RESHAPE STRATEGIES

DISTRICT ENERGY PRIMER

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1 INTRODUCTION

District energy, sometimes also referred to as neighbourhood energy, involves the central provision of heating and/or cooling services. Electricity is sometimes also produced as part of a combined heat and power (CHP) system (also referred to as co-generation). CHP systems are more efficient than stand-alone electricity plants without heat recovery. 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. However, as discussed in the section on microgrids below, a CHP plant can also serve as a source of local back-up when the main electricity grid goes down.

District energy systems typically consist of one or more central energy plants connected to buildings via a network of pipes. New district energy systems typically distribute heat as hot water rather than steam, unless there is still a large requirement for steam (e.g., buildings with older heating systems, large laundry and sterilization loads, or industrial processes). Even in these cases hybrid systems are increasingly common. Individual buildings are served via energy transfer stations consisting of heat exchangers and meters, eliminating the need for on-site boilers and, in the case of district cooling, chillers or cooling towers.[1] Within buildings, thermal energy must be provided to individual suites by hydronic systems, which could include fan coils, hydronic baseboards or in-floor radiant systems.

There are typically four main components to a district energy system.

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[1] Some district energy systems distribute only low-grade (i.e., low temperature) energy to users. This requires the use of on-site heat pumps and boilers to raise the energy to useful temperatures. These types of 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 uninsulated distribution pipes in some cases), and where there is simultaneous heating and cooling (facilitating waste heat recovery from cooling).

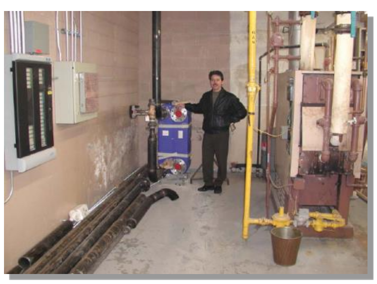
Energy Center(s)

This is a photo of the energy center that serves Southeast False Creek, the site of Vancouver's 2010 Olympic Athlete's Village. The plant is co-located with a sewer pump station, as one of the energy sources is waste heat recovered from sewage.

Distribution System

This is a heating only distribution system – one pipe for hot water supply and one pipe for return. Pre-insulated pipes with integrated leak detection are buried directly underground in this application.

Energy Transfer Stations



This blue box is an Energy Transfer Station. It is shown here in an old boiler room. The box contains heat exchangers and a meter. In a new building, there would be no requirement for the boiler room.

Building Hydronic HVAC

Within buildings, heat could be supplied via in-floor radiant heating systems, hot water radiators (shown in this picture) or fan coils, among other approaches. Developers can select the system appropriate to their needs. They simply have to ensure building systems are compatible with district energy supply temperatures.

Figure 1: Components of a District Energy System

The most common district energy system involves full centralization of equipment, eliminating the need for any on-site equipment to produce heat or cooling. In this configuration, the thermal energy provided to the building is at an adequate temperature without the need for additional onsite equipment. A second approach to district energy is the distribution of lower grades of heat or cold water. In this concept, the thermal energy to the building is supplemented with additional on-site equipment (e.g., boilers, heat pumps, etc.).

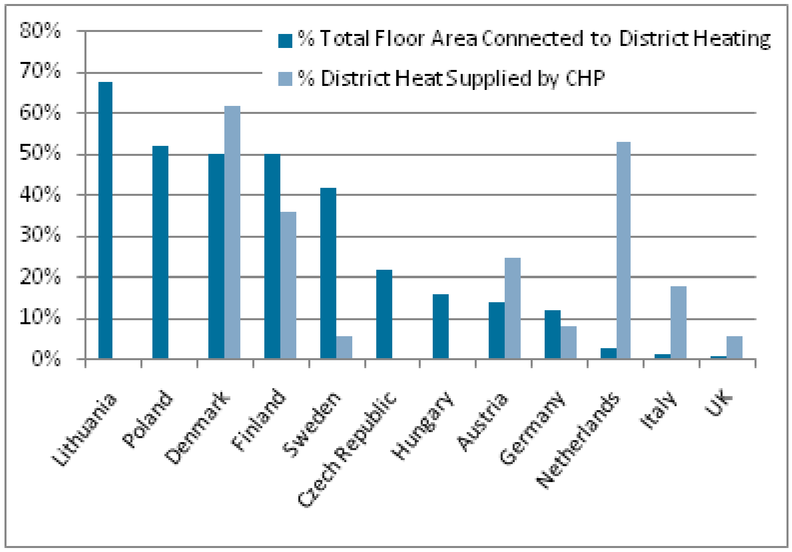
Alternative forms of energy systems can also be implemented on a distributed basis within individual parcels or smaller collections of parcels. Although these distributed systems may not be interconnected, they could also be organized under a utility ownership model. The main benefit of such a delivery model is that the upfront capital costs, which tend to be higher for many alternative energy technologies, are absorbed by a utility and recovered over the longer term through rates. An example of the distributed model is Sun Rivers near Kamloops, B.C. The utility installed and owns parcel-scale geo-exchange systems and recovers the cost through an ongoing access fee.

2 PREVALENCE OF DISTRICT ENERGY

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 incineration (known as Waste to Energy).

District energy helped the initial development of the electric power industry by enhancing the economics of new power plants through waste heat recovery. Many major cities throughout the world have district energy systems, or are looking to build them. Today, more than 50% of all building stock in some countries of Northern Europe is connected to district energy systems (Figure 2).

Figure 2: Penetration of District Energy in Europe



Source: International Association for District Heating, District Cooling and Combined Heat & Power. Data from 2003. CHP = Combined Heat and Power

There are more than 6,000 district energy systems in North America, most in older downtown cores and on medical, educational or military campuses. There has been a renewed interest in district energy as a strategy to capture alternative energy sources such as biomass and waste heat in order to reduce reliance on imported fuels and the production greenhouse gas emissions.

There are currently about 120 systems in Canada, with more under development. About one percent of all floor area in Canada is currently connected to a system, significantly less than many northern European countries. Ontario is currently the leader in district energy, with more than 40% of connected floor space in Canada (~6 million square meters). But district energy is evolving rapidly in other parts of Canada, growing by about 1%/year nationally.

