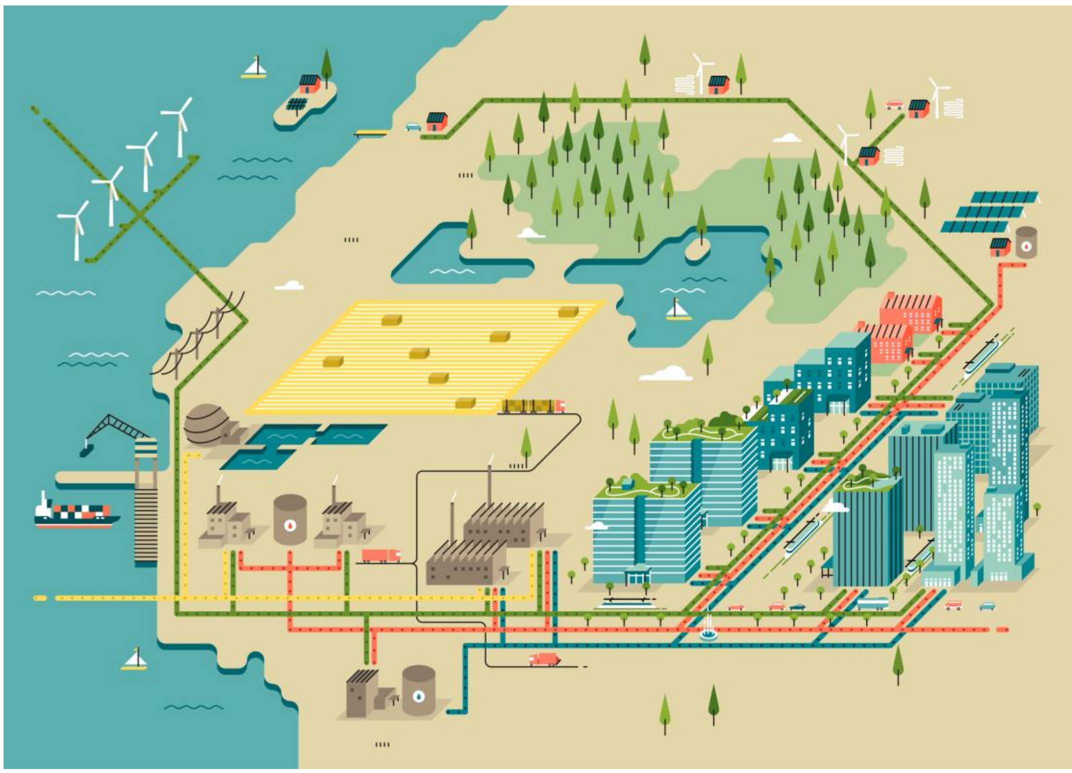
CITY OF CAMBRIDGE

LOW CARBON ENERGY SUPPLY STRATEGY



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DESCRIPTION
The City of Cambridge engaged a consultant team led by Ramboll to undertake a Low Carbon Energy Supply Strategy study in support of the City's commitment to reach carbon neutrality by 2050. The purpose of the study was to determine current and future energy demand, assess the potential for renewable energy generation in Cambridge, develop technical scenarios for renewable energy delivery systems, and evaluate the risks, benefits, and feasibility of each scenario along with discussion of potential implementation pathways.

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EXECUTIVE SUMMARY

In late 2016 the City of Cambridge engaged a consultant team led by Ramboll, a Danish consulting firm with significant international experience in renewable energy master planning, to undertake a Low Carbon Energy Supply Strategy study ("the study") in support of the City's commitment to reach carbon neutrality by 2050. The purpose of the study was to determine current and future energy demand, assess the potential for renewable energy generation in Cambridge, develop technical scenarios for renewable energy delivery systems, and evaluate the risks, benefits, and feasibility of each scenario along with discussion of potential implementation pathways. The 12-month study process was supported by a stakeholder advisory committee representing city departments, utilities, developers, property managers, universities, state agencies, and adjacent cities.

KEY BACKGROUND INFORMATION

In June 2015, a Net Zero Action Plan for buildings was adopted by the Cambridge City Council.[1] The action plan contains the following 5 focus areas to be addressed over the next 25 years in order to meet the objective of reducing greenhouse gas emissions by 70% by 2040 and set Cambridge on the pathway to carbon neutrality by mid-century:

1. Energy Efficiency in Existing Buildings
2. Net Zero New Construction
3. Energy Supply
   - **3.1 Low Carbon Energy Supply Strategy**
   - 3.2 Rooftop Solar Ready Requirement
   - 3.3 Memorandum of Understanding with Local Utilities
4. Local Carbon Fund
5. Engagement & Capacity Building

OBJECTIVE

The objective of this study is to provide a better understanding of the potential for and barriers to a transition to renewable energy and low carbon energy solutions in Cambridge considering the following framing questions:

- **Key Question 1:** What is the current and future energy demand from buildings?
- **Key Question 2:** What local and regional low carbon energy sources could be utilized in Cambridge to change its energy supply?
- **Key Question 3:** Which low carbon energy sources and scenarios are technically viable and meet Cambridge's financial, environmental and social objectives?
- **Key Question 4:** How can the goal for clean energy generation be advanced over the next 25 years in order to achieve the options outlined herein and the City's carbon neutral objective?

For the purposes of the study, the City adopted a set of goals, closely modeled after goals developed by the Carbon Neutral Cities Alliance[2], for a future energy supply system. The energy supply system should be:

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[1] See the full Net Zero Action Plan at http://www.cambridgema.gov/CDD/Projects/Climate/NetZeroTaskForce

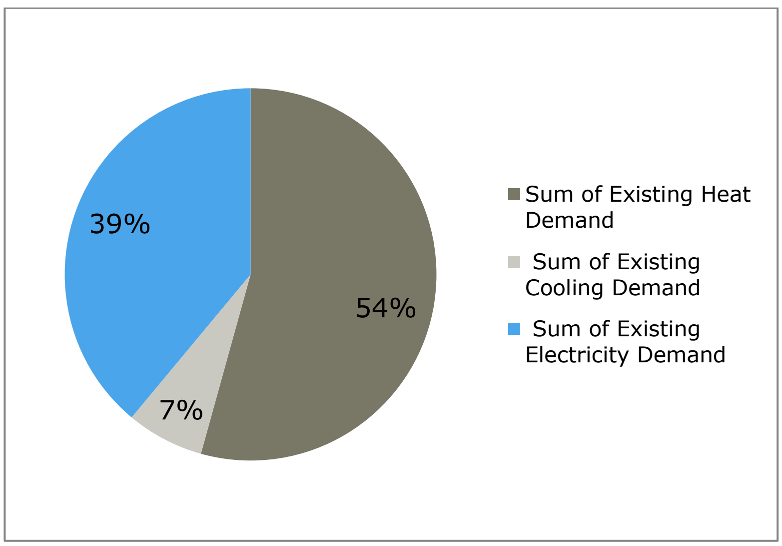
[2] From the Carbon Neutral Cities Alliance *Framework for Long-Term Deep Carbon Reduction Planning*, p. 60, available at http://usdn.org/uploads/cms/documents/cnca-framework-12-16-15.pdf

- **Clean**: Reduce carbon emissions and toxic pollutants created by the system.
- **Reliable**: Minimize system downtime from outages and ensure high quality of power delivered.
- **Affordable**: Keep rates as low as possible and maintain competitiveness.
- **Predictable**: Minimize rate volatility.
- **Transparent**: Consumers can understand their power costs and what drives changes in costs.
- **Local Control**: Give residents greater control over their energy resources and energy choices.
- **Wealth Creating**: Keep more energy revenue in the local economy instead of exporting it to outside suppliers to help drive local economic development, create new businesses and jobs.
- **Innovative:** The system spawns innovation, intellectual property creation, and entrepreneurship.
- **Just:** The system promotes "energy equity," protecting vulnerable populations from undue hardship, and promotes energy literacy.

APPROACH

The largest energy demand in the City to be supplied by low carbon energy today and in the future is the thermal demand to heat and cool Cambridge's buildings. Addressing this will derive the biggest impact when converting the energy supply to a low carbon energy supply system with a subsequent reduction in fossil fuel consumption.

Figure 1 Existing Energy Demand Split in Cambridge by use type



Over the next 20 years, it is expected that the total building energy demand will reduce by 35%, with a 59% decrease in heat energy consumption and a 28% decrease in electrical energy consumption resulting from improvements in building and equipment energy efficiency as well as reduced heating demand due to climate change. Increased summer temperatures, however, will lead to a 115% increase in cooling energy consumption.

