stantec recommended a full feasibility study be conducted.

In December 2011, UBC, with financial support from BC Hydro, commissioned FVB and Compass Resource Management to prepare a full feasibility study to assess the potential for a NDES serving Wesbrook Place, as well as several additional planned development areas (collectively, Development Areas) including:

- Acadia East – private residential;
- Acadia West – student residential;
- East Campus;
- Stadium Neighbourhood; and
- Block F Neighbourhood (UEL Zoning RM1. Musqueam lands)

These areas are highlighted in Figure 1.

**Figure 1: Study Area**


The full feasibility analysis was split into two components: a) a technical study; and b) the business case. The technical analysis was completed by FVB and includes the following elements:

- Load forecasts;
- System concepts (service areas, distribution system concepts, energy sources, and capital phasing considerations);
- Capital cost estimates and operating variables (e.g., staffing requirements, fuel efficiency, etc.).

The business case was completed by Compass using technical inputs developed by FVB. Specifically, Compass reviewed the economic, environmental and social merits of different NDES system concepts and different business models for delivery of the NDES.

For our analysis we assume a regulated cost of service utility model with a fixed (regulated) rate of return. In this approach, all utility costs and returns are recovered through customer rates. The business analysis compares the district energy rates that would need to be charged with the cost of on-site heating systems. Several supply and reference case scenarios are assessed. In addition to cost, we also consider the relative environmental performance of the proposed NDES and alternate approaches to heating new floorspace. This report includes a summary of the key inputs from the

technical study. Additional details on the technical inputs can be found in a separate report prepared by FVB.

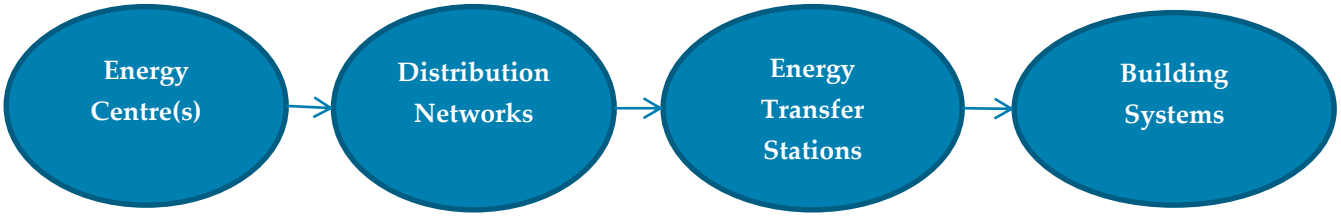
# 2 Background on District Energy

## 2.1 Concept

District energy, sometimes also referred to as community or neighborhood energy, involves the central provision of heating and/or cooling to multiple buildings (Figure 2). Electricity is also sometimes produced as part of a district energy system via a combined heat and power (CHP) plant (also referred to as co-generation). CHP systems are more efficient than stand-alone thermal electricity plants without any waste heat recovery. In a district energy application, the electricity from a CHP plant is typically sold into the local electric grid while the recovered heat is used within the district heating system. Alternatively the district energy provider may simply purchase the heat from the electricity plant owner. In a few cases, the district energy system is owned by the local electricity provider. In large campus systems, the output of the CHP plant may be used directly to meet the campus system owner's electricity needs as well as heating needs. A CHP plant can also sometimes provide a source of additional back-up for a local "microgrid" serving power users with very high reliability requirements.[2]

[2] A microgrid is defined as "…a cluster of electricity sources and (possibly controllable) loads at one or more locations that are connected to the traditional wider power system, or macrogrid, but which may, as circumstances or economics dictate, disconnect from it and operate as an island, at least for short periods." Hatziargyriou, N. et al., "Microgrids, An Overview of Ongoing Research, Development, and Demonstration Projects," IEEE Power & Energy, July/August 2007.

**Figure 2: Key Elements of a District Energy System**




District energy systems typically consist of one or more central energy plants. The choice of energy sources depends greatly on local conditions. Large systems may rely on multiple types of technologies and fuels. The ability to optimize production across several technologies and fuels in response to actual market conditions is one of the advantages of larger district energy systems. Alternative sources of energy may include waste heat, geothermal/geoexchange, sewer heat, solar (as a small fraction of total supply), and various forms of bioenergy. Gas- or bioenergy-fired CHP are also common. Low grade forms of energy (e.g., geoexchange, sewer and very low-grade waste heat) require the use of heat pumps to provide energy at useful temperatures, but heat pumps use much less electricity than electric resistance heating (e.g., electric baseboards) to produce an equivalent amount of useful heat. Alternative energy sources are typically sized to a smaller proportion of heat demand in order to maximize equipment utilization, with cheaper natural gas boilers providing peaking and back-up as required. Natural gas technologies can be implemented at a variety of scales. In district energy systems, natural gas is frequently also used as a bridging strategy in early stages of a new system until demand is large enough to economically sustain a larger, more capital intensive alternative energy system, at which point natural gas may continue to be used to provide low-cost peaking and back-up. Lastly, it may be possible to utilize existing natural gas boilers that have spare capacity in the early stages of district energy implementation (to reduce capital outlay in the early years when costs are high).

Thermal energy is distributed via a network of underground pipes. Historically, steam was the most common means of distributing heat, reflecting the fact that many early systems were built around high-grade waste heat from electricity generation plants and had many large end users (e.g., hospitals, industry) that required steam for sterilization and industrial processes. New district energy systems often use hot water

distribution for heat, reflecting the decline in industrial steam loads in communities, the rise of small-scale steam generation technologies and alternative sterilization options for health care facilities, and the ability of modern buildings to utilize lower temperature heating water. Modern hot water systems utilize pre-insulated distribution pipes with integrated leak detection, variable flow and varying supply temperatures (adjusting supply temperatures to actual weather conditions).[3] Modern hot water systems typically have long lives, lower maintenance requirements, and much lower energy losses than steam systems.

**The Conversion from Steam to Hot Water Systems**

Many new DE systems utilize hot water distribution. However, nearly 80% of all downtown district heating systems in the U.S. still distribute steam rather than hot water. In the late 1980s, St. Paul, Minnesota replaced an aging steam system with a new hot water system. Today St. Paul has one of the largest hot water systems in North America and the largest biomass-fired system. Several cities in Europe have embarked on long-term programs to convert their vintage steam systems to hot water, including Paris, Munich and Copenhagen. The University of British Columbia is currently undergoing a five-year, $85-million project to replace the campus' aging steam system (serving about 100 buildings) with a hot water based-system. The conversion will reduce the Vancouver campus' energy use by 24 per cent and its greenhouse gas emissions by 22 per cent, or 11,000 tonnes. UBC's project is one of the largest current conversion projects of its kind in North America. The University of Rochester recently completed a smaller conversion project. Stanford University has recently commenced planning for an even larger conversion project, in part to reduce energy losses from heating but also to allow recovery of waste heat from cooling.

Individual buildings are connected to the district energy distribution network via energy transfer stations (ETS) consisting of heat exchangers and meters. The ETS separates the district (primary) distribution network from the building (secondary) network while enabling the transfer of thermal energy. Within buildings, thermal energy must be distributed and utilized via hydronic systems. Buildings may use

[3] Some district energy systems distribute only low-grade (i.e., very low temperature) energy to users. These so-called ambient temperature systems are a partial service in that they require the continued use of on-site heat pumps and boilers to raise the energy to useful temperatures. These systems may make sense in situations where only low-grade energy sources are available (e.g., geoexchange or sewer heat, which require the use of heat pumps anyway), densities are very low (low temperature systems may use cheaper uninsulated distribution pipes in some cases), and where there is a high degree of simultaneous heating and cooling (facilitating waste heat recovery from cooling).

hydronic fan coils, hydronic baseboards, in-floor radiant systems, or capillary systems. The only requirement is that buildings be designed to maximize reliance on the district energy system (to ensure maximum system benefits) and to maximize the delta T (the difference between supply temperatures from and return temperatures to the district system). A higher in-building delta T results in lower return temperatures back to the energy centre and increased equipment efficiency.

The size of district energy systems may range from small neighbourhoods to entire cities. In many jurisdictions, individual systems have evolved in isolated locations and been knitted together by a single public agency (often a municipal utility) or through amalgamation of smaller utilities.

## 2.2 Global History and Recent Renaissance

District energy is an old concept, dating as far back as the Romans, who distributed water from hot springs to heat baths and greenhouses. District energy gained some prominence again in Europe during the Middle Ages. One system in the village of Chaudes-Aigues Cantal in France has operated continuously since the 14th century. Today, district energy systems are found throughout Europe, Eurasia, and North America. In Iceland district energy serves over 90% of all buildings; in Russia, nearly 70%. Many large European cities have extensive district energy systems. Paris has been using geothermal heating from a 55-70 °C source 1–2 km below the surface since the 1970s. Berlin has one of the largest district heating networks in Western Europe, with 27 percent of the city's buildings heated through a highly decentralized system of CHP plants of various sizes. Vienna has a large district energy system relying primarily on CHP and waste to energy. Many major cities throughout the world have district energy systems.

### 2.2.1 The Nordic Experience

In Finland, Sweden, and Denmark, district energy has undergone a remarkable country-wide expansion in recent years, nearly doubling since the early 1980s to reach more than 40 - 50% penetration at a national level.[4] In Helsinki, Stockholm, and Copenhagen district energy now serves over 98% of city-wide space heating needs.

[4] See for example: The Nordic Energy Perspectives Research Group. March 2009. *The Future of Nordic District Heating. A First Look at District Heat Pricing and Regulation. Intermediate Report.*

Virtually all commercial and multi-family buildings in these countries are served by district energy. Growth in district energy in these countries has now slowed as the industry matures, although new carbon policies may support further expansion. In contrast, Norway, which has a low level of penetration currently, is seeing rapid growth in district energy.

Within the Nordic countries, district energy has become a key pillar of national and local energy policies that seek to reduce reliance on imported fossil fuels, promote local economic development, increase energy efficiency (through cogeneration and waste heat recovery), and decrease carbon emissions. All Nordic countries have high energy prices, in part due to tax policy, which has provided an economic incentive for efficiency and fuel switching via district energy. The price of district energy has generally increased at a slower rate than competing forms of energy, although average prices vary greatly across countries and localities. There is also consistently high public acceptance for community-wide technical solutions among Nordic countries. Despite similar policy goals and outcomes, the policy levers and organization of the district energy sector actually vary greatly among the Nordic countries.

**Denmark**

The extensive growth in Denmark was achieved through a combination of heat planning laws (municipalities can designate service areas for natural gas and district heating), mandatory connection to district energy in designated areas (to achieve scale economies and support commercial lending), bans on electric heat, and laws requiring electric utilities to pursue CHP. In Denmark, district heating is considered a natural monopoly and companies must operate as non-profits (i.e., they can only recover actual expenses and no excess returns or rents). As a result, much of the sector is owned by municipal utilities, with many larger production plants and interregional transmission systems owned cooperatively by several municipalities. However, there is some private sector ownership of generation facilities (e.g., Dong Energy). Although growth in district energy in Denmark has slowed in recent years as the industry has matured, a renewed emphasis nationally on dramatic reduction of CO2 emissions and full penetration of renewable energy has brought a renewed interest in district heating. Consideration is being given to converting natural gas service areas to district heating and a new plan ("Varmeplan Danmark") suggests the possibility of increasing district energy market share from 47 % today to 60-70 % in the period from 2020-2050.

**Norway**

Policy support has been more limited to date in Norway but the country recently established ambitious 10-year targets to increase the use of district heating based on renewable fuels, to decrease the use of electric power for heating purposes, and to increase the use of waste to energy plants for replacement of fossil fuels. Norway has

also prohibited landfilling of organic waste, further encouraging waste to energy development. District energy is regulated by the Norwegian Water Resources and Energy Directorate (NVE). NVE issues licences (also referred to as concessions) and regulates prices (via a formal price cap and a complaints process). A license for district heating is a permit to build and operate a district heating plant with a certain installation and within a certain geographical area. An installation above 10 MW requires a licence, and only one licence can be given within a specified area (ensuring exclusivity). Municipalities can, when a licence is granted, adopt compulsory connection to the district heating system for new and renovated buildings. The Energy Act specifies that the price of district heating should not exceed the heating price of any alternative heating source, which in general is mainly electricity.

Prior to 2006, licenses were granted on a first come–first served basis. In 2007, interest for new district heating plants increased dramatically as a result of new financial support schemes by Enova, a public enterprise owned by the Royal Norwegian Ministry of Petroleum and Energy with a mission to support environmentally sound and rational use and production of energy. Since 2007, NVE has applied criteria for prioritizing between competing applications. The major criterion is efficient resource allocation, taking into account environmental impact, cost and security of supply. In 2009, NVE issued 33 new licences and rejected 17 applications because they were either unprofitable projects or less preferable than competing applications for the same areas. Concern has been expressed by stakeholder regarding delays in the license process, which has created uncertainty over outcome and delayed implementation of district heating in some cases.

**Sweden**

The district energy sector in Sweden has tended to operate on a more commercial basis. Customers typically have a free choice to connect to district energy. There are requirements for municipal energy planning, but this has not been a significant driver for development of district energy (compared to Denmark's mandatory zoning). Swedish systems emerged more through a combination of indirect tax policies and strong municipal leadership. Sweden also lacks natural gas networks except in limited areas of the country. As a result, the main source of competition for low GHG heating has been from electricity. Historically Sweden enjoyed low electricity prices (which encouraged electric heat), but prices have risen with the increase in fossil fuel prices, the phase-out of nuclear, the limited opportunities for further hydroelectric development, and the integration of Swedish electricity market with broader Nordic energy markets. Differential tax policies have provided a strong economic incentive for district energy. Other state policies to limit reliance on imported oil (including subsidies for fuel switching), ban landfills, and support (in recent years) for CHP have further spurred district energy development.

Early municipal leadership was a critical factor in the evolution of district energy in Sweden. Municipalities have tended to take a long view, supporting early investments in long-lived infrastructure. Municipal control over public buildings such as schools and hospitals helped secure initial loads. Municipal housing companies, which expanded greatly as a result of a national housing strategy, were also an important source of early loads for municipal district energy companies. Municipal ownership also supported district energy development by leveraging synergies with other municipal responsibilities such as waste management and sewage (e.g., waste to energy development).

Sweden recently undertook a major review of the district energy sector culminating in a new district heating law in 2008. The law aims to provide greater customer protection, more openness among the actors and clearer rules for the district energy market. The law does not include any direct price regulation but has provisions to increase price transparency and opportunities for external mediation. The law is expected to increase administration and additional compliance costs for district energy providers, possibly affecting competitiveness of district energy.

**Finland**

Finland does not have any national district heating legislation or regulations. Finland also does not regulate district heating prices. And there are no requirements for local heat plans or district heating zones. Connection is voluntary in most cases. Despite the lack of direct policy support, Finland has a comparable penetration of district energy as Sweden and Denmark. This reflects history (district energy is an older, more established approach to heating in Finland giving systems some market power), municipal leadership and indirect policies that promote CHP. Almost all new buildings in Finland voluntarily connect to the district heating networks, when available, suggesting competitive prices and high service quality. The very long heating season in Finland compensates for its lower population density, making district heating economical in many locations. Interestingly, Finland also has lower prices for district heating than many neighbouring countries, much lower than tariffs (before taxes) in both Denmark (regulated) and Sweden (unregulated). However, prices can vary greatly from location to location, a source of some controversy among consumers. Energiateollisuus, an industry association, has suggested the size of the network has the most influence on the local price. Still, concerns have been raised about the market power of district heating companies. A 2006 study by the Finnish Ministry of Trade and Industry concluded there was no need for additional supervision or policy support for district energy, although there was a call to increase the reporting and transparency of district energy prices, including separate accounting for district energy operations among integrated utilities.

### 2.2.2 Trends in the Rest of Europe and UK

Following on the Nordic model, district energy is undergoing a renaissance in other European countries. District heating networks based largely on renewable energy (primarily biomass energy) have grown rapidly in small Austrian towns. Despite a long history with district energy and one of the highest penetrations of CHP in Europe, Germany has a relatively low current penetration of district energy in the heating sector compared to many other European countries. However, there is considerable room for growth. A recent study by the Federal Environment Agency (UBA) revealed that DH and CHP are the key technologies for reducing $CO_2$ emissions in a cost-effective way, with significant growth potential. Through recent changes in CHP and renewable energy laws, the German government created a more favourable legislative framework for expansion of district energy and CHP, including a premium feed-in tariff for electricity CHP plants, funding support for district energy networks, minimum levels of renewable heating supply that may be met through district energy connection, and market stimulus for both district energy and CHP. The goal is to increase district heating penetration from current levels of ~8% to 18 – 22% by 2020.

After some poor experience with district heating in public housing projects in the 1950s, '60s and '70s, there is a renewed interest in district energy in Britain. In a recent draft strategy document, the UK Department of Energy and Climate Change highlighted district energy as one of the key strategies for a low-carbon future, particularly in dense urban areas.[5] In the London Plan 2011, the Mayor of London has set a target for 25 per cent of the heat and power used in London to be generated through the use of localised decentralised energy systems by 2025. To achieve this target the Mayor prioritises the development of decentralised heating and cooling networks at the development and area wide levels, including larger scale heat transmission networks. As part of local development frameworks, the Mayor expects that boroughs will develop policies and proposals to identify and establish decentralised energy network opportunities and to work with neighbouring boroughs to realise wider decentralised energy network opportunities where relevant. At a minimum, boroughs of London are expected to:

- identify and safeguard existing heating and cooling networks;
- identify opportunities for expanding existing networks or establishing new networks;

[5] UK Department of Energy and Climate Change. March 2012. *The Future of Heating: A strategic framework for low carbon heat in the UK*. See also: *The Carbon Plan: Delivering our low carbon future.* Presented to Parliament pursuant to Sections 12 and 14 of the Climate Change Act 2008 in December 2011.

- use the London Heat Map tool (developed by the Mayor's office) to identify opportunities arising from new development, planned major infrastructure works and energy supply opportunities;
- develop energy master plans for specific decentralised energy opportunities which identify:
    - major heat loads (including anchor heat loads, with particular reference to sites such as universities, hospitals and social housing);
    - major heat supply plant;
    - possible opportunities to utilise energy from waste
    - possible heating and cooling network routes
    - implementation options for delivering feasible projects, considering issues of procurement, funding and risk and the role of the public sector
    - require developers to prioritise connection to existing or planned decentralised energy networks where feasible.

With 3.3 million Euros in seed funding from the European Investment Bank's ELENA facility, the Mayor of London established the Decentralised Energy for London programme to provide London boroughs and other project sponsors with technical, financial and commercial assistance to develop and bring decentralised energy projects to market. The Mayor's office recently issued a discussion paper seeking input on a London District Energy Manual to provide developers and network designers with standardised technical and operational guidance on district energy in London. The intent of the initiative is to increase confidence in decentralized energy systems and ensure future connectivity of individual systems.

As part of its plan for a sustainable, low-carbon Olympics, London's Olympic Delivery Authority established a district heating and cooling system to serve the Olympic Park vicinity. The system will consist of 16 km of piping and two energy centres consisting of gas-fired cogeneration, biomass boilers, chillers and energy storage. Following a competitive procurement process, Cofely, a subsidiary of GDF Suez, was given a 40-year exclusive concession to finance, design, build and operate the district heating and cooling network and associated energy centres.

### 2.2.3 The North American Experience

North America has a lower overall penetration of district energy than many parts of Europe, reflecting in part the more dispersed nature of development, but there is still a

long history of district energy in North America.[6] There are hundreds of district energy systems at hospital, university and military campuses throughout North America. And many cities have large, world-class systems in their core. Con Edison's Steam Business Unit in Manhattan is one of the largest steam district energy systems in the world, providing steam to some 1,800+ buildings. About 300 customers also have steam-driven chillers, increasing the utilization of the steam system in the summer months. Con Edison's steam system is actually the result of the merger and consolidation of multiple downtown steam systems that once served respective segments of Manhattan.

Mature steam systems in cities such as Philadelphia, Indianapolis, Boston or Denver serve between 200 and 400 customer buildings. Larger and established combined district heating and district cooling systems such as those in Hartford, Minneapolis, and Omaha generally serve between 65 and 150 customer buildings on heating and between 50 and 125 customer buildings on cooling. Roughly 8% of all commercial office space in the U.S. is connected to district energy. There are fewer residential connections compared to European systems, reflecting the historical pattern of suburban residential development in North America and the concentration of systems on institutional campuses and within downtown cores.

There have been several waves of district energy development in North America. The U.S. Naval Academy in Annapolis began a steam district heating service in 1853. One of the first commercially successful district heating systems was launched in Lockport, New York, in 1877 by American hydraulic engineer Birdsill Holly, considered the founder of modern district heating. Two of the oldest known systems in North America that still operate today are in the City of Denver (Colorado) and the City of London (Ontario) - both built in the 1880s. Approximately 150 district energy systems of varying sizes are currently in operation in Canada. The district energy system currently owned and managed by Enwave first began supplying district heating to downtown Toronto in the early 1960s and is currently the largest such system in Canada.

Outside institutional campuses, many of the vintage steam systems in North American cities were initially developed by local investor-owned or municipal electric utilities. In the early days of the electric power industry, steam distribution was essentially a by-product of electric generation at downtown CHP stations. In fact, when the original "Edison Electric Utilities" were formed in major US cities such as Boston, New York, Chicago, Detroit, Philadelphia, Baltimore and others, waste heat recovery and the revenues from steam service were essential to financial viability. The supply of both

[6] For additional background on the historical development of district energy in North America see: International District Energy Association. August 2005. *IDEA Report: The District Energy Industry.*

electricity and heat was also important to entice early customers to connect to newly formed electricity systems. When Thomas Edison built his first electricity generating station on Walnut Street in downtown Philadelphia in 1906, he entered into an agreement to sell steam to the nearby Thomas Jefferson University Hospital to make the project financially viable, establishing Philadelphia's district steam system. Today, more than one hundred years later, Thomas Jefferson University Hospital is still a customer of the Philadelphia district steam system.

The owners of many downtown district energy systems in North America, many of whom were electric utilities, lost interest in the district heating business in the 1960s and 1970s. This was due to a combination of factors. First, there was a trend towards larger power generating stations in more remote locations. Coupled with new emission limits in urban centres and the oil shocks of the 1970s, many CHP plants in downtown cores were closed and electric utilities began to lose interest in their steam assets. With insufficient funding for maintenance, assets, reliability and service started to deteriorate. The result was that many systems started losing customers. At the same time, commercial buildings were becoming more efficient. Revenue growth slowed precisely when new investment was required. Many systems experienced a downward spiral and were eventually abandoned. For example, in Minnesota in the 1950s there were about 40 district steam systems; today only a few remain.

In the mid and late 1980's, several vintage systems were acquired from investor-owned electric utilities by other investors. An example is Catalyst Thermal (succeeded by United Thermal and Trigen Energy), which acquired the steam systems in Boston, Philadelphia, Baltimore, Youngstown, Cleveland and San Francisco. Catalyst and others renewed acquired systems and re-established customer confidence. They also pursued other strategies to improve business sustainability including adding CHP and alternatives sources of steam such as waste to energy. Some also developed district cooling businesses (examples include systems in Denver, Cleveland, Indianapolis) to increase revenues and utilization of existing assets, either through the installation of separated chilled water loops or through the marketing of absorption chillers (which use steam to produce cooling, increasing the use of steam assets during low heating months).

While many vintage systems were being abandoned and others were being acquired and renewed, there was also a wave of new system development after the 1960s. In 1962 the world's first downtown combined steam district heating and chilled water district cooling system was constructed by the Harford Gas Company in Hartford, Connecticut starting with a large urban renewal project at Constitution Plaza. New systems were developed as part of large urban renewal projects in several cities. Many of these newer systems used natural gas and were developed by natural gas distribution companies as a means of using excess gas infrastructure capacity in

summer months and a source of new growth. The provision of both heating and cooling greatly appealed to building owners by reducing the complexity of on-site mechanical plants.

District cooling received an additional boost with the ban on chlorofluorocarbons (CFCs) and the increase in peak electricity prices. District cooling systems provided an alternative to risky and complex on-site alternatives and provided a means of diversifying loads (to rationalize cooling capacity), leveraging thermal storage (to take advantage of cheaper off-peak electricity) and accessing cost-effective alternatives to banned refrigerants. Paradoxically, there was a renewed interest among electric utilities in district cooling as a source of growth and means of rationalizing electric capacity (cooling peaks put pressure on many electric grids and generating assets). Commonwealth Edison of Chicago was particularly active in developing joint ventures with the subsidiaries of local investor-owned electric utilities in several large cities, including Chicago, Boston, and Houston.

There has been a renewed interest in district energy systems in recent years to support environmental objectives and urban sustainability. District energy was lauded in 2001 by the U.S. National Energy Policy (NEP) for its environmental and efficiency benefits. President George Bush attended the opening of the largest biomass-fired district energy plant in the U.S. in St. Paul Minnesota. Cities such as San Francisco, Portland, Seattle, Vancouver and Toronto have all explored options for promoting low-carbon district energy in dense neighbourhoods as a less expensive and more robust alternative to on-site systems in these areas.

For example, the City of Toronto has included policies to promote the installation of district / distributed energy as part of its recent Sustainable Energy Strategy (The Power to Live Green, October 2009). Toronto is already home to the largest district energy company in Canada and one of the largest in North America. Enwave Energy Corporation, which is currently partly owned by the City, operates four large energy plants with over 20 kilometres of distribution piping. It has also installed a deep lake water cooling system that uses the cold water from Lake Ontario to cool buildings in downtown Toronto. The system has the capacity to serve about 100 large office towers and customers already include Toronto City Hall, Metro Hall, and Police Headquarters. A study conducted by the Canadian Urban Institute (CUI) in 2007 found that the development of new CHP-based district energy systems in three Toronto neighbourhoods (Scarborough Centre, North York Centre, and the Sheppard Corridor) would yield ~ 200,000 tonnes of greenhouse gas emissions reductions. As part of its Sustainable Energy Strategy, Toronto committed to facilitate the development of district/distributed energy system in existing and new neighbourhoods to reduce energy consumption and greenhouse gas emissions and enhance energy security by working with key stakeholders to establish in the system

potential, identify barriers and potential mechanisms to facilitate the installation of district/distributed energy infrastructure including:

1. Identifying the geographic areas with the greatest potential for district/distributed energy installations, based on energy utilization mapping and other research, experiences of existing programs, such as the Mayor's Tower Renewal, and assessments of neighbourhood interest;
2. Identifying and assessing appropriate energy sources for the district/distributed energy systems that will help achieve the greenhouse gas and smog causing emission reduction targets set in the Climate Change Action Plan;
3. Coordinating the installation of the infrastructure with other City infrastructure and stakeholder work, in order to reduce start-up costs;
4. Identifying and addressing any issues associated with existing City of Toronto by-laws and policies;
5. Advocating for any required changes or investments from the Province of Ontario, the Ontario Power Authority, the Ontario Energy Board or other relevant provincial bodies; and
6. Developing any necessary provisions, as permitted, under the City of Toronto Act.

There has been considerable district energy activity in the Lower Mainland of B.C. in recent years. Local trends are discussed more below.

### 2.2.4 Initiatives in Asia and the South Pacific

There are many other notable examples of district energy development in Asia and the South Pacific. South Korea began to develop district energy in the mid-1980s. Networks have grown in excess of 24% per year for the last 11 years. Initial development focussed on new urban growth areas. Municipalities were very active in early development but private companies have been involved since the late 1990s. Modern district heating was introduced in China in the 1980s. By 2002, 1.4 billion m2 of floor area was connected to district heat. Connected floor area has increased at an average annual growth rate of > 17% since the early 1990s, mainly in the country's north and northeast regions. Today over half of Chinese cities have district energy systems.

In Australia, Townsville, Adelaide, Sydney and Melbourne all now have emerging examples of low carbon district energy systems. Sydney has established very ambitious goals to develop the country's first city-wide low carbon network based on trigeneration and district energy. Under the plan, Sydney will develop a network of

combined heating, cooling and power plants (so-called trigeneration plants) in four low-carbon-zones across central Sydney. The plan aims to install 360 MW of electrical capacity and associated heating and cooling output by 2030 at a cost of ~$440m. The plans would provide 70 per cent of Sydney's electricity requirements with recovery of waste heat for heating and cooling to serve clusters of local buildings. A feasibility study showed that the Sydney trigeneration network could save electricity consumers up to $1.5 billion in avoided or delayed spending on grid upgrades and new power stations by 2030 and help achieve deep GHG emission reduction targets. Sydney recently entered into an agreement with Cogent, a fully owned subsidiary of Origin, Australia's largest energy company, to install and operate Phase 1 of the city's trigeneration network.

As part of its rebuilding plans from the 2011 earthquakes, Christchurch, New Zealand recently completed a feasibility study for New Zealand's first district energy scheme. The proposed project would ultimately provide electrical power, space and water heating and cooling from centralised power and heat co-generation plant fuelled by various renewable sources. The preliminary feasibility study was quite favourable and the Christchurch Agency for Energy is exploring next steps.

To some extent, the district energy industry is also returning to its early roots by adopting CHP as a principal source of thermal energy at many locations. This trend is particularly strong in campus district energy systems (university, hospital, and military complexes) as a result of higher commodity prices (incenting efficiency improvements), higher electricity prices, policies to facilitate the sale of power from CHP plants, and the growing demand for high electrical reliability among sensitive power users on campus systems.

## 2.3 Recent District Energy Developments in B.C.

British Columbia and in particular the Lower Mainland has become a leader in Canada for the development of new district energy systems serving mixed use communities. [7]

Most large institutional campuses in B.C. have on-site district energy systems, including major universities and hospital campuses. Many of these systems are now undergoing renewal or expansion including conversion from steam to hot water (e.g., UBC) and the installation of low-carbon energy sources (e.g., UBC and UNBC). Simon Fraser University (SFU) has been actively exploring with Corix Utilities a combined

[7] For an overview of recent experience in Canada and B.C. see also: *A Canadian Renaissance: District energy, new development go hand in hand.* District Energy, Second Quarter 2011, p. 31-36.

biomass-fired heating plant and gas peaking plant to serve the campus (currently supplied by a 40-year old gas-fired boiler plant) and the district energy system being developed by Corix to serve the SFU Property Trust's UniverCity development adjacent to the campus. Children and Women's Hospital in Vancouver is actively exploring outsourcing the replacement of its aging boiler plant to FortisBC, which would then install a new combined biomass-and gas-fired system to serve the hospital facilities as well as adjacent neighbourhood loads.

The largest and oldest operating commercial district energy system in B.C. is Central Heat in downtown Vancouver.[8] Central Heat currently supplies about 470,000 MWh/year of heat to approximately 200 residential and commercial buildings in the central business district. Established in the 1960's by private investors, the system continues to grow. Steam for the system is produced at a single plant located near BC Place. The plant itself is highly efficient but relies entirely on natural gas. As one of the largest point sources of GHG in Vancouver, Central Heat and the City have recently discussed opportunities to implement hot water based district energy neighbourhoods at the periphery of its current system (to enable integration of other technologies) and options for a large-scale switch to a low-carbon fuel.