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.[2] In Helsinki, Stockholm, and Copenhagen district energy now serves over 98% of city-wide space heating needs. 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 relative to North America, 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.

[2] 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.*

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 if 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. The Norwegian Water Resources and Energy Directorate (NVE) regulate district energy. 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.

Finland 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 Finish 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 Trends in the Rest of Europe and the UK

Following on the Nordic model, district energy is undergoing a renaissance in other European countries. District heating networks based largely on renewable biomass energy have grown rapidly in small Austrian towns. In Germany, despite a long history with district energy and one of the highest penetrations of CHP in Europe, the country has a relatively low current penetration, (8%), of district energy in the heating sector compared to its Nordic neighbours. However, this means there is considerable room for growth. A recent study by the German Federal Environment Agency identified increased use of CHP and district energy as the most cost-effective technologies for reducing the country's Co2 emissions. The government hopes that a new, more favourable legislative framework and several market based support mechanisms can increase district energy penetration to 22% by 2020.

In the United Kingdom, after a poor experience with expensive and inefficient district heating in public housing projects in the 1950s, '60s and '70s, there has been a recent renewed interest in the technology. 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.[3] In the London Plan 2011, the City of London set a target for 25 per cent of the heat and power used in London to be generated through the use of local, decentralized energy systems by 2025. As part of local development frameworks, the Mayor expects that boroughs will develop policies and proposals to identify and establish decentralized energy network opportunities and to work with neighbouring boroughs to realize wider decentralized 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
- 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 decentralized energy opportunities
- Identify implementation options for delivering feasible projects, considering issues of procurement, funding and risk and the role of the public sector
- Require developers to prioritize connection to existing or planned decentralized energy networks

With 3.3 million Euros in seed funding from the European Investment Bank's ELENA (European Local Energy Assistance) facility, the City of London established the "Decentralised Energy for London" program to provide London boroughs and other project sponsors with technical, financial and commercial assistance to develop and bring decentralized energy projects to

[3] 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.

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 standardized 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 consists 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.

2.3 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 focused 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 approximately $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 Syndey 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 economically favourable and the Christchurch Agency for Energy is now 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, environmental requirements and commitments among many institutions, and the growing demand for high electrical reliability among sensitive power users on campus systems.

2.4 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.[4] There are hundreds 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.

[4] 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.* 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.

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 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. As a result 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 from a single source was appealing to building owners as it reduced 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 provide an alternative to on-site air conditioning using banned refrigerants. They deliver a means of diversifying cooling loads across multiple users and potentially using thermal storage to take advantage of cheaper off-peak electricity. Particularly in the US, there has been an interest among electric utilities in district cooling as a means of reducing the peak demand loads from air conditioning during the summer months. 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 for just this reason.

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.

2.5 District Energy Developments in B.C. and Elsewhere in the Lower Mainland

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.[5] 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). Several new commercial systems have been installed in B.C. in recent years and many communities / developers are actively exploring new district energy systems and policies. To date there has been considerable focus on individual projects and nodal opportunities. However, 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.

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[5] 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.

The following is an overview of provincial and regional activity. It is not an exhaustive review. Initiatives around the province provide useful precedents for Vancouver, however, activity in adjacent areas such as Richmond, Burnaby and the University of British Columbia are particularly relevant to Vancouver in terms of possibilities for development of shared systems and/or energy sources.

Revelstoke

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 an outcome of that work, Council 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.

Dockside Green

In 2008, Dockside Green Energy (DGE) commenced operation to supply the award-winning, LEED Platinum development known as Dockside Green in Victoria. 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.[6]

There are numerous other district energy projects and studies underway in Victoria, the Capital Regional District, and southern Vancouver Island.

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

Resort Municipality of Whistler

In 2009, 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.

City of North Vancouver

In 2004, the City of North Vancouver began operation of one of the first commercial hot water district energy systems in B.C.[7] 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 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 an optional service.

District of North Vancouver

The District has explored district energy opportunities on a city-wide basis. They have identified 4 neighbourhoods with district energy potential: Lower Lynn, Lynn Valley Town Centre, Lower Capilano Village Centre, and Maplewood. Maplewood is being assessed as part of a broader district energy study being led by FortisBC. The proposed concept will capture waste heat from Erco, a large chemical manufacturing facility, supplemented with gas boiler for peaking conditions and backup. Capilano University is the proposed anchor tenant. Other potential customers include the Holliday Inn, a residential building across from Capilano

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

University, and other industrial buildings near Erco. Fortis is also working with Erco and Ballard Power Systems, a hydrogen fuel cell producer, to assess capturing a waste stream of hydrogen as feedstock for a fuel cell that would produce power and heat as a by-product. The District is currently evaluating approaches to district energy governance and implementation in each neighbourhood.

Richmond

For several years the City of Richmond has been exploring options to implement a district energy system around the Olympic Oval. The City has implemented a geo-exchange district energy system (with the field located in a city park) in partnership with Oris Consulting Ltd for the Cambie West neighbourhood. In addition to the Oris development, the system will also serve nearby Polygon and other developments. The system is being installed by Oris, and Oris is also providing capital, which will be recovered through a revenue sharing agreement with the City. Richmond will be the ultimate owner of the system, and will set rates. The City implemented a mandatory connection policy for the Cambie West neighbourhood (service area bylaw). Oris is pursuing district energy opportunities for the new Parc Riviera development on the south shore of the Fraser River.

The City is currently evaluating opportunities to require hydronic HVAC systems for buildings undergoing a rezoning in the City Centre. The City expects to develop formal policy beginning in the fall of 2012.

In 2011, the City issued a Request for Qualifications to find a private sector partner for development of district energy opportunities within the city. Corix was selected as the successful respondent. The initial focus was on opportunities at River Green around the Olympic Oval. The City is also exploring other opportunities with Corix, including possible involvement in the Cambie West project. The City has been exploring a concession model with Corix to retain City ownership and governance (and eliminate BCUC oversight), while minimizing City capital costs and leveraging private sector expertise and some risk transfer.

Coquitlam

There are several district energy initiatives are underway in the City of Coquitlam.

FortisBC signed an agreement with The Beedie Group (the developer) to design, build and manage an alternative district energy system for its large Fraser Mills development. Several heat sources are being assessed. Located on the Fraser River in Coquitlam, this 89-acre riverfront development will include 3,700 residential units, 275,000 sq. ft. of commercial/retail space and 600,000 sq. ft. of business park/ light industrial space and will feature 16 acres of open space, parks and trails.