To satisfy this energy demand, a total of 10 energy supply scenarios were developed, 3 of which were shortlisted and brought forward for assessment in this report in comparison with a Business as Usual case:

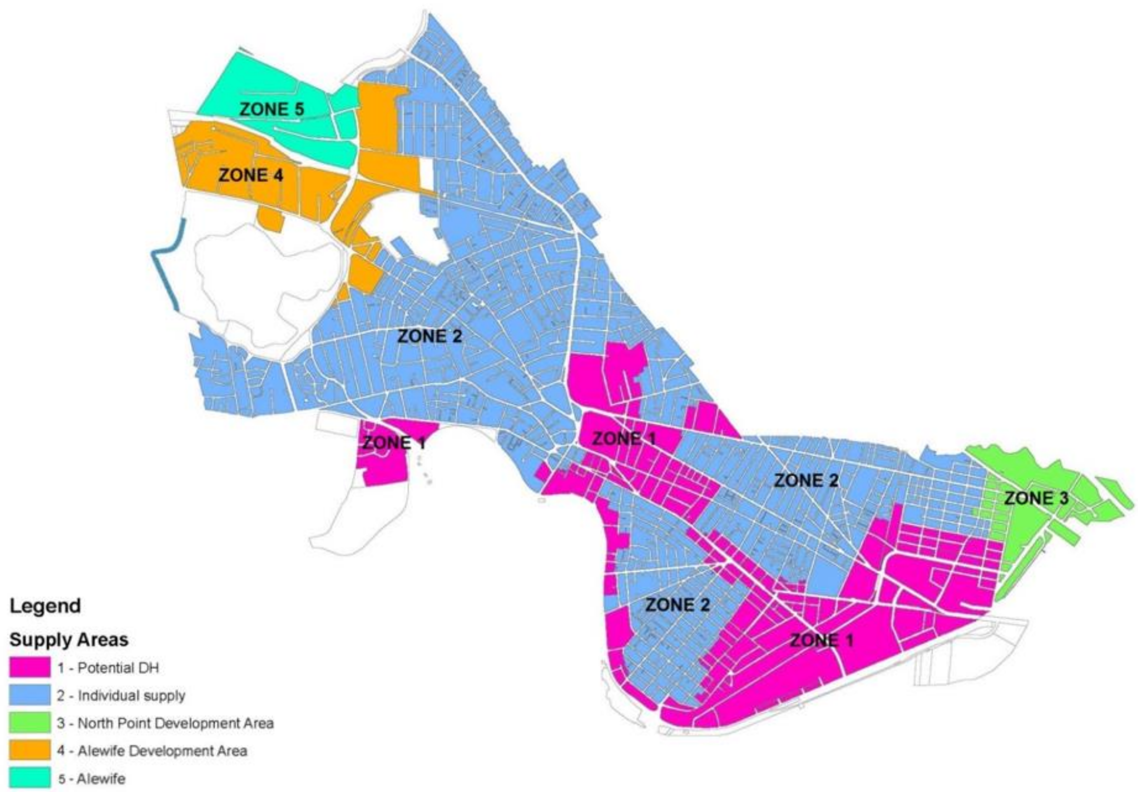
- Scenario 1: Individual building electrification
- Scenario 2: Individual building electrification with district heating/cooling where viable

- Scenario 3[3]: District heating and cooling with multiple supply technologies

For the purposes of the assessment, the city was split into zones based on thermal energy demand intensity:

- Zone 1 – Potential District Heating (high demand)
- Zone 2 – Individual Supply Area (mainly residential)
- Zone 3 – North Point Development Area (growing demand)
- Zone 4/5 –Alewife Development Area (growing demand)

Figure 2 Energy Zones Based on Energy Demand Intensity



The conclusions in the report are different for each scenario and zone.

For the **Business as Usual** (BAU) scenario it is assumed that the existing technologies for heating and cooling production are continued throughout the planning period from 2020 to 2040. Necessary reinvestments in the technologies are included. Heat pumps and gas boilers are assumed as the technologies of choice for new buildings in the development zones.

For **Scenario 1** it is assumed that heating technologies in all buildings are to be converted to 100% electric technologies such as heat pumps and electric boilers for heat production. A heat pump extracts energy (low temperature) from one source (typically air, ground or water) and supplies the energy to another source (higher temperature) or vice versa for cooling. Heat pumps can operate at a higher rate of efficiency than electric boilers, and so deliver more heat per unit of electrical energy consumed. Solar thermal (producing hot water utilizing the energy of the sun) is also a potential technology but it is assumed that in the future roof tops are already used for solar photovoltaic (PV) electricity production

[3] Scenario 4 in the main report has been changed to Scenario 3 in the Executive Summary for ease of reading.

and the available space for additional energy equipment is limited. Production of chilled water for cooling is assumed to continue to be based on electrical chillers as it is today.

Implementation of Scenario 1 will require the electrical transmission and distribution system to handle a significant capacity increase due to all thermal energy supply being delivered via the electrical grid versus the use of natural gas and other fuels today. It will be necessary to reinforce the entire electrical infrastructure in the city with a focus on Zone 1 and the main high voltage lines supplying the city.

Scenario 2 is very similar to Scenario 1 but with the addition of district energy infrastructure where viable. A district energy system consists of central energy production to create hot water or chilled water, a water pipe network distribution system, and a heat exchanger station (also called "Energy Transfer Station" or ETS) located at the consumer end. The network supplies the energy produced centrally to each consumer. Furthermore, there is often large thermal energy storage capacity connected to the network to enable independent production of electricity and heat, if the production technology is based on combined heat and power cogeneration. Such networks are often citywide and can supply several thousand consumers with hot or chilled water, but can also be developed at the district scale.

In order to demonstrate the technical potential of an efficient heat source in the vicinity of Cambridge, Scenario 2 assumes that heat for Zone 1 is produced by large-scale electrical heat pumps driven by energy extracted from the Mystic River at the approximate location of the existing Mystic River power plant. Extracting heat from the Mystic River is an economically and technically viable option, with the potential to supply 40% of the annual thermal demand of Zone 1, with the remainder coming from electric boilers. The heat pump will produce approximately 3 units of heat using 1 unit of electricity and two units of energy from the river. As a result, the increase in electricity consumption over BAU will be lower compared to the electric boilers necessary for Scenario 1.

In **Scenario 3**[4] numerous energy sources were investigated and assessed as potential alternative supply options for Cambridge, with the following being determined to be unviable sources of energy supply due to lack of sufficient production capacity or other barriers:

- Deep geothermal energy (>0.6 miles depth)
- Waste heat from sewers
- Waste heat from the MBTA tunnel system
- Heating / cooling from the Charles River
- Open system Aquifer Thermal Energy Storage
- Heat recovery from electricity substations
- Industrial waste heat recovery

The potential for a waste to energy plant to be sited in Cambridge was also investigated but rejected. Waste to energy plants combust municipal solid waste (MSW) as a fuel source to produce heat and electricity (it is possible to attain 95%+ efficiency at the Lower Heating Value). In addition to the issues with siting such a plant in the city, the waste streams generated in the city would meet only a very small percentage of the total future energy demand of the city, requiring the city to be a waste importer to use such a technology to meet its energy demand. Anaerobic digestion was discounted for the same reasons.

Due to the city's size, built out nature, close proximity to other cities and limited access to alternative energy sources there is limited potential for energy generation within the city's boundaries. Full roll out

[4] Note that this is referred to Scenario 4 in the body of the report because it was the fourth of the six scenarios considered initially before three scenarios were advanced for final analysis.

of photovoltaic and solar thermal technologies in available space within the City was modeled against demand, and this would not be able to supply a significant portion of citywide energy demand.

As a result, some options outside the city boundaries were also investigated. Siting a biomass combined heat and power (CHP) facility at the Mystic River power plant site was assessed and determined to be an economically and technically viable option with the delivery of biomass via ship along the Mystic River. Such a plant would produce heat and electricity using biomass as a fuel source.

Today in Massachusetts, biomass CHP plants with efficiency in excess of 60% receive a Renewable Energy Certificate (REC) for every MW produced which has monetary value, but the REC system is determined by state policy and is subject to change over time. In addition, there are outstanding questions to be resolved with regard to biomass in Massachusetts and whether it is truly carbon neutral since burning biomass does produce GHG emissions that may or may not be fully balanced by the GHGs absorbed by the growing of biomass, as well as where a sustainable feed stock would come from due to the limited supply chain currently in existence in Massachusetts.

STUDY RESULTS

Summary of Conclusions

Decarbonization of the energy supply for Cambridge buildings will require a combination of approaches over time. There are limited energy supply resources within Cambridge, yet a Business as Usual pathway locks in fossil fuel infrastructure in buildings and the supply chain in a way that precludes meeting the commitment of carbon neutrality by 2050. Electrification of buildings with grid-supplied electricity is likely to play a central role, but can't achieve acceptable levels of cost and environmental efficiency without introduction of district energy systems in areas of high energy demand and depends on decarbonization of the regional grid. District energy offers increased system efficiency, resilience and flexibility of energy sources, including biomass, which requires further consideration. Achievement of a future low carbon energy supply for Cambridge must be considered in the context of a regional clean energy transformation. Such consideration should occur through a regional stakeholder group which can identify and address key questions and barriers in a coordinated manner.

The results of the study show that Scenario 3 with hot water district heating combined with thermal energy storage and supplied by combined heat and power plants using low carbon fuel sources, such as biomass, has both the lowest cost as well as the lowest equivalent carbon emissions compared to alternative supply scenarios developed under this study if biomass can be determined to be carbon neutral. Additionally, this scenario has the potential to meet all of the City's goals for its future energy supply. Water based district energy also facilitates the following benefits:

- The use of both heat and power from CHP plants, thus providing highly efficient energy generation and making the most of primary energy used
- Thermal storage integrated into the energy system improves generation efficiency and resilience
- District energy networks and thermal storage can be used to store excess renewable electrical energy, increasing the electrical grid stability as a result and maximizing use of variable renewable energy sources
- Lower operation and maintenance costs than traditional steam networks
- Lower installed generation capacity is necessary as heat (or chilled water) is not needed at the same time leading to reduced capital investment

- Opens the potential utilization of low temperature waste heat sources such as those from industry, waste water treatment plants, data centers, rivers, geothermal etc.

District cooling is viable in clusters for all city zones except the residential Zone 2. District cooling will improve the efficiency of the cooling supply, reduce the load on the electrical supply and subsequently improve resilience where installed.

Electrification of the whole city is shown to be the costliest alternative scenario with the highest GHG emissions based on electrical grid carbon intensity forecasts for Massachusetts which incorporate future Renewable Energy System (RES) generation forecasts that do not achieve carbon neutrality during the study period. However, due to the lower thermal energy demand of the residential Zone 2, electrification should be pursued in this zone under all scenarios by promoting the use and understanding of the following technologies: air source heat pumps; ground source heat pumps; electric boilers; chillers; air conditioning units; solar photovoltaic and solar thermal.

Outlined in Table 1 below are the economic assessment of the scenarios as discussed above.

Table 1 Final economic results of all scenarios (Net Present Value; M$)

Financial results	BaU	Scenario 1	Scenario 2	Scenario 3
Fuel costs	4,111	5,637	4,618	3,531
Variable operation & maintenance	72	74	86	91
Fixed operation & maintenance	112	67	56	171
Capital expenditures (CAPEX)	600	2,942	1,689	1,386
Total	**4,896**	**8,721**	**6,449**	**5,180**
Additional cost compared to business-as-usual	---	+3,825	+1,553	+284

Outlined in Table 2 below are emissions per scenario together with the cost of offsetting the carbon emissions by buying carbon credits in 2040.