In 2004, the City of North Vancouver began operation of one of the first commercial hot water district energy systems in B.C.[9] Lonsdale Energy Corporation (LEC) was established as a wholly owned subsidiary of the City. LEC was initially formed to serve a rapidly developing area of the City known as Lower Lonsdale. The City established a Service Area Bylaw to require connection to the system within Lower Lonsdale and constructed a system of mini gas-fired plants to provide energy to the new network. The City subsequently added two additional distinct service areas (Harbourside and Central Lonsdale). The City also added a solar thermal system to provide a portion of the heat in Central Lonsdale, and is exploring the future addition of other alternative energy sources and an optional cooling service in parts of its system. In 2010, the City eliminated distinct service areas and expanded the service area to the whole City. Under the new bylaw, any new building more than 1,000 square metres (~10,000 sf) must connect to LEC for heating, unless the Director of Finance determines the cost to the City would be excessive. Cooling service is being explored to support the introduction of geoexchange but cooling is optional.

In 2008, Dockside Green Energy (DGE) commenced operation to supply the award-winning, LEED Platinum development known as Dockside Green in Victoria.

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[8] For comparison of Central Heat and the steam systems serving Montreal, and Toronto see: *A Tale of Three Cities: District Energy Thriving in Montreal, Vancouver and Toronto*. District Energy. Second Quarter 2011.

[9] In 2005, the City of Revelstoke implemented the first biomass-based hot water district energy system in B.C.

Initiated by the master developer (Windmill), owned jointly by Vancity, Corix Utilities and Terasen Energy Services (now FortisBC), and operated by Corix Utilities, DGE provides heating to the entire development from a biomass gasification system (provided by Nexterra) with natural gas-fired peaking and back-up.[10]

In 2010, the City of Vancouver commenced operation of the Neighbourhood Energy Utility (NEU) at Southeast False Creek (SEFC). One of only four district systems in the world to recover heat from untreated sewage, this was a showcase initiative in B.C. to supply not only the Olympic Village but the entire SEFC neighbourhood. Science World recently connected voluntarily to the NEU as an alternative to replacing their gas-fired boiler plant which was nearing the end of its life. The City is now considering expansion of the system to the adjacent False Creek Flats, including the site of the Great Northern Way Campus. The SEFC NEU is discussed in more detail in the case studies of ownership models.

In the same year, the Resort Municipality of Whistler implemented a system to serve the Whistler Athletes Village. This system provides both heating and cooling through a low-temperature network with distributed heat pumps in individual premises. The system captures low-grade waste heat from Whistler's wastewater treatment plant.

Two other privately owned commercial systems have recently received regulatory approval and commenced operation in the Lower Mainland: a system serving UniverCity adjacent to SFU and planned by the SFU Property Trust (owned and operated by Corix) and a system serving a large master planned community along the Fraser River in southeast Vancouver known as River District (owned and operated by the master developer, Parklane). FortisBC has applied to the BCUC for approval of capital costs and rates to own and operate a small geoexchange-based district energy system in Tsawwassen and is planning several other applications for systems around BC in the coming months. Other communities in the Lower Mainland are in various stages of studying or implementing new systems, including Richmond, Surrey, Coquitlam, Burnaby, and the District of North Vancouver.

The City of Revelstoke established the wholly-owned Revelstoke Community Energy Corporation (RCEC) to deliver thermal district energy services to downtown customers starting in 2005. The district energy system burns wood waste generated by the Downie Timber Sawmill to produce process steam for the Downie kiln and hot water for a number of municipal, institutional, residential and commercial buildings. RCEC is a community "partnership", contracting with Downie Timber Ltd. for biomass supply, heat sales, and plant operations. The City and RCEC have recently undergone community energy and emissions and RCEC business planning efforts. As

[10] Windmill, the developer of Dockside, was originally a partner to the joint venture but has since exited.

an outcome of that work, Council recently approved the establishment of an RCEC Task Force with the mandate to initiate a competitive process for potential private sector involvement in the ownership and operations of RCEC.

To date there has been considerable focus on individual projects and nodal opportunities. Communities such as Vancouver, Richmond, Surrey, Coquitlam, North Vancouver, and the District of North Vancouver have been developing more City-wide visions, strategies, and policies for district energy. These include ensuring technical standards and compatibility among nodal systems; planning long-term integration of systems (transmission interconnections); developing community-wide franchising and ownership or partnership strategies; formally incorporating district energy into green building policies, official community plans, and community energy and emission plans; strategic planning for large-scale supply options (as networks expand and integrate); connection requirements and support; and taxation policy.

## 2.4 Value Propositions for District Energy

There are several potential value propositions for district energy.[11] Historically, the main value proposition was economic – in the right conditions central supply can achieve a lower lifecycle cost than on-site systems. The best evidence for the economic case for district energy is the prevalence of district systems among hospital, military and educational campuses. These campuses often have densities comparable to urban areas with a mix of load types. However, they are planned and managed by a single institutional owner with a long-term view of their facilities. District systems are still often the preferred method of heating and cooling these campuses. Owners continue to maintain, renew, upgrade and expand their systems.

For institutional campuses, the main sources of cost advantage for district energy include the following.

> **Economies of scale.** Larger systems tend to have lower production costs than smaller systems. This arises from economies of scale in production equipment, as well as ancillary systems (e.g., hookups, buildings, etc.) and the design, tendering and installation of systems. Larger systems also offer more flexibility in design to allow mixing and matching among equipment sizes and types to improve overall economics. And there can be economies of scale in the sourcing of equipment. Finally economies of scale (together with economies of

[11] Additional background on the value proposition for district energy can be found in these recent reports: Canadian Urban Institute. 2008. *The New District Energy: Building Blocks for Sustainable Community Development*; An Assessment of District Energy Opportunities.

integration) can result in overall space savings compared to on-site systems. With economies of scale, owners can also invest in better equipment.

**Economies of integration.** Heating and cooling loads are very peaky. A large amount of capacity is required to meet fairly short-lived spikes in demand. When systems are centralized to serve a greater number and mix of loads, the total amount of installed capacity that is required for heating and cooling can often be reduced because individual loads peak at different times (and there is some natural thermal "storage" in distribution networks). A diversification effect of 15 – 25% has been demonstrated in numerous district energy systems (i.e., installed system capacity can be 15-25% lower than comparable on-site systems). Integration can also have benefits in terms of system efficiency. Compared with distributed systems, centralized systems serving larger and steadier loads (through diversification) can be designed to maximize the dispatch of individual pieces of equipment (thereby reduce partial loading conditions)., which can result in higher annual efficiency and a longer life. The efficiency benefit will vary depending upon the system size, equipment configuration, and load diversity. With size and integration of diverse loads, there can also be savings in the amount and cost of redundancy required to achieve high levels of reliability. There can be other economies of integration – e.g., the increased ability to recover waste heat from cooling in a larger system and the ability to implement CHP (many campus systems also have internal electricity networks and can more readily capture the energy and reliability benefits of CHP).

**Economies of management.** The centralization of heating and cooling equipment allows for central administration and maintenance of systems. The same may be true for distributed systems organized under a single utility ownership and operation model. Centralized systems often tend to be better maintained (extending life and ensuring optimum efficiency). Centralized management can also create opportunities for optimization across multiple fuels and technologies, and optimization of fuel portfolios through larger, bulk purchase agreements and an optimum mix of short and long-term fuel supply commitments.

**Opportunities for different technologies and fuels.** Centralization opens up the possibility to utilize resources and technologies not available at the scale or location of individual buildings. For example, CHP is more economic at larger scales. Similarly, individual building sites may lack adequate access to geoexchange or sewer heat recovery. Larger plants can also invest in better environmental controls that may be necessary to meet legal requirements or community expectations. For example, larger biomass systems can invest in

advanced particulate control systems. Biomass fuel deliveries and storage may also be easier at a central plant location.

**Reliability.** From a reliability perspective, larger, diversified and centralized systems may have a slight advantage over on-site systems. Most district energy systems operate at a reliability of well over 99 percent. The San Francisco system operated through the 1989 earthquake without interruption to customer service. During the 1998 ice storms in Montreal, the only buildings that were heated were connected to the Montreal District Energy system. Those buildings became emergency shelters during an electrical outage that lasted about three weeks. Most other buildings were electrically heated (electric heat is very common in Quebec because of the large reliance on hydro power) and the ice storm affected major transmission lines supplying the City of Montreal. During the Eastern Seaboard blackout in the summer of 2003 the only people that had cooling were connected to district cooling systems. A district energy system with cogeneration worked so well that during the 24-hour black out, it took patrons of a casino in Windsor, Ontario 12 hours to even realize there was a blackout.

Of course, the advantages of centralization must be weighed against the added costs of integration (primarily installing and maintaining energy distribution equipment). In reasonably dense campuses, the benefits of centralization often outweigh the integration costs. However, the economics of district energy vary greatly depending upon factors such as density, use mix, timing and rates of development (and availability of large anchor loads), the relative demands of heating and cooling, local energy sources, local energy prices, climate, and environmental drivers or constraints. There are also considerable location-specific differences in the economics of district heating and district cooling, as well as CHP solutions.

Historically, many campus systems have remained within their core institutional boundaries, despite potential cost reductions from increased system size and synergies with neighbouring loads. This reflects both the high transaction costs of dealing with external building developers and owners, as well as the lack of mandate, incentives or capital for institutions to pursue external synergies (that would result in cost reductions for their own energy supply), revenues and associated returns. There is a growing interest in capturing potential synergies between campus systems and surrounding urban areas. Local examples include Vancouver General Hospital and Children & Women's Hospital, UBC and SFU. This may be achieved by giving an expanded commercial mandate to campus-owned utilities (to reduce campus costs and generate incremental revenues/returns), by outsourcing of campus utilities to an external party that then serves both the campus and the neighbourhood, or through the creation of various sorts of public–private partnerships.

Many of the economic advantages to institutional owners apply to dense urban areas with mixed ownership of buildings and developments. However, in the absence of a single institutional owner with a long-term perspective, there are added barriers, transaction costs and risks to creating district-scale energy system. Developers with no long-term stake in ownership have strong incentives to minimize upfront costs and risks, rather than long-term lifecycle costs. Ultimate end users may be unaware of the benefits of district systems and are rarely present when the decision is being made to establish a new system. Establishing a new system in an urban context therefore often requires the vision and leadership of a master developer with control over a large amount of development and longer development perspective, or a strong community vision to align the interests of multiple developers and building owners. Once a system is established and has achieved some economic scale and operating track record, it can be much easier to attract new loads.

In a dense urban context with mixed ownership, district energy has other value propositions related more to the utility model itself rather than the specific technology. With on-site systems, the building developer and ultimate purchaser must pay these costs upfront. Developers and end users are typically more sensitive to first costs and tend to put less weight on lifecycle costs (i.e., total costs of ownership including ongoing maintenance and operation). For example, there is considerable literature showing that purchasers of efficient equipment discount future savings at very high rates when selecting between equipment with a lower efficiency (price) or equipment with a higher efficiency (price). Many sustainable technologies are also characterized by higher capital costs and lower lifecycle costs. So concern about first costs can be a major barrier to the adoption of sustainable technologies.

There are some additional value propositions to district energy for individual building owners and residents in an urban context. Institutional owners typically have a long-term perspective on investments in their facilities and can trade-off capital and future operating costs, as well as risks (of capital constraints may sometimes encourage a more short-term perspective). Individual consumers and building owners tend to have shorter time frames, capital constraints and higher costs of capital (leading to a much greater weight on upfront capital costs). In a district energy system, the upfront capital costs of alternative energy systems are collected over time in rates. This can help overcome first cost barriers to many sustainable technologies. Utility rates, in turn, typically reflect a longer amortization of capital (commensurate with expected asset life) and lower cost of capital (or capital constraints) than individual consumers. These advantages are greatest with patient capital (examples include infrastructure investment arms of large pension funds) and regulated systems. Adequate load commitments or policies are also required to ensure a low cost of capital and long amortization period for investments.

**Typical Advantages of District Energy for Building Owners**

- Ease of use and simplified building operations
- Avoided capital costs for in-building heating and air conditioning equipment[12]
- Reduced ongoing labor, repair, maintenance and depreciation expenses for on-site energy systems[13]
- Space is made available for alternative uses and other income activities (e.g., parking, storage, green roofs)
- Highly reliable energy services
- Less fuel and chemicals stored and combusted on-site
- Access to alternate technologies, larger systems with multiple technologies or fuels that are not available with on-site systems (providing risk diversification and fuel arbitrage opportunities)

In the case of district energy, the utility will pay for the upfront capital costs of energy systems and recover those costs, along with ongoing operating costs, through user rates.[14] In addition to addressing the first cost barrier, utilities typically have longer investment horizons allowing amortization and financing rates that better reflect actual asset life and risks. In addition, an energy utility with a long-term focus is usually in a better position to estimate and internalize lifecycle costs in their investment and maintenance decision making.

Central, professional maintenance is another potential benefit. Ongoing maintenance costs for on-site energy systems are often hidden in overall building maintenance budgets. But these costs can be significant. Boilers and chillers require regular minor maintenance and periodic major refurbishments. Equipment can fail early. Some equipment comes with unique requirements. For example, buildings with chillers must own and use refrigerants introducing refrigerant compliance responsibilities,

[12] District systems eliminate the need for on-site energy production equipment. In some cases, there can be increased costs associated with hydronic systems where these are not standard practice. This is the case in the Lower Mainland of B.C. where electric resistance heating is often (through not universally) common. However, there is also evidence that hydronic buildings can meet other building code requirements at lower cost than electrically-heated buildings.
[13] The introduction of new depreciation study requirements for stratas in B.C. is likely to increase transparency of costs and funding requirements for on-site energy systems.
[14] One exception is where the customer pays a capital contribution to the system upfront. Some utilities will use customer contributions as a source of capital. Some customers, particularly large institutions, often prefer to pay an upfront contribution out of capital budgets rather than repaying capital through a rate that is paid from annual operating budgets.

handling regulations, rising replacement costs, and capacity-loss issues. These issues are often outsourced to professional building management companies that can pool multiple customers and establish clear maintenance policies and programs. But when equipment is centralized, maintenance becomes easier. There are typically fewer pieces of equipment to maintain. And systems owners have more explicit financial incentives and data to develop and implement explicit maintenance programs.

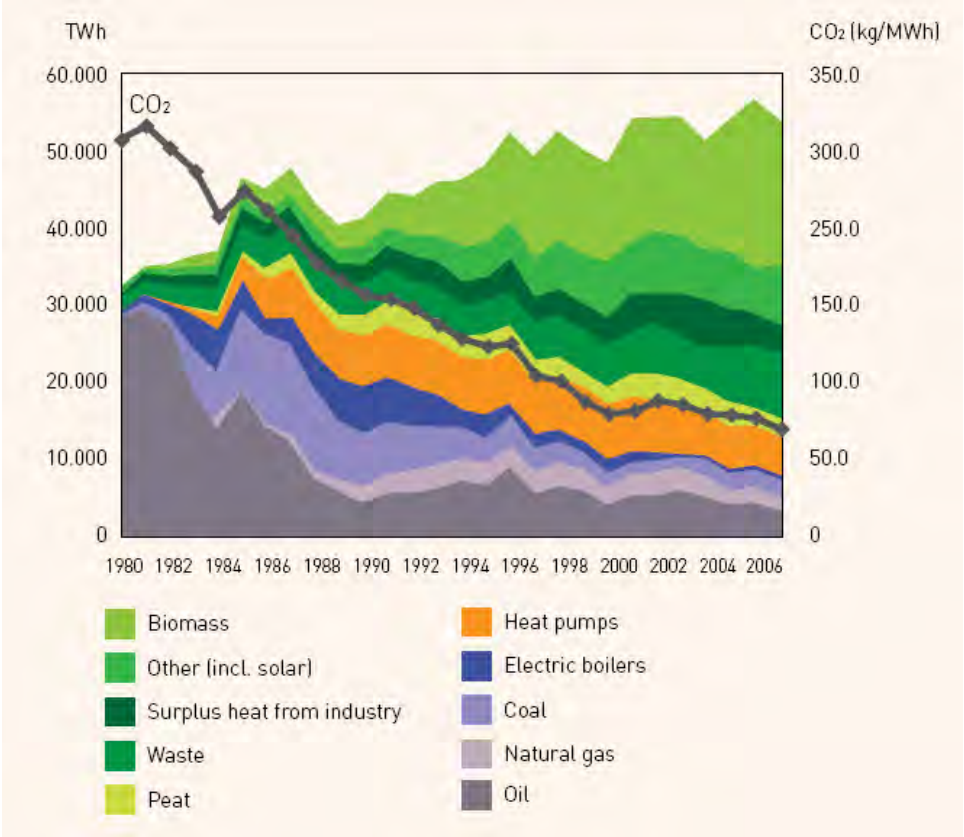
Despite economic advantages, transaction costs and other priorities have limited rapid expansion of district energy in North America and other jurisdictions. But environmental objectives and energy security are providing an added stimulus for district energy. On September 12, 2011, the lead story in the Environment section of The Wall Street Journal discussed "How to Build a Greener City." District energy was touted as the first solution on the paper's list of solutions to address the energy and environmental challenges facing growing cities. Many countries, states and cities around the world have highlighted the potential role of district energy in achieving deep reductions in carbon emissions. First, many low-carbon technologies are capital intensive. Scale and integration can reduce capital costs and improve utilization of low-carbon technologies, thereby lowering the cost of achieving deep reduction targets. Second, the ability to recover higher capital costs through rates overcomes the first cost barrier faced by many technologies. Third, many low-carbon technologies are not available or suitable at the scale of individual buildings. District energy networks also allow greater opportunities for capturing and sharing waste heat. Finally, the risks of new technologies can be professionally managed and pooled across a larger number of consumers, compared to on-site building systems. Expertise can also be more easily developed and maintained in a larger scale system then at the individual building scale.

From a broader societal perspective, district energy offers a flexible and robust platform for the adoption of new fuels and technologies over time. When new technologies are installed in individual buildings, risks are concentrated among a small group of owners. District energy systems pool the risks across a larger number of users. Most systems also use several technologies, creating some diversification and allowing arbitrage among individual technologies and fuel prices. The ability to adopt new technologies on a large scale has benefits both for individual consumers and also local economies.

The Swedish experience illustrates the potential flexibility of more centralized district energy systems (Figure 3). Since the 1980s, the penetration of district energy has nearly doubled so that nearly 50% of the building area in Sweden is now supplied with district energy. Over this same period, district energy systems in Sweden have transitioned from relying almost entirely on imported fuel oil to relying on a diverse mix of resources, including biomass, refuse and waste heat. In between, there were

periods in which coal and electricity were more dominant sources of heat. Over the same time period, the GHG intensity of heating in Sweden has declined more than 50%. It is unlikely such a large and rapid switch in fuels and technologies would have been possible if individual buildings had been heated by thousands of smaller plants, with different technologies and vintages of equipment.

**Figure 3: Swedish District Energy Fuel Sources (1980 – 2006)**




*Source: Swedish Energy Agency*

Realizing the various advantages of a collective energy system requires a long-term, shared vision, and coordination among individual actors with different interest and incentives. High upfront costs, high transaction costs, and the challenges of coordinating among many individual actors pose considerable development challenges for district energy. Careful staging of capital (e.g., through reliance on temporary plants and other transition strategies in early development stages), committed loads (e.g., through long-term commitments by large anchor loads, master developer commitments, and/or very rapid and certain development timelines and

knowledgeable developers), community leadership and vision, and clear / supportive policy framework are all critical to overcoming development barriers and achieving public benefits.

**Why Not Electric Heat?**

Electric heat has traditionally been viewed as a cost-effective and environmentally friendly form of heat in the Lower Mainland. From a consumer and societal perspective, there are several issues with electric heat as a low-cost, low-carbon strategy for new development.

**Cost.** Electric resistance heat is often installed because of low first costs. Lifecycle costs are rarely considered (capital and operating costs). Currently the lifecycle costs of electricity are increasing rapidly while other energy forms such as natural gas are declining. Average electricity rates in B.C. have increased more than 30% in the past few years. With the implementation of conservation (stepped) rates, the cost of electric heat (which because of its seasonal nature is most likely to push consumers into higher Step 2 rates) has actually increased more rapidly. Recent rate caps notwithstanding, long-term electricity rates in BC are set to continue to increase much more rapidly than inflation due to rapid growth in deferral accounts (i.e., deferred historical expenses), need to replace and upgrade aging infrastructure (average age of BC Hydro assets exceeds 50 years), commitments to electricity self-sufficiency and high levels of more expensive green power, and rapid growth in electricity demand (in particular from mining and liquefied natural gas developments). Retail rates in B.C. also mask the real cost of new electricity. Retail rates reflect the average cost of historical assets (very low-cost but aging hydroelectric facilities) and much more expensive new generation and transmission assets. Although residential customers pay on average around 8 cents per kWh, the marginal cost of new green power in B.C. exceeds 12 cents per kWh. As a result, developers and consumers are making decisions based on a lower average rate, while driving investments in much higher cost power. Stepped rates provide some price signals but new development receives the benefit of historical investments while driving growth in more expensive resources.

**GHG Emissions.** There is a common perception that buildings with electric resistance heat have very low GHG emissions. Recent studies of dozens of multi-family residential buildings in the Lower Mainland have found that up to 60% of the heat used by buildings with electric resistance heating in suites is still supplied by natural gas, either in the form of gas-fired domestic hot water or gas-fired make-up (ventilation) air. Although the bulk of BC Hydro's existing electricity supply is from hydroelectric sources, a portion is provided from thermal energy sources. Growth will

demand more expensive green energy sources and/or increased thermal energy. BC Hydro's latest proposed Integrated Resource Plan includes additional gas-fired generation. Finally, BC is part of a larger regional electricity market with a much higher market-wide GHG intensity. BC Hydro often imports coal-fired electricity at night and sells stored hydro -electricity during the day. While hydro exports typically displace gas-fired generation, there is still a net increase in emissions when importing coal-fired electricity and displacing gas-fired generation. Further, any reduction in electricity demand in B.C. will displace coal- and gas-fired generation in neighbouring jurisdictions.

**Competing Priorities for Electricity.** There are growing demands on electricity to displace other GHG emitting energy forms. For example, considerable growth in Liquefied Natural Gas (LNG) production is anticipated in B.C. as a result of the large differential between continental and global natural gas prices. LNG is very energy intensive and the Province would like producers to utilize green power rather than traditional gas-fired generation. Similarly, one of the least cost ways to reduce GHG emissions in the transportation sector is through electrification of transportation, increasing demand for green electricity. Heat is a very low-value form of energy. Unlike LNG production and transportation, there are several alternatives for reducing GHG emissions and electricity use in building heating including heat pumps, waste heat recovery and other forms of on-site or district-scale renewables.

**Why Not On-site Renewables?**

Renewable energy sources may not be available or suitable for individual building sites. Even when available, the loads of individual buildings are often not high enough to justify large systems with lower capital costs and good operating efficiencies. And most building owners lack the skills or interest to operate and maintain on-site renewable energy systems. When systems fail to work as expected, they are typically abandoned. District systems can tap off-site energy sources. Load profiles from many buildings can be combined, creating a larger and more constant energy demand to optimize the use of renewable sources. Operating costs (and system risks) can be shared, and management and maintenance can be centralised. And spare capacity can be shared with neighbouring systems. In dense urban neighbourhoods, there is a greater opportunity for collective strategies. Policies that favour on-site renewables may be better targeted to certain kinds of buildings and/or lower density areas. It is also important to note that district systems can facilitate more optimal on-site strategies in some cases. For example, on-site solar thermal systems could be oversized in buildings that are connected to district heating (resulting in lower costs), with surplus heat sold to the network in summer months. This strategy has been

employed in Vancouver's Olympic Village and was the most cost-effective way for one building to achieve net zero energy commitments on an annual basis.

## 2.5 District Energy Ownership Models

There is no universal ownership model for district energy. At a global scale, municipal ownership is still one of the most common models, reflecting in part the tight integration between district energy and municipal land use planning, infrastructure development, and policy goals. But other ownership models are also common. Private ownership has often evolved out of initial municipal ownership. However, there are examples of entirely privately owned new district energy developments. Whether initiated by private investors or acquired from pre-existing municipal utilities, successful private systems often include some form of local government involvement, whether in the form of passive policy frameworks or more proactive visions, coordination, regulation (including the proactive creation of formal franchises, and possibly granting exclusivity to franchisees), and in-kind support or formal financial involvement (grants, tax considerations or partial investment). Involvement by local government is particularly important to ensure systems serve broader policy objectives of energy security, economic development, community acceptability, and higher environmental performance (e.g., low GHG emissions, local air quality).

Denmark uses a mixture of regulated private and public ownership. At the municipal level, the ownership is predominantly public or joint ownership because of the law that mandates municipalities to build heat plants and to designate areas as District Heat only. In this case, there is limited advantage for private investment because risk is low and municipalities can borrow money on more favourable terms and guarantee the loans in the international market. Further, for smaller systems the owner/operators are vertically integrated companies. For the four larger systems (located in the largest cities, including Copenhagen), ownership of production facilities has been decoupled from ownership of the distribution networks. For example, a municipality may own the distribution network and purchase heat from a plant cooperatively owned with several other municipalities or from a privately-owned heat production plant. Many systems have remained in municipal ownership in Denmark and there has been some divestiture of private assets as a result of the non-profit regulatory requirements.

In contrast Sweden has seen a great transformation in the ownership of district energy utilities.[15] Initially, many systems were owned by municipalities and structured as a municipal department. Over time, most municipal district energy utilities were transformed into wholly-owned municipal energy companies, which act more freely and with less day to day political control. Following deregulation of Swedish energy markets in the mid-1990s, some of these municipal companies began operating outside their traditional municipal boundaries through amalgamation or acquisition of municipal companies into regional entities. Around the same time, financial difficulties among many Swedish municipalities resulted in a considerable number of municipal energy companies being sold to larger national or international energy companies such as Vattenfall, E.on and Fortum. Divestiture was also pursued in some cases to overcome political challenges with setting proper district energy tariffs. Today there is a fairly even split between private and municipal ownership on a national scale.

Figure 4 shows the continuum of possible ownership models for district energy, from 100% public ownership and governance (primarily municipal utilities) to full private ownership and governance (possibly with regulatory oversight). Examples are provided for each ownership structure, with detailed summaries of each example in Appendix 1.

There are numerous examples of public ownership models. Two local examples are Vancouver Neighbourhood Energy Utility (NEU) at Southeast False Creek SEFC) and the City of North Vancouver's Lonsdale Energy Corporation (LEC). Public ownership may take the form of a City or government department to a wholly-owned municipal or government subsidiary. A wholly-owned subsidiary may offer some additional protection in terms of liability and also provide for a more arms-length form of governance of commercial operations. Vancouver's NEU is part of the City's engineering department. LEC is organized as a wholly-owned subsidiary of the City of North Vancouver.

There are several hybrid public-private models between the ends of this spectrum. Examples of hybrid models include joint ventures, split assets, concessions, and strategic partnerships. Joint ventures involve pooled ownership of all assets. An example of this is Enwave in Toronto, jointly owned by the City of Toronto and Borealis Penco Infrastructure Fund (which is owned by the Ontario Municipal Employee Retirement System). In contrast, a split asset model involves separate

[15] See for example: Ericsson, Karen. March 2009. *Introduction and development of the Swedish district heating systems. Critical factors and lessons learned D5 of WP2 from the RES-H Policy project. A report prepared as part of the IEE project "Policy development for improving RES-H/C penetration in European Member States (RES-H Policy)."*

ownership of different assets with contractual relationships among the parties. An example of this model is the district energy system in Windsor, Ontario where the Windsor Utility Commission, a subsidiary of the City of Windsor, purchases energy from a plant owned and operated by Borealis and then distributes and sells the energy to end users through a municipally owned distribution grid.

A concession model typically involves a long-term agreement for the private sector to develop, finance and operate a system with the public sector retaining ownership of underlying assets. The private utility will likely require guaranteed revenues (via connection policy) to secure financing or the municipality can enter into a "take or pay" arrangement if it is confident customers will voluntarily connect. Although the public sector may not provide direct financing in a concession model, it may still bear some of the risk for revenues, costs and/or other liabilities. However, many concession models do involve partial risk transfer for capital cost overruns, operations and maintenance costs, and/or load development. The district energy system for London's Olympic Park was developed under a long-term concession model. The City of Richmond has been exploring concession style arrangements for district energy with Corix. Corix has established a long-term (50-year) concession for the operation of all utilities at Oklahoma University.

A strategic partnership model is a newer approach that does not involve any actual ownership of assets by the public sector (i.e., no direct liability, financing requirements, and/or a role in day-to-day management of the utility). But it does include proactive consideration and collaboration in the delivery of district energy. This model has been pioneered in the UK by Cofley, a subsidiary of GDF Suez one of the largest utility companies in the world. This model goes beyond a passive franchising and policy approach to district energy. It typically involves more formal and proactive collaboration to promote district energy including joint planning (collaboration on land use and infrastructure planning), possible in-kind forms of support (e.g., granting rights to land and/or resources for use in the provision of district energy), joint marketing, and tax exemptions or grants in exchange for public benefits. In addition to proactive consideration by the public sector, the model may impose formal requirements or expectations on the private sector, including obligations to serve and environmental targets. In the UK, where district energy prices are not regulated, the model has in some cases also included a role for the municipality in setting prices and/or sharing any returns above established benchmarks. Finally, in the UK the model has included provisions for the public sector to assume the ownership of the utility at pre-defined intervals (e.g., every 25 years) for net book value.

Further along the spectrum are non-profits and cooperatives. Non-profits are typically corporations without share capital. They are tax exempt and may be

controlled by a mix of private and public stakeholders, including customer groups, according to the rules established in their articles of incorporation. Any public sector involvement tends to be more indirect and arms-length than other models with public sector ownership or governance, and decision making is shared with other directors. Non-profits are typically 100% funded by grants and debt, with debt usually secured via long-term customer commitments. An example of a non-profit structure for district energy is District Energy St. Paul. Another example was the predecessor to Enwave, Toronto District Heating Corporation (TDHC), which was originally established by a special Act as a non-share capital corporation in the 1960s to integrate the steam systems of several downtown Toronto hospitals and eventually involved as stakeholders the hospitals, the City of Toronto, the Province of Ontario and the University of Toronto. TDHC was reorganized as a share capital corporation (Enwave) in 1999, which is currently jointly owned by the City of Toronto and OMERS.

Cooperatives are more complex and may involve share or non-share corporate structures. Cooperatives may be subject to income tax depending upon their corporate structure. They may distribute dividends to members or operate entirely as non-profits. The main distinguishing factor between a non-profit and a cooperative is that all customers of a cooperative would typically need to be a member of the cooperative. There are very few examples of cooperatives in district energy, perhaps reflecting the capital intensity and complexity of district energy systems. The most prominent example of the cooperative model is the Rochester District Heating Cooperative. There are several other examples of district energy producer and consumer cooperatives in Europe. Government may be involved in establishing a cooperative model. Government may remain involved by virtue of ongoing membership in the cooperative (as many government buildings would be connected to a district energy system) but government ownership is limited to its shares in the cooperative and decision making is shared with other cooperative members.

There are many local examples of fully privately owned district energy utilities in the world. As discussed below, private district energy companies in B.C. (along with some of the other ownership models) are regulated by the BCUC. Local examples include Central Heat in downtown Vancouver (owned by a group of private investors), UniverCity at SFU (owned by Corix), Dockside Green in Victoria (a joint venture between Vancity, FortisBC and Corix), and River District Energy in Vancouver (owned by Parklane, the master developer of River District).