Following a competitive process, the City selected FortisBC to evaluate energy efficiency opportunities and the potential to interconnect several municipal buildings into a district energy system (Coquitlam Municipal Campus). The study is currently underway.

The City engaged consultants to assess alternate energy supply options for the Partington village centre. The study was conducted over 3 phases to examine precedents, a preferred concept, and potential financial and governance models.

To achieve its corporate goals in the context of expected growth, the City of Coquitlam issued a Request for Qualifications and Information to select a firm to assess the feasibility and implement, if feasible, District Energy Projects in up to 4 neighbourhoods, including: Partington Creek, Burquitlam Transit Village area, Austin Heights, and Maillardville.

Burnaby

Following a competitive Expression of Interest, the SFU Property Trust selected Corix Utilities to explore the feasibility of implementing a district energy system using an alternative energy supply to serve Phases 3 and 4 of its award-winning UniverCity development. Following a successful feasibility study, the SFU Property Trust negotiated an Infrastructure Agreement with Corix to enable the development of the system. In parallel, SFU has been planning with Corix a combined biomass-fired heating plant and gas peaking plant to serve the campus (currently supplied by a 40-year old gas-fired boiler plant) and UniverCity.

Surrey

The City of Surrey is pursuing several district energy opportunities in the City Centre area in northeast Surrey. The new City Hall will hosts a small district energy system providing heating and cooling to the adjacent new library, as well as a new office and residential tower. The main energy source for this system is a geoexchange field underneath City Hall. The project is owned and operated by the City.

Surrey has also explored opportunities for a large scale hot water district heating system to serve the wider City Centre area. A mandatory connection bylaw for the King George Boulevard area between 112 Ave and 94A Ave was passed in July 2012. New development within the core area near King George Boulevard will be required to connect to the City's district energy system. Proposed projects within this area that have already received a development permit will be exempt from the full connection requirement, but will be required to connect their domestic hot water and make-up air to the district energy system. Buildings within a peripheral area further from King George Boulevard will be required to be constructed with hydronic systems to make them district energy-ready to enable future system expansion. A portion of the energy will be supplied by renewable natural gas.

University of British Columbia

The University of British Columbia (UBC) owns and operates its own district energy system. The system currently serves about 100 buildings, including UBC Hospital. UBC is currently undergoing a five-year, $85-million project to replace the campus' aging steam distribution system with a new 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. This is currently one of the largest steam-to-hot water conversion projects of its kind in North America.

In parallel with the hot water conversion, UBC installed a new biomass-fuelled combined heat and power system in collaboration with Nexterra Systems Corp., GE Jenbacher, a gas engine company, and FPInnovations, a forest products research facility. The project has two operating modes. The first uses Nexterra gasification technology to convert waste wood into a clean synthesis gas, or "syngas" that will replace some of the natural gas currently used for campus heating. The second mode is a demonstration project using Nexterra's proprietary syngas conditioning technology with a high-efficiency GE Jenbacher gas engine to convert syngas into electrical power with recovery of waste heat for use in the campus heating system. In heating only model, the system can provide ~25% of UBC's annual heating requirements, eliminating up to 4,500 tonnes of GHG emissions (and associated gas and GHG offset costs). In cogeneration mode, the project will provide approximately 12% of UBC's current annual heat requirements and up to 4.5% of UBC's peak power demand. UBC has also constructed a new gas-fired peaking plant which replaced its previous steam plant.

Like Simon Fraser University, the UBC Property Trust is developing substantial new neighbourhoods adjacent to the Vancouver academic campus. UBC recently approved an amended Neighbourhood Plan for Wesbrook Place, UBC's latest family housing initiative that 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 townhouses and apartments. Other substantial development is planned for areas to the east of Campus, including the areas known as Acadia and East Campus along with Block F, which is controlled by the Musqueam Nation.

UBC completed a detailed feasibility study for the implementation of district energy in expansion neighbourhoods using waste heat captured from TRIUMF (Canada's national laboratory for particle and nuclear physic), potentially supplemented by bioenergy in future. The system would be integrated with UBC's internal district energy system, allowing UBC to use surplus waste heat in early years to meet GHG reduction commitments and avoid the costs of natural gas, carbon taxes and public sector offset requirements. The neighbourhood system would also allow UBC to develop larger sources of alternative energy to the south of Campus. UBC is currently considering options for partners to help develop, own and operate the neighbourhood distribution system and heat recovery system.

3 DISTRICT ENERGY VALUE PROPOSITION

The potential benefits of centralized systems must be weighed against the additional costs of centralization, primarily the added cost of distribution networks and energy transfer stations. The overall value proposition for district energy tends to be very site specific, depending upon a combination of many factors such as local climate, building codes, density, use mix, timing and rates of development (and availability of large anchor loads), the relative demands of heating and cooling, local energy sources (and in particular the availability of low-cost local fuels and/or waste heat), local energy prices (and taxes), availability and cost of land for central plants and distribution systems, and environmental drivers or constraints. While centralized facilities have potential technical and economic advantages, they may also be subject to different and more stringent regulatory requirements then a comparable quantity of smaller, distributed plants in the same area. Finally, local history and culture also play an important role in both the business case and ability/willingness to act on a favourable business case.

Historically, the main value proposition for district energy was economic. In the right conditions, central energy supply can achieve a lower lifecycle cost than on-site systems. The best evidence of the economic value proposition is the prevalence of district energy systems among educational, hospital, and military campuses. District energy systems are still the preferred method of heating and cooling most large institutional campuses. And campuses around the world continue to establish, maintain, renew, upgrade and expand district energy systems. These campuses often have densities comparable to urban areas with a mix of load types. However, they are planned and managed by a single administrator with a holistic and long-term view of their facilities and operations (small savings in space, capital, operations, and maintenance at individual facilities quickly become large savings at a campus scale), and with access to their own plant sites, rights of way, and energy resources.

In theory, many of the economic advantages to institutional owners apply to dense urban areas with mixed ownership of buildings and developments. However, there are added barriers, transaction costs and risks to capturing these benefits in an urban setting with mixed owners and public rights of way. 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 maintain and expand.