Table 2 Emissions per scenario in 2040

Emissions results[5]	BaU	Scenario 1	Scenario 2	Scenario 3
CO_2 equivalent (kton)	387	162	136	63
SO_2 emissions (ton)	27	1	1	38
NO_X emissions (ton)	286	112	92	193
$PM_{2.5}$ emissions (kg)	1,126	211	165	5,456[6]
Cost of off-setting carbon emissions with a carbon price of 50 $/ton (M$)	19.35	8.1	6.9	3.2

[5] CO_2: carbon dioxide; SO_2: sulfur dioxide; NO_x: nitrous oxides; $PM_{2.5}$: particulate matter

[6] It should be noted that PM2.5 is reported in kilograms here and not tonnes. The emissions level indicated for Scenario 3 is based on Best Available Technology standards for emission control in the Industry Emissions Directive in Europe http://ec.europa.eu/environment/industry/stationary/ied/legislation.htm. This emissions level can be further reduced, but the costs increase significantly to do this and this level of emissions is deemed acceptable across Europe for emissions from industrial plants. To give further context to this, the current permit for the Kendall Square plant shows a limit of 86.3 TPY (tonnes per year) or 86,300 kg/year total PM emissions (PM10+PM2.5) based on their permit MBR-00-COM- 029: https://www.mass.gov/files/documents/2016/08/ta/op-kendallgreen.pdf

KEY CONSIDERATIONS FOLLOWING THE STUDY

- The thermal heating and cooling demand of Cambridge today and in 2040 exceeds the electrical demand of the City (excluding any increases in demand due to electrification of vehicles).
- Continuing with the current energy supply approach locks in fossil fuel infrastructure in buildings and the current supply chain in a way that precludes meeting the commitment of carbon neutrality by 2050.
- Fuel costs constitute a significant proportion of the total net present value over the next 20 years for each scenario, ranging from 84% for the Business as Usual case to 68% for Scenario 3. This emphasizes the impact of utilizing primary energy efficiently to generate and distribute thermal energy and power to consumers, as well as understanding the certainty of fuel costs under each scenario.
- Decarbonization of the electrical grid is necessary to achieve emission reduction goals for Scenarios 1 & 2, the continued use of electricity for cooling, and the electrification of low density areas such as Zone 2. Yet the carbon intensity of grid electricity is very dependent on the regional grid and electricity market stakeholders: Eversource, NEPOOL, ISO-NE, etc. Current plans for the grid do not achieve a low carbon supply by 2040. However, shifts in policy could change this condition.
- Full roll out of photovoltaic and solar thermal technologies in available space within the City should be pursued where possible, but will not make a significant effect on the renewable energy supply of the City.
- Low carbon energy sources within City limits are limited.
- Electrical grid upgrades should be planned and implemented to facilitate building electrification where required and the bearer of these costs needs to be considered in relation to who benefits from the changes.
- Biomass is proposed in Scenario 3 as the cogeneration low carbon fuel supply. Today this is the best low carbon fuel supply for on-demand generation and is more sustainable than fossil fuel alternatives. This is currently supported by the state policy-driven Renewable Portfolio Standard scheme which provides RECs for biomass energy generation, provided it meets certain energy generation criteria. However, the true carbon neutrality of biomass is still subject to significant debate and Cambridge will need to determine its position before pursuing this course. As with all fuel supply for energy projects, the logistics and market supply of biomass will also need to be considered further for each specific project proposed.
- Due to the limited renewable energy generating potential in the city and the fact that the electrical grid is expected to still have a moderate to high carbon intensity by 2040, there may be a need for the City to utilize a suitable carbon offsetting mechanism to meet its Net Zero objective. Options for this include establishing a renewable electricity project outside the City boundaries, Power Purchase Agreements (PPAs) or Community Choice Aggregation (CCA) expanded beyond the current program.
- Cambridge is a small city situated within numerous cities in the greater Boston Metropolitan Area. Due to the built-out nature of the cities and the limited alternative resources available to each, it is important that a regional approach be pursued to identify and address the key outstanding questions and barriers to achieving a low carbon energy supply. Such a regional approach could incorporate the involvement of the following stakeholders:
    - Neighboring communities
    - MAPC

- State agencies, such as DOER, MassCEC, MassDEP, DPU
- Relevant utilities
- Potential district energy network participants (customers, operators, etc.)

OUTSTANDING QUESTIONS FOLLOWING THE STUDY

Technical Basis for a Low Carbon Energy Supply

This study has investigated, assessed and modeled numerous energy supply scenarios involving multiple technologies for Cambridge in order to determine the best path forward towards the carbon neutral target for its energy supply.

The study provides a menu of solutions and pathways for to how to proceed, which can be used as a template regionally to build regional solutions for achieving a low carbon energy supply.

The following sets of questions can help Cambridge advance the key conclusions of the study.

How does Cambridge transition to all-electric buildings?

Heat pumps will likely play a key role in decarbonizing the heat supply of the residential Zone 2 and in other city zones where district energy connection is not viable. Under the state Alternative Energy Portfolio Standard (APS) scheme, financial incentives are provided for installation of ground and air source heat pumps.

If such technologies are to be further incentivized, it should be structured in such a way to encourage ground source heat pump installation over air source heat pumps when the option is available as done by the current APS. Ground source heat pumps are more efficient than air-source heat pumps, as the ground provides a more consistent heat source, so require less electricity capacity to power them. However, ground source heat pumps and the associated installation have a higher capital cost and so may not be invested in by consumers, even when they have the space to install them.

Some additional questions to be considered with regard to all-electric buildings include:

- How to match the regional grid capacity and grid modernization process with Cambridge thermal demand needs?
- How to utilize the existing city outreach and support network to make consumers aware of electrification technology and incentives?
- All customer uses and need for resilience should be considered when progressing; who bears responsibility for building and grid-level capacity, resilience, and necessary upgrades?
- How best to incentivize and motivate building owners to make such a change to electrification?

How does Cambridge establish hot water district heating and cooling networks in the high-density areas of the city?

Establishing district heating and cooling infrastructure, business, and institutional arrangements would require considering many elements as outlined below.

<u>Technical Considerations</u>

- What is the existing heating technology in place in the building, the cost of changing to water-based systems, and the benefits of district heating connections?
- Where will the long term energy supply source and location for the greater heating network be?

- How can district energy be used by the City to meet energy storage goals? How can thermal energy storage and greater use of district energy be used regionally to facilitate integration of intermittent generation sources while improving resilience?

Economic Considerations

- Which consumer types will connect to district energy in the high density area?
- Which buildings have sufficient energy demand to make connection viable, and who will finance the cost of their conversions to utilize the network?
- What buildings can fulfill the role of anchor consumers to establish initial networks from which to expand?
- What is the best business model for district heating and cooling implementation?

Regulatory Considerations

- Existing large heat generation sources in the city are likely to have over-capacity available for supply at certain times which could be used to contribute to a district energy system. What technical and regulatory approaches can enable the use of this capacity?
- Hot water district energy and tariff regulation need to be established at the state level to facilitate the purchase and sale of heat between multiple parties and will require state agency engagement.

Where will clean energy come from to meet Cambridge's energy demand?

In addition to methods of energy transmission such as the electrical grid and district energy networks, additional low carbon energy needs to be generated in order to be supplied. The following questions should be considered in this context.

Technical Considerations

- What is the technical and political viability of biomass as a low-carbon fuel source in Cambridge?
- How to maximize local renewable energy generation, e.g. solar PV?
- How can large generation plants be sited to supply Cambridge in context of the greater Boston region?

Policy Considerations

- How best to enable state and utility action to modernize the grid and develop renewable energy to meet low carbon requirements?
- How to drive the development of more grid-scale renewable energy using tools such as the Renewable Portfolio Standard and joint renewable energy procurement?
- Does carbon offsetting meet the requirements of the Net Zero target?
- Do Power Purchase Agreements (PPAs) or Community Choice Aggregation (CCA) providing Renewable Energy Certificates (RECs) from outside of the Regional Greenhouse Gas Initiative (RGGI) states meet the requirements of the Net Zero target?

Regulatory Considerations

- What potential is there for regional agreement on how and where additional clean energy could be generated in order to meet the regional low carbon intensity electrical demand which ISO-NE cannot provide?
- How to manage the transition away from fossil fuel and its infrastructure such as the natural gas networks?

Economic considerations

- Who will drive the process of and pay for grid modernization?
- How to finance the construction cost of clean energy facilities in Cambridge and the region?

Next Steps for Cambridge

Collaborative Stakeholder Driven Approach Required

Ramboll has undertaken a change management assessment in parallel with the technical feasibility stage for this project. This process has identified the steps that could be followed in Cambridge in order to achieve the decarbonization of the city's energy supply.

Achieving a low carbon energy supply will be a significant challenge with complex parts to be addressed, many of which are not under the City's direct control, but require decisions and actions by utilities and state agencies and are best undertaken at a regional scale across municipal boundaries. In order to make progress towards identifying a common strategy for achieving a carbon neutral energy supply, a stakeholder group should be identified to drive this agenda and continue to push for the changes needed to make progress on a timeline that will lead to carbon neutrality by 2050. This group could include the members of the study Advisory Committee who represented local academic institutions, utilities, businesses, state agencies, and City Departments. Additional state and regional entities such as the Department of Public Utilities and ISO-New England should also be included. An organization and leadership structure will need to be established for this group, with potential coordination by the Metropolitan Regional Planning Council (MAPC). Initial questions for the group to address include:

- What are current state energy-related planning processes and what allowances do they make for municipal collaboration?
- What form would regional project organization for implementation take and who would lead such efforts regionally?
- What are the enabling factors for regional approaches to challenges raised above?