Rarely do ownership models remain constant over a system's lifespan, reflecting changes in capital requirements (e.g., funding growth), technology (e.g., lack of experience of current owners in new technologies), risk profile (e.g., higher risk during establishment and initial growth phase, followed by a more stable operating and slow expansion phase followed by a renewal phase), and owner objectives . For new

systems, this points to the importance an ownership and governance model that is easily adapted to suit a range of possible owner-types. Giving forethought to the utility accounting approach, agreements with the municipality, asset transfer provisions, approach to customer rates and clear assignment of roles and responsibilities among the parties can result in a model that is easily suited to multiple owner types with (potentially) different regulatory requirements. Examples of ownership evolution include the following.

- Epcor (a subsidiary of the City of Edmonton) began as a private consortium in 1891 as Edmonton Electric Lighting and Power Company. Ten years later, the company became the first municipally owned electric utility in Canada.

- Revelstoke Community Energy Corporation was originally intended to be a private district energy system. Due to lack of investor response at the time, the City decided to develop the system under the banner of a wholly owned Subsidiary.

- Oklahoma University campus utilities were developed and operated by campus staff. The university later decided to focus elsewhere and granted Corix Utilities the right to operate all campus utility services under a concession agreement.

- Enwave Energy Corporation began as the Toronto District Heating Corporation, a non-profit co-operative. The utility later evolved to a share corporation to facilitate a private sector equity partner. Recently, the two shareholders (City of Toronto and Borealis, a business unit of the Ontario Municipal Employees Retirement System) announced they will divest Enwave through an auction process.

- Windsor District Heating was started and continues to be a split asset ownership model. While the municipality has retained ownership of distribution assets since system inception, the private sector generation assets have changed hands twice. It remains to be seen whether Borealis, the current generation asset owner divests itself of the Windsor system in tandem with the Enwave divestiture.

- Rochestor District Heating began as a privately owned utility, later becoming a customer owned co-operative in an effort to save the utility business.

- Though ownership has remained in the hands of Cofely UK, the City of Southampton UK re-negotiated a joint co-operation agreement with Cofely after system start-up.

- Toronto Community Housing engaged a utility partner to help develop a new district energy system. The joint venture partnership with Corix underwent restructuring in January 2012 when TCH bought out Corix's 40% equity share to hold full ownership in Regent Park Energy.

**Figure 4: District Energy Ownership Models with Examples**

| Ownership/ Governance | | Examples (Appendix 1) |
|---|---|---|
| **100% Public** | Government Department | Southeast False Creek (Vancouver) |
| | Government Subsidiary | Lonsdale Energy Cooperation (North Van)<br>Markham District Energy |
| | Public-Private Joint Venture (For Profit or Not for Profit) | Enwave (Toronto) |
| **Hybrids (Shared Ownership and/or Governance)** | Split Assets | Windsor District Energy |
| | Concession | Oklahoma University<br>London Olympic Park, UK |
| | Strategic Partnership | South Hampton, UK |
| | Cooperative* | Rochester District Heating Cooperative / Town of Toblach, Italy |
| | Non-Profit | District Energy St. Paul |
| **100% Private** | For-Profit | UniverCity (SFU, Burnaby) |

*May include public sector members that are customers of the system.

**Figure 5: Location of Ownership / System Case Studies (Appendix 1)**


## 2.6 Regulation of District Energy

There is no universal regulatory model for district energy. Regulation varies among jurisdictions as a result of differences in the historical development patterns of the district energy industry, predominant ownership models (e.g., independent regulation is less common when utilities are publicly owned), and differences in the general approach to regulating public utilities and natural monopolies. As illustrated in the review of Nordic countries, district energy systems may be regulated or non-regulated, with mandatory or non-mandatory connection.[16] In cases where connection is voluntary, many jurisdictions rely on competition from other sources of heat to ensure fair prices. This can be adequate for protecting consumers but may not be optimal for coordinating with other infrastructure development or ensuring infrastructure that supports broad economic, energy or environmental public policy goals. In situations with mandatory connection, there is often some form of government industry oversight, either through public ownership or independent regulation. Regulation in turn may take the form of price caps (e.g., Norway) or restrictions on profits (e.g., Denmark). Sometimes there are a range of regulatory models employed in the same jurisdiction.

[16] See for example "Regulatory Concepts and Issues of District Heating (National vs. local regulation, Municipal vs. Private vs. PPP ownership). Dr. Valdas Lukosevicius. Technical Exchange Programme: Sustainable energy regulation March 3-4, 2011, Warsaw, Poland.

District energy has many characteristics of public infrastructure and natural monopoly. Public infrastructure is characterized by the use of public resources (e.g., public rights of way) and significant public costs and benefits. A natural monopoly is an industry characterized by high upfront costs (capital intensive) and economies of scale. This means there are efficiencies from a single supplier rather than competing infrastructure. Few industries are perfect natural monopolies. And conditions may change with changes in technology. For example, after an early period of non-regulated development, the electric utility industry came under regulation with governments establishing monopoly service areas and independent economic regulators to ensure fair returns and low costs. This was considered necessary to develop extensive, interconnected electric power grids and larger electric generation plants with lower costs such as large hydroelectric systems. As the industry has matured (together with the development of other markets such as continent-wide natural gas markets) and technology has improved for smaller-scale generation, some governments have deregulated aspects of the electric power industry (e.g., generation and retail choice) while retaining regulation over networks (common carriers). Independent regulation is more common in the case of private utilities. Where utilities are publicly owned, direct government oversight of the utility is often considered sufficient to ensure no abuse of monopoly power.

In North America, there are some vintage district energy systems that are regulated by public utilities commissions by virtue of the fact they were originally part of regulated investor-owned utilities. Some states and provinces have statutory provisions for regulation of district energy by public utilities commissions, similar to gas and electric utilities. But many jurisdictions in North America do not directly regulate district energy providers.

In non-regulated situations, prices are typically negotiated in bilateral contracts between the utility and individual customers. In regulated systems, standardised tariffs are often developed, with variations among customers possible through the creation of different rate classes and various riders or adjustments to accommodate customer-specific considerations. Some non-regulated utilities also use published tariffs to increase transparency and reduce administrative complexity. Whether regulated or not, district energy utilities typically require franchises granting access to public rights of way (which may or may not grant exclusive access to one district energy provider) and they must comply with all relevant regulations (e.g., environmental standards and building codes).

In British Columbia, privately owned district energy utilities are regulated by the BC Utilities Commission (BCUC).[17] Private district energy utilities typically require a Certificate of Public Convenience and Necessity (CPCN) from the BCUC and are subject to regulatory oversight of costs and rates.[18] Municipally owned systems operating in their boundaries are not regulated by the BCUC.[19] Entities that are exempt may still submit to regulation by the BCUC. The Minister of Energy may also exempt, by regulation, any entity or project that does not have an automatic exemption.

The BCUC has a duty to protect the public interest and, particularly, the interests of ratepayers by ensuring that public utilities provide safe and reliable service at a reasonable price. The BCUC's powers are quite broad. Some of the BCUC's specific functions include:

- setting utility rates based on fair, just and reasonable costs;
- approving new facilities and/or extensions of service or facilities;
- deciding whether utilities should be permitted to issue new shares in their corporate entities;
- supervising the consolidation, amalgamation, and mergers of utility corporations; and
- supervising contracts between the utilities and large customers.

Regulated utilities are required to submit regular reports, formal applications for certain approvals, and respond to complaints to the BCUC. The BCUC may require oral or written hearings, and can also use alternative dispute resolution.

Although the Utilities Commission Act is subject to some interpretation, it is very likely that any district energy system serving residential and commercial development outside UBC's own academic facilities would be regulated by the BCUC, even if the

[17] This would likely include a non-profit corporation, although there are no precedents for this to date in B.C. Cooperatives may be exempt where sales are limited entirely to members. There are few precedents in B.C. for cooperative utilities but as one example the BCUC has not pursued regulation of joint gas processing facilities in northeast B.C. where these serve only parties of the joint venture. Similarly, the BCUC also received an opinion some time ago that a strata is not a public utility because they are collectively doing something for themselves (*Brian Williston, personal communication*).

[18] Small utilities or established utilities may not require a formal CPCN if capital requirements are below a pre-defined threshold, but would still be subject to Commission oversight of capital spending, operating costs and rates. The regulation of district energy in B.C. continues to evolve with the growth in new systems.

[19] There are questions whether this exemption would apply to a system that is partially owned by a municipality or regional district. To date, the BCUC has not had to deal with a hybrid municipal ownership model but has suggested it may depend in part upon the terms of the arrangement and the degree of municipal control.

system is owned by UBC.[20] This means the BCUC would need to provide a CPCN before constructing and operating a district energy system in the Development Areas. In reviewing a CPCN Application, the BCUC will consider project alternatives and the reasonableness of costs and other assumptions. The BCUC may issue CPCNs with conditions attached. These conditions may specify the scope of the project, its schedule and its expected costs. If these and other relevant conditions are met, the utility's cost of the project will be added to its rate base for recovery in future rates. If, for reasons within the control of the utility, the conditions are not met, the BCUC may deny cost recovery of all or part of the costs.

When considering rates, the BCUC will review all costs associated with operating the utility including:

- the cost to build, operate and maintain the utility's facilities (as outlined in the original CPCN and including any additions to assets over time);
- the cost to finance debt incurred from building these facilities;
- depreciation and amortization expenses;
- the costs of financing debt generally; and
- the capital structure and return on shareholders' equity including the resulting income taxes.

The permitted capital structure and allowed return on equity are intended to reflect the risk associated with a particular utility. These risks include the risk disallowance of costs, of under-recovery of costs, and/or stranded investments. Both debt rates and return on equity may be subject to periodic adjustments. Higher equity thickness and/or returns may be permitted under alternative approaches to rates that transfer more risk to the utility.

[20] UBC is not considered a municipality. Further, the Act defines (in part) a public utility as "a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for (a) the production, generation, storage, transmission, sale, delivery or 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 ... but does not include… (d) 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…" It is not clear whether stratas on 99-year leases would qualify as "tenants" or whether the fact that stratas in turn provide the energy to member residents qualifies as reselling to or use by others. It is also likely that any sales / service to Block F (Musqueam) would be subject to regulation as this Development Area is not on UBC owned land. The system at UniverCity is regulated by the BCUC but that was a clear case because it is being developed by a private utility, Corix (through an enabling infrastructure agreement with the SFU Property Trust).

The BCUC normally uses a "future forecast" methodology to review utility expenditures. This means that utilities apply for rate increases prospectively, to cover expenses that they expect to incur over a specified period in the future, called the "forecast test year" period. The term "test year" refers to a typical year, usually one, two or three years in the future. Once the total revenue requirements for the test period have been determined by the BCUC, this total cost is divided by the annual forecast sales volume for this period to arrive at the average rate that the utility may now charge for its services. The utility normally bears any benefits or risks associated with over- or under-recovery relative to forecast in the test period. The utility's rate tariff is then amended to adopt the new rates. In determining a utility's revenue requirements, the BCUC also examines the utility's rate base, or the assets on which a utility may collect a return. If the BCUC decides that any of the costs claimed by the utility in its application are not reasonable or prudent, it may disallow the recovery of those costs in customer rates. This is part of the risk assumed by a regulated utility, and one of the rationales for equity financing and a higher return on equity.

# 3 UBC Policy Context for NDES

The NDES is consistent with district energy systems being studied or installed in new high density, mixed use developments throughout the Lower Mainland and beyond. The proposed NDES concept also supports UBC's own vision, goals, targets, strategies, and actions, both for the Academic Lands and Development Areas of the Vancouver Campus.

As one of the world's leading universities, UBC's vision is to create "an exceptional learning environment that fosters global citizenship, advances a civil and sustainable society, and supports outstanding research to serve the people of British Columbia, Canada and the world." One of UBC's core values is to embody the highest standards of service and stewardship of resources and work within the wider community to enhance societal good. A second value is to explore and exemplify all aspects of economic, environmental, and social sustainability. Among UBC's key goals is to "…make UBC a living laboratory in environmental sustainability by combining its sustainability leadership in teaching, research, and operations." A supporting action towards this end is to "…integrate the University's physical operations with its research and teaching mandate as a living laboratory." This is exemplified in the introduction of experimental or near-commercial technologies in UBC's ADES. The proposed NDES offers UBC additional opportunities for sustainability teaching and research. These include teaching, research and demonstration opportunities related to technology such as large-scale waste heat recovery systems, improved hydronic building design, sub-metering and control of heat, and integration of supplemental

renewable systems into large community-scale district systems. There are also numerous teaching, research, and demonstration opportunities related to economic and institutional features of the NDES such as ownership structures, pricing systems, and governance mechanisms.

A further goal of UBC is to create a vibrant and sustainable community. This is further echoed in one of the five strategies in UBC's Vancouver Campus Plan to "…create a sustainable campus with outcomes such as:

- Campus as a living laboratory
- More student housing
- Public realm designed with nature
- Greener buildings and infrastructure
- Compact campus
- Vibrant campus life

UBC has also established formal targets to reduce institutional GHG emissions from 2007 levels by 33 per cent by 2015, 67 per cent by 2020 and 100 per cent by 2050. These are the most aggressive carbon-reduction targets among the world's top 40 universities. The waste heat from TRIUMF represents one of the largest, most economic sources of near-term carbon reductions for UBC. The NDES provides a tool to minimize the long-term costs and risks of accessing this heat to meet near-term targets, while also supporting the viability of a low-carbon system for the Development Areas. The NDES will also reduce the future cost to UBC of tapping other alternative energy sources in the South Campus and beyond. The benefits to the ADES are explored in more detail in the development of this business case, including quantification and valuation of potential GHG reductions to the ADES.

The Land Use Plan for UBC's Vancouver Campus envisions a model university community that is vibrant, livable and sustainable, and that both supports and advances the academic mission on the Vancouver Campus. At UBC Vancouver, family housing is restricted to eight local areas. Overall densities and floor space allocations to these areas are defined in the Land Use Plan for the Campus. Before development can take place, the UBC Board of Governors must approve Neighbourhood or Development Plans for each local development area. These include detailed land use plans, development controls, design guidelines, and servicing and transportation strategies consistent with UBC's Land Use Plan.

UBC recently approved an amended Neighbourhood Plan for Wesbrook Place. Wesbrook Place, UBC's latest family housing initiative, stretches across 110 acres of South Campus. When completed, Wesbrook Place will be the largest neighbourhood on UBC's Vancouver Campus. Over 12,500 students, faculty, staff, parents, alumni and members of the general public will live here in a mix of low rise and high rise housing.

A development plan has not yet been completed or approved for the Acadia and Stadium Development Areas, although it will likely include similar provisions as Wesbrook in terms of sustainability and community amenity commitments.

Under the Neighbourhood Plan, Wesbrook Place aims to be a vibrant, complete, ecologically sensitive neighbourhood that contributes to the larger UBC community. One of the strategies for achieving this includes the provision of "safe, effective and innovative infrastructure systems within economically reasonable cost parameters, including alternative energy and waste management systems." The Neighbourhood Plan includes explicit provisions for energy infrastructure. Specifically, the Plan states "Wesbrook Place will have an energy system that meets the residents' needs in a highly energy-efficient manner, and provides opportunity for research and innovation such as harvesting renewable energy sources within the neighbourhood and sharing energy between land uses." The NDES is an important tool for increasing overall energy efficiency (through large-scale waste heat recovery) and energy sharing (including optimizing on-site renewables), while providing unique opportunities for teaching and research.

The Wesbrook Neighbourhood Plan commits to the following energy strategies to be undertaken by the University and/or private developers as set out in UBC's Residential Environmental Assessment Program (REAP) building guidelines:

a) The buildings, landscape, infrastructure and operations will be designed to be as energy efficient as possible through a wide range of market-friendly design and operational measures;

b) Systems will be explored to harvest renewable energy sources such as solar, geothermal, waste heat and others at various scales and possible for sale (net metering or others);

c) A neighbourhood scale energy distribution system will be explored to offer opportunities for linking, generating and sharing energy to optimize overall performance;

d) Innovative systems at an appropriate scale will be encouraged to pilot-test incoming technology in recognition of energy supply and technology shifts coming in this century, including hydrogen as an energy source;

e) A cost sharing agreement will be explored with BC Hydro, Terasen Gas and UBC to hire an energy manager for the neighbourhood to work with businesses, strata councils and developers for a few years during and after development to optimize energy opportunities and performance; and

f) Opportunities will be explored for developing or using existing capacity associated with an energy utility at UBC (sole or joint venture) to invest in alternative energy systems and retain the revenues in the future.

Further, the Neighbourhood Plan states that residential buildings must be designed to achieve a rating of REAP Gold or better and that building designs should incorporate heating systems that can be converted to a district energy heating system to be installed in the future.

The NDES has the potential to support the above strategies as follows.

- The NDES will increase overall energy efficiency through existing waste heat recovery from TRIUMF.

- In addition to waste heat recovery, the NDES can increase the cost-effectiveness of certain on-site renewables such as solar thermal through net metering (as demonstrated in Vancouver's Olympic Village) and will allow both the Development Areas and ADES to tap renewables at a larger scale (e.g., biomass and hydrogen) in the South Campus and beyond that may not be available or suitable at individual building sites.

- The NDES is a neighbourhood scale energy distribution system for linking, generating and sharing energy to optimize overall performance.

- The NDES could integrate broader energy management functions to assist more directly businesses, stratas, and developers in design and maintenance of high-performance buildings. As all heat use for individual buildings would be metered at a single location, the NDES also provides very unique opportunities for collecting information on overall building performance.

- The proposed interconnection of the NDES and ADES (with a clear interface to allow metering and separate operations and rate making) will create opportunities for UBC to optimize ADES infrastructure. For example, during detailed design and future development phases, UBC can explore selling or purchasing peaking or back-up services to reduce costs to both the ADES and NDES. The integration with a growing NDES will also permit UBC to redeploy capacity freed up by future efficiency improvements to meet growth in surrounding Development Areas, reducing the potential for stranded investments.

- The NDES will create additional linkages between academic and community developments supporting the sense of a community that serves and benefits from the core academic mission of UBC.

# 4 NDES System Concept

During the pre-feasibility study for Wesbrook Place, a range of district energy sources were considered and screened. After some preliminary screening, four energy supply alternatives were evaluated in more detail:

- Connection to the future medium temperature hot water system for the main Campus;
- Heat capture from the TRIUMF cooling facilities;
- Biomass combustion from a facility located on South Campus; and
- Sewer heat capture from South Campus sewer lines.

The pre-feasibility study found the most promising options were heat capture from the TRIUMF facility and/or connection to the North Campus (Academic) DE system.

The full feasibility study uses the waste heat recovery from the TRIUMF cooling water system for the NDES Reference Case. Biomass combustion is considered as a supplemental source of alternative energy (for the NDES and ADES) in future phases, and also as an alternative to waste heat recovery from TRIUMF in sensitivity analyses. In all scenarios, peaking and back-up for the NDES is provided by the ADES and/or dedicated gas-fired boilers.

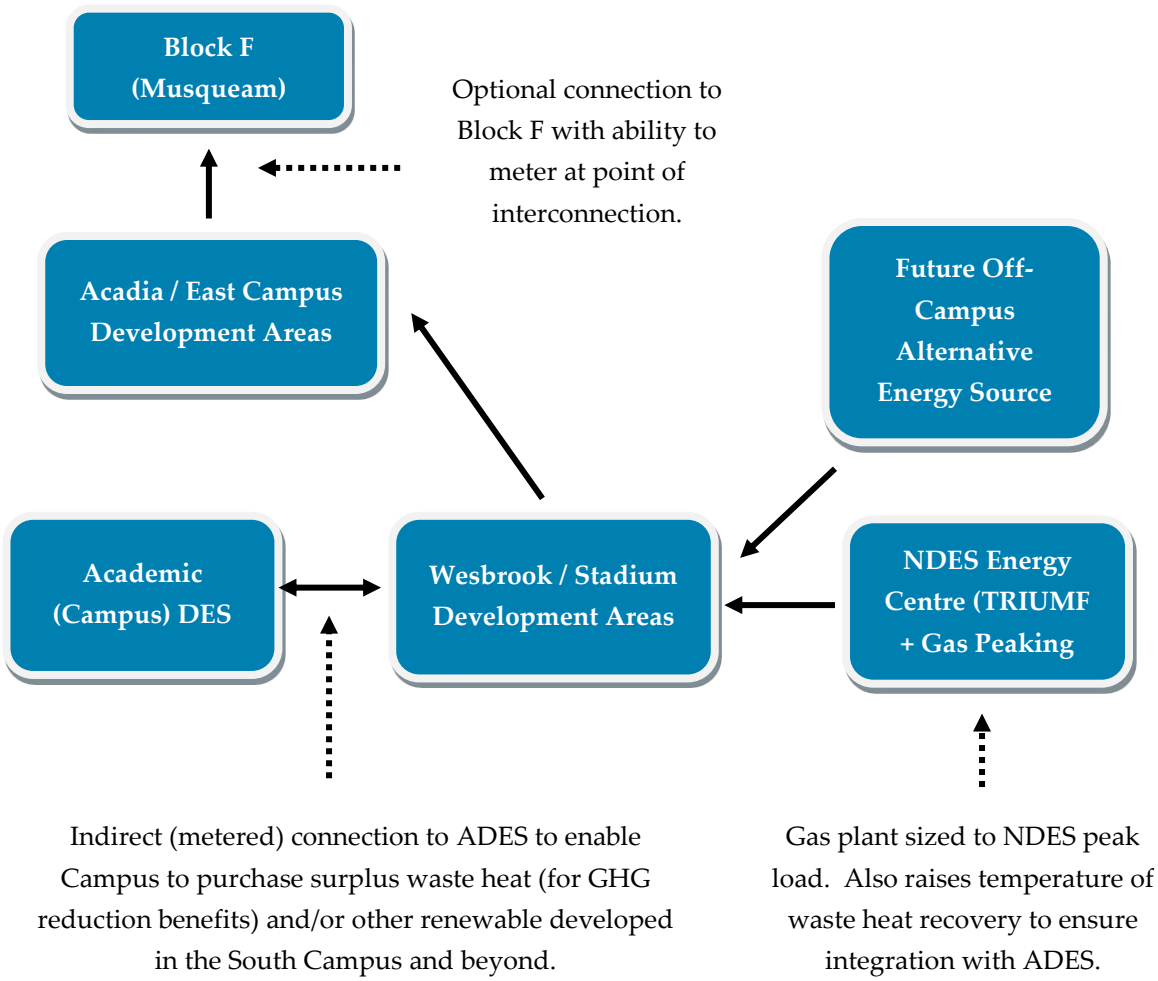
It was decided early in this study that integrating the NDES with the ADES would be beneficial to both the NDES and ADES. UBC is interested in obtaining alternative energy for the ADES. Waste heat from TRIUMF represents one of the most viable near-term sources of alternative (low-carbon) energy sources for the ADES. Furthermore, the connection will allow the ADES to more easily and cost-effectively access resources located in the South Campus and beyond (e.g., biomass). In the absence of the ADES, the NDES would not have sufficient load to support the large upfront cost of waste heat recovery at TRIUMF and the project would need to be deferred until the development of sufficient NDES loads, meaning greater reliance on natural gas in the early years of development. There are other potential benefits from interconnection including possible synergies in O&M and the ability to optimize installed plant capacity on each system (e.g., shared peaking and/or back-up). The integration could also increase the value of future efficiency improvements in the ADES since any surplus capacity arising from changes in Campus demand could be redeployed to serve growth in surrounding Development Areas.

UBC was initially concerned that interconnection of the NDES and ADES would require UBC ownership of the NDES and/or would trigger BCUC regulation of the ADES. The proposed NDES concept would involve one or two points of indirect interconnection (via heat exchangers) with full metering of any energy transfers between the ADES and NDES. This allows for separate ownership of the NDES and ADES, with energy transfers governed by a wholesale energy contract for purchases or sales. In the event the NDES is regulated by the BCUC (likely), BCUC oversight would likely be limited to the NDES assets and to the terms, conditions and prices for any contractual transfers between UBC and the NDES. Such contracts are normally reviewed to ensure they are just and fair to both the customers of the NDES and UBC. IF UBC owned the Energy Centre at TRIUMF (one of the options under a shared ownership model), it would still be possible to have a third party own the NDES distribution system and take responsibility for sales to stratas. In this case, the BCUC oversight would extend to the energy supply contract between UBC and the NDES from the TRIUMF Energy Centre, but not to the remainder of the ADES.

Figure 6 summarizes the base case concept used as the Reference Case in the business case analysis. In addition to one discreet point of interconnection with the ADES, the base concept includes a clear demarcation point between the local Acadia/East Campus distribution system and Block F, which is controlled by the Musqueam. This would permit an integrated system (the business case for waste heat recovery is improved with the larger load) but allow for a separate owner of the distribution system in Block F, if desired. Acadia/East Campus are connected directly to Wesbrook.[21] The Stadium node would be served by virtue of the interconnection line between Wesbrook and the ADES. FVB's technical report provides a diagram of the detailed layout of the base concept used in all costing. There will be opportunities to optimize the layout and staging during the detailed design and implementation phases. It should be noted that a detailed distribution layout was not prepared for the Acadia/East Campus node, which is in the very early planning stages. Costing for the Acadia/East Campus/Block F distribution system was developed using unit costs rather than an explicit distribution system layout. For this reason, distribution system cost estimates for this node are considered Class D with a higher level of uncertainty than the Wesbrook node.

[21] An alternative technical configuration is to connect the Acadia/East Campus/Block F node directly to the ADES and wheel heat energy through the ADES. Based on an initial investigation, FVB believes that the capital cost would be similar to the alternative, in which these areas are connected to the ADES. These options can be explored further in future design and implementation phases.

**Figure 6: Base Case System Concept**




The integration of the ADES and NDES introduces one added complexity for the NDES system design. Distribution systems are designed and operated to optimize pipe sizes and pumping requirements. Systems typically operate with a temperature re-set and variable flow strategy. For much of the year, many new systems operate at close to 65 degrees C, the minimum temperature to supply domestic hot water (DHW). Supply temperatures are then increased as ambient outdoor temperatures decline in order to meet peak heating requirements with smaller pipe sizes and lower pumping requirements. New buildings are typically designed to accept a lower maximum supply temperature during peak design conditions for heating and to minimize return temperatures (i.e., maximize heat extraction from hot water supply).

This allows greater use of low-grade heat sources and lower use of gas-fired peaking energy.

New buildings in the Development Areas will be able to accept lower peak supply temperatures. However, the ADES serves many older buildings requiring higher supply temperatures under all operating conditions (without major retrofits). In order to transfer energy between the NDES and ADES, the NDES will have to utilize higher supply temperatures. This will result in slightly lower efficiency of the heat pump and higher natural gas use by the NDES. However, early screening determined that the benefits of the integrated system strategy far outweigh the costs.

Specification of exact heat pump configuration (refrigerant, compressor type, number of units, etc.) is beyond the scope of this Study. For the purposes of this business case, it is assumed that an industrial scale heat pump would be capable of delivering at least 80ºC water, which has been demonstrated locally in the City of Vancouver's NEU at Southeast False Creek.

For costing and phasing purposes, the NDES is subdivided into three main components:

- Building Interfaces (also called Energy Transfer Stations or ETS);
- Distribution Piping System (i.e. pipes connecting buildings to Energy Centers, including mainlines and branch connections); and
- Energy Centers (also called Heating Plants).

The Energy Transfer Station (ETS) is the interface between the DES and the building heating systems. An ETS typically consists of heat exchangers, controls, energy meters, valves, and associated equipment and piping. The ETS can be installed with load so ETS costs have been phased accordingly within the business analysis. The Distribution Piping System is the physical link between energy sinks (customers) and sources (Energy Centers). For all costing, FVB has assumed a medium temperature, below ground, direct buried hot water distribution network with side by side supply and return piping in a closed circuit. The assumed piping meets European standards and consists of thin walled steel pipe, insulated with PUR insulation, enclosed in an outer HDPE jacket and including a built in leak detection system.

Hot water production will be located in a single Energy Centre (EC) located at TRIUMF. The EC contains all heat recovery equipment, as well gas-fired boilers to raise system temperatures and provide peaking and back-up support. FVB considered two concepts for the TRIUMF Energy Centre. One concept assumes gas boilers are sized to provide trim-up energy (i.e., to raise the temperature of water output from the heat pump), provide back-up for the heat pump, and meet peak demands in the NDES. This full scenario (TRIUMF 1) was used for the Reference Case. This concept

also requires a full staffing complement. A second concept assumes the gas boilers at TRIUMF are limited to the capacity of the heat pump (to provide trim-up energy and back-up for the heat pump only) and that peaking energy is provided by the ADES (TRIUMF 2). This option is considered as a potential optimization in the sensitivity and scenario analyses. A biomass option was considered in an alternate scenario (as an alternative to TRIUMF heat recovery) and in sensitivity analysis as a supplemental resource in Phase 4.

For the purposes of this Study, FVB and UBC agreed on a set of assumptions for the quantity and profile of waste heat available from TRIUMF. The base concept assumes a constant waste heat source of 8.5 MW throughout the year, except for the annual shutdown in January – March (reflecting expected waste heat available after an expansion currently underway). The business case considers the impact of an alternate annual shutdown schedule (subject to negotiation) to better match waste heat recovery with peak heating demands. FVB also estimated the capital cost (including interconnection costs) for a larger biomass plant located further south. This was included in the business case as a source of supplemental energy in the last phase of development (beyond 20 years), as well as in sensitivity analyses as a near-term alternative to waste heat recovery from TRIUMF.

Under the base concept, the NDES would supply energy to the ADES when the available waste heat from TRIUMF exceeds the demand in Development Areas. Available waste heat is higher in early phases of development and declines as the Development Areas are built out. Under the current operating schedule for TRIUMF, the majority of waste heat supplied to the ADES would be in summer and shoulder seasons when neighbourhood demands are much lower. The waste heat recovery is expected to displace gas-fired generation (and associated GHG emissions) in the ADES. The installed capacity of gas boilers at the TRIUMF EC is sufficient to meet the full peak loads of the Development Areas even when the heat pump is not available. There may be further opportunities to optimize the sizing of the gas boiler plant at TRIUMF through additional capacity sharing between the NDES and ADES.

**The Sustainability of Waste Heat from TRIUMF**

The NDES Feasibility Study assumes that up to 8MW of waste heat will be available from TRIUMF at no charge (beyond the costs of recovering this waste heat, which is current vented to atmosphere), until all capital investments have been repaid. The business model assumes that the upfront capital investment for the TRIUMF Energy Centre will be recovered over 25 years (the approximate life of assets required to recover the waste heat). For this to be realized TRIUMF must continue operation at UBC until 2038 and planned expansions must be implemented.

TRIUMF has a 99 year land lease agreement with UBC; however, TRIUMF's existence is contingent on continued Federal Government funding. Federal funding is renewed every 5 years and there is no guarantee that the funding will be approved. However, there are mitigating factors that indicate that the likelihood of funding continuing for at least the next 20 years is high.

The following factors suggest that continued TRIUMF operation is likely for at least the next 25 years and that the planned developments will be implemented.[22]

1. TRIUMF is Canada's National Research Laboratory for Particle Physics. Particle Physics is a very active field internationally and over the last decade the worldwide investment in Rare Isotope Beam based research was $4.4 billion. TRIUMF's biggest challenge strategically is which direction to take research as the opportunities are many and varied.

2. TRIUMF represents over $1 billion of government investment over the last 42 years. The government of Canada recently funded the ARIEL project which has a 20 year lifetime. The facility is ideally located in terms of low energy costs and as an attractive location for visiting researchers.