In many dense urban settings, institutional district energy systems now border dense urban areas with multiple building owners and public rights of way. Yet 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. However, 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. Synergies may be achieved by giving an expanded commercial mandate (and capital / incentives) 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 surrounding neighbourhood (a common approach among urban campuses in older cities), or through some form of partnership between the campus owner and city or private utility.

A final challenge facing district energy is the fact the business case is often a mix of private and public benefits. In some cases, private benefits may be sufficient to justify a district system. This is particularly true in institutional campuses with a single owner (low transaction costs) that has a comprehensive and long-term perspective on value. Many institutional owners also incorporate a broader public interest in their mandate, although they often also face financial and other constraints on their ability to pursue broader public benefits. In urban contexts with mixed building ownership, private benefits may be insufficient to overcome additional transaction costs and other barriers. Even in the case of private benefits (long-term lifecycle costs), there are often split incentives between developers and long-term building owners, and other factors may cause building owners to favour shorter time horizons (borrowing constraints, risk of recovering costs from future owners, etc.). And private owners have limited incentive to favour systems with broader public benefits where there is a smaller but real private cost to doing so. These broader public benefits may include energy security, local economic competitiveness and development, greenhouse gas emissions and other environmental or social benefits. Public ownership and/or strong public vision, coordination and policy support may be required to maximize the combined private and public benefits of 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, very rapid and certain development timelines and knowledgeable developers, and/or mandatory connection requirements or connection incentives); overall community leadership, coordination and vision; and clear / supportive policy framework are all critical to overcoming development barriers and achieving public benefits.

Typical Advantages of District Energy for Building Owners

- Ease of use and simplified building operations
- Avoided reserves for replacement of in-building heating and air conditioning equipment[8]
- Reduced ongoing labour, repair, maintenance and depreciation expenses for on-site energy systems[9]
- 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 and larger systems with multiple technologies or fuels that are not available with on-site systems (providing risk diversification and fuel arbitrage opportunities)

The following sections discuss in more detail some of the key value propositions for district energy. [10]

3.1 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., hook-ups, 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 integration) can result in overall space

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[8] 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 sometimes the case in the Lower Mainland of B.C. where electric resistance heating is often (through not universally) common. However, there is also some evidence that hydronic buildings can meet other building code requirements at lower cost than electrically-heated buildings.

[9] 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.

[10] Additional background on the value proposition for district energy can be found in reports such as Canadian Urban Institute. 2008. *The New District Energy: Building Blocks for Sustainable Community Development*; Canadian District Energy Association. 2010. *An Assessment of District Energy Opportunities.* A Report Prepared by Elenchus Research Associates Inc.; International District Energy Association. 2012. *Community Energy: Planning, Development and Delivery.*

savings compared to on-site systems. With economies of scale, owners can also invest in better equipment (e.g., longer-lived equipment and better emission controls).

3.2 Economies of integration

Heating and cooling loads experience substantial demand peaks. A large amount of capacity is required to meet these generally 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).

3.3 Economies of centralized professional management

The centralization of heating and cooling equipment allows for central administration and maintenance of systems.[11] Ongoing maintenance costs for on-site energy systems are often hidden in overall building maintenance budgets. 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, handling regulations, rising replacement costs, and capacity-loss issues. These issues are sometimes outsourced to professional building management companies that can pool multiple customers and establish clear maintenance policies and programs. However, many individual

[11] This may also be possible for distributed systems organized under a single utility ownership and operation model.

building owners (particularly in residential buildings) do not have a clear understanding of maintenance requirements or costs, and will often defer normal maintenance until a catastrophic event.

Centralized systems often tend to be better maintained (extending life and ensuring optimum efficiency). 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. 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.

A recent outbreak of legionnaires' disease in Quebec City provides a vivid illustration of the potential risks and challenges associated with distributed energy systems. The Quebec City outbreak is one of the largest and deadliest in Canadian history. As of late August 2012, the outbreak had claimed the lives of eight people and sickened more than 100. The deadly bacteria that cause legionnaires can grow in cooling systems, spreading in tiny droplets through air conditioning vents and out of the rooftop cooling towers. Authorities have identified up to 100 individual building cooling towers as the likely source of the outbreak. A 1997 report on legionnaires' disease outbreaks in the province recommended more stringent regulations for building ventilation maintenance and the government at the time promised to take steps to prevent outbreaks, including holding building owners legally responsible for maintaining their cooling systems. But the latest outbreak demonstrates the difficulties of ensuring professional maintenance of on-site energy systems and the potential risks they pose. Where economic, a centralized system is easier to maintain (one site rather than hundreds) and to regulate.

3.4 Long amortization, lower financing costs and risk sharing

With on-site systems, the building developer and ultimate purchaser must pay system 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 and price and equipment with a higher efficiency and 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.

In theory at least, 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. Capital constraints in organizations, however, may create some pressure for a more short-term perspective. Individual consumers and building owners tend to have even shorter time frames, greater sensitivity to upfront capital costs and higher costs of capital. A district utility model can overcome first cost barriers for sustainable technologies (the utility recovers higher capital costs over time through rates). The utility model also permits longer amortization of capital (commensurate with asset life) and the ability to access lower cost financing (compared to consumers). These advantages, however, can only be realized with patient capital (examples include infrastructure investment arms of large pension funds) and adequate load commitments (high risk of loads materializing or leaving the system will dissuade initial investment, shorten required amortization periods, and/or increase financing costs).

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.[12] 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.

3.5 Reliability and energy security

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

[12] 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.

system with cogeneration worked so well that during the 24-hour black out, it took patrons of a casino in Windsor, Ontario twelve hours to even realize there was a blackout.

Larger systems tend to use multiple fuels (e.g., gas, oil and biomass) providing additional security in the event one or more fuels become unavailable. Larger plants can absorb the cost of additional back-up systems (e.g., electrical back-up, on-site fuel storage, etc.). Large, professionally managed systems will typically have contingency plans in the event of major events – e.g., loss of electricity, loss of fuel supplies, or loss of water. These reliability benefits are particularly important in seismically prone areas such as Vancouver.

CHP, when combined with a micro grid, can provide electrical reliability in addition to thermal reliability. A multi-fuel plant may offer further benefits. For example, in the event of a loss of natural gas, oil storage can be used but only for a limited time. In the case of a biomass plant with gas-fired back-up and peaking, there is additional fuel storage and alternate delivery options for solid fuels in the event of an extended gas grid outage.