Based on the study conclusions, action on the following areas should be prioritized for implementation of a low carbon energy supply strategy in Cambridge:

Residential Electrification

A common aspect of the study's findings is that electrification of the energy supply in low density residential areas of the city should be pursued under all scenarios. This includes the installation of solar PV and the transition to electric heating systems such as air and ground-source heat pumps. The Cambridge Energy Alliance can be an effective proponent of these measures through programs such as Sunny Cambridge[7] and a new platform to connect consumers to vendors of renewable thermal systems.

Existing Infrastructure Strengthening

Electrification would include the heating, cooling and cooking aspects of energy demand in low-density residential area and replacement of related equipment. A key step to facilitate electrification is increased investment in grid strengthening and modernization in partnership with Eversource. This will build on their Grid Modernization and Planning (GMP) program to ensure that the increased electricity needs identified in this report can be met.

[7] http://www.sunnycambridge.org

Electrification of these residential areas would also require changes to the building stock to accommodate an electric heat source. This effort should be integrated with the implementation of the Cambridge Net Zero Action Plan.

Enabling District Energy

Densely populated areas of the city with high thermal energy demand should work towards the development of water-based district heating and cooling networks. As described in detail in Section 6 of the report, eight steps have been drawn from the United Nations Environment Programme report on District Energy in Cities:[8]

Step 1: Assess existing energy and climate policy objectives, strategies and targets, and identify catalysts

The City has set a 2050 target for reaching carbon neutrality. A technical analysis has been undertaken, demonstrating the viability of district energy in current or emerging high-energy demand districts.

Step 2: Map local energy demand and evaluate local energy resources

This step has been completed but will need to be regularly updated and expanded upon (see Step 5).

Step 3: Strengthen or develop the institutional multi-stakeholder co-ordination framework

The Advisory Committee assembled under this study has provided significant input and opinion to develop this study. For the realization of a district energy utility, there would be a need for multiple stakeholders to be assembled to work within a coordinated framework.

Step 4: Determine relevant regulatory and policy design considerations and integrate district energy standards into state and/or local energy strategy and planning

Water based district energy is not an established utility in the City today and no regulatory framework exists at the state level, although the benefits and economic viability exist to support its establishment. In order to catalyze its establishment as a utility there will be a need for well-considered state and local policy and regulatory design to encourage its establishment.

It is recommended that district energy with relevant modern standards be incorporated into state plans and regulations through agencies such as the Department of Public Utilities and citywide planning recommendations and that, once hot water district energy is enabled at the state level, any necessary changes be made to the municipal zoning ordinance to enable and encourage its adoption in the zones highlighted within this report.

Step 5: Carry out project feasibility and viability

The feasibility assessment of district projects should include further evaluation of district energy boundaries and participants and an economic viability model that considers: available incentives at the time of development to support the utility's installation; how gas consumers could be switched over; and the approach to transitioning institutions and infrastructure away from the use of natural gas.

[8] http://staging.unep.org/energy/portals/50177/Documents/DistrictEnergyReportBook.pdf

Step 6: Develop business plan and financing approach

A project business plan serves as a blueprint to guide and supervise the project's objectives, policies and strategies. A business model which is replicable and scalable both technically and financially at the district level will be key to the acceleration of district energy in the City.
Some business model options include:

- The "wholly public" business model
- The "hybrid public and private" business models
- The "wholly private" business models

Financing will depend on the business plan developed and the model for implementation. With all investment, the lower the risk and the higher the return, the more attractive the investment becomes. For district energy projects, capital is typically invested prior to the connection of customer buildings; thus, the greatest risk in system deployment is load uncertainty.

Step 7: Analyze procurement options

In cases where a municipality plans to maintain ultimate ownership of the utility, whether through a concession contract or some form of Public Private Partnership (P3), the preferred method of Utility Operator procurement should be assessed once a project has been defined and the business model and plan are established.

Step 8: Set measurable, reportable and verifiable project indicators

Milestones can be set by working backwards from the carbon neutral target year of 2050 and establishing critical pathways to ensure success. The milestones and their associated indicators need to be measurable and verifiable to facilitate management of the program and maintain progress.

1. INTRODUCTION

1.1 Project Rationale

Ramboll have been appointed by the City of Cambridge to develop a Low Carbon Energy Supply Strategy study ("the study").

In June 2015, a Net Zero Action Plan for buildings was adopted by the City Council of Cambridge. The action plan contains the following 5 actions to be addressed over the next 25 years in order to meet the objective of reducing Green House Gas Emissions by 70% by 2040, based on 2014 emissions data.

1. Energy Efficiency in Existing Buildings
2. Net Zero New Construction
3. Energy Supply
    3.1 Low Carbon Energy Supply Strategy
    3.2 Rooftop Solar Ready Requirement
    3.3 Develop a Memorandum of Understanding with Local Utilities
4. Investigate Local Carbon Fund
5. Engagement & Capacity Building

The action plan sets a trajectory to achieve continued GHG reductions until net zero has been achieved by mid-century, while accommodating growth of the community and local economy.

Additionally in November 2016, as part of the second Metro Mayors Climate Preparedness Summit, the Metropolitan Mayors Coalition (MMC) members, including the City of Cambridge, pledged to develop and/or update a local climate mitigation plan and implement at least three climate mitigation actions by 2020. In addition, the member cities and towns committed that the region will achieve net zero/carbon-neutral status by 2050.

This study is in line with the Mayoral commitments made as part of the MMC and forms the basis for Action 3.1 of the 25 year Net Zero Action Plan[9]. To achieve these goals and address renewable energy production, a significant shift in the supply of energy to Cambridge buildings away from fossil fuel based sources and toward low or zero-carbon sources will be required.

The objective of this study therefore is to provide a better understanding for the City of the full potential for and barriers to renewable energy and low carbon energy solutions in Cambridge considering:

- What is the current and future building energy demand from buildings?
- What low carbon energy sources could be utilized by the City of Cambridge to change its energy supply?
- Which low carbon energy sources are technically viable and meet Cambridge financial, environmental and social objectives?
- What are the steps that need to be taken in Cambridge over the next 25 years in order to achieve the options outlined herein and the City's Net Zero objective?

1.2 Energy Supply Goals

The City has adopted a set of energy supply goals informed by goals developed by the Carbon Neutral Cities Alliance[10] that envision a future energy supply system with the following characteristics:

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[9] See http://www.cambridgema.gov/CDD/Projects/Climate/~/media/BF531928BB7D4526AE2D8538E025E0BA.ashx, p. 19

[10] From the Carbon Neutral Cities Alliance *Framework for Long-Term Deep Carbon Reduction Planning*, p. 60, available at http://usdn.org/uploads/cms/documents/cnca-framework-12-16-15.pdf

- **Clean**: Reduce carbon emissions and toxic pollutants created by the system.
- **Reliable**: Minimize system downtime from outages and ensure high quality of power delivered.
- **Affordable**: Keep rates as low as possible and maintain competitiveness.
- **Predictable**: Minimize rate volatility.
- **Transparent**: Consumers can understand their power costs and what drives changes in costs.
- **Local Control**: Give residents greater control over their energy resources and energy choices.
- **Wealth Creating**: Keep more energy revenue in the local economy instead of exporting it to outside suppliers — to help drive local economic development, create new businesses and jobs.
- **Innovative**: The system spawns innovation, intellectual property creation, and entrepreneurship.
- **Just**: The system promotes "energy equity," protecting vulnerable populations from undue hardship, and promotes energy literacy.

1.3 Project and Report Structure

The project was structured in four work packages as outlined in Figure 3 below. Each work package provided a basis for progression to the next work package and provided a solid basis for the project findings as derived in Work Packages 3 and 4 and outlined within this report.

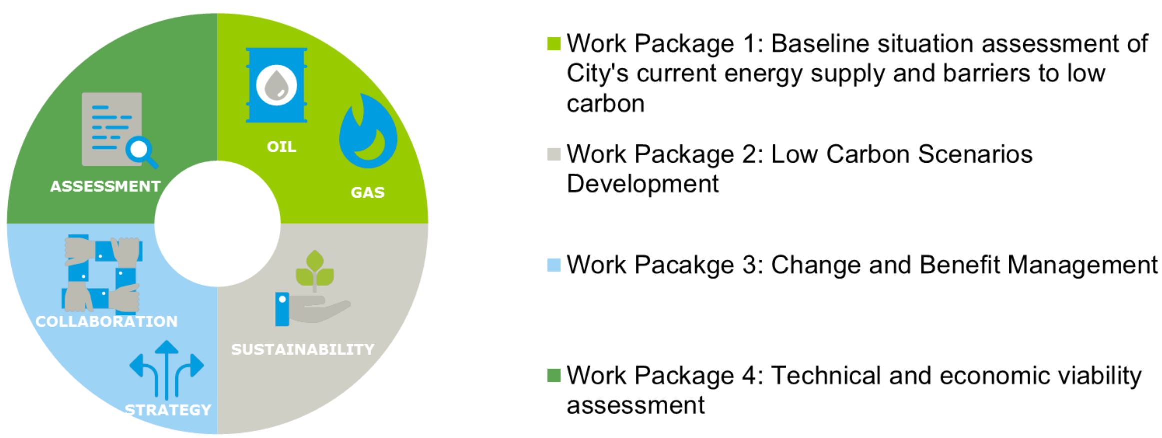

Figure 3 Project Structure

This report outlines the process employed to achieve the objectives of the study and includes a technical and economic viability assessment for the shortlisted scenarios with associated recommendations.

2. ASSESSMENT OF THE EXISTING SITUATION IN THE CITY OF CAMBRIDGE (WORK PACKAGE 1)

The purpose of Work Package 1 was to establish a baseline for energy demand, supply and regulations in order to inform the development of low carbon energy supply scenarios for Cambridge under Work Package 2. The below sections outline a summary of the findings of Work Package 1. Additional details on data processing and works completed under this work package can be found in the full Work Package 1 report, Appendix 1.

2.1 Energy Demand in Cambridge

The City of Cambridge energy usage by building type generally coincides with national averages established by CBECS. In some instances, Cambridge properties show improved building performance when compared against national benchmarks.