3. TRIUMF occupies a valuable niche among the second tier of particle physics research organizations. TRIUMF is considered high quality on a small scale, "small but mighty". It has a very high level of expertise for a small organization and is well known in the field.

4. TRIUMF continues to expand its nuclear medicine production. The facility is able to produce the most valuable medical isotopes on a "small" scale and owns the intellectual property. TRIUMF is very well integrated into the BC Life Science Industry.

5. The BC government is targeting development of the cyclotron manufacturing industry in BC and there is lots of potential for TRIUMF "spin offs". TRIUMF has already resulted in successful "spin off" companies that manufacture parts for the cyclotron industry.

6. The regulatory burden on TRIUMF is like to be reduced in the next years, which will make development approvals much simpler. It is currently categorized as a Class I facility and licensed for 5 years at a time. TRIUMF has been asked to renew its license for 10 years, and there are indications that at the end of this period it will be regulated like a Hospital and offered a Class II license.

[22] Based on telephone interview by Orion Henderson with Nigel Lockyer, TRIUMF Director.

Although no near-term payment is proposed for the waste heat from TRIUMF, it is important to note that the heat is currently released to the atmosphere and that recovery by the NDES (at the NDES' cost) will lower operating costs for TRIUMF's existing cooling tower (which will continue to be required for back-up rejection of waste heat). Furthermore, the recovery represents an opportunity for TRIUMF to demonstrate goodwill towards the community within which it operates, and to contribute to its own sustainability performance.

The risk that waste heat is not available is mitigated by the fact that the NDES will have sufficient gas-fired boiler capacity to continue to meet NDES loads. From a cost perspective, the main impact will depend upon the difference between the operating cost for waste heat recovery (including the cost of electricity) and natural gas. This differential will vary with gas and electricity prices over time. A sensitivity analysis was conducted as part of this study to show the effect of switching from waste heat to gas-fired heat prior to the 25-year life of heat recovery assets. Gas represents a ceiling on financial risk. Depending upon relative gas and biomass prices in the future, it may be possible to reduce financial impacts, if any, by accelerating the introduction of biomass should waste heat from TRIUMF no longer be available.

# 5 NDES Ownership Scenarios

A key issue for the business analysis is the advantages and disadvantages of different ownership models for the NDES. As noted in Section 2 of this report, there are a wide range of potential DE ownership models. Following a preliminary scoping workshop with UBC staff, four models were selected for formal consideration in the business case (representing four points along a continuum of options). These four scenarios are summarized below, together with recommendations for optimizing the design of each model and other optional elements or designs of the model.

From the perspective of capital requirements and rates, there is very little difference between the Joint Venture and Split Asset models discussed below. During the course of the study, the project steering committee also determined that from a legal and governance perspective, the Split Asset model was a preferable option to the Joint Venture model. For the purposes of the financial modelling that follows this section, we therefore focus on the Split Asset model. The Joint Venture model could still be considered during the negotiations with a third party without altering the basic findings of this study.

## 5.1 Model 1: UBC Ownership

In this model, UBC (either directly or via the UBC Properties Trust or another UBC entity) would be the primary owner of all NDES infrastructure including the TRIUMF Energy Centre and any future supplemental energy sources, the neighbourhood distribution system, and all Energy Transfer Stations. Given the desirability / likelihood of regulation of the NDES by the BCUC, clear demarcation points between the ADES and NDES will still be required and clear transfer pricing arrangements (contracts) should be established for any energy transfers or shared services.

Under full UBC ownership, the project steering committee indicated it would likely still want to outsource the retail customer service function (metering, billing, call centre). UBC could also consider contracting out other system functions such as system maintenance and operation. These are optional strategies within the full UBC ownership model. The financial analysis includes an allowance for all staffing, maintenance, billing, and customer service, regardless of whether these are provided internally or outsourced.

During discussions of this model, the project steering committee indicated a preference for a wholly-owned subsidiary approach. While not essential (with clear internal accounting, transfer pricing and governance mechanisms), the project steering committee noted several additional benefits to a wholly owned subsidiary model, including increased transparency and possible arms-length approach to governance.

In the event the NDES was not regulated by the BCUC (e.g., it is determined to be formally exempt under the definition of a public utility and UBC chooses not to submit to voluntary regulation by the BCUC), the project steering committee recommended establishing an independent rate review panel, similar to the panel set up by the City of Vancouver for the SEFC NEU. In order to maintain any exemption from BCUC regulation, UBC would likely need to retain ultimate control over rates but a rate review panel can provide a source of independent review and advice concerning rates and other service issues. A customer advisory group could also be created to provide more regular and formal feedback to the utility and rate review panel.

Even in the absence of formal BCUC regulation, we have assumed as a starting point that this model would still emulate a BCUC-regulated utility capital structure and cost of service approach to setting rates. This was the approach adopted by the City of Vancouver for the SEFC NEU. The City created a pro forma that emulates typical utility accounting practices for rate setting. The City also adopted a deemed capital structure and return comparable to a benchmark utility. The only difference is that the City chose not to include notional income taxes in the utility pro forma. Finally, the City emulated other regulated district energy utilities in developing rate setting

principles, designing rate structures, establishing transfer pricing policies, and utilizing deferral accounts and levelized rates to ensure competitiveness of rates during early phases of development (when capital is installed in advance of load).

The City saw several advantages to adopting this approach to rates.

- It allows clear benchmarking with other regulated DE utilities (rates may vary but the principles and methods for setting rates are similar across utilities), including benchmarks for financing costs and overheads.
- It enhances transparency in rate setting.
- It ensures the City (taxpayers) is adequately compensated for risk (although the utility is 100% debt financed, the deemed capital structure and WACC reflects the typical risk premium for a comparable district energy utility owned by private investors).
- It minimizes the possibility of future rate shocks in the event that the City divests of the utility to the private sector.

It remains to be seen how the BCUC would establish a deemed capital structure, cost of debt and cost of equity for a regulated utility owned by UBC. We believe the assumptions used in this report are reasonable for this stage of consideration.

During the review of this ownership model, the project steering committee also discussed options for an arms-length approach to the governance of the NDES. Specifically, the EPCOR governance model was discussed. This is summarized further below. This model would not significantly alter the financial analysis in this report but could have strategic benefits in terms of transparency, commercial responsiveness and accountability. Should UBC ownership or other UBC equity participation be pursued, there may be merit in considering the EPCOR model for the governance of a wholly-owned subsidiary. This model may entail some additional upfront and ongoing costs to set up and administer, particularly at the scale of a small utility.

**Concession Model Alternative**

An alternative model for full UBC ownership would be a concession style arrangement. In a concession, UBC would retain ownership of the underlying NDES assets but design, development, financing, and operation would be undertaken by a private sector partner. The concession owner would recover costs through customer rates over a pre-defined term (with renewal options). Financing would typically be secured by the concession owner through a guarantee on revenues. As a result, UBC would continue to assume most of the revenue risk, although there may be opportunities to transfer some revenue and cost risks to the concession owner (with some impact on financing rates). This model would have similar risks and impacts as the wholly owned UBC subsidiary, except that development, financing, and operation would be outsourced. However, it is not clear whether a concession arrangement would effectively overcome capital constraints faced by UBC if a revenue guarantee is required for NDES loads and/or a long-term contract for UBC purchases, and if the guarantee or contract is considered a capital lease under provincial accounting policies. A mandatory connection requirement may provide sufficient guarantees for financing the NDES, but proponents may still want a long-term purchase contract for surplus energy from UBC to ensure financing. Should UBC wish to explore this arrangement further, additional analysis of the accounting treatment of the concession would be required.

**The EPCOR Model of Subsidiary Governance**

EPCOR Utilities Inc. is a wholly owned subsidiary of the City of Edmonton. EPCOR builds, owns and operates electrical transmission and distribution networks, water and wastewater treatment facilities and infrastructure, and provides energy and water services and products to residential and commercial customers. EPCOR is governed by an independent Board of Directors and its sole shareholder is the City of Edmonton. EPCOR is not in the business of thermal district energy; however, it is an example of an arms-length public sector subsidiary model in the utility sector.

EPCOR's beginning dates back to 1891 when a private consortium established the Edmonton Electric Lighting and Power Company. Ten years later, the company was made public becoming the first municipally owned electric utility in Canada. In the years following, the utility expanded operations to include potable water and wastewater treatment plants throughout North America.

EPCOR provides utility services to over one million people in more than 70 communities across Western Canada. EPCOR enters into P3s with communities, leading the design, construction and operation of the infrastructure

project over a long-term contract for pre-determined annual payments. Contracts are typically 10-20 years. EPCOR recently ventured into water treatment in the Alberta Oil Sands. EPCOR Utilities is the parent company to a number of subsidiaries that focus on various lines of utility business and operations (water, wastewater, electrical distribution).

In 2009, EPCOR spun off its electricity generation assets, including 31 plants across North America. The large capital requirements and risk profile did not match up with that of the shareholder. Furthermore, the bulk of the asset mix was in power generation, held in projects outside the City of Edmonton. Since spinning off the power generation assets, EPCOR has focussed entirely on regulated and electrical distribution in the Edmonton area, water treatment in the Alberta oil sands, and commercial water investments outside of Edmonton (in the form of P3s).

In 2010, EPCOR had revenues of $1,473 million and net income of $133 million. It paid common share dividends to the City of Edmonton of ~$135 million. EPCOR also pays franchise fees and taxes to the City. The dividend represents the equivalent of 25% of the City of Edmonton's residential property taxes. EPCOR's common dividend is set by policy. The dividend grew by $10 million annually between 2001 and 2004 until it reached 60% of earnings available to common shares in the applicable year. The dividend continues to grow at a rate equal to inflation. EPCOR employs 2200 people within the City of Edmonton (90% of the EPCOR employee base)

Key features of EPCOR's governance include the following:

- The Board is appointed by the City of Edmonton.
- The Board operates independently of the Shareholder with full authority to make strategic business decisions. There are no employees or elected representatives of the City on the Board.
- The Board is led by an independent Chairman; Directors are respected business leaders from across Canada.
- Operating under a clear Charter of Expectations, the Board approves the goals of the business, including correlating objectives and policies, and also evaluates management's performance.
- The selection, assessment and evaluation process for Directors seeks to match individual skills with EPCOR's needs. An independent consultant and skills matrix are employed.
- The City grants EPCOR a franchise for the sole rights to electrical power and water distribution within the City of Edmonton.
- The City maintains the ability to control power and water rates within the City of Edmonton through an EPCOR Rates and Procedures Bylaw. The Bylaw ensures fair and reliable service to utility customers. Rates are based on a cost

of service model, including an allowable margin of profit to EPCOR. EPCOR service levels and environmental management are compared to industry benchmarks to ensure adequate performance.

## 5.2 Model 2: Third Party (Private) Ownership

This model would involve a third party to develop, own and operate the NDES infrastructure, with a contract for any energy purchases from or sales to the ADES. This is essentially the model for the Neighbourhood Utility System (NUS) at UniverCity. A detailed case study of the origin and structure of the NUS at UniverCity is provided in Appendix 1 of this report.

Under this model, UBC would select a third party (likely through a competitive process) to develop, own and operate the NDES. Once selected, UBC would negotiate definitive agreements with the selected party. At UniverCity the primary definitive agreement is an Infrastructure Agreement between Corix (the selected private owner) and the SFU Property Trust which sets out among other things general goals and expectations, obligations of the parties, environmental and regulatory matters, access to lands and infrastructure, franchise and other fees (as compensation for access to Trust lands and other business considerations), and other legal requirements or conditions. The private utility would be subject to BCUC regulation. UBC would not be directly regulated although any contract to supply or purchase energy would likely be reviewable by the BCUC. UBC could also contract other services to or from the third party, such as system maintenance services.

An optional design element for this model could be a more proactive Strategic Partnership or Joint Cooperation agreement between the third party and UBC. An example of the Strategic Partnership model is provided in Appendix 1. In this model, UBC would not take a formal ownership position or operating responsibility, but the Strategic Partnership could include provisions for asset buy back at periodic intervals; formal mechanisms to coordinate infrastructure planning; environmental commitments; joint marketing; in-kind support; and possible involvement by UBC in ongoing governance (e.g., a Strategic Partnership Board), among other provisions.

## 5.3 Model 3: Shared Ownership - Split Asset Model

A split assets model involves at least two owners, but ownership is split across assets, with contractual relationships among the parties, rather than pooled as in the case of a joint venture or single corporate entity with multiple shareowners. With district energy, the most logical split of assets would be between distribution assets (including

customer connection and retail service) and generation assets (heat production). This is the model for district energy in the City of Windsor (see Appendix 1).

The base NDES concept already includes some energy sharing between the existing ADES and proposed NDES. In the split asset model, UBC would own some of the actual NDES assets. The most logical approach to Split Assets would be for UBC to own and operate the Energy Centre at TRIUMF (and potentially any future additional alternative energy system) and for a third party to own and operate the NDES distribution and ETS assets. The third party would purchase wholesale energy from UBC and would then be responsible for distribution and retail sales. UBC would also require a contract with the third party to distribute and sell energy from the TRIUMF Energy Centre through the NDES system to the ADES.

This is the most logical form of split of assets because it aligns with UBC's existing functions and also the fact that, at least in the near-term, most of the waste heat from TRIUMF will be utilized by UBC. It also removes UBC from the management of retail sales, including rate setting and from financing assets not directly related to academic functions and strategic goals. Conveniently, about 50% of the total capital costs of the NDES are associated with the TRIUMF Energy Centre and so from a financial perspective, this model looks very similar to a typical 50/50 Joint Venture model with pooled assets and equal interests (below). However, this structure may allow for greater transparency and separation of roles and responsibilities than a Joint Venture Structure. Nonetheless, it will require careful design of contractual relationships to ensure the interests of all parties are properly aligned and there is adequate accountability for each party.

This model would also enable the contracting of services by either party (e.g., the third party owner of the distribution system could contract for maintenance support from UBC, or vice versa).

There would be the same options and considerations for structuring and governing UBC's ownership interest in the TRIUMF Energy Centre as under the 100% UBC ownership model. However, there may be fewer drivers for a subsidiary and/or arms-length governance model if UBC only owns the energy generation assets, compared to the situation in which UBC is also responsible for retail distribution and energy sales.

## 5.4 Model 4: Shared Ownership - Joint Venture Model

Under this model, UBC would establish a Joint Venture with one or more external entities for the development and delivery of the NDES. Potential partners to the Joint Venture could include one or more private utilities (one of whom could also be the

managing partner responsible for operations and customer service), the Musqueam Nation, and TRIUMF. The entity could be established as a for-profit or not-for profit entity. The latter would imply primarily debt financing and no income taxes.

A Joint Venture involves pooled assets and shared decision making. Some key provisions in a Joint Venture agreement would include the share of capital, risks, and returns; decision making (governance), including growth and technology decisions; and provisions for a shareholder exit / buy-out. Dockside Green Energy (the district energy system serving the Dockside Green development in Victoria) is set up as a Joint Venture between VancityCapital, Corix, and FortisBC (previously Terasen Utility Services). Windmill, the developer of Dockside, was originally a partner of the Joint Venture but has since exited the arrangement. Corix is the operating company under the Joint Venture agreement.

Another prominent example of a Joint Venture arrangement is Enwave in Toronto, one of the largest district energy companies in North America. The Joint Venture partners in Enwave (City of Toronto and OMERS) are currently considering bids to sell the system and extract their respective capital investment.

The Joint Venture would be separate from the Campus utility, but UBC may also purchase or supply energy and/or services to the Joint Venture under contract. Additional cooperative agreements between the Campus and the Joint Venture may also be possible.

# 6 Approach to the Business Analysis

For the business analysis we developed a regulated cost of service model (pro forma) that calculates the required customer rates (revenue requirement) under a set of input assumptions. The cost of service model is consistent with the approach to rate setting for other regulated utilities in B.C.

We first develop a Reference Case using the base technical concept discussed in Section 4, together with other input assumptions described further below. We calculate rates for the Reference Case under three ownership models: 1) Full UBC Ownership; 2) Third Party Ownership; and 3) Shared Ownership. For the latter we assumed a split assets model, which from a financial perspective is virtually the same as a 50/50 Joint Venture model. We then compare the rates with other benchmarks to determine the viability (competitiveness) of the NDES under different ownership models. We then consider a range of sensitivity and scenario analyses to reflect risks, uncertainties and opportunities for further optimization.

For all ownership models, including UBC ownership, we use a fully allocated cost of service. This means that we have included all costs that can be reasonably allocated to the NDES, including property taxes, rent on land for the Energy Centre, all staffing costs (whether the staff are entirely incremental or not), and other overhead costs.

In the case of UBC ownership, we have assumed a deemed capital structure and post-tax returns comparable to a regulated private utility in setting rates. This is similar to the approach used by the City of Vancouver in setting rates for the SEFC NEU. In the case of SEFC, this was intended to ensure the City is adequately compensated for risk, and to minimize any potential rate shocks in the event the City were to divest itself of the NEU.[23] Under this policy, customers still benefit from the City's exemption from income taxes.

For each scenario, we calculate a levelized cost. The levelized cost converts a stream of costs into an equivalent constant cost over a specific term, taking into account the time value of money. This is a standard approach for evaluating and comparing options in the utility sector. It permits an' apples to apples' comparison. The levelized cost is not a formal rate design but approximates the cost to consumers over the defined term for testing viability.

There is one added complication with new DE systems. With a new development, some infrastructure is typically installed in advance of loads. Any attempt to recover these costs from initial customers could lead to uncompetitive rates, detracting from the success of the utility. Many new district energy utilities in B.C. have employed a levelized approach to rates in which rates are phased in to minimize the burden on initial customers and ensure competitiveness. Deferred costs are recovered in future rates as load develops. This requires the creation of a deferral account. The deferral account balance may include cash and non-cash costs. The utility is allowed to rate base deferred costs to ensure their future recovery together with an appropriate rate of return for financing the deferral account. As load / rates increase and unit costs decrease (with growth) the deferral account is eventually eliminated and utility rates are eventually reset to reflect current rate base and operating costs. The deferral account adds to capital requirements in early years. The deferral account requirements are included in all calculations of total capital requirements and levelized costs.

[23] In reality the City of Vancouver has used debt to finance the utility. However, the use of 100% debt financing would not be possible without the added guarantee of the City's taxing authority. The use of a deemed private sector capital structure and return on equity is intended to compensate tax payers for specific business risks, as reflected in the allowed capital structure and return on equity for similar private utilities. This approach to rates was also considered important because the NEU serves only a portion of the City. The debt rate in the pro forma does reflect the benefit of low-cost financing received from the Federation of Canadian Municipalities for the project.

To test the viability of the utility under various ownership models, we compare the levelized cost to a series of market benchmarks as discussed further below.

# 7 Heating Loads in Development Areas

A key input to the business analysis is the magnitude and timing of loads. FVB estimated the potential heating loads for each of the target Development Areas.[24] Heating loads are derived from estimates of connectible floor area, use mix, and expected energy use intensities (EUIs). UBC Properties Trust provided input on the amount, mix and timing of connectible floor area. Connectible area was broken into five phases. Phase 0 consists of existing buildings which could be connected to the NDES. Phase 1 includes some existing floor area in the East Campus area, but largely consists of new floorspace. Phases 2 – 4 are entirely new floorspace. The total connectable floor area is approximately 1 million m2, with the bulk of this area developed in Phases 1 – 3.

The expected (Reference Case) development timelines for each phase are summarized in Table 1. Within each phase, development is assumed to proceed in a linear fashion. Shorter and longer phasing assumptions are considered in risk and sensitivity analysis.

**Table 1: Reference Case Phasing**

| | Phase 0 | Phase 1 | Phase 2 | Phase 3 | Phase 4 |
|---|---|---|---|---|---|
| **Timing** | 2014 | 2015-2017 | 2018-2023 | 2024-2029 | 2030-2036 |

FVB evaluated two scenarios of heating demand:

- **Full Service:** All new construction buildings would be fully hydronic. All in-suite space heat, common area make-up air, and DHW would be served by the NDES. The existing buildings included in the study area have electric baseboards for in-suite heating, and they would not be converted, so existing buildings would receive partial service only (common area make-up air and DHW).

- **Partial Service:** All new buildings would have electric baseboard in-suite heaters. Common area make-up air and DHW would be served by the NDES. Existing buildings would also have this level of service.

[24] District cooling in a largely residential neighbourhood is generally not feasible in Vancouver's climate and was screened out during the NDES pre-feasibility study.

For the Reference Case, we adopted the full service configuration. The Partial Service scenario was developed to test the potential impact of forgoing the incremental cost of requiring buildings that are fully hydronic. As shown in the results, the reduced capital costs for Partial Service are not sufficient to offset the reduced revenues.

FVB prepared peak and annual heating EUIs for low-rise and mid/high-rise building archetypes.[25] The peak EUIs drive capital costs, while the annual EUIs determine fuel costs. Several scenarios for EUIs were prepared. Per instruction from UBC, the Reference Case assumes a constant development-wide heating EUI of 100 kWh/m2/year in new buildings and 70 kWh/m2/year for existing buildings (reflecting partial service).[26] These EUIs are consistent with several recent data sets on actual building energy consumption, including an analysis prepared by UBC Campus Sustainability for nine existing residential buildings in Wesbrook Place, consumption data from a recent study of multi-unit residential buildings prepared for BC Hydro, and metered data from the neighbourhood energy utility serving Southeast False Creek in Vancouver.

The Reference Case of expected annual energy by phase and sub-area is shown in Table 2. Table 3 summarizes the anticipated heating demand under the Partial Service scenario. Sensitivity analysis was also conducted on heating loads assuming a decline in EUIs over time. Under the full service scenario, the target Development Areas could require up to 105,000 MWh/year of heating. For context, UBC's existing heating load is approximately 170,000 MWh/year, and could grow to 205,000 MWh by 2035.

Table 4 compares the proposed UBC NDES system to other examples of district energy systems in B.C. At build out, the UBC NDES would be about one quarter the size of Central Heat currently. The UBC NDES is much larger than a number of other new systems (e.g., UniverCity, Dockside). It is more than 50% larger than the SEFC NEU at build out, but the Science World recently joined the NEU and the City recently approved expansion of the NEU to the False Creek Flats. The projects are now more comparable in absolute size, although SEFC is still denser.

[25] The archetype EUIs reflect an expected (virtually best case) energy consumption in a single representative building. In reality, energy usage can vary greatly within the same building archetype depending upon the specific building design, actual use, occupancy, commissioning of systems, ongoing maintenance of systems, and occupant behaviour. The presence of amenities such as fitness centres and pools can greatly increase EUIs. The EUIs in this study are intended to reflect an expected neighbourhood-wide average for all new and existing buildings, including natural variation in design, construction, commission, maintenance and use.
[26] Capital costs were originally developed assuming some decline in EUIs over time. Capital costs were not adjusted to reflect updated EUIs but are within the range of uncertainty for this stage of analysis.

**Table 2: Incremental Annual Energy, Full Service (Reference Case) [MWh / year]**

| | Phase 0 | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|---|
| **Wesbrook** | 5,950 | 18,598 | 15,297 | 6,984 | - | 46,829 |
| **Stadium** | - | 1,388 | 1,313 | 2,055 | 2,317 | 7,073 |
| **Acadia** | - | 3,586 | 2,189 | 17,971 | 9,746 | 33,492 |
| **Block F** | - | 4,640 | 8,614 | 4,123 | - | 17,377 |
| **Total** | 5,950 | 28,212 | 27,413 | 31,133 | 12,063 | 104,771 |

**Table 3: Incremental Annual Energy, Partial Service) [MWh / year]**

| | Phase 0 | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|---|
| **Wesbrook** | 5,922 | 13,048 | 11,382 | 5,488 | - | 35,840 |
| **Stadium** | - | 973 | 973 | 1,624 | 1,624 | 5,194 |
| **Acadia** | - | 2,765 | 1,624 | 11,382 | 6,825 | 22,596 |
| **Block F** | - | 3,255 | 5,201 | 3,255 | - | 11,711 |
| **Total** | 5,922 | 20,041 | 19,180 | 21,749 | 8,449 | 75,341 |

**Table 4: Comparisons of UBC NDES to Other District Energy Systems in BC**

| | Build Out Load (MWh/year) | Development Area | Other Features |
|---|---|---|---|
| **UBC NDES (All Expansion Areas)** | 105,000 | ~40 ha | - Waste heat recovery<br>- Long build out but ability to leverage synergies with campus loads |
| **Central Heat, Vancouver** | 470,000 (~200 buildings) | N/A | - Gas-fired steam system<br>- Operating for ~40 years<br>- Continues to expand<br>- Mix of residential / commercial loads |
| **Southeast False Creek, Vancouver** | 63,000 (Note 1) | 32 ha | - Sewer heat recovery<br>- Large initial load (Olympic Village)<br>- City controls about 25% of development floor area<br>- Mandatory connection bylaw |
| **River District, Vancouver** | 66,000 | 53 ha | - Starting with temporary gas-fired plant<br>- Future connection to Metro Waste to Energy Plant<br>- Single master developer (individual development sites will be sold) |
| **UniverCity, SFU, Burnaby** | 15,000 (Note 2) | 9 ha | - Starting with temporary gas-fired plant.<br>- Biomass plant planned once load reaches economic threshold.<br>- Exploring combined biomass plant and peaking plant to serve both the neighbourhood and Campus |
| **Dockside Green** | 8,800 | 6.1 ha | - LEED Platinum development<br>- Single master developer<br>- Biomass gasification system, which was implemented in first phase of development |
| **Lonsdale Energy Corporation** | Currently 23,000 (~2 million sf of connected buildings | N/A | - Distributed gas-fired plants<br>- Small amount of solar thermal<br>- Exploring other alternative energy sources for future<br>- Several distinct service areas<br>- Continuing to expand (no defined build out) |

All data from public sources and rounded for simplicity.
Note 1: Load in core area. SEFC has acquired one voluntary connection outside the core area (Science World) and the City has approved an expansion of the service area to include development in the False Creek Flats Area (including Great Northern Way Campus).
Note 2: This reflects only the neighbourhood loads. SFU and Corix are negotiating to construct a shared alternative energy centre that would serve both the neighbourhood and Campus loads. Campus load is ~54,000 MWh/year.

# 8 Other Input Assumptions to the Business Analysis

## 8.1 Overview

A common set of assumptions was selected for the Reference Case. Table 5 provides an overview of key inputs to the business analysis. The sections that follow provide additional details on certain input assumptions, where required.

We have used realistic but still conservative assumptions for the Reference Case. The Reference Case is not a worst case scenario but it is also not an overly optimistic scenario. We selected defensible values for key inputs, but there is still uncertainty in some key variables. The impact of key uncertainties is discussed in Section 11: Risk and Sensitivity Analysis. In Section 11 we also identify several proactive opportunities for risk management and for further optimization of the business case. However, these optimizations require more analysis, internal discussion, and often require cooperation from third parties. Our approach in this section is to establish a realistic Reference Case to support a decision whether to proceed with further study and development of the project, including further optimization.

Many of the assumptions in the Reference Case are the same across the three ownership models. The main differences across ownership models include the following:

- Service levy and property taxes – Service levy is included in all ownership models. Property taxes are excluded from the UBC ownership scenario (UBC is exempt from rural property taxes).

- Income taxes – No income taxes are payable on revenues earned by UBC.

- Labour requirements – Model assumes slightly higher labour requirements under private ownership models because of stand-alone operation and lack of synergies with ADES.

We have assumed a common (regulated) capital structure, debt rate, and allowed return on equity (combined weighted average cost of capital) in all ownership models.

**Table 5: Summary of Key Inputs to the Business Analysis**

| Input | Assumptions | Comments |
|---|---|---|
| **Capital costs** | Provided by FVB. Cost estimates are preliminary and considered Class C (+/- 25-40%) for the TRIUMF EC and Wesbrook DPS and ETS, and Class D for all Acadia/East Campus and Block F DPS and ETS. | Contingency, PST, UBC PM fee and interest during construction all added separately in the pro forma model. Additional $1 million contingency added for architecture on Energy Centre (~$550 per m2). |
| **Depreciation rates** | Overall average depreciation rate for this project is 3.4% per year. | Have used industry standard depreciation rates for all installed capital. Depreciation charges are used to recovery capital costs in rates. |
| **Weighted Average Cost of Capital (WACC)** | 4.9% real WACC (6.9% nominal). | Reflects recently approved WACC for several systems regulated by the BCUC. For the UBC ownership scenarios, we have assumed deemed capital structure and capital costs comparable to a regulated utility (excluding income taxes). |
| **Income Taxes** | 25% average tax rate, applied on a cash taxes basis. | Only included in private sector models. Taxes are a flow through to rate payers. |
| **Grants** | No grants included. | Grant support may be available. |
| **Fuel Efficiency** | Heat pump COP= 3<br>Average gas boiler efficiency = 80% | Applied to TRIUMF Energy Centre |
| **Fuel Prices** | Public forecasts of all fuel prices (gas, electricity and biomass). | |
| **Carbon Taxes and Offsets** | Fuel prices include BC Carbon Tax. Analysis assumes no further increases in carbon taxes.<br>Avoided cost of offsets included in value to UBC. No further escalation in offset costs is assumed (conservative). | No financial value is assumed from GHG reductions in the Development Areas. |
| **Labour requirements** | Under UBC ownership: 4.5 FTEs for TRIUMF 1 configuration (Reference Case) and 1.0 FTEs for TRIUMF 2 (sensitivity analysis) plus 0.25 chief engineer time.<br>Under private ownership: same as above plus additional 0.5 FTE and assume full incremental chief engineer. | Lower labour requirements assumed in UBC ownership because of synergies with existing facilities management (vs. stand-alone entity). However, it may be possible to capture some synergies under private ownership through a service contract with UBC. |

| Input | Assumptions | Comments |
|---|---|---|
| **Labour costs** | $100k per FTE | Affects operating costs for NDES. For purposes of Reference Case a full staffing complement is assumed with a fully allocated unit labour rate from UBC (i.e., including salaries and overheads). |
| **Service Levy & Property Taxes** | All ownership models include Service Levy of $30.146 per $1,000 assessed value. Private ownership also includes property tax of $25.495 per $1,000 assessed value. | UBC could reduce or defer Service Levy to maintain competitiveness if necessary. |
| **Land Rent for Energy Centre** | $54 per m2 per year. | Reference Case energy centre footprint is 1,950 m2. |
| **NDES Maintenance Costs** | ETS maintenance 0.65% of installed capital. DPS maintenance 0.20% of installed capital. Energy Centre maintenance 0.75% of installed capital. | |
| **Other NDES Operating Costs** | Insurance 0.25% of installed capital. $26,000 per year in water and sewer costs, 2,200 MWh per year of additional electric consumption at plant, 5% corporate overheads. | |
| **Price of Surplus Heat Purchased by ADES.** | Real levelized rate of $45 per MWh | Based on levelized cost of output from heat pump, including trim-up natural gas. |

## 8.2 Capital Costs and Depreciation Rates

Table 6 summarizes the expected capital costs by phase in real (2012) dollars before contingency, taxes (PST), UBC project management fee, and interest during construction (accumulated prior to going into service). These are added separately within the pro forma model. We assumed in all ownership models that the full 7% PST (to be reintroduced in B.C.) would apply to the taxable portions of capital costs (~45%). For the Reference Case, we assume an average contingency of 10% for all capital costs. The UBC project management fee is equivalent to 2% of capital costs and is applied to all ownership scenarios (representing an additional contingency). For interest during construction, we assume an average of one year construction across all assets. Interest during construction is financed at the full utility weighted average cost of capital, consistent with current practice and approvals for other BCUC-regulated utilities.