3.6 Opportunities to access different technologies and fuels

Centralization opens up the possibility to use resources and technologies not available or appropriate 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.

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.

3.7 Environmental benefits

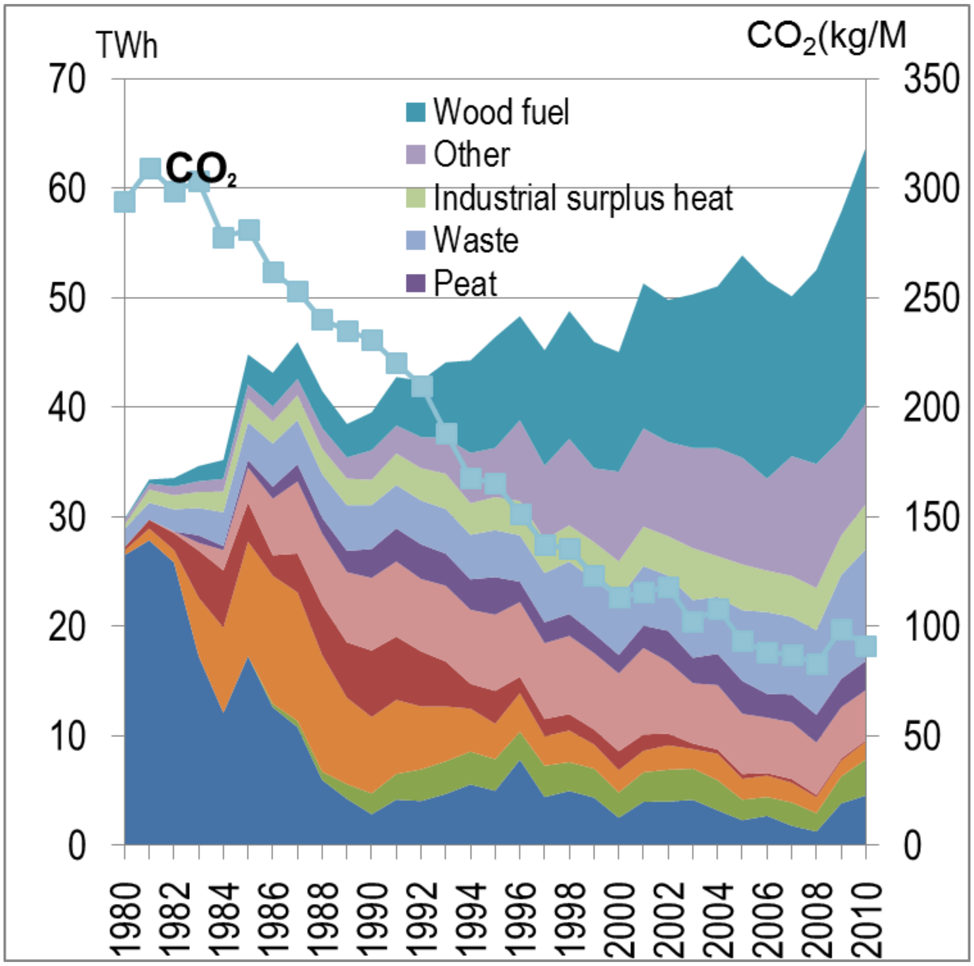
Environmental objectives and energy security are providing an added stimulus for the technologies and resources that are made possible with district energy. On September 12, 2011, the lead story in the Environment section of The Wall Street Journal discussed "How to Build a Greener City." District energy 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 these new technologies can be professionally managed and pooled across a larger number of consumers, compared to on-site building systems.

3.8 Long-term flexibility and adaptability

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 more than doubled so that more than 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 65%. 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 – 2010)



Source: Swedish District Heating Association

4 ALTERNATIVES TO DE

4.1 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 of Electricity. 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 8-10 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 use 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.

Code and LEED Requirements. Regardless of the above points, there is also some debate in Vancouver whether it is technically feasible or cost-effective to achieve LEED Gold (with the City's mandatory requirement for a minimum of six EAC1 points) in high-rise residential buildings with high window-to-wall ratios and electric resistance heating.

4.2 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.

Green buildings alone are insufficient. Well-designed new buildings typically consume less energy. And it is often easier to integrate renewables into new construction (although their use is still limited for the reasons noted above). There are many examples of so-called "deep" green buildings around the world. But these buildings often do little to improve the performance of surrounding development. And a focus on new buildings alone neglects the fact the turnover of the existing building stock is slow – 50-100 years or more. City planners must consider both the performance of new buildings and the opportunities to leverage new construction to create greener shared infrastructure that can improve the performance of a broader neighbourhood. In dense urban neighbourhoods, district energy systems are one of the least cost ways to serve historical buildings as they can provide lower-cost energy services with lower carbon content without the need for any substantial changes to the buildings' existing fabric or design. New construction can be a useful catalyst and anchor to establish systems. Once established they can be extended to existing development. Except in very unique situations, existing development is often not the best starting point for new systems. This is because cities have less direct influence over the connection of existing buildings, and the optimal timing and cost of connection is highly site specific, reflecting large differences in the age and type of on-site energy systems and other unique building characteristics.

Policies that favour on-site renewables may be better targeted to certain kinds of buildings and/or lower density areas. It is 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.

4.3 The costs of hydronic heating

One of the costs for developers is the requirement of constructing buildings with in-suite hydronic heating systems compatible with district energy. Depending on the technology used, in some cases these can be more expensive to install than conventional electric or furnace heating systems.

There is a large range of opinion in the industry regarding the incremental cost of installing hydronic heating, and this varies with building type. There is also considerable variation in the costs quoted by different developers for the same building type. This may reflect differences in scope, assumptions or experience. When comparing incremental cost estimates provided by developers, it is important to ensure equal comparisons. There are many types of hydronic systems that are compatible with district energy. Some developers may quote only the cost of premium hydronic systems such as in-floor radiant. While developers may certainly with to pursue such systems, it is important to note that these are not a requirement for compatibility with district energy. Hydronic baseboard systems are the most comparable to a base case system with electric baseboards.