The total energy demand at a building level for the city of Cambridge is as follows:

Demand Type	Energy Demand (MMBTU)
Heating	7,664,000
Cooling	952,000
Electricity	5,496,000 (1,612GWh)
Total	14,112,000

Table 3 Total Demand Values for Cambridge

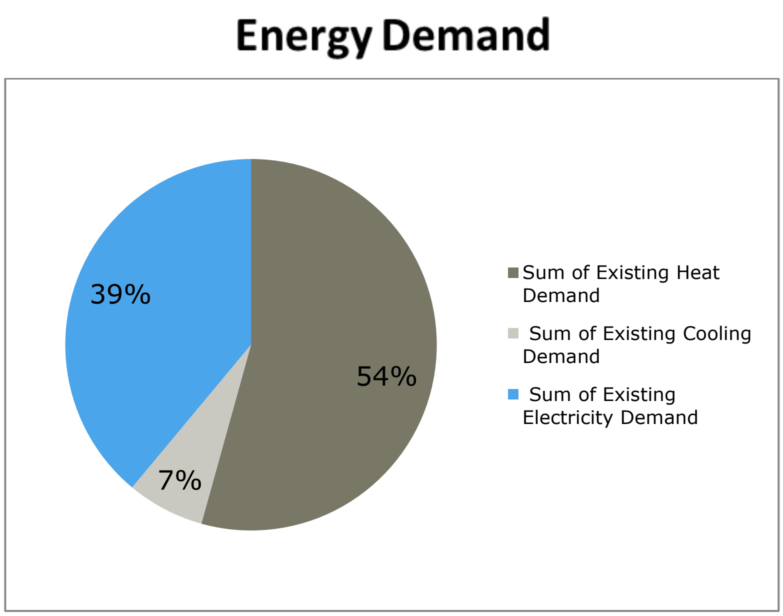

Figure 4 Current Energy Demand Split in Cambridge by Use Type

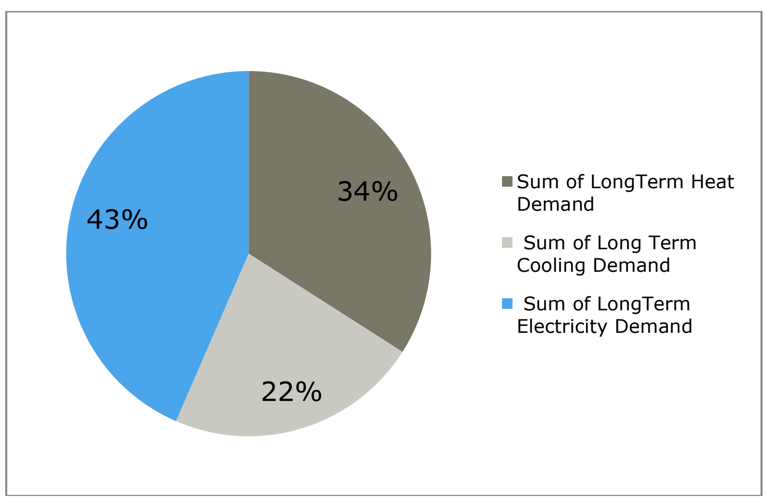

Figure 5 Future Energy Demand Split in Cambridge by Use Type

As can be seen in the figures above heating is currently the primary energy demand in Cambridge, with electricity a close second.[11] Cooling and electricity proportional demand is expected to increase over time as described below in Table 4, due to warmer climates resulting from climate change and expected upgrades to buildings within Cambridge, where a greater degree of space cooling will be installed to ensure the comfort of building occupants. Heating will still be the more dominant thermal energy demand however.

This highlights the importance of heating when considering how to reduce the carbon footprint of Cambridge's Energy Supply.

2.1.1 Existing Building Energy Use – Medium and Long Term Projections

In addition to understanding the city's current energy profile, low-carbon energy supply options must also consider future climate conditions as well as building improvements and how these changes may affect energy use at the building and community level.

Climate Change

While building improvements will help reduce energy consumption, consideration must be given to climate change and how future weather changes will impact building performance. Projected heating and cooling degree days were assessed based on the climate change assessment undertaken for the Cambridge Climate Change Vulnerability Assessment[12] in order to evaluate changes to heating and cooling loads. Results found that heating will see a reduction in energy use, and cooling will see an increase in energy use as outlined in Table 4 below.

Energy Demand for Space Heating	Energy Demand for Space Cooling
A warming climate will reduce heating demand.	A warming climate will increase the need for cooling.
• **16% reduction** by 2030 • **27% reduction** by 2040	• **78% increase** by 2030 • **129% increase** by 2040

Table 4 Projected changes to heating and cooling loads

Building Improvements

According to the Kendall Square Eco District Energy Demand Study, Cambridge has grown by over 10 million square feet[13] city-wide in the last decade. Further studies show that total energy use in Cambridge has decreased over this same time period. Based on trend data and the Net Zero Action Plan[14], it was assumed that existing buildings will continue to realize a reduction in energy consumption over the next 25 years.

Considering existing buildings only, the potential to reduce energy depends on a number of factors, the core items being:

- Building age

[11] Some cooling energy demand may be accounted for in the electricity category, for example plug-in window AC units

[12] Vulnerability Assessment, November 2015, Climate Projections and Scenario

[13] Kendall Square EcoDistrict Energy Study, June 2016

[14] http://www.cambridgema.gov/cdd/projects/climate/netzerotaskforce

- Future building codes applicable to major renovations
- Lighting upgrades
- Heating and cooling plant retrofits, including upgrades to building automation and control
- Building envelope (insulation and glazing)

Referencing analysis produced by the Kendall Square EcoDistrict and Integral Greenhouse Gas studies[15], a reduction factor (shown in Table 5 below and Appendix 1) was applied to existing building benchmark data to forecast anticipated heating and cooling energy use for the year 2030 (medium-term) and 2040 (long-term).

Table 5 Existing building energy consumption benchmark data reduction factors

GHG Model Type	2025 Improvement	2040 Improvement
Commercial Lab	14%	21%
Commercial Office	16%	23%
Hotel	16%	23%
Retail	20%	27%
Hospital	20%	27%
Warehouse	20%	27%
University Lab	9%	16%
Academic/Admin	21%	34%
University Residential	21%	28%
Athletics/Museums/Support	21%	28%
Government	21%	28%
Other	21%	28%
1-Family	14%	21%
2-3 Family	14%	21%
4-8 Units	14%	21%
8-51 Units	14%	21%
51 + Units	14%	21%

2.1.2 Future Energy Demand: Planned Developments

There are three areas of the City where significant new development is anticipated over the course of the LCESS study period (2017-2040). These developments will result in the build-out of the last remaining large parcels of development land in the city and so account for the majority of planned future development in Cambridge.

These development areas are described below and included in the energy demand forecast mapping:

Northpoint: 45 acre site in the east of Cambridge and is one of the largest (permitted for 5.2 million sq. ft.) undeveloped sites in the whole of the Boston/Cambridge area. The total increase in energy demand is expected to be 202,400 MMBTU.

Kendall Square: Kendall Square is due to undergo significant development over the next eighteen years including on the Volpe site. The total increase in energy demand is expected to be 926,969 MMBTU.

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[15] Cambridge Net Zero Action Plan, GHG Reduction Model, April 2015

Alewife: The development plans for Alewife are still being developed. Within the timeframe of this report the energy demand in Alewife is expected to increase by 478,000 MMBTU.

2.1.3 Energy Demand Mapping

Using the above demand information and analysis, GIS maps were prepared to spatially reference the energy demand data in a visual form for ease of reference and understanding of the energy consumption in the City. The full set of maps can be found in Appendix 1. This was done for the demand today and for the expected demand in the year 2030 and 2040 based on the projections discussed in Section 2.1.1 above.

Figure 6 below shows that the majority of the heating demand is in the eastern part of Cambridge closest to Boston. This is where the building density is highest and where many of the largest energy consumers in Cambridge are located (such as: MIT, Biogen, Novartis etc.).

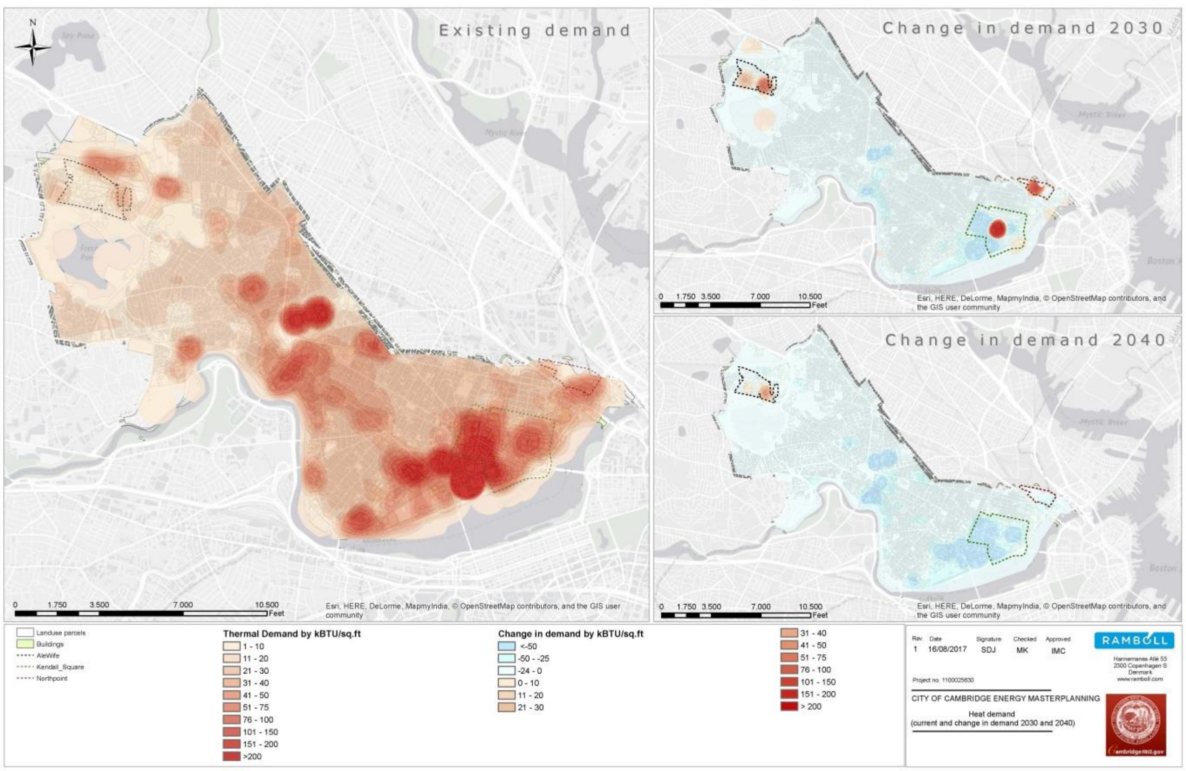

Figure 6 Heating Demand in Cambridge

Heating demand then slowly reduces to the west as the building density and demand intensity of smaller residential buildings become the norm. A notable demand spot in the center of the map relates to the demand from the Harvard University campus in Cambridge.