FVB cost estimates assumed a utility-grade building for the TRIUMF Energy Centre (built suitable for purpose). Based on feedback from the project steering committee, we added a further $1 million contingency in the pro forma for additional architectural features ($550 / m2).

Capital costs are recovered in rates through annual depreciation charges. Standard depreciation rates were used for different types of infrastructure and reflect depreciation rates recently approved by the BCUC for other district energy utilities. Lower rates are assumed for long-lived infrastructure such as distribution piping. Average annual depreciation across all asset classes is approximately 3.4% per year. Depreciation rates also affect rate base, which is used to calculate annual financing costs.

**Table 6: Capital Cost Inputs (thousands $2012) Before Contingency, Taxes, Project Management Fees and Interest during Construction**

| | Phase 0 | Phase 1 | Phase 2 | Phase 3 | Phase 4 | Total |
|---|---|---|---|---|---|---|
| **DPS*** | 11,660 | 4,720 | 1,200 | 1,580 | 510 | 19,160 |
| **ETS**** | 1,380 | 3,310 | 2,560 | 3,670 | 1,270 | 10,920 |
| **Energy Centre** | 28,190 | - | 1,300 | 1,190 | - | 30,680 |
| **Totals** | 41,230 | 8,030 | 5,060 | 6,440 | 1,780 | 60,760 |

* Distribution piping system.
** Energy transfer stations.

## 8.3 Input Energy Prices

Fuel prices are a major determinant of NDES costs as well as the cost of competitive benchmarks. Given the long-term nature of this investment, it is important to consider not only current fuel prices but also long-term price trends. Relevant fuel prices for this project include electricity, natural gas, and biomass (for optional resource additions and sensitivity analysis). Current and future prices are estimated using publicly available forecasts, current information from suppliers, and recent regulatory filings.

**Natural Gas**

Natural gas prices include a commodity component and a delivery/transmission component. Commodity charges are more volatile and can be forecasted using publicly available natural gas price forecasts for a region's trading hub. Delivery and transmission charges are much less volatile and are utility-specific.

FortisBC is the distributor of natural gas in the Lower Mainland. Large volume customers, including the existing natural gas peaking plant on UBC's Campus, have several options for purchasing natural gas. UBC's existing plant is served under Rate 22, which allows UBC to purchase gas themselves through third parties, potentially securing a more advantageous rate. Rate 22 also gives UBC interruptible service. As the NDES natural gas plant would be a sufficiently large customer to qualify for Rate 22, we have applied Rate 22 to the NDES plant as well, with the assumption that the NDES would be a standalone Rate 22 customer and would incur all basic charges as well as the per-GJ transportation charge.[27]

For marginal gas generation at the existing ADES plant, we have included all marginal costs associated with Rate 22 but have excluded the basic charge, as this is not an incremental cost for providing energy to this project. If the ADES plant does provide significant amounts of gas-fired energy to this project, UBC may seek to recover some share of the basic charge through energy sales rates to the NDES. This is an optimization which can be pursued if necessary, but which has a relatively small effect on the project's overall financial viability.

FortisBC delivery charges have recently been increasing above inflation. One driver for this is the recent amalgamation of several FortisBC service territories. Beyond 2014, we assume further delivery rate increases are limited to inflation (flat real delivery charges).

Natural gas commodity prices are more volatile and very difficult to forecast. For the Reference Case, we have used a publicly available forecast from Sproule for Sumas, which is the same hub from which the NDES would purchase gas under Rate 22. The Sproule forecast has the advantage of being tied to a specific location and provided in Canadian dollars. Figure 7 shows historical average annual gas prices at Sumas (to 2011) and the Sproule forecast beyond 2014. Actuals and forecast values are in nominal dollars (the pro forma uses the real dollar equivalents). The Sproule forecast

[27] Because Rate 22 is an interruptible service rate, fuel oil back up would be required. The capital costs for the TRIUMF Energy Centre include an allowance for fuel oil back boilers and storage. However, the actual use of fuel oil would likely be very limited and this has not been included in the analysis.

shows some recovery from historic (cyclical) lows to 2015 (reflecting in part a broader economic recovery) and then escalation at inflation beyond. By 2020, real prices are still about 50% below historic highs from several years ago.

There is considerable debate regarding the future of natural gas prices. Recent lows reflect several factors including the rapid expansion of shale gas (and in particular the surplus gas from liquid (oil) rich shale plays developed in response to high world oil prices), the general economic downturn, and the previous destruction of gas demand in response to previous high prices (e.g., the previous reduction in gas-fired electricity generation). Recent lows also reflect an unusually warm winter (and high levels of storage). There are several factors suggesting a recovery in prices, although the timing of such a recovery is very difficult to predict and could take years. First, there has not yet been a full economic recovery in North America and that alone is expected to increase demand. Second, low prices are encouraging fuel switching (e.g., from coal-fired to gas-fired electricity, natural gas vehicles, etc.). Third, there is growing evidence that many shale plays are not sustainable at current prices (activity is starting to decline, particularly outside liquid rich plays). And there is also some evidence that reserves may be overestimated (depletion rates are higher than expected). There are also emerging environmental concerns with shale gas (including higher lifecycle GHG emissions) that may limit future extraction. Finally, the low North American prices in relation to Asian natural gas prices is stimulating a rush to develop liquefied natural gas plants, which could have a significant impact on North American prices given the number and capacity of proposed projects.

In the past, UBC has relied on the gas price forecast prepared by the U.S. Energy Information Administration (EIA). The EIA does not produce a price forecast specific to the Sumas hub. Furthermore, it does not include a forecast of exchange rates. We prepared an alternate forecast for Sumas based on the EIA's most recent forecast for wellhead natural gas prices (latest forecast from late 2011). We established a starting price for Sumas (2011) and then applied an escalation factor equivalent to the escalation factors in the EIA wellhead price forecast. This is a slight simplification in that it ignores any long-term changes in the average basis differential between trading hubs, but it represents a reasonable approximation. Figure 8 compares the Sproule forecast with the EIA forecast using this methodology (real 2012$/MWh equivalent). Both forecasts reach similar end points but Sproule predicts an earlier recovery in prices.

We note that the EIA forecast tends to be heavily influenced by current conditions (e.g., low spot prices), as evidenced by the changes in their forecasts over time. The Sproule gas price forecast used in this business analysis is lower than the mid-case scenario and closer to the low scenario used by BC Hydro in its recent Integrated Resource Plan.

**Figure 7: Historical and Projected (Sproule) Natural Gas Prices at Sumas (Nominal dollars)**

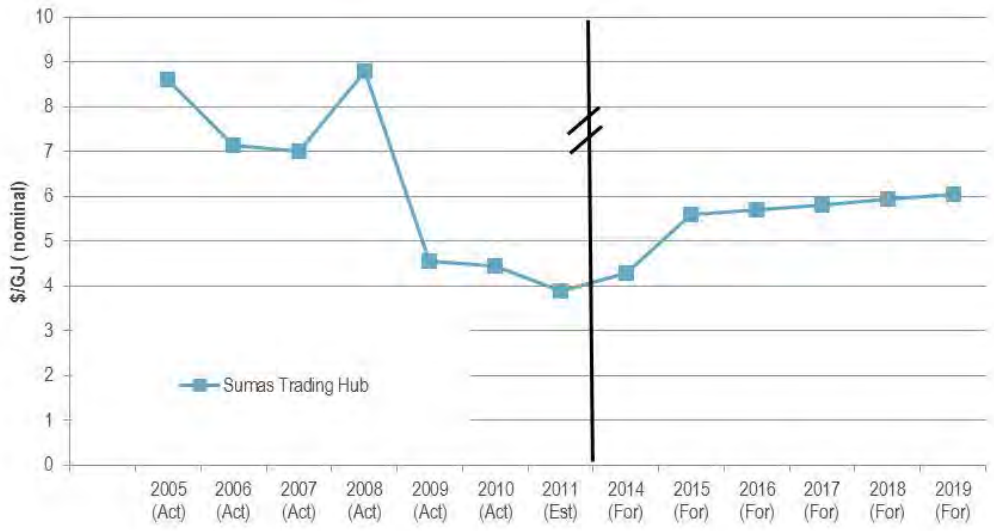
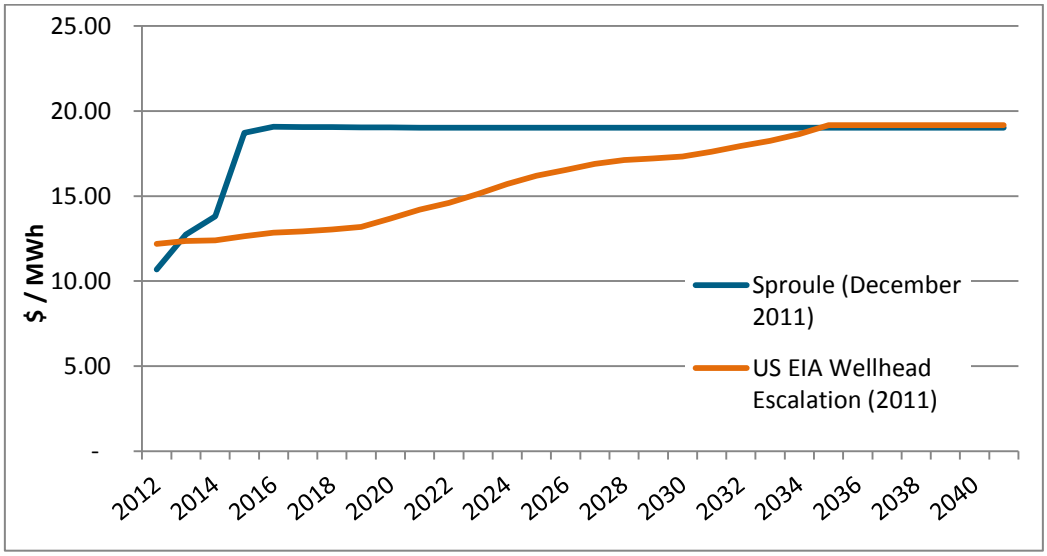



**Figure 8: Sproule Escalation vs. EIA Escalation of Natural Gas Prices at Sumas ($2012)**



**Electricity**

Electricity is provided by BC Hydro. Electricity is an input to the heat pump required for waste heat recovery from TRIUMF. As discussed further below, electricity is also one of the benchmarks we have used to test the competitiveness of the NDES. Electricity has been used as a benchmark in several recent district energy applications approved by the BCUC, including UniverCity and River District. In addition, the City of Vancouver adopted electricity rates as a benchmark for its NEU in SEFC.

Electricity rates are currently increasing above inflation in BC. Rates have increased in excess of 30% in recent years. As discussed previously, long-term electricity rates in B.C. are set to continue to increase much more rapidly than inflation due to rapid growth in deferral accounts (i.e., deferred historical expenses), need to replace and upgrade aging infrastructure (average age of BC Hydro assets exceeds 50 years), commitments to electricity self-sufficiency and high levels of more expensive green power, and rapid growth in electricity demand (in particular from mining and liquefied natural gas developments). We have assumed an average escalation for electricity of 3.9% nominal (2% above inflation) throughout the analysis period, consistent with other recent studies and advice from BC Hydro.

Residential rates are actually broken into two tiers. The higher Tier 2 rate applies to consumption above a particular baseline. Electric heat is a major trigger of Tier 2 rates. Our benchmark for electric heat uses a 50/50 blend of Tier 1 and Tier 2. Tier 2 is actually increasing at a more rapid rate in the near term to be consistent with BC Hydro's marginal cost of new generation.

UBC purchases electricity from BC Hydro under Rate Schedule 1827, a heritage rate which is not available to new customers. This is a transmission-level rate. UBC is responsible for local distribution. For this study, we have assumed that the NDES heat pump can be served through UBC's existing connection with BC Hydro. This rate is not a 'stepped' rate, but instead allows UBC to purchase incremental energy at the same cost. The rate is currently $35 per MWh, with an additional demand charge of ~$6 per kW. We have computed an effective rate for the heat pump based on the heat pump demand profile and the combined energy and demand charge. This produces an effective rate of ~$43 per MWh in 2012. We have applied the same escalation to Schedule 1827 as to the residential rate.

**Biomass**

In this study we consider a biomass plant as an additional or alternate energy source for the NDES. We assume a plant using locally available wood waste. Current wood

waste prices in the Lower Mainland are ~$10 per MWh (adjusted for average heat value of biomass) and we have assumed flat real rates (i.e., escalation at inflation). This is consistent with indicative bids received in several recent projects. This is only used in sensitivity and scenario analyses since biomass is not part of the Reference Case scenario.

**Summary**

Table 7 provides a summary of fuel price assumptions used in all Reference Case calculations. The first column depicts current (2012) price levels. The second column shows the 20-year levelized price. The levelized price is a way of converting a price curve into an equivalent constant price reflecting the discount rate. It is a useful tool for depicting and comparing forecasts.

**Table 7: Summary of Fuel Price Inputs**

| Fuel | Current Cost | 20-year Levelized ($2012/MWh) |
|---|---|---|
| **BC Hydro Residential Tier 1*** | $72 | $91 |
| **BC Hydro Residential Tier 2*** | $104 | $131 |
| **BC Hydro 1827 Rate (UBC Purchase Price of Electricity)** | $43 | $54 |
| **Biomass (Woodwaste)** | $10 | $10 |
| **Natural Gas Commodity + FortisBC Delivery Rate 22 + Carbon Tax** | $19 | $26 |

*For the electric heat benchmark, we assume a blended average of 50% Tier 1 and 50% Tier 2. The actual share of Tier 1 and Tier 2 will vary across individual customers but this is a reasonable midpoint based on modelling and data from other studies.

## 8.4 Carbon Taxes and Offsets

The natural gas prices described above include projected provincial carbon taxes. We have included legislated increases in the B.C. Carbon Tax to $30/tonne (equivalent to $1.50/GJ or $5.40/MWh of natural gas) and we assume the carbon tax remains constant in real dollar terms.

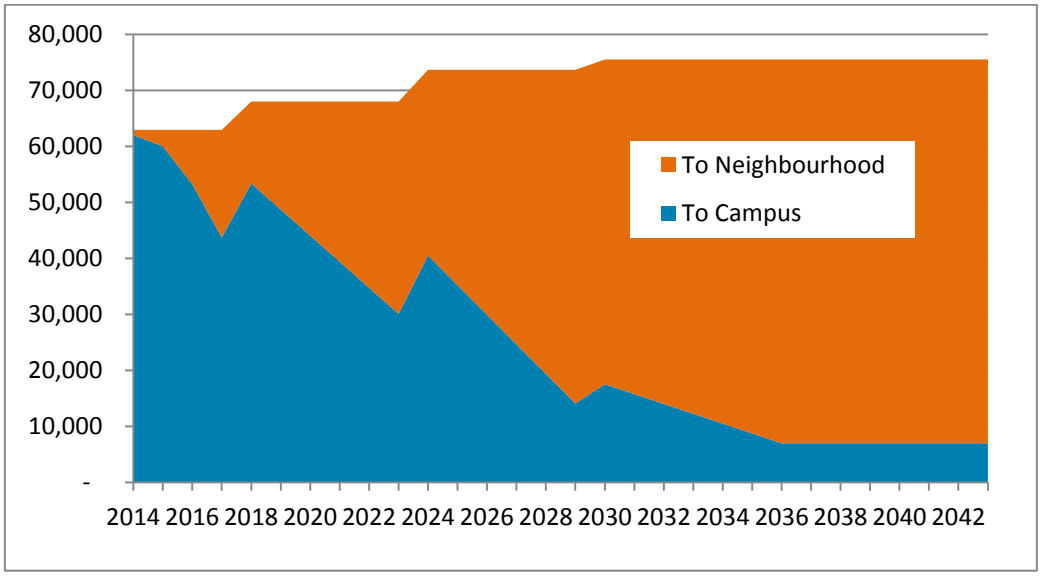
In addition to the carbon tax, the pro forma model includes the avoided cost of offsets that must be purchased by the ADES in the value of any purchases it makes of waste heat from TRIUMF. We assume current offset costs of $25/tonne and we assume these remain constant in real dollar terms. In fact, there is some uncertainty whether the Pacific Carbon Trust will be able to meet all future public sector offset requirements at current prices given growth in demand and the fact that many low cost projects have already been pursued in the province.

## 8.5 Heat Pump Output and Allocation

Figure 9 illustrates the anticipated useful heat output from the waste heat pump at the TRIUMF Energy Centre and the expected allocation of waste heat between the ADES and the NDES under the Reference Case. The increase in total heat recovery over time is a function of the available load during the operating period of TRIUMF used in the Reference Case (i.e., reflects a winter shutdown). The spikes in the allocation to the ADES is an artifact of the modelling approach which was based on distinct phases, with the loads in Development Areas added continuously during each phase. In reality, the trend in allocation would be somewhat smoother but this does not significantly affect the financial results.

At buildout, the heat pump supplies about 65% of the annual NDES load, after accounting for the heat pump energy which goes to the ADES. The energy from the heat pump is actually about 97% heat pump output and 3% trim-up gas (to raise the output temperatures to those required by the ADES).

**Figure 9: Output and Allocation of Heat Pump at TRIUMF (Reference Case)**




## 8.6 Weighted Average Cost of Capital

As discussed above, we have used a private sector (regulated) cost of capital (post-tax) for all ownership scenarios. In the models with private sector involvement, income taxes are also added to the pro forma. Table 8 summaries the weighted average cost of capital recently approved by the BCUC for UniverCity and River District Energy. Compass has used a slightly updated reference case to reflect more recent requests for an additional risk premium on equity and to reflect updated information on marginal long-term debt rates. The resulting WACC used in the Reference Case is 4.9% real, equivalent to approximately 6.9% nominal.

The BCUC has recently established a Generic Cost of Capital (GCOC) Proceeding for regulated utilities. The main purposes of the GCOC Proceeding are:

1. to establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, and to establish how the Benchmark return on equity (ROE) will be reviewed, and if required, adjusted on a regular basis;
2. to establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and
3. to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

District energy utilities are considered for the most part smaller utilities. One of the issues to be explored is a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt. This would involve setting a methodology on how to calculate a deemed interest rate and how to adjust the interest rate. The GCOC Proceeding will not conclude until early 2013.

**Table 8: Real Weighted Cost of Capital Assumptions**

| | Recently Approved by BCUC | Updated (For Reference Case) |
|---|---|---|
| Equity Thickness | 40% | 40% |
| Debt Thickness | 60% | 60% |
| Cost of Equity | 10% | 10.5% |
| Cost of Debt | 5.5% | 4.5% |
| Nominal Weighted Average Cost of Capital (WACC) | 7.3% | 6.9% |
| Real WACC Equivalent | ~5.3% | ~4.9% |

## 8.7 Value of Energy Sales to and from the Academic Campus

UBC is assumed to purchase energy from the NDES at the levelized cost of waste heat energy from TRIUMF. The levelized cost of waste heat includes the cost of electricity and natural gas used to generate the heat (natural gas is required to trim up the temperature), a share of plant maintenance and operating costs, as well as a share of the annualized capital costs associated with this heat. The assumed transfer price (levelized cost) of waste heat for the Reference Case is $45 per MWh. This includes a share of the following capital costs:

- $1.9 million building costs;
- $15.6 million plant costs; and
- $1.5 million distribution system (connection) costs.

This price would likely be reviewable by the BCUC. A key issue is whether the price ensures UBC has made a fair contribution to the system costs, including interconnection costs. On the other hand, another consideration would also be the value of the energy to UBC.

We have also estimated UBC's avoided costs for waste heat purchases, assuming all marginal generation would be at the ADES natural gas plant. These avoided costs include avoided natural gas costs, carbon taxes, and some offset costs. UBC's academic operations are required under Bill 44 to offset all their emissions, so while UBC would avoid all offset costs associated with natural gas generation at the ADES plant, UBC would have to pay some smaller offset cost for the partially fossil-fuel derived energy received from the NDES.

There is some uncertainty around whether thermal energy derived from multiple fuel sources is legally allowed to receive an emissions factor which reflects only some of the fuels used to derive that energy. In the absence of more certainty around this issue, we have assumed that energy purchased by the ADES will have an emissions factor based on overall average emissions from the NDES plant, including the NDES gas plant. The gas plant is used to both trim up the heat pump output to a useful temperature and also for peaking energy in the NDES.

Given UBC's Bill 44 obligations, the low-GHG energy produced by the heat pump may have higher value to UBC than to the residents in the Development Areas, and there are a variety of tools available, including offset projects, to capture a higher proportion of this GHG reduction benefit for UBC. Opportunities to capture additional GHG benefit for UBC should be considered optimizations to this project. As noted above, we have assumed a constant (real) cost of offsets of $25 / tonne, although it is not clear the Pacific Carbon Trust will be able to meet all future public sector offset requirements at this price.

On a levelized basis, the direct financial value of waste heat purchases to UBC is approximately $37/MWh. This is based strictly on avoided gas, carbon tax and offset costs. Avoided gas reflects the forecast for gas commodity. No change is assumed in carbon tax and offset costs over time. However, the actual value to UBC of waste heat purchases may be higher than these marginal costs.

- **Avoided Capacity** – Under the Reference Case, TRIUMF would continue with its current scheduled winter shutdown and would be available from April through December. If the TRIUMF shutdown were moved to summertime, the energy from the heat pump may have additional value to UBC as a firm energy source, offsetting additional capital investment in the ADES.

- **Higher Value on GHG Free Energy** – UBC may value the energy produced by the heat pump at more than simply the avoided cost of gas and offsets. UBC has established deep on-Campus reduction targets (62% by 2020). Despite recent building upgrades, the steam to hot water conversion, and a new bioenergy centre, UBC will still require additional sources of on-Campus GHG reductions to achieve its GHG reduction targets for 2020. Examples of some other alternatives include additional biomass energy capacity, accessing TRIUMF Waste Heat directly for UBC (no NDES), and/or a new cogeneration facility. The NDES project could defer these other capital-intensive projects to meet reduction targets, thereby increasing the value of surplus waste heat purchases over simply the avoided cost of gas and carbon offsets.

# 9 Reference Case Results

## 9.1 Cost of Service Analysis

Table 9 summarizes the levelized cost of service for the Reference Case under the three ownership scenarios. The cost of service is depicted in terms of $/m2/year for all connected floor area (gross floor area). This can be compared with other benchmarks for the annual cost of heating. Under Reference Case assumptions, the difference in cost of service between 100% UBC ownership and 100% private ownership is approximately 13%, primarily reflecting the addition of income taxes, rural property taxes and reduced operating synergies (with the existing ADES) in the private sector model. A hybrid structure results in a cost of service approximately midway between these two bookends. To put the cost of service in perspective, a 100 m2 suite (~1,100 sf) would pay approximately $1,300 per year for heating (this assumes a contribution to heating of common spaces, assumed in this example to be about 30% of gross floor area.

Table 9 also shows the total capital requirements for UBC under each ownership model. There is no capital requirement under a 100% private scenario. In the 100% UBC ownership scenario, the total capital required is approximately $109 million ($2012). This includes the peak deferral account balance of approximately $31 million. The actual cost of physical assets is approximately $77 million. The deferral account balance represents under recoveries of accounting costs in early years as a result of lower loads and lower benchmark prices (we assume rates are tied to electricity price escalation). In reality only a portion of the deferral account balances are real cash costs. The bulk of the balance is deferred return on equity and other internal cost

recoveries (e.g., service levies). The peak cash balance is approximately $6.6 million.[28] In addition, the capital requirements are spread between 2013 and 2030. The upfront capital requirement under current system design and cost assumptions is approximately $50 million, with periodic increases in capital required to 2030 to fund growth and deferrals. The time profile of capital requirements is summarized in Figure 10. There is a slightly larger peak deferral account balance under private sector ownership because of the added effect of rural property taxes and income taxes. Note the peak deferral account balance is a function of rate setting decisions. The peak balance and time to recover can be decreased by implementing higher starting NDES rates (relative to the electricity benchmark).

Table 9 also includes an estimate of the present value of savings to residents relative to 100% electric heat price benchmark (a low-GHG baseline) and assuming a slightly higher consumer discount rate of 10%. The 100% private ownership model results in rates that are virtually identical to the electric benchmark. There are some potential savings to consumers under scenarios with UBC ownership as a result of tax effects.

Figure 11 illustrates in more detail the annual cost of service (also referred to as a revenue requirement) under the UBC ownership scenario, including the major components of the cost of service. Figure 11 shows the total cost of service before the revenues from sales to the ADES. The net line is the amount allocated to NDES customers and included in the NDES cost of service in Table 9.

[28] Actual cash deferrals are estimated by subtracting real cash costs from revenues in each year and assuming the balance is financed with 100% debt (from an accounting perspective the balance is financed at the assumed WACC).

**Table 9: Reference Case Cost of Service, Capital Requirements and Savings**

| Impact Category | Units | UBC | Private | Shared Ownership |
|---|---|---|---|---|
| Cost of Service | $/m2/year | $10.20 | $11.50 | $10.80 |
| UBC Capital Requirement (incl. deferral account) | $2012 millions | $109* | None | $38** |
| 30-Year NPV Costs (Savings) to Residents at a 10% Discount Rate (Relative to 100% Low-GHG Electricity Baseline) | $2012 millions | ($8) | <$100k*** | ($4) |

*Includes $77 million in capital costs and $31 million total deferral balance. Deferral balance includes non-cash costs; peak cash balance of deferral account is ~$6.6 million in $2012.

**Includes $38 million in asset costs with no deferral account contribution. Assumes that deferral account is financed by private partner (as retailer).

*** This represents a small increase to the Reference Case of 100% electricity.

**Figure 10: Time Profile of Equipment Costs and Deferral Account Balances**

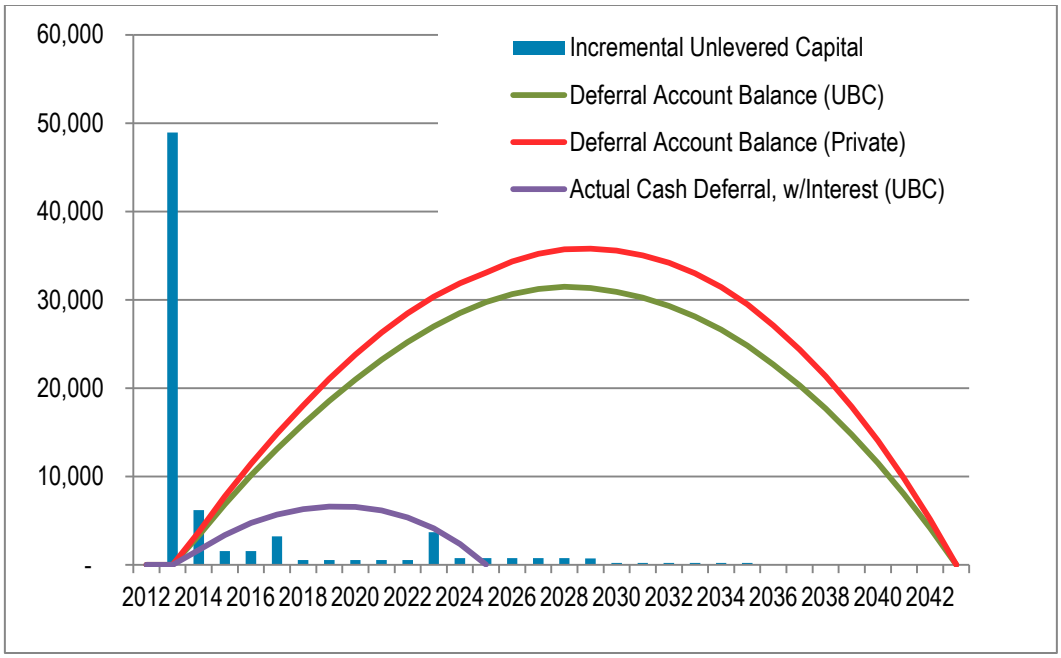


**Figure 11: Annual NDES Cost of Service (UBC Ownership Scenario)**

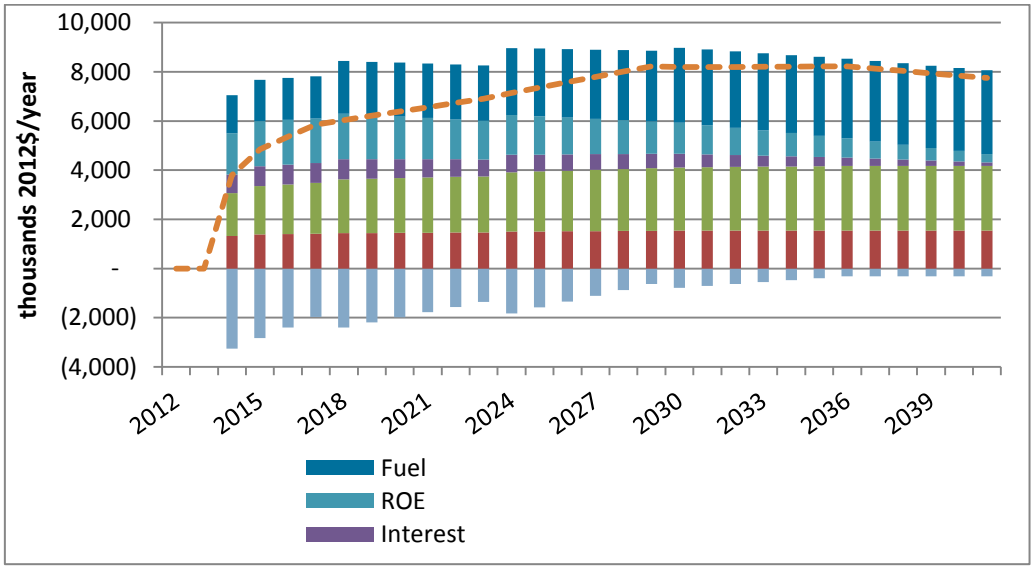



Figure 12 provides the same type of breakdown on a levelized basis (over 30 years) per m2 of connected floor area. The 100% electric benchmark is shown for comparison purposes. Electricity is one accepted benchmark by the BCUC and other district energy developers for evaluating the cost-effectiveness of district energy. Gas prices are lower than electricity prices, but the cost of gas heat must also reflect efficiency differences, higher capital costs (and capital replacement costs), and higher ongoing maintenance costs. The all-in cost of gas heat is much higher than gas prices alone would suggest. In addition, electricity is a low-GHG benchmark.[29]

A levelized cost converts a forecast of costs into an equivalent constant value over the specified term, taking into account the discount rate. Figure 13 shows the actual annual cost used in the calculation of levelized NDES costs and the electricity benchmark. As shown, for the purposes of this analysis, NDES rates are set slightly above the electric benchmark in early years. They are lower than the electric benchmark in later years (based on a conservative electricity price forecast). This is comparable to the approach to rates for both River District Energy and the SEFC NEU. The electric benchmark is only one comparator. This and other comparators are described further below.

[29] The electricity benchmark assumes electric resistance heat (100% efficiency) and a weighted average of Tier 1 and Tier 2 electricity (since electric heat is typically the main driver of Tier 2 consumption in winter months). As discussed below, heat pumps would be more efficient but the added capital and maintenance costs of heat pumps must also be considered.