A further challenge when comparing cost estimates is the scope of the estimate. In stand-alone hydronic systems, developers would typically install an on-site boiler plant. This is often included in the total cost of hydronic systems by developers. However, DE-ready buildings do not require a boiler plant. They simply require an internal hydronic distribution system and end use appliances. It is important to exclude the costs of on-site boilers and other energy sources when evaluating the incremental cost of DE-ready buildings.

There can also be issues with the normalization of costs. Some developers will report costs on a gross floor areas basis (including common areas), others will report costs on a net floor areas basis (suite areas only) or per suite. Each will lead to a different unit cost, even with comparable gross system costs. Cost estimates need to be normalized to a common unit for appropriate comparison (e.g., gross floor area).

The incremental cost of hydronic systems is only part of the story. There are also other incremental benefits that may fully or in part offset incremental costs. In particular, it may in fact be easier and less costly to achieve LEED Gold or higher with a hydronic building. An electric base case would require developers to achieve an efficiency level equivalent to an air source heat pump. If electric resistance heating is installed, this will require more significant building envelope improvements, which can prove very costly in buildings with a high window to wall ratio, as is typical in Vancouver. Further, to achieve the minimum number of energy points required for LEED Gold or higher, developers would typically need to install heat recovery on ventilation air.

Some developers have also suggested a small benefit in terms of consumer acceptance, which may translate into increased sales value. Developers may also choose to adjust other building features to accommodate part of the incremental cost of hydronic systems. Finally, the premium appears to decline with experience (as evidenced by the vast range in estimates from different developers). In some jurisdictions, builders are seeking synergies with other building systems (e.g., building fire safety systems) to reduce the cost of hydronic heating systems.

The following is a sample of recent estimates of the incremental costs of hydronic heating from around the Lower Mainland:

- In Northeast False Creek, a 2009 study by Compass, FVB, EnerSys, and Advicas Quantity Surveyors assessed the proposed building types for the area and their different HVAC systems for compatibility with district energy. These included multi-unit residential (high-rise), office, retail, grocery, hotel and casino. The study examined the incremental cost of hydronic upgrades for DE-ready buildings with no on-site energy production, and for buildings with and without cooling. It considered incremental capital costs and savings, as well as the lifecycle impacts including operations, maintenance and replacement. The study found the incremental capital cost of installing DE-ready hydronic radiators in high-rise, mixed-use residential buildings to be between $22 – $30/m2 ($2 - $2.8 /sf).

- In Surrey, a developer in Central City estimated incremental costs for hydronic heat of $2.5 – 3.15/sf (~0.8% of sales value).

- In Southeast False Creek, the City consulted a mechanical consultant to review the hydronic cost premium for buildings in the SEFC NEU Service Area. Based on their analysis the incremental cost premium to install hydronic baseboard heating is currently approximately $1,100 per suite ($1.10/sf). Basic assumptions for the analysis are a 150,000sqft concrete structure, with 150 suites using gas for makeup air and DHW, and electric resistance for space heat. For the hydronic costing, there is no central plant or ETS include (both are part of the DE system). This analysis assumes no impact of hydronic heating on other building requirements (e.g., contribution to LEED requirements).

- In Burnaby, the SFU Property Trust has estimated no incremental cost for hydronic baseboard and up to $1.25/sf for in-floor at UniverCity. This excludes the value of the additional parking spaces freed up by avoiding an on-site boiler.

The above cost estimates reflect upfront costs and exclude any incremental benefits in terms of other building requirements or marketing. There is also evidence there are savings to residents of DE-connected buildings in the form of ongoing operations and maintenance of on-site systems, even in buildings with in-suite electric heat. Furthermore, under the Province's new requirements for depreciation studies, it remains to be seen what impacts on-site energy systems will have on depreciation costs and strata reserve fund requirements.

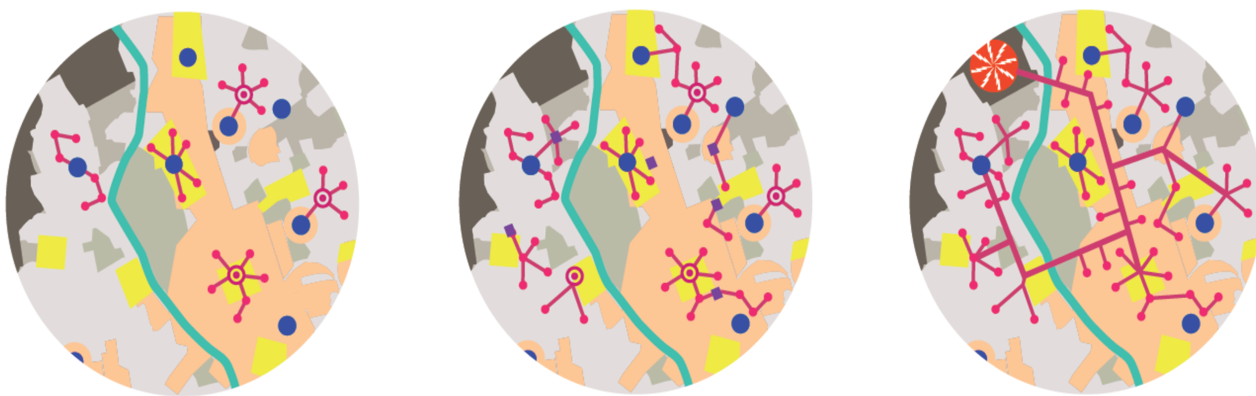
Richmond has recently allowed several proposed developments to choose between improvements in on-site energy systems or construction of DE-ready hydronic systems as a condition of rezoning and virtually all developers to date have chosen the latter. The SFU Property Trust has observed no obvious impact on land lease rates since introducing their hydronic requirements at UniverCity. They found no obvious change in lease values pre- and post-introduction, and UniverCity still sees among the highest land values in Burnaby. The hydronic requirement does come with credit towards green building requirements at UniverCity (which exceed normal standards) and helps developers meet requirements for a density bonus. At the same time, developers must also pay an upfront contribution to the Neighbourhood Utility System owned and operated by Corix, regardless of whether they actually connect.