In terms of changes over time, in general the trend is for a reduction in heating demand brought about by the projected building efficiency programs to be implemented under the Net Zero Action Plan. Projected changes in climate also contribute to the overall energy demand variation.

Also represented on this map is the change in energy demand due to the three major new developments expected to come forward in the years to 2030 (medium term) and 2040 (long term). These are highlighted here as large positive change areas using dashed line polygons.

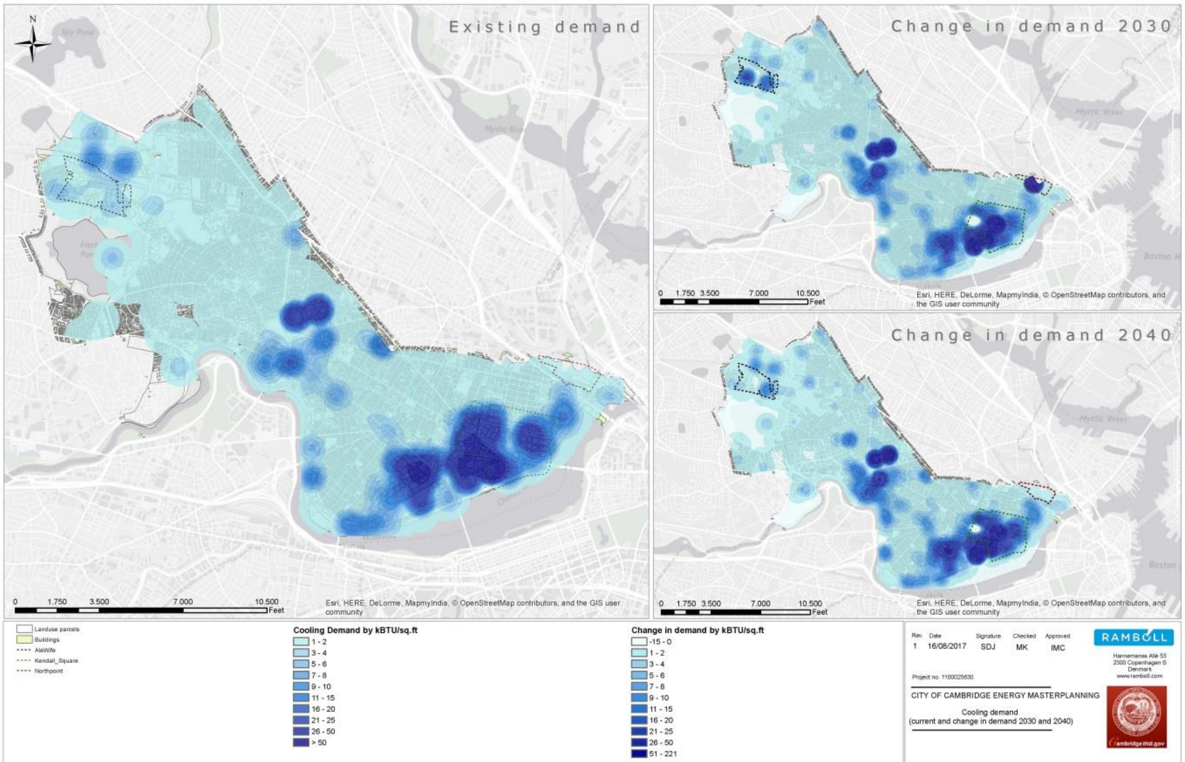

Figure 7 Cooling Demand in Cambridge

Cooling demand shown in Figure 7 above, displays a similar pattern to heating demand. The majority of demand is in the Kendall Square/MIT area. There is a lot of light blue on the main map indicating cooling demand between 0-2 kBTU/hr; this is primarily due to smaller residential buildings with no air conditioning (individual window air conditioning units are not captured here). Significant changes are expected in cooling demand across Cambridge due to climate change, increased retrofitting to air condition existing buildings and of course the new development areas.

Further energy demand mapping, including those for electrical demand can be found in Appendix 1.

It should be noted that energy supply for transport is not included in the scope of this study, with the focus primarily being on buildings and their energy demand. However, the decarbonization of transport and the move from fossil fuels to other fuels (including electric vehicles) will likely contribute significantly to the electrical demand of the city and is not included in the electrical demand forecast maps.

2.2 Energy Supply in Cambridge

Energy supply in Cambridge is dominated by a number of large cogeneration (CHP) plants, numerous small scale CHP (<1MW$_e$) and the electricity and natural gas supplier, Eversource. The primary existing large-scale energy production within Cambridge is from cogeneration plants at MIT, Harvard and Veolia's Kendall Square power plant. Further details of these plants are outlined below in addition to some smaller cogeneration facilities at Biogen and Novartis. The energy supply asset map shown in Figure 8 for Cambridge shows both the significant existing and potential energy supplies identified.

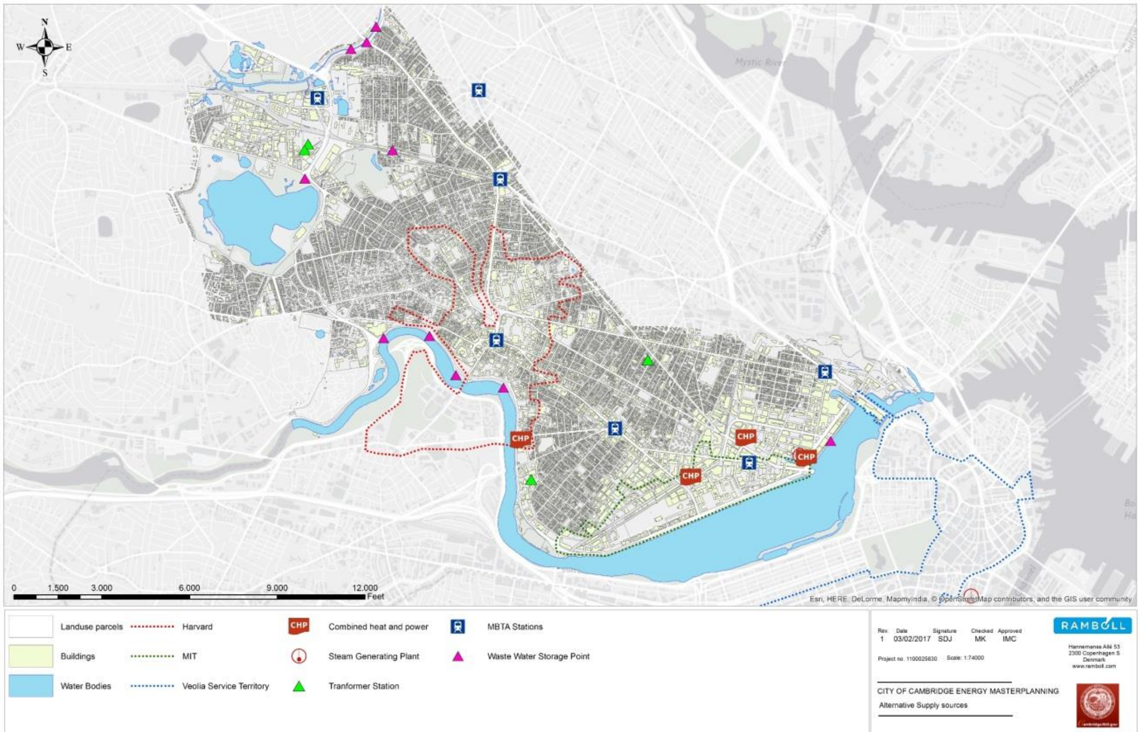

Figure 8 Supply Asset Map Cambridge

Outside of plant generation, a small amount of energy supply within Cambridge is generated primarily via renewable/alternative energy sources. Currently the total solar capacity is roughly 5 MW and some larger facilities, including multiple municipal buildings, also utilize geothermal energy combined with ground source heat pumps.

2.2.1 Veolia (eastern Cambridge)

The Kendall Cogeneration Station produces steam from its Combined Heat and Power (CHP) plant to meet the thermal energy needs of over 250 medical research institutions, hospitals, hotels, museums and government buildings throughout Boston and Cambridge. In Cambridge, Veolia supplies steam to office buildings, manufacturing, biotechnology and pharmaceutical facilities, in addition to operating Biogen's CHP plant as discussed further below.

Veolia currently produces 2.8 million lbs/hour of steam and their district energy steam distribution system comprises 26 miles of piping network[16].

2.2.2 Massachusetts Institute of Technology

The current cogeneration plant is a 21MW gas turbine that generates electricity and steam, which is then used for heating and cooling (via steam turbine driven chillers) and meets the majority of the campuses electric needs. The turbine was installed in 1995 and is near the end of its useful life and is scheduled for replacement in 2020 by two new cogeneration units.

Each cogeneration unit will produce approximately 22MW of electricity for a total installed capacity of 44 MW. The cogeneration units will be large combustion gas turbines firing on natural gas with ultra-low sulfur diesel as back up fuel. Waste heat will be recovered to produce steam through natural gas

[16] (Source: veolianorthamerica.com, accessed January 20, 2017)

fired heat recovery steam generators (HRSGs). Upgrades to the chilled water plant will also be completed.