**Figure 12: Detailed Comparison of Levelized Cost by Ownership Model**

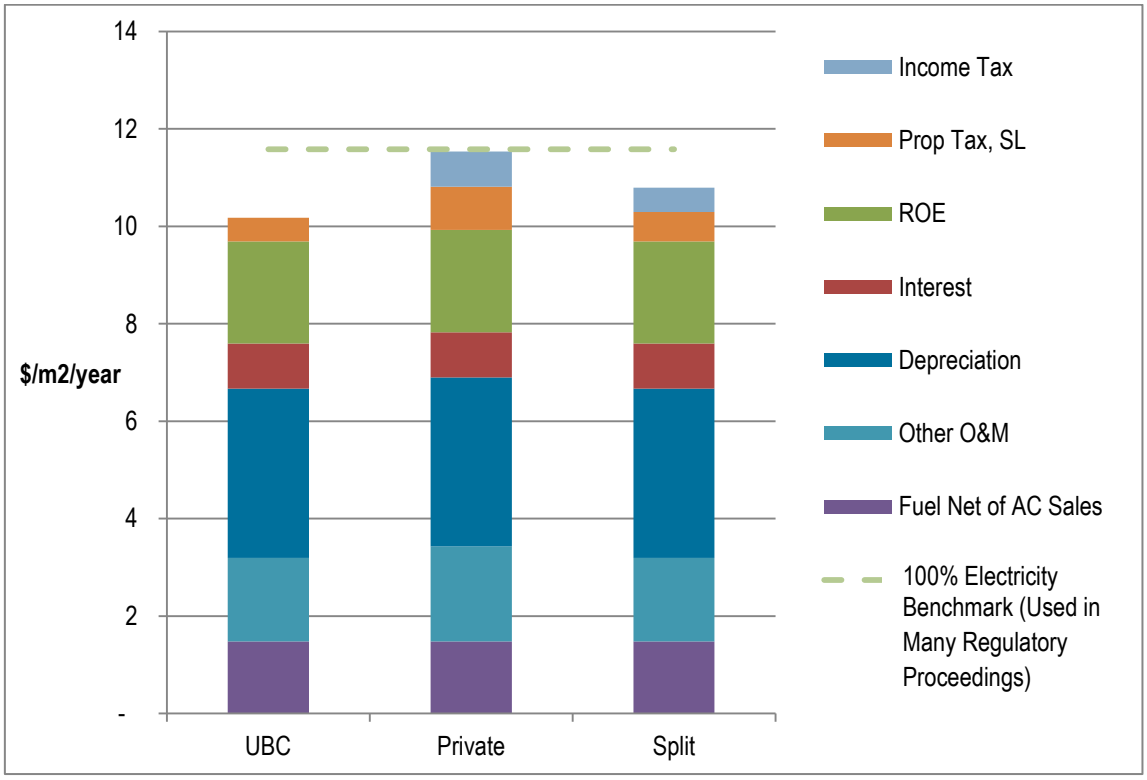
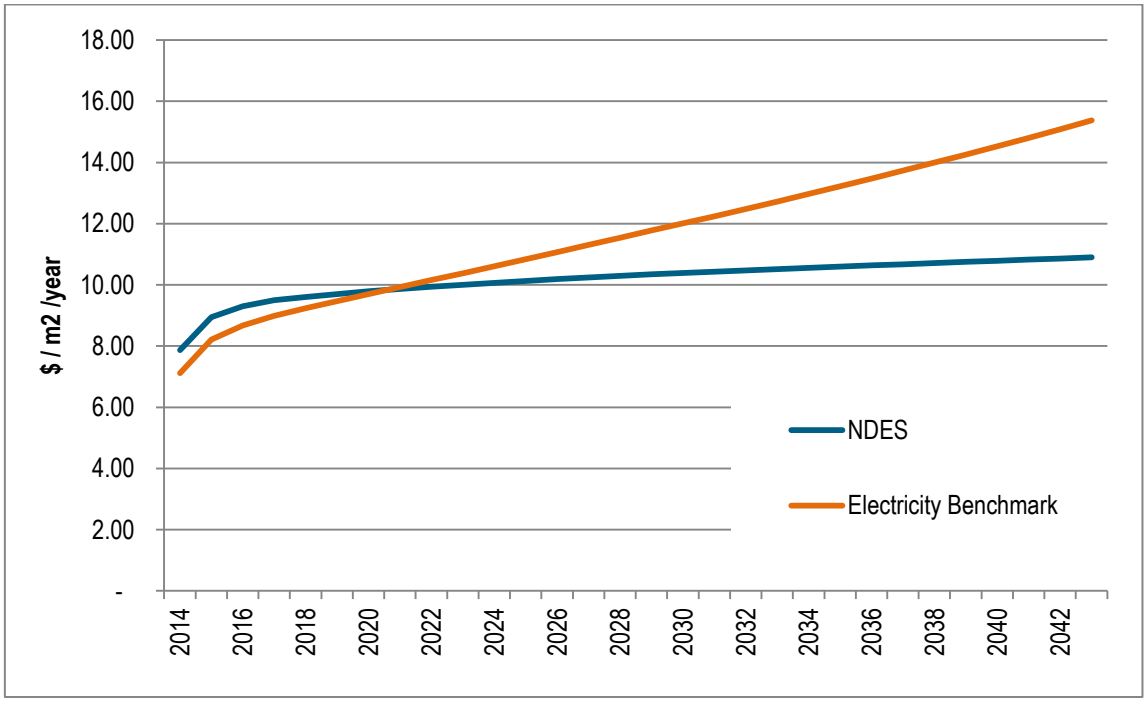



**Figure 13: Annual Cost of NDES vs. Electricity Benchmark**



## 9.2 Greenhouse Gas Emission Reductions

The project will also result in significant GHG reductions. Figure 14 summarizes annual GHG emissions reductions. Total emission reductions are 13,000 tonnes in early years, declining to approximately 8,500 tonnes in later years. The decrease in emission reductions may seem counterintuitive but it is a result of the higher marginal emission reductions for energy purchased by the ADES. As shown in Figure 15, the average emission factor for the ADES is about 75 kg / MWh higher than for the NDES. This is because the waste heat purchased by the ADES will avoid 100% gas-fired energy. In the case of the NDES, the business as usual benchmark used in this study (consistent with dozens of other recent studies) is a combination of electric baseboard heat (already low GHG emissions) and gas-fired heat. Even in buildings with electric baseboards, both domestic hot water and ventilation air are still typically met with natural gas. Based on recent studies of actual building operation (including existing buildings at Wesbrook), natural gas can account for as much as 60-70% of total building heating requirements. These represent averages and actuals may vary from building to building. As more waste heat is diverted to the NDES, avoided emissions decrease.

The analysis assumes there is no financial value to emission reductions in the Development Areas (beyond avoided carbon taxes). Assuming that reductions in the Development Areas were also worth $25 per tonne, the PV of all reductions in the Development Areas would be $2.3 million. Allocating more of the heat pump energy to the ADES could also increase the financial value from GHG emission reductions. However, it is not clear whether the full benefit could be realized under public sector accounting rules for external energy purchases (i.e., whether the output of individual pieces of equipment could be allocated to the public sector customer). Further, consideration must also be given to the GHG benefits of the project used in marketing and communications with the residents (emission reductions should not be double counted).

The analysis includes an allowance for some incremental emissions for the trim up gas used to raise the temperature of waste heat from TRIUMF to the level required for integration of the NDES and ADES.

**Figure 14: Annual GHG Reductions from NDES Project**

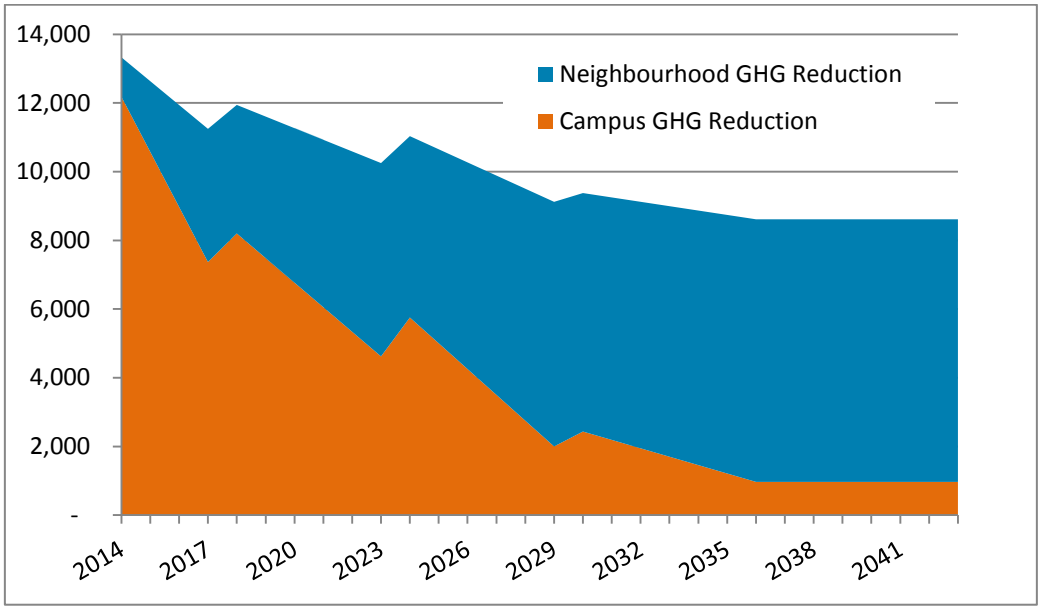
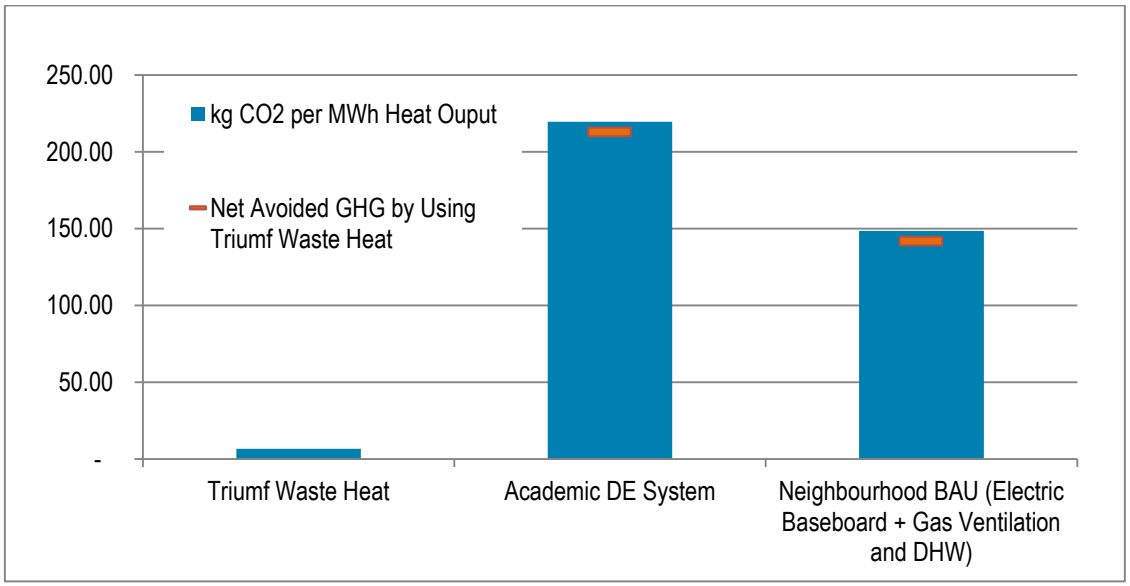



**Figure 15: Unit GHG Factors for TRIUMF Waste Heat vs. Business as Usual**



## 9.3 Fuel Use Reductions

The NDES with waste heat recovery from TRIUMF will reduce total gas and electricity use within the Campus and target Development Areas. Table 10summarizes the annual savings, which vary as load grows. In early years there is a large reduction in gas use and a large increase in electricity use as a result of most of the waste heat being used by the Campus. As the NDES grows to build out, gas savings decrease and there are net savings in electricity use compared with the benchmark of in-suite electric heat and gas-fired make-up air and DHW.

**Table 10: Cumulative Reductions in Annual Gas and Electricity Use from NDES (MW.h)**

| | Phase 0 | Phase 1 | Phase 2 | Phase 3 | Phase 4 |
|---|---|---|---|---|---|
| **Start Year** | 2014 | 2017 | 2023 | 2029 | 2036 |
| **Benchmark Residential Electricity Use** | - | 9,500 | 18,800 | 29,400 | 33,500 |
| **Benchmark Residential Gas Use** | 8,200 | 31,300 | 53,900 | 79,600 | 89,500 |
| **Benchmark Academic Gas Use** | 88,400 | 53,600 | 41,700 | 26,900 | 20,200 |
| | | | | | |
| **DES Electricity Use (HP and Pumping)** | 22,600 | 22,600 | 24,200 | 26,000 | 26,600 |
| **DES Gas Use** | 22,600 | 22,600 | 39,300 | 56,900 | 63,100 |
| | | | | | |
| **Change in Total Electricity Use** | 22,600 | 13,100 | 5,400 | (3,400) | (6,900) |
| **Change in Total Gas Use** | (74,000) | (62,300) | (56,300) | (49,600) | (46,600) |

## 9.4 Local Air Emission Reductions

The reduction in natural gas use relative to the benchmark systems will reduce other local air emissions. Reductions depend upon benchmark system performance. Distributed gas boilers tend to perform more poorly than larger centralized plants for many local air emissions. UBC's existing gas-fired plant is older and likely performs more poorly than a new plant, which is under development.

Table 11 summarizes estimated reductions in criteria air contaminants as a result of reduced natural gas use. These estimates are based on emission factors for gas-fired boilers from U.S. EPA AP-42 emission factor database, stack test data from the new gas-fired central boiler plant at Vancouver General Hospital, and data from a permit database maintained by Levelton.

**Table 11: Local Air Emission Reductions from NDES**

| Criteria Air Contaminant | Particulate Matter (filterable) | Particulate Matter (condensable) | CO | VOC | NOX |
|---|---|---|---|---|---|
| **Reductions (kg/year)** | 134 | 403 | 290 | 399 | 3,531 |

## 9.5 Other Benefits

There are a number of other potential benefits from the NDES not reflected in the financial and GHG analysis above. Specific examples include the following.

- There are possible development, revenue and employment opportunities for the Musqueam Nation, an important community partner for UBC.
- There are risk sharing and risk reduction benefits of a district system (compared to on-site systems). This includes the ability to arbitrage across multiple fuels and technologies in a larger heating system (relative to lock-in created by individual building systems).
- The NDES is a platform to enable other cost-effective renewable energy sources in the South Campus and beyond, including on-site resources such as solar thermal (opportunities for net metering) and large-scale bioenergy.
- The system, whether owned by UBC or not, aligns with strategic objectives for both the academic Campus and surrounding Development Areas, including integration of academic and community uses (waste heat recovery from an academic facility for community benefits), promotion of sustainable energy systems, possibilities for both technical and non-technical sustainability teaching, research and demonstration, and GHG emission reductions.

# 10 Competitiveness of NDES Service

A key consideration in the business analysis is the competitiveness of the NDES service. In other studies and applications before the BCUC, electricity has been used as an economic benchmark for the competitiveness of low-carbon district energy. In reality a typical "business as usual" for new construction typically (though not exclusively) involves a mix of gas and electric heat sources. A common practice is to

install electric baseboards in suites and utilize gas for domestic hot water and make-up air. The full (lifecycle) cost of ownership for such a system includes:

- The cost of electricity used in suites for electric heating (including the impact of electric heat on Tier 2 electricity demand);
- The cost of gas for domestic hot water and make-up air (reflecting the lower average fuel efficiency of typical equipment on a seasonal basis);
- The regular ongoing maintenance of gas-fired systems; and
- Ongoing replacement costs of gas-fired equipment (including risk of early failure).

Prior to the very significant reduction in natural gas prices in the last couple of years, the projected lifecycle cost of gas and electric heat were very similar, taking into account the higher capital costs of gas-fired equipment. In recent years, the projected lifecycle cost of gas heat has declined somewhat. But electricity has continued to be used as a benchmark for low-carbon heat (the lower cost of gas systems must be weighed against the higher GHG emissions).

It should also be noted that changes in building energy codes and the adoption of LEED certification requirements are also a relevant consideration. In order to meet more stringent energy codes and higher levels of LEED certification, developers must make other (often costly) changes to the building envelope and other building systems (particularly in high rise construction with a higher ratio of windows to walls). These added costs are not reflected in the "business as usual" benchmark with electric resistance heating and gas-fired make-up air and DHW.

In reality there is no single benchmark of competitiveness. Buyers of condo units in the region select from a large range of existing and new stock. Actual heating costs vary widely depending upon the building type (high rise or low rise), age, specific heating systems and user behaviour. Comparisons of district energy rates to a single benchmark ignore natural market variability.

Although buildings with electric baseboards and gas-fired domestic hot water and make-up air have been the most common approach in the Lower Mainland in recent years there are still many other types of heating systems installed based on specific developer and market preferences. More costly heat pump systems with geoexchange are common where active cooling is desired (for higher end construction and for noise abatement requirements). As noted above, building energy codes and mandatory or voluntary LEED certification requirements are also driving different kinds of heating systems.

Developers are usually more sensitive to first costs than lifecycle costs. From a developer perspective, a full hydronic heating system has a higher first cost than a typical electric baseboard building with gas-fired domestic hot water and make-up air. However, this is a simplistic comparison as there are many examples of developers and developments that pursue other types of heating systems even without any formal requirement to do so. Also, the incremental cost of hydronic heat must be weighed against other incremental benefits. For example, there are space savings when connecting a building to a district energy system.[30] Furthermore, the hydronic system may alter other requirements to meet building codes and green building certification requirements (e.g., avoid the need for costly changes to the building envelope and/or other building systems). Some communities provide streamlined approval processes, density bonuses and other benefits to offset these costs. And finally, developers may trade-off hydronic heat with other optional building features. There is also some evidence that hydronic buildings appeal to consumers. Whether that translates into higher selling prices or merely more rapid sales is a subject of some debate with developers on both sides. The evidence at UniverCity is that new hydronic building requirements have not affected land values, have provided savings in other requirements to meet building energy performance, and have has marketing benefits for projects.

Ignoring any differences in upfront costs for HVAC systems, which may come from developer margins or other offsetting benefits, the real comparison for the NDES is the ongoing cost of ownership for various systems, including fuel costs, operations and maintenance costs and depreciation / replacement costs. The latter will likely become more transparent with the recent introduction of mandatory requirements for regular depreciation reports by stratas.

Table 12 compares the levelized real cost of the NDES (Reference Case assumptions, private ownership model) with several other benchmarks, including the comparable cost of serving the UBC NDES buildings with on-site systems as well as the cost for buildings connected to SEFC, UniverCity, River District and Lonsdale Energy Corporation.[31] Levelized costs are typically higher than current costs as they reflect expected changes in input costs (fuel prices) and rates. However, levelized cost

[30] As ETS is much smaller than in-building boilers (often requiring 10 – 50% of the footprint of a boiler). Assuming that a typical building's basement boiler room is 30 m2 and only 25% of that is required for an ETS, there is about 23 m2 of avoided space and mechanical room requirements.

[31] Because the NDES analysis for UBC was done in real dollars (a common approach for feasibility), we have adjusted all benchmarks to reflect real dollar comparators. Inflation does not alter the relative differences among the comparators. However, the levelized costs shown in Table 12 may differ from other reports if those reports are in nominal dollars. Readers are always cautioned to confirm whether stated costs are in real or nominal dollars when making comparisons.

projections are a more relevant comparator for long-term investment or policy decisions. Short-term differences in costs can be addressed through actual rate design.

**Table 12: Comparison of Levelized Annual Cost Benchmarks**

| | Average EUI (Build out) | Levelized Cost | Annual GHG |
|---|---|---|---|
| | kWh/m2/year | $/m2/year | kg/m2/year |
| **UBC NDES*** | 98 | $ 11.5 | 7.9 |
| **UBC 100% Electric** | 98 | $ 11.8 | 2.0 |
| **UBC Gas / Electric Split** | 98 | $ 10.6 | 15.7 |
| **Londsale**** | 100 | $ 7.4 | 20 |
| **Southeast False Creek** | 110 | $ 10.6 | 6.9 |
| **River District Energy** | 93 | $ 11.0 | 3.0 |
| **UniverCity** | 69 | $ 7.7 | 3.0 |

*Private ownership scenario.

**Lonsdale has no published cost of service model, future rate projections or average energy intensity. Estimate here is based on average EUI from UBC NDES study and current natural gas price forecast. Assumes other costs of utility remain constant in real dollars.

There are challenges with computing levelized costs for each example in Table 12. For on-site benchmarks (e.g., on-site gas-fired and electric systems) we must make assumptions about replacement cost, asset life, customer discount rate (financing costs) and ongoing maintenance costs. We have used publicly available forecasts of gas and electricity prices, as well as conservative estimates for other carrying costs. For utility rates, we require realistic projections. Utilities such as River District Energy and UniverCity have filed rate forecasts with the BCUC as part of their Applications for a CPCN. The City of Vancouver has provided publicly available forecasts through Council reports. These forecasts are based on a detailed pro forma similar to regulated systems and are reviewed by an independent rate panel.[32] No public projections of future costs are available for Londsale Energy Corporation (LEC). This system relies on natural gas and rates are tied to natural gas prices. For LEC we have therefore computed a levelized cost based on the same gas price forecast used for the NDES Reference Case. The calculation assumes all other costs (depreciation, financing, taxes, etc.) remain essentially flat in real terms. This may be a conservative assumption given capital replacement plans and/or system growth. For example, LEC is growing

[32] The SEFC benchmark in **Error! Reference source not found.** reflects most recent projects by the City. Projected SEFC rates have been declining as a result of better than expected performance (heat pump availability, COP and share of load), more rapid rate of development, and recent service area expansions.

rapidly and also has plans to install alternative source of energy. LEC also does not publish any information on average energy use intensity of buildings connected to its system. For the purposes of comparison we have assumed an average consumption of 100 kWh/m2/year, which is similar to projected consumption of new construction at UBC.

The total cost of heating is estimated based on gross building floor area. Total per suite costs for heating can be calculated by multiplying the gross costs of ownership in Table 12 and average suite size (including an allowance for common areas).[33] For example, assuming an average gross cost of heating of $1/m2/year, an average suite size of 100 m2, and common space equivalent to 30% of gross floor area (ratio of gross to suite floor area of 1.3), the cost of ownership per suite would be approximately $1/m2/year * 100m2 *1.3 = $130/year/suite.

Many comparators of district energy systems focus strictly on rates. However, consumers really care about annual costs. The differences among the various systems and scenarios in Table 12 reflect differences in both rates and underlying energy use assumptions.[34] For example, UniverCity is composed of buildings with very low expected energy consumption (actual long-term energy use still to be confirmed). This reflects several factors. First, UniverCity has a slightly higher proportion of low-rise construction which tends to have a lower fraction of windows and different energy performance than high-rise construction. In addition, UniverCity is built to higher than normal standards (UniverCity has a stringent energy performance requirement and density bonus system to reward higher performance). The district energy system for UniverCity has higher unit energy rates (i.e., $/MW.h) but lower annual costs as a result of lower expected energy use.

SEFC and RDE have more high-rise buildings and higher glazing expectations and are built mostly to LEED Silver or Gold standards. These systems have lower unit energy rates (i.e., $/MW.h) but higher annual costs as a result of higher overall expected energy use.

For the 100% electricity and conventional on-site gas/electric scenarios, we have estimated a levelized cost using forecasts for each scenario together with the load

[33] The costs of on-site systems are typically recovered through a combination of direct energy bills (e.g., in-suite electricity or gas use) and strata fees to recover common system costs (e.g., building-level fuel purchases, operating and maintenance costs, and funding requirements for reserves to replace common equipment).

[34] Annual costs are also a more robust comparator because fixed costs make up a large portion of many systems. Fixed costs do not vary with annual energy use. Rates can be made to look lower by assuming a high energy use intensity, whether this is realistic or not. Annual carrying costs will vary with energy use intensity but a 10% increase or decrease in energy intensity will have a much smaller impact on annual costs because of the high percentage of fixed costs for many systems.

forecast for the UBC NDES. The on-site gas/electric scenario assumes electric resistance heating in suites and gas-fired make-up air and DHW with a seasonal average efficiency of 80%. Electricity makes up about 40% of the total annual heating requirement in this scenario. Buildings with higher or lower energy use characteristics would have higher or lower carrying costs are these scenarios.

In addition to annual heating cost, the scenarios and systems in Table 12 vary greatly in GHG intensity (horizontal axis). In general costs will be higher for systems with lower GHG intensity, particularly given natural gas prices that are at historic lows.

As shown in **Error! Reference source not found.** the projected costs for the UBC NDES (Reference Case, Private Ownership scenario) are similar to comparable systems such as SEFC and RDE. Costs are also comparable to the 100% electric heat benchmark (for buildings with comparable energy use intensity). Costs are slightly higher than on-site gas systems and LEC. But these systems have much higher natural gas emissions. Further the projects for LEC are very conservative as there is no published rate forecast. UniverCity has a much lower cost but that is due in part to the mix of construction times, the much higher energy performance assumed for UniverCity (based on bylaw requirements and density bonus system), and the shorter build out period.

# 11 Risk and Uncertainty Analysis

We evaluated a wide range of risks and uncertainties through sensitivity analysis, including alternate system concepts and possible optimizations.

Some alternate system concepts and potential system optimization are described in Table 13 below. The resulting cost of service under each of these alternate system concepts and optimizations is summarized in Table 14. For ease of review, scenarios with higher costs than the Reference Case are shaded in red, while scenarios with lower costs are shaded in green. Scenarios with virtually no change are not shaded. In reality, some of these alternate concepts and optimizations could be combined to achieve greater benefits.

Some key observations related to alternate system concepts and optimizations include the following.

- There are economies of scale with a larger service area. The negative impacts of a smaller service area may be mitigated in part through further optimization of the distribution system layout and sizing, and from refined staging of other system components.

- The partial service scenario results in higher lifecycle costs to residents. This scenario may reduce upfront costs to developers (by eliminating a hydronic premium, if any) but the magnitude of the hydronic premium is uncertain and the hydronic system with connection to the high efficiency NDES may reduce other costs incurred to meet building code and certification requirements.

- Changing the shutdown schedule of TRIUMF has minimal impacts under current assumptions for the value of heat to the ADES. This is because virtually all of the heat can still be utilized in summer months by the combined loads of the Campus and Development Areas. However, the winter availability may have other benefits not yet captured in the analysis (e.g., deferred capacity additions in the ADES and the potential to avoid higher natural gas prices in winter assuming UBC is exposed to seasonal variation in gas prices).

- There are potential savings from a shared peaking plant (i.e., smaller plant at TRIUMF and peaking support provided by the ADES). This alternative could be explored as an optimization in a more detailed design phase. It offers potential upside to mitigate other uncertainties.

- There is no significant benefit to deferring the heat pump assuming the ADES purchases excess waste heat in early years.

- Under current assumptions, the waste heat from TRIUMF is cheaper than a biomass alternative. However, the biomass alternative is not much more expensive and can be retained as an alternate solution while UBC or its partner continues to explore the waste heat recovery from TRIUMF.

- Increasing the electricity rate to the heat pump will increase NDES costs (both for the Development Areas as well for purchases of surplus energy by UBC).

- There is some potential upside from capturing additional synergies in operator requirements or relaxed requirements for full-time supervision of the TRIUMF Energy Centre (under the TRIUMF 1 scenario).

- Higher levels of heat pump performance than assumed for this analysis will also have some positive, although smaller, impact on overall economics.

- Grants and/or careful control of capital costs will have a significant impact on future rates.

There may be other opportunities for optimization during detailed system design and phasing. Temporary gas plants could be used to optimize the timing of distribution system infrastructure. Further, the output of a future biomass boiler is limited in some cases by the sizing of the mainline between the TRIUMF Energy Centre and the ADES. If the size of this line were increased, it may enable greater utilization of a future biomass plant. This would of course also depend upon the dispatch profile of the TRIUMF waste heat.

**Table 13: Description of Alternate System Concepts and Potential Optimizations**

| Scenario | Description |
|---|---|
| **Wesbrook Node Only** | This scenario estimates the cost of service for an NDES limited only to the Wesbrook Neighbourhood. The scenario demonstrates the economies of scale associated with a larger NDES. Further capital optimizations would be required if this option were pursued. |

| Scenario | Description |
|---|---|
| **Partial service (EBB)** | This scenario considers the impact of a partial NDES service. In this scenario suites continue to be served with electric baseboards and the NDES provides only domestic hot water and make-up air. This approach reduces the upfront cost to developers for full hydronic systems. However, loads decline more than system costs and customers would pay the full cost of electricity used for electric heat within suites. NDES load is reduced about 25% in this scenario, while the cost of service is only reduced about 18%. Overall this option results in higher lifecycle costs to residents. Furthermore, the savings to developers may be smaller than any premium for hydronic systems because hydronic systems and connection to the NDES (with waste heat recovery) would have some space savings and also contribute to other measures required to meet building certification requirements. |
| **Shared peaking plant** | The Reference Case assumes that the TRIUMF Energy Centre can meet the entire peak demand of the NDES. Furthermore, the Reference Case assumes that the only value of heat purchases to the ADES is the avoided cost of gas, carbon taxes and offsets. There is no capacity value attributed to the waste heat purchases by the ADES (e.g., the ability to defer new peaking capacity in the ADES). One of the options considered in the technical analysis was a shared peaking plant. As this requires more study and negotiation, a shared peaking plant was treated as an optimization opportunity. Under this scenario (referred to as TRIUMF 2 in technical study), the gas boilers at the TRIUMF Energy Centre would be sized to the waste heat capacity only (these are required to trim up the temperature of waste heat). Peaking and back-up for the NDES would then be supplied by the ADES from the proposed new ADES peaking plant. In this scenario, we assume the levelized cost of peaking energy to the NDES would be $60/ MWh, which reflects the approximate marginal cost of gas-fired energy (based on the long-term price forecast for gas) plus the incremental capital cost of additional boiler capacity at the ADES peaking plant. A shared peaking plant could reduce the total required boiler capacity for peaking and back-up through diversification benefits (i.e., differences in the load profiles of the NDES and ADES). |
| **Summer shutdown at TRIUMF** | The Reference Case assumes current winter shutdown of TRIUMF. This sensitivity reflects the impact of shifting the annual shutdown at TRIUMF from winter to summer months, when waste heat recovery has less value. For this sensitivity analysis, we did not alter the value of heat to the ADES. However, winter heat may defer peaking capacity requirements in the ADES (or have other system benefits) which may increase the value of this optimization. |

| Scenario | Description |
|---|---|
| **Deferral of heat pump to 2024** | This scenario defers the connection to the ADES and installation of the TRIUMF heat pump to 2024. |
| **Addition of biomass plant in 2030** | This scenario includes the addition of a 14 MW biomass plant in 2030. Heat pump output is unchanged. However, the use of natural gas peaking boilers at the NDES is reduced and there is some additional low-carbon energy sold in later phases to the ADES (resulting in additional avoided gas and offset costs). |
| **Biomass replaces TRIUMF** | The TRIUMF heat pump is not installed and a 14 MW biomass plant is installed instead in 2014. Excess energy is sold to the ADES at that time. |
| **Heat pump electricity rate +$10/MWh** | The Reference Case assumes electricity for the heat pump at TRIUMF is purchased from UBC under Rate 1827. This scenario adds an additional margin of $10/MWh to the cost of electricity, which is close to the cost of electricity under BC Hydro's Large General Service Rate. All other things being equal, this would increase the levelized cost of energy from the heat pump from $45/MWh to $49/MWh. |
| **Reduced operator requirements** | In this scenario we reduced the number of incremental operators for the NDES from 4.5 to 3.0, reflecting even greater potential synergies with the ADES and/or reduced requirements for full-time supervision. |
| **Higher heat pump COP** | The reference case assumes a COP of 3.0. This is considered conservative and we test the impact of a COP of 3.2 to illustrate the impact of a better outcome. |
| **Lower capital costs** | The pro forma assumes no external grants and includes a 10% contingency on total capital costs. For this scenario we eliminate the contingency to illustrate the impact of contingency on system costs. This is also illustrates the indirect impact of a comparable level of grants on the project. |

**Table 14: Impact of Alternate System Concepts and Optimizations on NDES Cost of Service (levelized $/m2/year)**

| | UBC Ownership | Split Ownership | Private Ownership |
|---|---|---|---|
| **Reference Case** | **10.20** | **10.80** | **11.50** |
| **Wesbrook Node Only**** | 11.80 | 12.60 | 13.70 |
| **Partial service (EBB)*** | 11.25 | 11.75 | 12.25 |
| **Shared peaking plant (TRIUMF 2)** | 9.90 | 10.40 | 11.00 |
| **Summer shutdown at TRIUMF** | 10.10 | 10.70 | 11.50 |
| **Deferral of heat pump to 2024** | 10.20 | 10.70 | 11.40 |
| **Addition of biomass plant in 2030** | 10.70 | 11.30 | 12.10 |
| **Biomass replaces TRIUMF** | 11.40 | 12.00 | 12.70 |
| **Heat pump electricity rate +$10/MWh** | 10.60 | 11.20 | 11.90 |
| **Reduced operator requirements** | 9.90 | 10.50 | 11.20 |
| **Higher COP** | 10.10 | 10.70 | 11.40 |
| **Lower capital costs** | 9.60 | 10.10 | 10.90 |

* Includes the additional cost borne by unit holders for in-suite electric heat. On a lifecycle basis in-suite electricity use would add approximately $2.85 / m2 / year to the total cost of heat to residents over and above the NDES cost of service. When these additional in-suite costs are added to the NDES costs, the total cost to users is higher in this scenario.
**Estimate. In reality, there may be opportunities to adjust DPS if the Acadia and Block F Development Areas are not expected.