5 THE EVOLUTION OF DISTRICT ENERGY NETWORKS

Establishing new district energy systems in existing cities requires long-term vision and planning. In existing urban areas, systems often start as disconnected nodal developments. This may take the form of a small plant serving a large anchor load (possibly also acting as the host for a small energy plant) or several smaller buildings. Or it could involve the interconnection of new or existing development to an existing institutional system. Over time, nodal networks may expand through additional developments, in-fill development or retrofits of existing buildings. As nodal networks expand, they may be interconnected, allowing the elimination of temporary or smaller plants and the eventual addition of larger plants (greater economies of scale) and transmission backbones. This type of evolution is illustrated graphically in Figure 4.

Growth may be organic and partially unpredictable, but the optimal evolution of networks still requires some foresight and planning. Near-term decisions at individual nodes (e.g., investment in a very long-lived technology) can create technology lock-in that limits optimal expansion and interconnection. A long-term view may favour a temporary or shorter-lived technology to capture greater long-term savings and larger environmental benefits. Nodal networks must be designed to similar standards to facilitate easy interconnection. Greater flexibility and larger savings may be possible with some preservation of strategic transmission corridors and sites for larger energy plants. Low-cost strategies may be used to preserve flexibility for future growth (e.g., pre-installing conduit for future infrastructure at critical road crossings or upsizing strategic lines). Ownership and franchising policies may impact the eventual integration of systems. Competition for loads in close proximity to multiple networks may provide incentives for innovation and efficiency, but can also introduce confusion for building developers and additional risks and uncertainties for district energy providers, ultimately hindering the overall expansion of systems.

Figure 4: The Typical Evolution of District Energy Networks in Existing Urban Areas



Development
Distribution pipeline
Heat source
Anchor heat loads

Heat loads
Transmission pipeline
Power station

1. Nodal networks develop around anchor loads, often linked to new development, served by a small heat source.

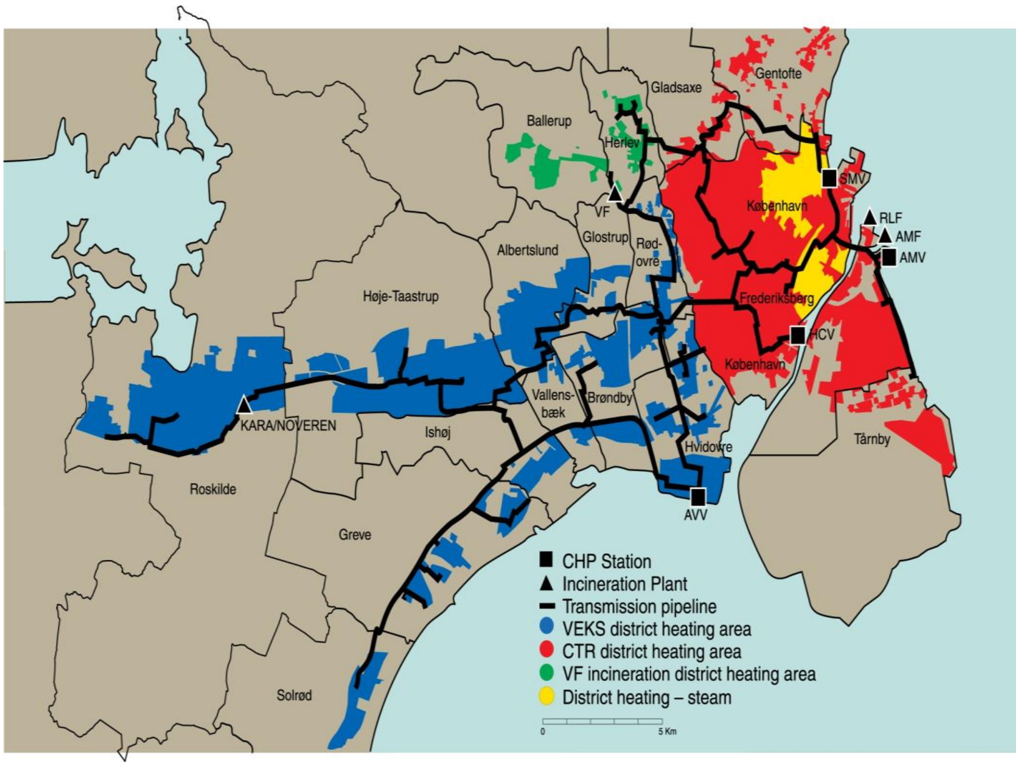
2. Networks expand and larger heat sources start to emerge to meet growing demand.

3. Networks begin to link to each other in order to share excess heat capacity. Original heat sources are replaced as they reach the end of their life, potentially with waste heat from a power station. A transition main will carry large volumes of heat over long distances.

Source: International District Energy Association. 2012. *Community Energy: Planning, Development and Delivery.*

Over time, district energy infrastructure can span an entire region. Figure 5 illustrates the district energy infrastructure in the Greater Copenhagen region of Denmark. Copenhagen has a similar climate to the Metro Vancouver region. As discussed in the historical section above, district energy serves a large portion of all buildings in Greater Copenhagen as a result of national policies and municipal plans and activities. At a regional scale, district energy exhibits similar patterns as gas and electric grids, with local distribution systems (and some distributed energy sources) and larger transmission networks interconnecting multiple distribution grids and larger central plants. In Copenhagen municipalities own many local distribution networks. Transmission infrastructure spanning individual networks has been developed to share energy and access larger supply sources. Transmission systems in many cases have evolved as partnerships (cooperatives) among municipal distribution companies. Larger supply sources (including two large waste to energy plants) have been developed either as partnerships among municipalities or by private investors that sell heat to the regional network.

Figure 5: Overview of Current District Energy Infrastructure in Greater Copenhagen



6 DE OWNERSHIP AND REGULATORY MODELS

6.1 DE 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. Furthermore, for smaller systems the owner/operators are typically 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.[13] 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 6 shows the continuum of possible ownership models for district energy, from 100% public ownership and governance (primarily municipal or regional utilities) to full private ownership and governance (possibly with regulatory oversight). The location of all case studies is summarized in **Error! Reference source not found.**.