MIT has also invested in off-site emissions reduction through a 25 year Power Purchase Agreement it signed in 2016 for annual supply of 44MW of power and RECs from the Summit Farms solar panel array in North Carolina. This accounts for 40% of the total electricity use on campus.[17]

2.2.3 Harvard University

The Harvard-owned Blackstone Steam Plant located on Blackstone Street, Cambridge supplies steam and electricity to 160 buildings on the Cambridge and Allston campuses. The Plant includes four steam boilers, a 7.5 MW combustion turbine generator and heat recovery system, and a 5MW backpressure steam turbine generator. The fuel mix is predominantly natural gas with oil and ultra-low sulfur diesel being used only for emergency backup situations.

Systems in operation on campus currently consist of:

- Three district chilled water plants, two in Cambridge and one in Allston, supply chilled water to approximately 100 buildings.
- An electric microgrid (13,800 V microgrid) for power distribution, supplying 250 buildings on the Cambridge and Allston campuses.
- On-site renewable and alternative energy installations serve buildings throughout campus, including 18 solar PV installations with a capacity of 1.5MW, 2 roof-mounted wind turbines, 8 geothermal systems, 6 on-site solar hot water systems, and 1 off-site biomass facility.
- Four smaller combined heat and power systems are also located on Harvard-owned properties including Harvard Athletics pools, Doubletree Hotel and Shad Hall at Harvard Business School.

Harvard has additionally invested in off-site emissions reduction through a long-term Power Purchase Agreement it signed in 2009 for 12MW of power and RECs from the Stetson II wind project in Maine. The University currently purchases 12MW of power and RECs from the Stetson II wind project. This accounts for 10% of the power the University needs from renewable sources.

Harvard has also aggressively invested in on-site renewable energy generation by piloting emerging technologies, assessing wind energy potential along the Charles River and investing in solar projects to accelerate the transition to clean energy.

Source	Capacity
Solar PV	18 campus projects, total capacity 1.5 MW (Additionally, Harvard was responsible for installing a 500kW system on Arsenal Mall but the building was sold in 2013)
Roof Mounted Wind Turbines	2 x 10 kW
Geothermal with 1/30/35 ton water source heat pumps	10 x 1,500 foot open geothermal wells 3 x 400-600 foot open geothermal wells 88 x 500 foot closed vertical geothermal wells
Solar Hot Water	6 campus locations

Table 6 Harvard Onsite Renewable Energy Generation

[17] http://web.mit.edu/facilities/environmental/solar-ppa.html

2.2.4 Biogen

The Biogen biotechnology company energy supply system in Cambridge is based on a 5 MW cogeneration system which includes steam distribution, electric distribution and a chilled-water loop that serves multiple buildings on their corporate campus in Kendall Square[18].

The Biogen central plant includes:

- 5.4 MW gas turbine,
- Heat recovery boiler with a capacity of 50,000 lb/hr,
- Two gas-fired boilers with a combined capacity of 50,000 lb/hr,
- 1,200-ton absorption chiller.

The campus systems include steam distribution, electric distribution and a chilled-water loop. The Biogen campus system is interconnected with Veolia's adjacent district energy system, which allows Biogen the option of removing its peak load boiler which has infrequent use throughout the year. This improvement has increased the system reliability on both sides of the interconnection valve.

2.2.5 Novartis

The Novartis Institute for BioMedical Research has two 1.4 MW gas fired reciprocating engines. The cogeneration engines produce electricity and hot water. Hot water is generated from hot flue gas, the lube oil cooler, jacket water cooling, and engine intercooler. Hot water and electricity are used on site to offset utility costs.

2.3 Energy Supply External to Cambridge

Where the electricity supply is not coming from the sources of cogeneration or solar PV in Cambridge, it is coming from the New England Power Grid (NEPOOL) which is supplied by plants such as the Mystic River power plant. The New England ISO which operates NEPOOL plans to advance its supply mix so that it decreases its reliance on fossil fuels. The Massachusetts Renewable Energy Portfolio Standard (RPS) plays an important role in this for MA as a statutory obligation that suppliers must obtain a percentage of renewable electricity from qualifying Units for their retail customers. The RPS is further discussed in Section 2.4.1.3. Other states in New England also have RPS targets. The New England ISO plans to decreases its reliance on fossil fuels is as outlined below.

2.3.1 Wave One: Natural Gas

The late 1990s ushered in a steady shift to natural-gas-fired generation in New England. These resources are easier to site, cheaper to build, and generally more efficient to operate than oil-fired, coal-fired, and nuclear power plants. About 80% of new electric capacity built in the region since 1997 runs on natural gas. Gas-fired units remain the top choice for developers, representing more than 60%—about 8,200 megawatts (MW)—of all new generation currently proposed.

2.3.2 Wave Two: Renewable Energy and Demand Resources

In the 2000s, wind power, solar power, and demand resources began to make up a growing share of New England's resource mix, representing 16% (including hydroelectric) of supply in 2015.

[18] https://www.bostonplans.org/getattachment/0e8f81b8-4b32-4872-9c57-7c1d082ae7c3

	Wind Generation MA	Solar Generation MA
2016	9MW[19]	1,487MW[20]
2020 Target		1,600MW[10][21]
2027 Target	1,600MW[22]	

Table 7 Wind and Solar Generation Capacity in MA today and future targets

The region's capacity market includes about 600 MW of active demand response, which relieves grid demand by reducing power consumption in real time, and 1,700 MW of energy-efficiency (EE) measures, which have essentially flattened demand growth over the next decade. Although renewable and demand resources comprise a small share of the power system's total capacity today, over 30% (about 4,200 MW) of all proposed new regional generation is wind-powered, and small-scale solar arrays are multiplying rapidly. While still many years off, renewable resources could in time satisfy a significant portion of New England's electricity needs.

2.3.3 Wave Three: Distributed Generation (DG)

In the next decade or so, New England could have a "hybrid grid." Up to 20% of power resources in New England could be connected directly to retail customers or to local distribution utilities—and not to the transmission system. Widespread residential solar power and storage systems, electric vehicles, and smart meters will change not only how much electricity people draw from the grid, but when they draw it.

2.3.4 Changes to the New England Power Pool (NEPOOL)

NEPOOL has shifted away from coal and oil towards natural gas (with fewer carbon emissions). Figure 9 outlines the dramatic shift in the energy supply of New England over the past 15 years.

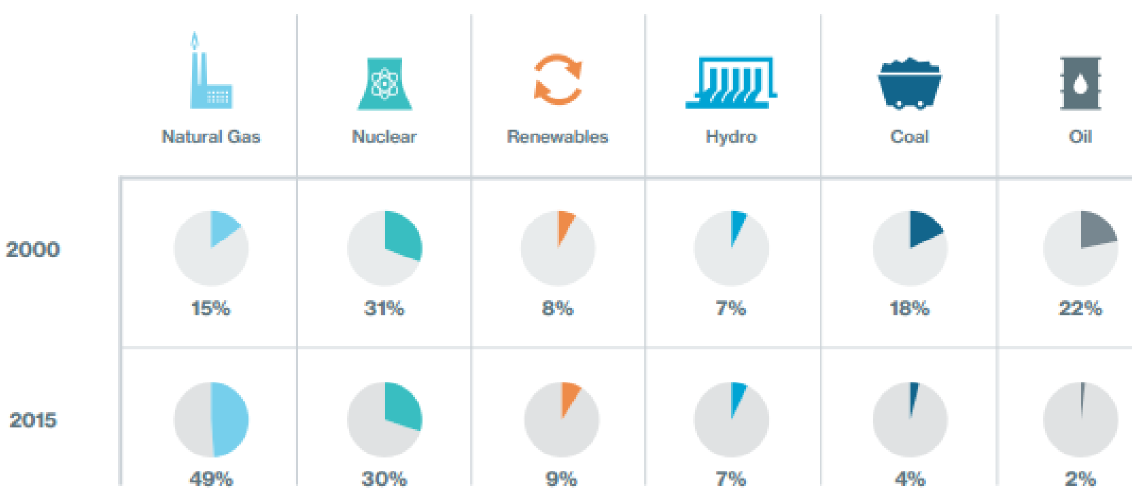

Figure 9 Changes in Energy Supply to NEPOOL over 15 years[23]

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[19] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/wind/why-wind.html

[20] http://www.seia.org/state-solar-policy/massachusetts

[21] [21] Note this has effectively been met, and a new incentive program to enable another 1,600MW of solar is in development: http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/development-of-the-next-solar-incentive.html

[22] https://www.northeastern.edu/climatereview/?p=294

[23] Source: ISO-NE.com, ISO New England Assets Annual Report

Figure 9 above outlines the changing nature of the electricity mix for NEPOOL over the past 15 years and is not specific to Massachusetts. Only ten years ago Massachusetts had approximately 5%[24] contribution to its electricity generation coming from renewable resources. By 2015 this had risen to over 10%[17], with wind and solar power accounting for almost two fifths of this. This has been possible in large part due to the RPS scheme. Over 3 GW[25] of generating capacity is due to be retired in Massachusetts in the coming years. In order for the state to meet its 2030 goal of 25%[18] Class 1 or new renewable resources supplying the grid and reducing GHG emissions to 80%[18] below 1990 levels by 2050 a large proportion of this retired supply will need to be met by renewable or low carbon resources.

By far the largest planned contributor to these goals is expected to be wind power with a short term goal of 2 GW of wind power on the Massachusetts grid by 2020, only 5% of this goal is currently in place.[17].

2.3.5 Mystic River power plant

The Mystic River Power Plant is located north of Cambridge on the Mystic River as seen in Figure 10, which provides ease of access for barge fuel delivery. The plant is a combined cycle gas turbine (CCGT) consisting of four units:

- Mystic Jet is an 8.6 MW peak load gas engine
- Mystic 7 is a 577.6 MW unit
- Mystic 8 is a 703 MW unit
- Mystic 9 is a 711 MW unit

Figure 10 Mystic River Power Plant (Source Google Earth)

Mystic units 8 & 9 are connected to the Distrigas LNG (Liquified Natural Gas) by a dedicated high-pressure pipeline. Mystic unit 7 is supplied by either natural gas from the grid or oil depending on market conditions. Mystic Jet is an oil fueled peaking unit. The Mystic River Power Plant is currently operated as a condensation plant.