In addition to alternate system concepts and potential optimizations, there are several important risks and uncertainties that are largely beyond the NDES control. Key risks and uncertainties are described in Table 15. Results are summarized in Table 16. Some key observations related to key risks and uncertainties include the following.

- The timing and magnitude of load represents one of the largest risks and uncertainties for the NDES. A delay in loads will increase the levelized cost of

service, all things being equal. However, the levelized cost under a delay in build out from 2036 to 2046 is still lower than many other competitive benchmarks. The exposure to load risk may be further mitigated through additional optimization of capital phasing to reduce exposure to future load uncertainty.

- A reduction in assumed EUIs would reduce the overall cost of service, but would also imply a lower competitive benchmark cost. Overall, a lower EUIs decrease competitiveness of the NDES but the change is very small. Assuming a 100% electric Reference Case, the scenario with lower EUIs would increase any premium between the Reference Case and NDES by 10%, all things being equal.

- The addition of Block F enhances overall economies of scale. There may be further opportunities to optimize system design and phasing if Block F is to be excluded.

- An early closure of TRIUMF has minimal impact on economics. The TRIUMF heat pump is amortized over ~25 years. In the event of early closure, there is no impact on capital costs as existing boiler capacity can meet total NDES energy demand. The main effect is increased reliance on natural gas (vs. waste heat and electricity). With increasing electricity costs and continued low gas prices, the differential between waste heat and gas-fired heat declines over time. The main impact would be on GHG emissions. There may be opportunities to advance an additional alternative energy source (e.g., biomass) depending upon relative gas and biomass prices at the time.

- Higher gas prices will increase system costs, but will also affect competitive heating benchmarks.

- Higher capital costs increase NDES costs. Each 10% increase in contingency will increase the levelized cost of service by approximately 6%.

- As with improved heat pump performance, the pro forma is comparatively less sensitive to lower heat pump performance.

**Table 15: Description of Key Risks and Uncertainties**

| Scenario | Description |
|---|---|
| **Buildout Delayed from 2036 to 2046** | As in the Reference Case, the heat pump is installed in 2014, but future phases of load and capital are all lengthened, extending the overall build out by 10 years to 2046. The capital associated with each phase is delayed, but no further capital optimization is assumed. |
| **Energy Use Intensity Declines** | This scenario assumes that improved performance in newer buildings leads to declining energy use. Energy use intensity (EUI) declines from 100 kWh for buildings built in 2016 to 70 kWh / m2 for buildings built in 2031 and beyond. Overall average EUI is 85 kWh / m2. This scenario results in lower cost of service because of lower operating costs. Capital costs are assumed unchanged, although these could be optimized as a result of trends in future energy use. It is important to note that although the cost of service in this scenario declines, the competitive benchmark would also decline as a result of lower energy use and so this scenario is not directly comparable to the Reference Case in terms of significance. |
| **Block F Excluded** | Block F is controlled by the Musqueam Nation. This scenario assumed Block F does not connect to the NDES. DPS and ETS costs associated with Block F are avoided, but all other capital is unchanged. There may be further optimizations possible if this scenario materialized. |
| **TRIUMF Closed in 2025** | This scenario assumes TRIUMF's operations are discontinued in 2025 and no waste heat is available. Natural gas boilers would provide all of the thermal energy to the NDES after 2025, and no heat is sold to the ADES. There may be opportunities to advance other sources of alternative energy in responses to this scenario. |
| **Natural Gas Prices Increase 50%** | This scenario assumes levelized delivered natural gas costs increase 50% above the Reference Case. In addition to the NDES costs, this scenario would also affect competitiveness benchmarks that include gas. This scenario still results in real natural gas prices well below the prices seen 3 – 4 years ago. |
| **Higher Capital Costs** | The contingency on all capital costs is increased from 10% to 20% to reflect additional (real dollar) cost increases. |

| Scenario | Description |
|---|---|
| **Lower Heat Pump COP** | A conservative estimate of the heat pump COP was used. This scenario assumes the COP on waste heat recovery is even lower (2.8 vs. 3.0). |

**Table 16: Impact of Key Risks and Uncertainties on NDES Cost of Service (levelized $/m2/year)**

| | UBC Ownership | Split | Private |
|---|---|---|---|
| **Reference Case** | 10.20 | 10.80 | 11.50 |
| **Buildout Delayed from 2036 to 2046*** | 11.50 | 12.30 | 13.20 |
| **Energy Use Intensity Declines*** | 9.70 | 10.30 | 11.10 |
| **Block F Excluded** | 10.40 | 11.10 | 11.80 |
| **TRIUMF Closed in 2025** | 10.50 | 11.40 | 12.10 |
| **Natural Gas Prices Increase 50%** | 11.00 | 11.60 | 12.30 |
| **Higher capital costs** | 10.80 | 11.50 | 12.20 |
| **Lower Heat Pump COP** | 10.30 | 10.90 | 11.70 |

* These scenarios will also affect the levelized cost of the competitive benchmarks used for this analysis so direct comparison to the Reference Case is not relevant. For example, the 15% reduction in average EUIs will decrease the 100% electric benchmark by 15% vs. the 10% decline in NDES cost of service. As a result, under this scenario the spread between the NDES and electric benchmark (and other benchmarks) would increase slightly.

# 12 Conclusions and Recommendations

Some key conclusions and recommended next steps from the detailed feasibility study are as follows:

- District energy is one of the most common approaches worldwide for heating university, medical, and military campuses with single owners. District energy is also an established and growing strategy for heating high-density, mixed use, multi-owner urban developments. District energy provides a flexible platform for integrating alternative technologies not available, appropriate or economic at a building scale. District energy is increasingly seen as one of the key tools to provide deep GHG reductions in dense urban areas, while providing other community benefits such as energy security, economic development, and more productive use of various waste streams.

- There are large existing commercial DE systems in the Lower Mainland (e.g., Central Heat in downtown Vancouver) and virtually all significant master planned developments in the region are considering or have installed district energy systems to meet economic, environmental and social objectives, including major developments in Vancouver, North Vancouver, Richmond, Surrey, and Coquitlam. A system is currently being installed by Corix Utilities to serve Phases 3 and 4 of UniverCity (initiated and facilitated by the SFU Property Trust).

- A NDES serving UBC's Wesbrook, Stadium, Acadia and Block F Development Areas and using waste heat from TRIUMF and/or biomass is technically feasible. Waste heat will be captured from TRIUMF's cooling towers. Heat recovery from cooling towers is a very common practice.

- The NDES will provide significant reductions in natural gas use and GHG emissions and moderate reductions in electricity use (at build out), both to the Development Areas and Campus. The NDES supports UBC's near-term GHG reduction targets. It also facilitates access to more distant alternative energy sources to meet more aggressive significant long-term reduction targets. The system supports UBC's vision for a sustainable community with seamless integration to surrounding academic uses. There are also many teaching, research, and demonstration opportunities associated with the NDES (both in terms of technical and socio-economic aspects), which is consistent with UBC's vision of a living lab.

- Waste heat from TRIUMF is the preferable starting technology, but biomass offers an economically viable alternative to TRIUMF if agreements cannot be reached with TRIUMF to access waste heat and optimize system design. Biomass also offers a source of supplemental alternative energy in future phases of development.

- The integration of the NDES and Academic District Energy System (ADES) provides significant benefits to both the NDES and ADES. The campus loads support the early installation of significant infrastructure, including the waste heat recovery system and help to reduce the system cost to residents. The ADES, in turn, will benefit from the ability to secure low-carbon energy to meet 2020 targets at a competitive cost with other alternatives. The NDES will also enable the ADES to more easily and cheaply access other alternative energy sources in the future within the South Campus and beyond. In addition to avoided gas and offset costs, there may be additional opportunities to avoid or defer certain capital costs within the ADES (e.g., additional peaking capacity). These opportunities can be explored more fully during detailed phases of system design and contract negotiations.

- The integration of the NDES and ADES can be achieved through an indirect connection, permitting separate ownership of NDES and ADES assets. Transfers of energy between systems can be governed by an explicit internal transfer pricing system (if the NDES is owned by UBC) or through contract with a third party owner.

- The NDES is likely to be regulated by the BCUC, regardless of ownership. Even if exempted under UBC ownership (which is not guaranteed based on an initial review of the *Utilities Commission Act*), UBC may wish to submit to voluntary regulation of retail rates to ensure transparency and minimize potential disputes. Integration of the NDES and ADES is not likely to trigger BCUC oversight of the ADES, although the BCUC would likely review any contract or transfer pricing provisions between the NDES and ADES to ensure fairness to residents. BCUC oversight of a third party owner of the NDES would also provide additional (ongoing) oversight of the cost inputs, price, terms and conditions of any energy purchase agreement by UBC.

- Under a set of conservative but realistic Reference Case assumptions and a variety of ownership scenarios, the NDES cost to residents would be equal to or lower than the benchmark cost for 100% electric heat. This benchmark of 100% electric heat has been used to evaluate the cost-effectiveness of other low-carbon district energy systems throughout the Lower Mainland, and has

also been accepted by the BCUC as one of benchmarks for determining whether systems are in the public interest. Under low expected natural gas prices, the cost of the NDES cost is slightly higher than a benchmark of a mix of electricity and natural gas (including additional capital replacement costs and operations associated with gas-fired equipment), but there is also higher uncertainty over future gas prices and GHG costs. The mixed gas/electric benchmark also has much higher GHG emissions than 100% electric. The projected NDES cost is within the range of heating costs for both existing and new buildings in the Lower Mainland reflecting a wide range of energy use intensities and energy sources.

- Assuming a fully allocated cost model and comparable cost of capital for UBC and private owners, there are minimal differences in the cost to customers under different ownership models. UBC ownership offers slight advantages in terms of income and property tax treatment, and some potential staffing synergies with the existing ADES. The latter synergies could potentially be captured under private ownership through a service contract between the NDES owner and UBC. Greater leverage and/or lower debt costs would also increase the net benefits to customers.

- Key downside risks (risks that would result in higher rates to residents and/or reduced returns or forgone non-cash costs) include slower development, persistently low natural gas prices (which lower the NDES gas costs but also the value of waste heat all things being equal), lower energy consumption (from higher than expected improvements in energy efficiency), and higher capital costs. Heat pump performance is important but has less impact than other uncertainties. Under a regulated model, these risks are borne largely by ratepayers in terms of higher potential rates. Under most scenarios tested, NDES rates remain within an acceptable range. There are also project optimizations and risk management strategies to reduce or eliminate the impact of certain uncertainties.

- There are also several opportunities for optimizing the system including:

    - Altering the annual shutdown at TRIUMF.

    - Sharing peaking capacity between the NDES and ADES.

    - Further monetization of GHG reduction benefits in the NDES.

    - Securing grants and low cost financing.

- Additional optimization of the sizing and phasing of capital equipment, including use of temporary gas plants to optimize installation of distribution infrastructure and connection of Acadia / Block F Development Areas to the ADES (vs. direct connection to Wesbrook).

- Reducing staffing requirements through reduced requirements for full time supervision and/or additional staffing synergies with the ADES.

- Bulk purchasing of distribution piping in conjunction with the hot water conversion of the ADES.

- Securing additional loads (e.g., Centre for Comparative Medicine located south of TRIUMF).

- The project has additional upside under certain scenarios (e.g., higher carbon taxes, rapid growth, higher energy demands, higher gas prices, deferral or redeployment of Academic system capacity, marketing or other community development benefits).

- Discussions with TRIUMF suggest the facility will continue to operate for some time. Additional due diligence will be required regarding the actual quantity of waste heat available from TRIUMF and the best method of interfacing with the facility's cooling water system. This can be investigated during the next phase of development, in advance of formal investment. Ideally, these investigations would be undertaken by or in partnership with the ultimate NDES owner.

- Regardless of system ownership, as the master developer of the target development areas and as a major purchaser of energy in the near-term UBC has considerable influence over system development and business risk. UBC also has the ability to reduce or defer certain non-cash costs in the near-term in order to enhance competitiveness and mitigate development risks.

- For UBC, the main concerns with ownership of the NDES are available capital and complexities associated with governing a commercial (and potentially regulated) service to non-academic users. UBC is facing considerable constraints on future capital available for core academic purposes. At the same time, the NDES provides financial and strategic benefits to UBC.

- Given the strategic alignment of the NDES with UBC's academic and community visions, goals and strategies we recommend UBC proceed to the next steps of facilitating development of the NDES with a connection to the ADES and initially utilizing waste heat from TIRIUMF. Some key next steps include:
    - Require buildings to be DE ready and to connect to the NDES as condition of their ground lease (this requirement will reduce DE development risk and financing costs).
    - Explore other policy support for the NDES including access to rights of way for NDES infrastructure and principles for cost allocation.
    - Commence discussions with Musqueam Nation regarding the inclusion of Block F in a future system and potential partnership or employment opportunities for Musqueam.
    - Pursue any available grants for the NDES. In the case of the hybrid ownership options, there may be funds available through P3 Canada.
    - Ensure building mechanical systems are compatible and designed to maximize reliance on NDES and efficiency of NDES. This means creating a design document and design review to ensure compatible and optimized buildings systems similar to the design documents created by the Cities of North Vancouver and Vancouver. In the case of the City of North Vancouver, they have included a requirement for a security deposit to be returned when the building meets design and commissioning requirements for connection.[35]
    - Commence formal discussions with TRIUMF regarding the terms and conditions of waste heat recovery (access, conditions, governance, etc.), including discussions regarding the annual shutdown period. Ideally this would result in a formal term sheet. This should involve the ultimate NDES owner but in the absence of an identified party, UBC should commence preliminary discussions to maintain viability and meet project schedules.
    - Consider further optimization of sizing and configuration of the NDES Energy Centre and distribution system during detailed design phase, in particular options for optimizing phasing of distribution system and

[35] UBC has created hydronic system requirements for new development but recent projects are not optimized for utilization of district energy.

Energy Centre (e.g., through the possible use of temporary plants) and the possibility of sharing peaking services between the NDES and ADES.

- Given the capital constraints facing UBC and concerns about governance and providing a commercial service for non-academic users, seek a possible private sector partner to design, develop, own and operate the NDES. The first step in this process would be to issue a Request for Qualifications, similar to the process used for UniverCity among others.
- We recommend deferring the decision on the form of agreement with the successful RFQ proponent. There are several options ranging from no UBC partnership to partial ownership by UBC. In the case of partial ownership, we recommend a split assets model with UBC owning or partly owning the TRIUMF Energy Centre given UBC's expected use of the Energy Centre and the closer alignment with UBC's core competencies in energy production. Even if UBC does not participate in ownership of the NDES, there may be opportunities for strategic agreements to support and guide the development of the NDES, including an energy purchase agreement (for surplus heat in early years), an energy sales agreement (in the event the ADES provides peaking support), a franchise agreement (including exclusivity and possible franchise fees), various shared services agreements (to secure operating synergies between systems), environmental targets/commitments, and joint development opportunities for additional green energy sources.
- Establish tentative transfer pricing policy for purchases / sales by Academic Campus from / to NDES (in event of UBC ownership or to guide contract discussions with a third party).
- Regardless of the ownership model, pursue a fully-allocated pricing policy for the use of all UBC land and services by the NDES.

# Appendix 1: System and Ownership Case Studies

## City-owned System: Southeast False Creek Neighbourhood Energy Utility (Municipal Department)

Southeast False Creek (SEFC) is an 80-acre waterfront industrial brownfield site near downtown Vancouver. In March 2005, Vancouver City Council approved an Official Development Plan for a sustainable, mixed-use community. SEFC will eventually contain about 6 million square feet of development. About 90% of floorspace will be residential with a population of approximately 16,000. A 15-year development timeframe is currently anticipated for the full site. Phase 1 of the development was home to the Athlete's Village for the Vancouver 2010 Winter Olympics (about 20% of the total anticipated floor area). The Village is being converted to a mix of market-rate and subsidized housing post-games.

As one tool to achieve its sustainability goals, the City of Vancouver created the SEFC Neighborhood Energy Utility (SEFC NEU) to produce and distribute hot water for space heating and domestic hot water in buildings. There were three key goals for the creation of NEU: provide reliable, comfortable and cost-competitive thermal energy; lower GHG emissions; and reduce the use of high-quality energy (electricity) for the provision of low-grade space and hot water heating.

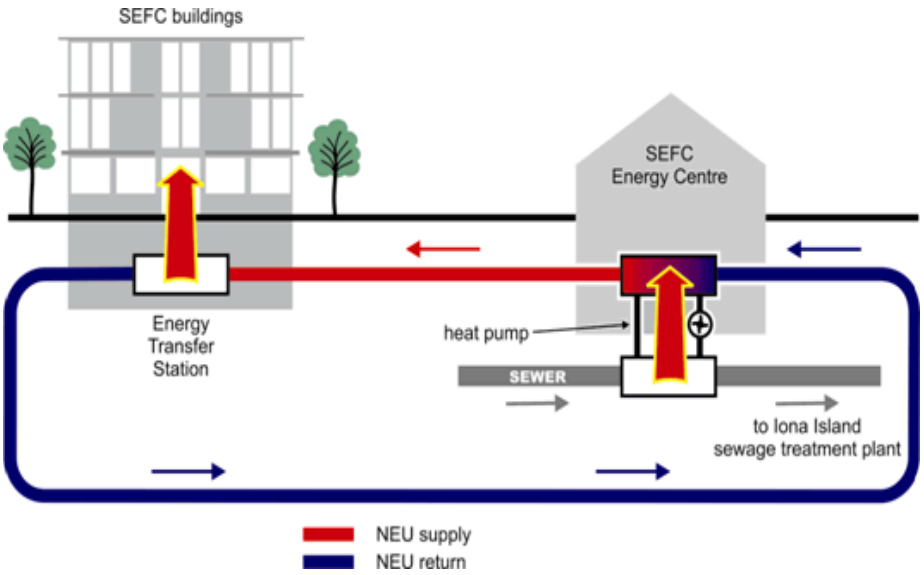
**Figure 16: Southeast False Creek Official Development Area, Vancouver, BC**

The SEFC NEU draws low-grade heat from the sewer system, and uses centralized heat pumps to provide high-grade heat to customers. The heat pump is sized to about 30% of peak demands but supplies 60 - 70% of annual energy requirements on average. Peaking and back-up is provided with natural gas boilers. There are only three other such systems in the world recovering heat directly from raw sewage on a large scale.

Energy Transfer Stations are capable of moving energy in both directions between the NEU and the customer-building system. In the first phase of development, three buildings have roof-top, solar-domestic hot water collectors that deliver energy not used by building to the NEU. Building owners receive a credit for this energy. This has allowed building owners to oversize their solar systems and to achieve effectively net zero energy on an annual basis more cheaply than if building-scaled systems were used with no net metering to balance seasonal imbalances in supply and demand.

The system began operating in early 2010, and is able to add additional capacity as further development takes place in Southeast False Creek. The system is expected to provide approximately 64,000 MWh of heat per year at build out. However, the City is already adding voluntary connections outside the mandatory service area and is considering expansion to the adjacent False Creek Flats neighbourhood.

**Figure 17: SEFC Sewage Heat Recovery System**




The City chose to develop and own the system, given the Olympics timeline for completing Phase 1 and the tight integration with the City's new sewer pump station

in the development. However, the City established a business model (e.g., used a notional capital structure and return comparable to a regulated private utility) that would allow it to divest itself of the system in the future.

The estimated total capital cost of the system will be $42 million by build out ($2010). The system is expected to generate a levelized total return of about 8% over 25 years, comparable to a regulated private district energy utility in British Columbia. A two-part tariff was established: a fixed monthly tariff per unit of building area to recover fixed costs (e.g., capital costs) and a variable tariff per unit of heat used to recover variable costs (e.g., fuel).

The City's rate policy seeks to recover all costs, including a commercial rate of return, subject to a soft rate cap that prices be no more than 10% above electricity rates. Electricity was used as the competitive benchmark for the business case because electric resistance heat is most prevalent in Vancouver, at least in the multi-family residential sector. Electricity rates are also projected to rise considerably in the next few years.

Under the levelized rate approach, the utility will operate with a revenue shortfall in early years, which will be made up with surpluses in later years, with the growth of loads and increase in electricity prices. A rate stabilization account was established to finance operating deficits in early years. The operating deficit reflects accounting costs and in fact is financed in part through deferral of items such as property taxes, corporate overheads, and return on equity. The system is expected to reduce GHG emission by 6 to 8 kt/year (50 – 65%), relative to the business-as-usual approach to heating.[36]

Since implementation, Science World decided to connect voluntarily to the system, rather than upgrade its aging boiler plant. The City has recently approved expansion of the NEU's service area to the False Creek Flats, including the location of the Great Northern Way Campus (GNWC). The GNWC is an 18-acre site site gifted by Finning in 2001. It houses the Centre for Digitial Media, which offers a Master in Digital Media jointly operated by four of the largest educational institutions in Vanouver - the University of British Columbia, Simon Fraser University, the BC Institute of Technology and Emily Carr University. The area is an emerging district for the digital and creative sectors. The expansion of the SEFC NEU was triggered by a planned large student housing project. The project will generate sufficient heat and hot water demand to make the extension of the NEU into the False Creek Flats economically viable, and allow NEU to serve future loads at both the GNWC and between GNWC and SEFC. Council approved amending the City's Energy Utility System Bylaw to

[36] There are different benchmarks for business-as-usual emissions and there is some uncertainty in the long-term efficiency of the heat pump system.

extend the service area of the NEU to the GNWC Lands and the adjacent lands in the False Creek Flats South area. It will make connection mandatory in these areas.

### City-owned System: Lonsdale Energy Corporation (Municipal Subsidiary)

LEC was established in 2003 to serve customers in the Lower Lonsdale area of City of North Vancouver. District energy is delivered via a series of natural gas "mini plants" located throughout the service area, and a network of underground pipes. LEC has recently installed a solar hot water collector to supplement gas-fired heat in the summer and is exploring other alternative energy sources for expansion. As of 2011, LEC served approximately 1,850 residential units and numerous commercial premises including a 106-room hotel.

LEC is a wholly-owned subsidiary of the City of North Vancouver. The subsidiary model was seen by the City to provide the greatest flexibility over management, contracting, and any future decisions with respect to divestiture of LEC. As a subsidiary, LEC received a formal loan from the City. There are formal cross-charging arrangements for any City employees working for the utility. To date, LEC has been managed entirely by City employees on a part-time basis, excluding the services provided by Corix (see below). LEC received a temporary property tax exemption from the City upon formation.

LEC is governed by a three-person board composed of City employees (City Manager, Director of Finance and Chief Engineer). Council decided not to have any political representation on the board to keep arms-length and allow it to focus on rate setting. Council approves rates via bylaw. LEC carries its own insurance including Director Liability Insurance.

Under a service area bylaw, connection is mandatory for City-owned lands and voluntary for private lands. In 2007, the City created a second service area in Central Lonsdale. Creation of a third service area (Harbour Side) followed. The City recently revised LEC's service area bylaw to include the entire City. All eligible buildings throughout the City are now required to connect where service is available. The City retains the right to exclude buildings that are not in LEC's interest to connect (i.e., do not meet an economic and/or strategic connection test). LEC is considering the introduction of cooling service (voluntary) in select locations as a strategy to improve the economics of geoexchange, one of the alternative energy sources currently being explored by LEC.

Since 2004, LEC has engaged Corix (at the time Terasen Utility Services) to operate and maintain all boilers, heat exchangers, control systems, and energy meters.

In the early years of development, LEC experienced several issues that have since been addressed. LEC's rate structure is based on a fixed and variable fee. The fixed fee is assessed based on a subscribed capacity. In the initial phases, many developers subscribed a high capacity, probably reflecting typical design assumptions for on-site systems including redundancy and safety factors. In addition, LEC underestimated the benefits of load diversification. As a result, the utility was overcapitalized in early years (installed capacity exceeded actual requirements), which increased unit rates. That coupled with high subscribed capacity requests by developers resulted in high fixed costs for early buildings. Another problem was that early buildings were not properly designed, commissioned and operated to minimize return temperatures, increasing operating costs in early years. LEC supported existing customers to optimize buildings for district energy. Based on this experience, LEC also developed a design document for developers to assist in the design process. LEC subsequently introduced a security deposit for developers that is returned when buildings and designed and commissioned to the standards set out in design documents. Excess capacity was eliminated through growth. And finally fixed charges were updated to reflect the rationalization of capacity and operations. Variable energy rates have continued to decline with lower natural gas prices.

### City-owned System: Markham District Energy (Municipal Subsidiary)

Markham District Energy became operational in 2001, providing heating and cooling service from the first of four planned energy plants to 3 buildings consisting of 90,000 m2. Presently, the system serves approximately 190,000 m2 of floor space. Future plans include approximately 500,000 m2 of connected floor space. The system consists of natural gas fired heating and power, centralized chillers, thermal energy storage, and a 20-km network of underground pipes.

MDE is a subsidiary corporation of the Town of Markham (sole shareholder). The subsidiary Board includes the Mayor and three councillors, and four independent members (not customers). MDE is not regulated (district energy is exempt from Ontario Energy Board regulation in Ontario). Rates are negotiated with individual customers based on estimated avoided cost.

The City does not employ mandatory connection policy but connection is highly encouraged via the planning approval process. The City has a point-based development application process. Developers are encouraged to talk to MDE about interconnection, which earns points on the application. Connecting to the district energy service is not mandatory for application approval. MDE presents district energy connection as an option to developers, explaining the rate structure and

avoided capital and design requirements to the developer. According to MDE, to date all developers have connected to the MDE system.

### Joint Venture: Enwave (Toronto)

One of the largest district energy utilities in North America, Enwave provides heating (steam) and cooling (chilled water) services to downtown Toronto buildings. Enwave is the sole commercial provider of district heating to customers in downtown Toronto. Three steam plants provide over 600 MWth of steam to +140 buildings via 40 km of underground piping. The steam plants can fuel switch between natural gas or oil in response to fuel price dynamics. In 1998, Enwave established the Deep Water Lake Cooling system to provide space conditioning services to downtown buildings. Cold water is extracted from depths of Lake Ontario, passes through an energy transfer station, then the higher temperature water continues on to Toronto's potable water supply plant. Enwave has also established an energy services subsidiary to provide additional energy services to downtown customers (e.g., building maintenance and services, retrofits, etc). Enwave also manages a large district energy plant in Windsor, Ontario. See Windsor District Energy example in the split asset ownership model.

Enwave is an example of how ownership can evolve over time. Enwave is currently owned jointly by the City of Toronto and the Ontario Municipal Employees Retirement System's (OMERS) Borealis Penco infrastructure fund (Borealis). What is now Enwave originally began as a steam-based district energy system owned by Toronto Hydro (City of Toronto). The system evolved into the Toronto District Heating Corporation (THDC), a non-profit (no share capital) corporation. TDHC consolidated and operated several systems on behalf of the founding partners (Toronto Hydro system, Hospitals Steam Corporation, Queens Park and Terminal Railways). The original legislation which created THDC included many provisions to limit risk, which restricted the company's borrowing. The legislation also required considerable involvement from the City of Toronto in routine business transactions, which hampered the system's ability to grow.

In 1998 TDHC became a share capital corporation. All but one of the original statutory shareholders divested of their ownership interests. The remaining owner, City of Toronto entered into a joint venture with Borealis to capitalize system expansion. Each party originally owned a 50% share in the newly formed private venture known today as "Enwave". With growth, the City of Toronto 43% of Enwave.

Enwave is governed by the Toronto District Heating Corporation Act. Both public and private bonds were used to pay for the deep water lake cooling system improvements.

Customers were required to sign contracts or letters of intent to sign in order to secure the financing for the deep lake cooling project.

The shareholders of Enwave established a board of directors for supervising business affairs within the terms of the shareholder's agreement. Board members are elected on a 3 year term. The board consists of 6 members: 3 nominated by each of City of Toronto and Borealis. City representatives include the Mayor or a member of Council designate and 2 citizens at large. The Board is chaired by one of the City's citizen appointees provided the City owns at least 35% of Enwave shares. The Mayor or their designate cannot be chair.

In November 2011, Toronto City Council authorized the City of Toronto to sell its interest in Enwave. The decision was driven by a desire to reduce the City's debt obligations but was hotly debated among Council. OMERS (Borealis' parent) subsequently waived their right of first refusal to purchase Enwave shares pursuant to the shareholders agreement. In December 2011, the City of Toronto and Borealis issued a joint solicitation for proposals to purchase 100% of Enwave Energy Corporation through an auction process. The Board of Directors of Enwave created the Special Committee to oversee the sale process. The process is currently underway.

### Split Assets: District Energy Windsor

In 1995, the Windsor Utilities Commission (WUC), a subsidiary of the City of Windsor, studied the feasibility of a district energy system with support from Natural Resources Canada. The feasibility study showed the market in Windsor to be very favourable for a district heating and cooling system, especially with the proposed Casino project as the anchor district energy customer. The system was commissioned in 1996. It was originally developed by Northwind Windsor, a private company, and the WUC. Northwind built and owned the central heating and cooling plant to supply all thermal energy to District Energy Windsor (DEW), a division of WUC. Today, DEW provides heating and cooling service throughout the Windsor downtown core, including a gaming/hotel development, City Hall, several commercial / institutional buildings, and an art gallery. In 2000, DEW built an additional peak chiller plant to supplement energy purchased from Northwind. In 2003, Northwind was bought out by Borealis (a business unit of the Ontario Municipal Employees Retirement System). DEW purchases heat from Borealis, the owner of the generation assets, and then distributes the heat to customers and manages billing and customer services.