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[13] 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)."*

Figure 6: District Energy Ownership Models with Examples

Ownership/ Governance		Examples
	Government Department	Southeast False Creek (Vancouver)
100% Public	Government Subsidiary	Lonsdale Energy Cooperation (North Van) Markham District Energy
	Public-Private Joint Venture (For Profit or Not for Profit)	Oslo (Hafslund)
	Split Assets	Windsor District Energy
Hybrids (Shared Ownership and/or Governance)	Concession	London Olympic Park, UK Richmond, BC
	Strategic Partnership	South Hampton, UK
	Cooperative*	Rochester District Heating Cooperative Town of Toblach, Italy
	Non-Profit (No Share Capital Corporation)	District Energy St. Paul
100% Private	Private For-Profit	UniverCity (SFU, Burnaby) UBC

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

Along the spectrum between 100% public and 100% private systems, there exist several hybrid ownership models worldwide. The following list is not meant to be exhaustive, however prominent examples include: Joint ventures, Split assets, Concessions, Strategic partnerships, Non Profits, and Cooperatives.

1. **Publicly Owned:** There are numerous examples of public ownership models for District Energy. Two local examples include 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 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.

2. **Joint Ventures**: involve pooled ownership of all assets. An example of this is Hafslund in Oslo, Norway.

3. **Split Asset:** model involves separate 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.

4. **Concessions**: This 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 recently begun a concession style arrangement for district energy with Corix.

5. **Strategic Partnership:** This model is a newer approach that does not involve any actual ownership of asset 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 Cofely, 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

RESHAPE STRATEGIES

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. 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.

6. **Non-profits: These** 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 more direct public 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 was jointly owned by the City of Toronto and OMERS until recently.

7. **Cooperatives:** The cooperative model is more complex than a non-profit model 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.[14] Government may be

[14] Producer cooperatives are distinct from consumer cooperatives. Austria in particular has a high prevalence of producer cooperatives. These include biomass supply co-operatives and district heating co-operatives. In a biomass supply cooperative, individual forest managers and small land owners band together to develop a central collection and processing facility (e.g., drying) for biomass fuel harvested by members. This approach pools investment costs and risks, while achieving economies of scale and diversification. These cooperatives supply biomass to many district energy systems in Austria. One step further is when biomass producers also invest in a heating plant and distribution network to produce and sell energy from their biomass feedstock (a full biomass district heating cooperative). This model emerged in Austria as a result of several factors. Biomass-based systems require aggregation of a local fuel supply from many small sources. There are large subsidies for biomass-based district heating systems in Austria (to promote energy security, environmental benefits and economic development). The majority of

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.

8. **Privately Owned:** There are many local examples of fully privately owned district energy utilities in the world. The British Columbia Utilities Commission, (BCUC) regulates private district energy companies in B.C. 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, and approach to customer rates and clear assignment of roles and responsibilities among the parties can result in 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 capital elsewhere and granted Corix Utilities the right to operate all campus utility services under a concession agreement. Through the agreement, Oklahoma University was able to extract capital sunk in its existing utilities (via an upfront concession payment to be recovered by Corix in utility rates) for investment in other activities.

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the systems in Austria are < 1MW in size. Smaller capital requirements couple with high subsidies are more conducive to producer or consumer co-operatives.

- 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) divested 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.

- Rochester District Heating began as a privately owned utility, which later became a customer-owned co-operative when it did not prove as profitable as expected as a private enterprise.

- 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.

- In the late 1990's, the city of Hamburg, Germany, spun out its electric distribution and district energy systems to Vattenfall (a Swedish energy company), which was granted a set-term concession. The concession was set to expire in 2014. In 2009, the city founded a new municipal utility, Hamburg Energie, as a subsidiary of the local waterworks. The purpose of this utility was to ensure environmentally friendly energy supply. At the same time, Hamburg indicated it would tender a new concession for the district heating network after the expiration of the existing concession agreement, requiring any new holder to invest more in renewable and alternative energy. Late last year, Vattenfall and the city reached a new agreement to operate the electricity distribution and district heating networks as partners. The city will acquire approximately 25.1 per cent of Vattenfall's electricity distribution and district heating networks for a total investment of about $450 million Euros. Vattenfall will retain the operational management of the networks. In exchange, the City will receive a guaranteed annual dividend of 4.2 per cent for the electricity distribution network and 4.5 per cent for the heat business. The agreement includes provisions to develop new alternative energy concepts within the city, including a new high efficiency combined cycle plant with state-of-the-art storage technology, as well as smart grid infrastructure. The total investment in more renewable and alternative energy is expected to exceed EUR 1.5 billion over the next five years.

The EPCOR Model of Subsidiary Governance

For municipally owned systems, a common question is whether to form a wholly-owned subsidiary. When setting up the SEFC NEU, the City of Vancouver concluded the costs outweighed the benefits, at least for a small utility. Specifically, the City concluded that a subsidiary model would do little to limit effective liability of the City's taxpayers. The City also concluded that the debt, assets and revenues of a wholly owned subsidiary would need to be included in the City's consolidated statements and would be considered in the overall evaluation of the City by credit rating agencies.

The main benefit of a wholly-owned subsidiary is likely increased flexibility (speed of decisions) and clear separation of the City-wide policy role and core functions from the day to day activities and needs of a more commercial operation serving a portion of the City. The latter offers greater transparency and accountability. However, these benefits must be weighed against set up costs and ongoing administrative costs.

EPCOR is often used as a model of subsidiary governance for cities. 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. An independent Board of Directors governs EPCOR 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 Public Private Partnerships (P3), with communities, where it leads 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.

6.1 The 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 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.[15] 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.

District energy has many characteristics of other 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

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[15] 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.

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 for distribution systems (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).[16] 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.[17] Municipally owned systems operating in their boundaries are not regulated by the BCUC.[18] However, municipally owned systems may still submit to regulation by the

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[16] 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).

[17] 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.

[18] 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

BCUC. The Minister of Energy may at their discretion exempt, by regulation, any other entity or project that does not have an automatic exemption under the Act.[19]

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
- 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.

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:

- Cost to build, operate and maintain the utility's facilities (as outlined in the original CPCN and including any additions to assets over time)
- Cost to finance debt incurred from building these facilities

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ownership model but has suggested it may depend in part upon the terms of the arrangement and the degree of municipal control.

[19] For additional background on the regulation of district energy in B.C. see: The Pacific Institute for Climate Solutions. May 2012. *The Regulation of District Energy Systems*.

- Depreciation and amortization expenses
- Costs of financing debt generally
- 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.

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.