## Concession: Oklahoma University

Following a competitive solicitation, Corix Utilities was granted a 50-year concession (with renewal options) to maintain, operate and expand Oklahoma University's (OU) energy, water and wastewater utilities. Corix made an upfront concession payment to OU for the rights to be the concessionaire. OU retains legal ownership of the assets. The concession payment is treated similar to a Corix capital cost and included in the rate base. Rates are set according to a regulated utility model. Rates include depreciation, operations, etc. Rates are based on a deemed capital structure and the return on equity (ROE) is benchmarked to the three largest regulated utilities in Oklahoma, which are determined by the Public Utilities Board.

Under the concession agreement, Corix employs an open book accounting model. Utility cost and services are regulated by OU through contract, including independent expert reviewer and dispute resolution mechanisms. Some features of the agreement include the following:

- Corix can identify opportunities to improve system efficiencies and OU can approve investments (costs are added to the rate base). Savings are shared as an incentive to identify opportunities for efficiency / innovation.
- OU can continue to contribute capital to new investments (grants, etc.) as a contribution in aid of construction and those contributions do not get rate based, nor does Corix earn any return on OU's capital contribution.
- The parties are working on service performance standards, subject to prudency review and dispute resolution clauses in the contract.
- The agreement has a variety of termination and renewal provisions.
- Corix reports to a contract administrator (the OU campus utilities manager).

Corix was able to secure financing against the security offered by the concession agreement.

## Concession: London Olympic Park

Many of the sporting events for the 2012 Summer Olympics will take place in London's new Olympic Park, which covers an area of 2.5 square kilometres. Reducing carbon dioxide emissions was a key component of

London's bid for the 2012 Games, and the local planning authority also set challenging targets as planning conditions for the UK Olympic Delivery Authority's (ODA's) energy strategy including the need to reduce carbon dioxide emissions by 50% compared with those that would have been expected in order to comply with 2006 Building Regulations (DCLG, 2006). The Olympic Park district energy utility was

central to the delivery of these targets. It is the largest such scheme to be built in the UK so far and started operation in October 2010. The system will deliver low-carbon heating and cooling across the site for the games and for new buildings and communities after 2012. The design strategy for this project has been to provide utilities networks that have both flexibility and capacity to serve this part of east London for years to come. The approach was to provide an infrastructure that would not require the extensive digging up of roads to re-lay utility services as buildings are developed after the 2012 games.

In 2006 ODA conducted an assessment of the available procurement options for all utilities infrastructure was conducted. Options included: a conventional approach, procuring infrastructure from incumbent utility companies; competitive procurement from third parties under long-term concession contracts; and competitive procurement from third parties under short-term design and build contracts. ODA concluded that substantial capital cost savings could be achieved through a long-term concession approach. ODA eventually collaborated on procurement with the adjacent Stratford City development, which had decided on a similar strategy for new development.

During the feasibility stage, ODA determined that a site-wide district heating system with a more limited district cooling system was the key to delivering a sustainable low carbon park. Two energy centres, one at Stratford City and the other in Kings Yard on the Olympic Park, were specified to convert fuel into electricity (combined heat and power), hot and cold water. Having decided on this community energy network strategy, ODA then considered best practices for energy sources. With industry research, ODA developed a reference design with prescriptive outputs to drive efficiencies higher. Vendors were obligated to tender against this design, but were able to offer alternative designs in addition.

Key elements of the ODA reference design for the energy centres included the following.

- Combined cooling, heat and power (trigeneration CCHP) to maximise carbon dioxide reduction. CCHP engines that could be switched to renewable, synthetic gas from natural gas when established and available in order to maximise future potential for carbon dioxide reduction. Combined heat and power, even when based on natural gas, would reduce global GHG emissions given the high penetration and lower average efficiency of thermal only electricity generation in the UK. Trigeneration refers to the ability to utilize waste heat in summer months (when heating loads are low) to supply cooling via absorption chillers.

- Low flow and return temperatures to the district heating network (a maximum of 95 degrees C supply and 55 degrees C return in the primary network, and 85 degrees C supply and 45 degrees C return in venues and secondary systems).

- Very large storage tanks at the energy centre to prolong the running hours of the CCHP engines during periods of fluctuating or low heat demand. This has the benefit of increasing carbon dioxide reduction for the system and increasing the economic viability of the system.

- The provision of a limited district cooling system to local high cooling demand buildings to extend the running hours of CCHP engines in the summer months.

- A variable flow district heating system with two port valves throughout to enable water flow rates (and thus energy) to be reduced as demand reduces.

- Valve termination chambers near buildings to allow temporary heat generators to be connected if needed for resilience to customers.

- Modular plant design to ensure not only that plant systems operate near maximum output and thus maximum efficiency, but also that future technological advances could be included at a later date.

- Large biomass boilers to deliver a renewable energy contribution.

- The use of ammonia as a refrigerant within the electric chillers instead of hydrochlorofluorocarbons, which are commonly associated with global warming.

- A requirement for a high-quality architectural approach with a design brief, parameters for scale and volume and a client design approval process.

One of the challenges for ODA was to balance the need for a reliable system that would attract private sector investment with the objective of achieving carbon dioxide emission savings for the Olympic Park as a whole. Newer technologies such as biomass gasification and waste to gas were explored at various stages during the procurement process and revisited during design phase. However, at the scale of energy demand at the energy centres, the market was not prepared to accept risks associated with reliability and return on investment.

Ultimately, the renewable energy element of ODA's energy strategy included a 3MW biomass boiler, designed to burn wood chips. This boiler is operated as a base load supply source in conjunction with the CCHP units to provide an additional reduction in carbon dioxide emissions of at least 1000 t per year. At the Stratford energy centre, there was insufficient space for the inclusion of a solid biomass boiler, so the renewable energy element is delivered using a locally sourced bio-oil. ODA was also prescriptive to the Olympic Park's venue design teams (and worked closely with them in the design process) to exclude the use of conventional permanent heating systems within venues and to design secondary heating networks to work with the supply and return temperatures of the primary community heating network.

ODA and Straford City originally intended to procure a single contractor to provide gas, electrical and district energy services. The procurement process was launched in the autumn of 2006 with market testing before the procurement strategy was finalised. A pre-qualification questionnaire was issued in November 2006 and an invitation to negotiate in January 2007. The time and cost of getting to contract exceeded expectations. The absence of regulations for district heating in the UK is believed to have made the contracting process more expensive. The Olympic Park site also presented some unique challenges in terms of timelines and site security. Excessive estimates for construction costs ultimately undermined the procurement of a single vendor for all utilities (a multi-utility approach) and resulted in the award of separate contracts for each of the utility projects.

Shortlisted bidders for the community energy system tendered against the energy centre specification, which included architectural requirements and an additional optional zero carbon reference design using either biomass gasification plant and engines, or biomass boilers with steam turbines. All of the shortlisted bidders declined to offer this option due to perceived risks with plant reliability, service levels to customers and fuel price.

The contract for private finance, design, build and operation of the district heating and cooling network and associated energy centres at the Stratford City development and Olympic Park was ultimately awarded to Cofely, a subsidiary of GDF Suez, under a 40-year concession. District heating and cooling is not regulated in the UK. The Concession Agreement was required to provide for connections, supply and service levels. Financial viability and increased certainty over renewable targets were achieved by providing exclusivity to Cofely for the supply of heating and, in some areas, cooling for all permanent developments within the Athletes' Village, Olympic Park and Stratford City development. The Concession Agreement was signed in April 2008, planning permission was granted in July 2008 and construction started in September 2008, allowing for a 2.5 year construction period. The scheme was apparently delivered without any premium to conventional energy, which may in part

be attributed to the long-term concession and ability to amortize capital over a long period with low risk premium.

The total private sector investment in utilities and energy exceeds £200 million, with over £100 million in the district energy scheme alone. In the case of district heating, this investment is made by Cofely and recovered through connection charges and revenue over the 40-year concession period. The Concession Agreement is between Cofely, Stratford City Developments Ltd and ODA. The Concession Agreement:

- Provides an Area of Exclusivity to Cofely for the term of the agreement;
- Sets out terms whereby heat and cooling is supplied to consumers;
- Requires carbon savings to be delivered as compared to conventional energy sources.

Under the Agreement, Cofely will design, build, finance, and operate (maintaining, repairing and replacing) all plant contained in 2 Energy Centres; all sub stations; and all heating and cooling networks (from the Energy Centres to Consumer interface points).

The community energy system is now operational (it was commissioned well in advance of this summer's games). Both energy centres were designed using common building blocks and design rationale. They both contain space to allow further infrastructure to capture future growth. The two sites have sufficient space to provide up to 200MW of heat (~25 MW today), 64MW of cooling (~11 MW today) and 30MW of low carbon electricity (~3.3 MW today).

The scheme provides a strategic hub for a larger vision of heat networks in London being actively promoted by the Mayor.

### Strategic Partnership: South Hampton and Birmingham, UK

Southampton, UK is located approximately 100 km southwest of London on the southern England Coast. Originally a port town, Southampton now has a fairly diverse economy, with the health and education sector providing a large percentage of employment. Other significant sectors include industrial and retail/wholesale. The City remains a major port for cruise ships and hosts the largest freight port on the Channel coast. Southampton is the region's major commercial service centre. The local authority is Southampton City Council (SCC).


The Southampton District Energy Scheme (SDES) was established in 1986. The scheme started as a geothermal heating project for the community's Civic Centre, located in the city centre. Additional city centre buildings soon followed. Once the core node was established, the scheme was expanded to include cooling service (1994), CHP (1998) and several new redevelopment areas beyond city centre were connection (1988 onwards). While CHP now supplies most of the heating needs, the original geothermal concept still contributes approximately 15% of the required heat. The open loop configuration accesses 74°C water from aquifers 1.7 km underground.

The SDES includes the following technical features:

- Annual energy sales of 70,000 MWh/year (approximately the size of Vancouver's SEFC NEU) generated from a mix of geothermal (open loop), gas/oil-fired CHP, and a conventional gas-fired boilers. Chilled water is generated using absorption chillers that utilize waste heat from CHP and conventional vapour-compression refrigeration system.

- A 5.7 MWe Wartsila CHP engine and two 400 kWe gas-fired reciprocating engines. About 23 GW.h / year of electricity generated and sold to a single customer at the port under a supply contract. The CHP unit is capable of running on light fuel oil or gas to optimize dispatch mix according to current and anticipated fuel prices. However, it mostly runs on natural gas. Cofely is constantly looking for biogas supply opportunities to reduce carbon costs (UK currently levies a £12/tonne carbon tax on all carbon consumption)

- 11 km of distribution piping.

- Heating, cooling and electricity sales to over 40 public and private sector customers and hundreds of domestic customers.

The original geothermal scheme was investigated by SCC, with European Union support. From the outset, the scheme was supported by Council and championed by a SCC Executive Director (equivalent to a Director of a municipal department in North America). Council made a decision to develop the scheme but did not want to undertake a finance or ownership role, so it partnered with Utilicom to develop the geothermal resource via a competitive selection process. Utilicom was chosen because of its extensive experience in the design, construction and operation of large district heating schemes, some of which utilized geothermal heat. Utilicom was subsequently purchased by Cofely District Energy, which forms part of the energy services branch of its parent company, GDF Suez.

Utilicom/Cofely delivered the scheme under a Design, Build, Finance, Own and Operate business arrangement. However, municipal involvement in the scheme's success was and continues to be essential. The business arrangement was formalized in a Joint Co-operation Agreement (JCA), which outlines the parties' roles and responsibilities for ensuring the scheme's success.

Under the JCA, Cofely committed to:

- Develop the scheme initially utilizing the city's geothermal resource, and then adding CHP;
- Sell heat to SCC buildings with agreed savings;
- Provide all necessary financing, technical and management expertise required to deliver the scheme; and
- Provide open book accounting and a long-term profit share to SCC.

SCC in turn committed to:

- Take heat wherever practical for SCC buildings;
- Help promote the scheme to other potential users;
- Support scheme development through co-ordinated infrastructure and land use planning;
- Providing the land for the energy centre while foregoing property taxes;
- Granting Cofely ownership of the geothermal resource; and

- Treating Cofely as a 'statutory utility' within City boundaries (facilitates access to easements and rights of way for district energy infrastructure)

At start-up a SCC Executive Director allocated approximately 15% of his time to develop the scheme. This level of municipal leadership, combined with unanimous Council support is considered a key ingredient to the project's success.

The Southampton JCA includes a profit sharing provision for the division of any annual Net Operating Profit (essentially, net profit before corporate taxes).[37] The profit sharing provision is triggered in a given year when: a) there is a cumulative net profit, and b) there has been a full year of third party consumer connections. Third party in this instance refers to a customer other than the City. All NOP up to 5% of gross revenue is kept by Cofely. Any NOP above 5% of gross revenue is split 50/50 between Cofely and the City. To date, there has not been any profit greater than 5% of gross revenue. The JCA requires open book accounting so the municipality can access financial statements at any time.

As part of the profit sharing provision, Cofely pays a fixed sum of £25,000 / year to SCC, irrespective of any profits or losses. That sum has been paid every year.

Cofely sets rates independently of SCC and maintains a direct relationship with customers. SCC is not involved in the financial aspect of the scheme other than sharing in profits, when available. Thermal energy rates are based on an avoided cost model. Under this regime, customers' self-generation costs (including capital, fuel and non-fuel O&M) are estimated and compared to the cost of district energy. Where costs are equal to or lower than a customer's self-generation costs, there may be a willingness to connect.

Not all potential customers connect, nor has the City established mandatory connection. According to staff, the City is not legally able to require connection because SCC can benefit from the scheme (in the form of fixed annual payment from Cofely and any potential profit sharing). According to staff, requiring connection would constitute a conflict. However, all new buildings within a pre-determined service area are required to consider district energy connection within the development permit process. This requirement includes meeting with Cofely to learn about district energy service and rates.

Self-generation costs are calculated as an annualized life cycle cost (LCC) and compared to district energy rates. Customer self-generation costs include capital,

[37] Note this form of profit sharing is likely not viable in the context of a regulated utility rate of return as exists for private district energy systems in B.C.

maintenance, carbon tax and non-fuel O&M. Fuel prices are assumed to be flat in real terms over the projection period. Cofely justifies this on the grounds that the same escalation would also apply to centralized generation. Heat supply agreements include a commitment to remain between 5-10% below what customers otherwise would have paid.

Rates are comprised of a fixed and variable component with a connection charge that can be tailored to each customer. The fixed component is indexed to the Retail Price Index and labour rates. The variable portion is indexed to HEREN, the UK's natural gas index. The fixed component typically represents approximately 30% of the rate and the remainder is generally comprised of the variable portion. Carbon tax on central generation fuel is flowed through to customers as part of the variable rate. All heat supply agreements are for a 20 year term.

The JCA was renewed in 2005 and includes a 25-year term with a renewal clause. The Agreement does not include any buy back provision that would enable SCC to take ownership of the scheme or any assets at the JCA's expiry. Thus, the scheme will remain under Cofely ownership into the subsequent renewal term.

The Southampton scheme is governed by a Strategic Partnership Board. The Board is chaired by an Executive Director of the municipality. The board consists of approximately 10-12 board members at any given time, with 3 positions filled by Cofely and the remainder filled by senior level SCC staff. The Strategic Project Board meets 4 times per year and reports directly to Council. The Board does not have Executive power – all major decisions must be reported to and approved by Council via the Environment cabinet.

The scheme also relies on a technical committee for strategic direction and land use and infrastructure co-ordination. The technical committee is a sub-set of the Strategic Project Board. The technical group meets once every 6 weeks. Typical tasks include:

- Identifying potential new customers;
- Communicating future land use and infrastructure plans;
- Discuss and assess capacity expansion and/or required refurbishing (the original borehole and pumps are currently being refurbished); and
- Assessing distribution piping layout routing, among other technical tasks.

The technical committee consists of Cofely technical staff and mid-level City staff.

Cofely has replicated this model in several other communities in the UK. For example, Cofely owns and operates a similar scheme in Birmingham, UK (160 km northwest of London). The system was conceived in 2003 under the banner of the Birmingham District Energy Company. The company was formed after several parties considering distinct schemes within Birmingham issued a joint procurement package for an external party to Design, Build, Finance, Own, and Operate the three systems in a coordinated fashion. Cofely was the successful Proponent. The result was two separate systems, both owned and operated by Cofely:

- Broad Street – a tri-generation concept that supplies thermal energy to a number of civic and commercial customers;
- Eastside – 2 distinct schemes that provide thermal energy to the Birmingham Children's Hospital and Aston University campus. Several civic buildings are also connected within each scheme.

Combined, the schemes deliver 41 GW.h / year of heat energy and 4.9 GW.h / year of chilled water via 4 km of insulated pipes. Approximately 6.7 GW.h / year of electricity is also produced and sold to the national grid. Future plans included the physical integration of the two schemes, the extension of service to third parties, and the introduction of additional alternative energy sources.

The combined schemes are owned and operated under a single utility company. In contrast to the Southampton scheme, there are 4 parties that participate in the Project Agreement: Cofely, the City, the Hospital Trust and the University. All partake in strategic decision making and profit sharing. In contrast to the Southampton arrangement, the Birmingham Project Agreement stipulates that profit sharing beyond 5% of gross revenue is divided by the 4 parties proportionate to heat sales. The core parties take a more active role in financial review than Southampton. Cofely is required to provide detailed statements of accounts to the parties at regular intervals.

Unlike in Southampton, the Birmingham Project Agreement includes an option for the core parties to take ownership of district energy assets at year 25 (in 2028).

In Birmingham, there is also a Strategic Board; however, membership is broader to include Cofely, the City, the University and the Hospital Trust. These members represent the core project team. Unlike in Southampton, each customer's heat supply terms are integrated into the Project Agreement. The document has become quite cumbersome with the addition of new customers and revisions to original heat supply arrangements. Cofely prefers the Southampton arrangement where heat supply contracts are established separately from the JCA and the business arrangement is directly between Cofely and the customer.

## Cooperative: Rochester District Heating

Rochester District Heating (RDH) is a private cooperative owned by the customers of RDH. The system was originally developed in the 1880s. It is the 3rd oldest district energy system in U.S. By the 1980s the system was in decline and the operator, Rochester Gas and Electric, was considering shutting it down. Existing customers, faced with installing their own systems, banded together to form a cooperative. All customers signed 15 year contracts with stringent buyout penalties and were able to use these contracts to finance the purchase of RDH.

The City and county government are significant customers (and were instrumental in setting up RDH) and are equal status members of the coop as other customers. Members vote on rates and annual budget. Votes are weighted based on proportion of energy load. The coop is run by a volunteer board of directors. The utility is exempt from regulation by New York State Public Service Commission.

New members are not required to purchase coop shares. The only up-front costs for new members are the capital costs of system extension and connection to the building.

## Cooperative: Toblach, Italy

In 1995 the Town of Toblach initiated the development of a biomass-based district heating system. Today, the system has 14MW of heating capacity and 1.5MW of electrical capacity from biomass CHP (organic Rankine cycle). The systems deliver heat to 900 customers in Toblach and the nearby town of Innichen via 44 km of distribution piping.

The system was developed following a mandate from the Town of Toblach's mayor. The Town established a requirement of 70% subscription before proceeding with the project. The Town guided the system for its first 10 years, leading the development of the co-op membership arrangement. Each customer/owner has one vote and can join in decision-making. The member with the greatest voting power is the municipality itself, which owns the local schools, a number of city buildings, and a large office complex. Membership has since grown to more than 500 members in Toblach and 400 in Innichen.

To finance initial system developing, building owners provided 20% of the system capital, with one-fifth of their portion coming from the municipality. Grants from the provincial government of South Tyrol met between 30 and 40% of the initial capital cost, with low-interest loans comprising the rest. Local banks agreed to defer principal repayments in the system's early years (i.e., agreed to interest-only payments).

To strengthen the link between energy use and local, family-owned forests, the system pays local farmers 75 percent more than the market rate for biomass feedstock.

The system has reportedly been building cash reserves and rates have remained flat for 15 years. Upon repaying outstanding debt, the co-op's board will decide whether to reduce rates or pay dividends to members.

## Non-Profit System: St. Paul District Energy

District Energy St Paul (DESP) started off as a demonstration project in 1983. The initiative was spearheaded by then Mayor George Latimer, who lobbied state and federal governments for assistance in replacing a former steam system with a modern hot water district energy system serving the downtown core. Established in part as a response to the oil crises of the 1970s, the system was designed to be energy efficient, provide local fuel flexibility, and secure stable rates for customers. It was developed through a partnership among the City of St Paul, the State of Minnesota, the U.S. Department of Energy and the downtown business community.

The system started with high-efficiency fossil fuel heat (coal). In 1993, DESP began offering district cooling service to downtown building owners. In 2003, DESP an affiliate of DESP commissioned a biomass-fired combined heat and power (CHP) plant primarily fueled by urban wood waste. Some excess biomass heat is used to provide renewable cooling via absorption chillers. The system also has thermal storage to reduce peak electricity demand for cooling. The biomass CHP facility plant now supplies 75 percent of all thermal energy, with coal and natural gas mainly used for peaking. The project helped the community solve a local wood waste disposal problem and created a new industry for collecting and processing wood. It also puts an estimated $12 million annually back into St Paul's local economy (rather than imported fuels). The plant opening was attended by then President George W. Bush.

Today, DESP is one of the largest biomass-fired systems in North America. Both the installed capacity and service area of DESP have grown steadily over time, and as of 2010, DESP has 289 MW of total heating capacity, 65 MW of which is from a biomass combined heat and power plant (with 33 MW of electrical output). DESP's annual heat sales are over 300,000 MWh. DESP now heats approximately 185 buildings and 300 single-family homes (30 million square feet) and cools approximately 95 buildings (19 million square feet) in downtown St Paul and adjacent areas, about 80% of the central business district and adjacent areas, including many members of the St. Paul Building Owners and Manager Association, four hospitals, and several large downtown office towers. DESP serves twice as much building area as the former steam system it

replaced, while consuming the same amount of fuel. Heat rates have been relatively stable and generally below the cost of new on-site natural gas heat production.

District Cooling St. Paul, an affiliate of DESP, offers cooling to over 90 customers occupying 17.5 million ft2. The cooling system utilizes nine electric chillers, two steam absorption chillers (to maximize annual use of biomass boilers), and two chilled water storage systems located at plants around the municipality providing a total installed cooling capacity of 33,000 tonnes.

In 2011, DESP implemented the first integrated large-scale solar thermal system in the U.S. The project was made possible through the Department of Energy (DOE) Solar America Communities program in partnership with the City of Saint Paul and the City of Minneapolis and the Minnesota Division of Energy Services. The City of Saint Paul secured a $1 million DOE Market Transformation grant to match $1.1 million in funding from District Energy St. Paul. The roof of the Saint Paul RiverCentre (convention facility) was selected as the site of the plant because of its proximity to DESP's infrastructure, street level visibility, visitor traffic, and leadership in sustainability for the convention and hospitality industry. After considering the $2.1 million budget and 30,000 square feet of roof space available, DESP selected Arcon Solar collectors from Denmark, which are larger and produce 30% more energy than existing typical U.S. residential collectors. DESP installed 144 of Arcon's high performance panels, capable of producing 1.1 MW of hot water under peak solar conditions. The solar energy is primarily used by the RiverCentre for space heating and domestic hot water, with excess energy exported to the District Energy heating loop for use downstream. The project was slowed by structural challenges to retrofit the existing building roof for such a major installation on a tight project schedule. There were many lessons learned in the installation and the project has stimulated interest among U.S. solar panel makers to design and build larger panels.

The Metropolitan Council, a regional planning agency serving the Twin Cities seven-county metropolitan area and providing essential services to the region, is currently constructing a new light rail transit line in one of the region's most heavily traveled corridors - the 11-mile Central Corridor linking downtown St. Paul and downtown Minneapolis via Washington and University avenues. DESP has joined a diverse group of public, private and nonprofit organizations to develop a broader Energy Innovation Corridor along this route and serve national model for transportation and energy infrastructure development. The partnership was created to showcase clean energy projects in the corridor, including renewable energy installations, grassroots energy efficiency, and transportation programs. DESP is exploring ways to leverage the transit project to extend its system. This has proven challenging but DESP has used the project as an opportunity to upgrade its distribution system, fiber optics, and service lines to individual customer buildings. Through the process, DESP has learned

that joint planning of energy systems with transit systems creates new opportunities for all of the partners.

DESP was set up as a private, non-profit corporation, governed by a seven-member board. Three members are appointed by local government, three members are selected by customers, and the seventh member is selected by the other six. The board oversees the activities of DESP, District Energy St. Paul and their affiliates. DESP employees, with the exception of the president, are employees of Market Street Energy Company, a for-profit district energy company. Market Street Energy oversees the management of DESP, as well as its affiliate district cooling company, District Cooling St. Paul. Both the heating and cooling companies remain non-profit community-based corporations.

DESP has created several non-profit affiliated companies to develop and manage different aspects of the system, and to seek growth opportunities in other communities. As noted above, District Cooling St Paul provides district cooling service to downtown St Paul building owners. Ever-Green Energy was formed to develop the biomass-fueled CHP and to manage the operations of DESP, its affiliates, and another St Paul district energy system. The company is also involved in a variety of projects outside St Paul related to renewable energy, biomass and deep water cooling. St Paul Cogeneration owns and operates the St Paul CHP plant. Environmental Wood Supply locates, collects, processes and hauls wood waste to the CHP facility. Renewable Energy Innovations, an affiliate of Ever-Green Energy, develops deep-water cooling renewable energy projects.

The initial system (hot water distribution and fossil fuel plant) cost approximately $45.8-million. This was financed by $30.5 million in 30-year tax-exempt revenue bonds (secured against long-term contracts with initial customers), $9.8 million in 20- year loans from various government agencies, and $5.5 million in an equity loan from the City of St. Paul. The initial cooling system cost $55 million to develop and was funded through revenue bonds plus a $3.0 million subordinated loan from St. Paul Housing and Redevelopment Authority. The biomass-fired CHP plant was initiated in 1999 and commissioned in 2003 by an affiliate of DESP, Market Street Energy Company, together with Trigen Cinergy Solutions at a cost of $75 million.

When St. Paul's District Heating Development Corporation was created to develop the initial project, investment risk was initially mitigated through long-term contracts with initial customers. Original customers were expected to 30-year contracts before development and to help underwrite the project. Initial interest was limited, with only 8 customers totalling 14 MW signing contracts, even though natural gas prices at the time were rising rapidly and the old steam-based system was unreliable. Working closely with the St. Paul Building Owners and Management Association, DESP created

a more attractive contract and better marketing program. Within a year, long-term commitments for 135 MW were obtained, allowing the project to proceed.

A key factor influencing early customer connections was the creation of an Energy Reinvestment Fund for non-profit organizations to help offset initial building conversion costs, especially older buildings served by the steam system. Today, DESP continues to work closely with new customers to provide a full thermal (heating and cooling) package, including conversion costs, building efficiency upgrades, and monitoring services.

For major infrastructure projects, DESP also discovered how important it was to coordinate with local officials, building owners and other stakeholders to minimize disruptions, minimize installation costs, and ensure community acceptance of final infrastructure. Developing a larger biomass-fired CHP plant in the downtown core posed unique challenges. With such a large plant, the site must accommodate more than 50 trucks a day for biomass fuel deliveries. Special hoppers were designed that allow two trucks to discharge simultaneously.

DESP charges have risen on average only 0.3 percent annually over the past 25 years. This is compared to an annual increase of 2.7 percent for natural gas users over the same period. In 2005, DESP estimated that customers saved a combined total of $7 million compared to alternative in-building heating and cooling systems.

### Private For-Profit: UniverCity

The district energy system at UniverCity next to Simon Fraser University (SFU) is being developed by Corix Utilities in partnership with the Simon Fraser University Property Trust (SFU Property Trust). The system will serve Phases 3 and 4 of UniverCity, a predominantly residential development adjacent to Simon Fraser University on Burnaby Mountain. UniverCity is a master planned sustainable community on Trust lands. Development parcels are sold to developers under 99-year leases, with a mix of housing types.

At the outset, SFU Property Trust wanted to provide green energy services to new developments but lacked access to capital to develop the system in house. The Trust issued a Request for Expressions of Interest for a private utility company to conduct a feasibility study and, pending a positive business case, develop a district energy utility. Corix was selected for to undertake further due diligence and negotiation. The responsibility for all business development costs were assigned to Corix for recovery through customer rates. As part of the original Memorandum of Understanding (MOU) with Corix, the Trust agreed to compensate Corix for third party study costs in

the event the system was not considered viable or the Trust failed to enter into definitive agreements with Corix to enable the utility if it proved viable. The Trust also agreed to help the private partner secure government grants, where applicable.

Following a positive feasibility study, the Trust negotiated an Infrastructure Agreement with Corix to enable the Neighbourhood Utility System (NUS). The Infrastructure Agreement sets out among other things general goals and expectations for the system (including carbon reduction expectations), respective obligations of the parties, environmental and regulatory matters, access to certain lands and infrastructure, franchise and other fees (as compensation for access to Trust lands and other business considerations), and other legal requirements and conditions. Under the Infrastructure Agreement, Corix was granted an exclusive franchise and also pays the Trust a franchise fee for use of rights of way. Customer connection is voluntary. However, the Trust requires in all land leases an upfront contribution of $1/sf from developers payable to Corix to defray the cost of NUS infrastructure. This payment is less than the avoided cost of an on-site gas boiler plant. The Trust also facilitates introductions and negotiations between Corix and developers. Finally, connection to the NUS is one strategy developers can use to receive a density bonus for achieving higher levels of building performance. As a condition of rezoning, buildings at UniverCity must be between 30% and 45% more efficient than the Model National Energy Code. Since the formation of the utility, all new developments have entered into agreements to connect to the system and the Trust has observed no impacts on land prices or development interest.

As a privately owned utility, the system is regulated by the BCUC. In 2011, the BC Utilities Commission approved the creation of the utility, the initial distribution infrastructure, the development of a temporary high efficiency boiler plant, and initial rates reflecting the temporary boiler plant. All approvals were subsequently received from the City of Burnaby, and the installation was undertaken by Corix of the temporary plant, the distribution and return piping, and the heat exchangers into the first two buildings. In March of 2012, the first two buildings were connected and have been fully operational and are performing as designed.

The system relies on a temporary high efficiency natural gas boiler plant to reduce the initial development costs. Once sufficient load is connected (~1,400 units), the current plan is to install a small biomass boiler plant. At the same time, Corix is currently negotiating with SFU to develop a larger permanent biomass and gas-fired heating plant to serve both UniverCity and SFU Campus. SFU's existing gas-fired plant is more than 40 years old and near the end of its useful life. The current plant is also located centrally within the basement of the SFU library and SFU would like to locate a new plant outside the core academic area. A larger joint plant would provide economies of scale in capital and operation for both SFU and UniverCity. Institutional

sustainability commitments, coupled with provincial carbon taxes and offset requirements for public sector organizations have provided SFU a further incentive for the acquisition of alternative energy supplies for the Campus system. SFU also received a grant of $4.76 million under the Province's Public Sector Energy Conservation Agreement (PSECA) towards an alternative energy source. SFU and Corix have selected a technology vendor and site but are still negotiating a long-term energy supply contract to enable final design and construction.

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