The close location of this large energy plant to Cambridge and neighbouring cities provides an opportunity for refurbishment to supply district heating to neighbouring cities or for a new biomass plant to be constructed on the site, considering the site's river access and its potential suitability for delivery of biomass.

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[24] https://www.eia.gov/state/print.php?sid=MA

[25] https://www.iso-ne.com/static-assets/documents/2017/01/ne_power_grid_2016_2017_state_profile.pdf

2.4 Regulatory Framework[26]

This section summarizes work completed by the consultant in January 2017 under work package 1. It is included below as a summation of this information to inform the regulatory framework basis from which the study was completed. However it should be noted that elements may have changed since January 2017 with regards the regulatory framework and supporting programs, and it should be noted that this will continue to happen over the lifetime of the study period and this must be borne in mind by all process stakeholders.

The findings and recommendations that result from this study, will ultimately sit within a regulatory framework within which they (the report findings and recommendations) must comply. This section outlines the existing regulatory framework for energy supply in Cambridge.

The Department of Public Utilities (DPU) is responsible for the structure and control of energy provision in the Commonwealth of Massachusetts; monitoring service quality; regulating safety in the transportation and gas pipeline areas; and for the siting of energy facilities.

The mission of the Department is:

- To ensure that utility consumers are provided with the most reliable service at the lowest possible cost;
- To protect the public safety from transportation and gas pipeline related accidents;
- To oversee the energy facilities siting process; and
- To ensure that ratepayers' rights are protected.

2.4.1 Electricity

2.4.1.1 Electricity Supply to customers

Massachusetts operates a decoupled electricity sector where privately- and publicly-owned electric utilities transmit, distribute, and/or sell electricity primarily for use by the public. Generation is separate to the transmission, distribution and sale of electricity in Massachusetts where competitive suppliers sell into NEPOOL. These include investor-owned electric utilities, municipal and state utilities, Federal electric utilities, and rural electric cooperatives.

DPU Regulation 220 CMR 8.00 outlines the conditions for the sale of electricity by qualified facilities and on-site generating facilities to distribution companies, and the conditions for the sale of electricity by distribution companies to qualifying facilities and on-site generating facilities.

The City of Cambridge is currently served by the investor owned company Eversource (www.eversource.com).

Massachusetts is part of the New England Independent System Operator (ISO-NE). The New England ISO engages in long-term planning that involves identifying effective, cost-efficient ways to ensure

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[26]The following resources were used in the writing of this section and accessed during February 2017: http://www.mass.gov/eea/pr-2016/pr-massachusetts-clean-energy-and-climate-plan-for-2020.html; http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/; https://www.ferc.gov/about/ferc-does.asp; http://www.mass.gov/eea/grants-and-tech-assistance/laws-and-regulations/utility-statues-and-regs/dpu-regulations/220-cmr-dpu/; http://programs.dsireusa.org/system/program?state=MA; http://www.mass.gov/eea/grants-and-tech-assistance/laws-and-regulations/utility-statues-and-regs/dpu-regulations/220-cmr-dpu/; http://www.masssave.com/en/about-mass-save ; http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/energy-storage-initiative/ .

grid reliability and system-wide benefits. Coordination and cooperation between utilities, state Public Utility Commissions and RTOs (regional transmission organizations)/ISOs are often required to advance energy efficiency goals.

2.4.1.2 Connecting new supply to the Grid

Net metering allows customers with distributed generation systems, typically wind or solar, to be compensated when their systems generate more electricity than the customer is using onsite by exporting to the grid. The size threshold for net metering varies; for example, for some technologies and situations, net metering may be allowed up to 2 MW.

Eligibility varies by technology and project owner. For public entities installing wind or solar systems, the cap is 2 MW per unit installed by the public entity. For private entities installing wind or solar, the cap is 2 MW per project developed by the private entity. In some cases, larger generators may also establish power purchase agreements with their utility. Onsite generating facilities of any type are eligible for net metering if they are 60 kW or smaller in size.[27]

Net metering is allowed by all of the investor-owned utilities in Massachusetts, including Eversource. Massachusetts law previously limited net metering capacity to 6% of each utility's historical system peak load. Half of that capacity (3% of the total) was available for public facilities and half for private. As of April 2016, the legislation was changed to increase the cap to 7% for private projects and 8% for public projects and lowers the net metering credit rate for most private projects nearer to wholesale rates.

All distributed generation looking to connect to the distribution grid must follow the interconnection process. All investor-owned utilities in Massachusetts (such as Eversource) must follow this same interconnection process, as required by tariffs regulated by the Department of Public Utilities.

This interconnection process includes the steps to obtain approval from the local utility / distribution company to connect a distributed generation system to the electric grid (or distribution system). Municipally owned utilities are not required to follow this same process and may use different criteria for review. When you apply to an investor-owned utility for interconnection, the utility reviews your project to make sure there are no negative impacts on the grid. If potential impacts are identified, the utility will request additional review and in some cases will require you to pay for new equipment to protect the grid. Additional reviews and equipment upgrades are not usually necessary for most small renewable generators, but may be required for larger projects, more complex projects, or generation that is located on a network system.

2.4.1.3 Sustainability Promotion Initiatives in the Electricity Sector

The Green Communities Act of 2008 sets a goal for the Commonwealth of Massachusetts to have clean energy generation serve 20% of customer load by 2020.

The Massachusetts **Renewable Energy Portfolio Standard (RPS)** is a statutory obligation that suppliers (both regulated distribution utilities and competitive suppliers) must obtain a percentage of electricity from qualifying Units for their retail customers.

[27] https://www.mass.gov/files/documents/2017/09/19/Net%20Metering%20FAQs%209.19.17.pdf

Suppliers meet their annual RPS obligations by acquiring a sufficient quantity of RPS-qualified renewable energy certificates (RECs) that are created and recorded at the New England Power Pool (NEPOOL) Generation Information System (GIS).

Under the 2008 Act, the Renewable Energy Portfolio Standard (RPS) was broken into RPS Class I and RPS Class II. RPS Class I applies to renewable generation units that began operation in 1998 onward, and RPS Class II to renewable generation units which began operation prior to 1998.

The technologies which qualify as Renewable Generation are as follows:

- Solar photovoltaic
- Solar thermal
- Wind energy
- Small hydropower
- Landfill methane and anaerobic digester gas
- Marine or hydrokinetic energy
- Geothermal energy
- Eligible biomass fuel

In 2010, RPS Class I requirements were altered to require a greater portion of Solar Photovoltaic energy to be supplied. This was called the **RPS Solar Carve Out** and supported distributed solar PV energy facilities across the Commonwealth. In 2014 this was further amended to continue supporting new solar photovoltaic (PV) installations until 1,600 MW of capacity is installed across the entire Commonwealth.

On June 30, 2016 the 1,600 MW of capacity was met. As a result DOER has been working to create a long-term sustainable solar incentive program to follow on from the Solar Carve Out program, take account of recent development in the PV market and promote cost-effective solar development in the Commonwealth. The final proposal for the design of the next generation incentive program for Solar was finalized in August 2017 and is called the Solar Massachusetts Renewable Target (SMART) program[28]. Significantly, this new incentive program includes a Declining Block tariff program that is designed to provide more long-term stability (10-20 years) for solar projects. This will reduce financing risks and reduce costs accordingly.

The Declining Block Program means the solar facility receiving the incentive will receive a single compensation rate which accounts for both the energy and the incentive. The resulting value of the incentive is the net difference between the all-in rate and the value of the energy. The incentive will decrease with the declining cost of solar. The SMART program and associated Block Tariff will come into effect in 2018.

The 2017 RPS Class I requirement is twelve percent, and is set to increase by one percent each year.

RPS Class II is different from Class I in that generation is from older plants and that it mandates that a minimum percentage of electricity sales come from each of two sources, renewable energy and waste energy. As a result, Waste to Energy units which burn Municipal Solid Waste to generate heat and power are included within Class II generation units.

The current RPS Class II Renewable Generation obligation is 3.6 percent, and the Waste Energy Generation obligation is 3.5 percent. The obligation does not increase annually. A Supplier must comply with both the minimum percentage of Renewable and Waste Energy obligations.

The **Alternative Energy Portfolio Standard (APS)** (225 CMR 16.00) offers the opportunity for Massachusetts businesses, institutions, and governments to receive an incentive for installing eligible

[28] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/development-of-the-next-solar-incentive.html

alternative energy systems, which are not renewable. Similar to the RPS, it requires a certain percentage of the state's electric load to be met by eligible technologies, which for APS include Combined Heat and Power (CHP), flywheel storage, coal gasification, and efficient steam technologies (draft revisions of this APS currently under public consultation propose to additionally include rebates/subsidies towards wood pellet boilers/stoves, air source heat pumps, ground source heat pumps, heat pump water heaters and solar water heating[29]). These resources contribute to the Commonwealth's clean energy goals by increasing energy efficiency and reducing the need for conventional fossil fuel-based power generation. In 2009, the Suppliers obligation was 1%, and is set to increase 0.5% each following year until 2014, when the growth rate was reduced to 0.25% per year.

Retail Electric Suppliers are required to document compliance with RPS and APS in annual filings submitted to the Department of Energy Resources (DOER). Suppliers who cannot meet their compliance obligations through their plant, can meet them by purchasing **Renewable Energy Certificates (RECs)** from qualified generators and/or making **Alternative Compliance Payments (ACPs)** to the Massachusetts Clean Energy Center.

DOER sets an Alternative Compliance Payment (ACP) Rate which serves as a ceiling price for RECs and acts as a penalty which must be paid by RES (Retail Electricity Suppliers), should they not purchase RECs from qualified projects for something less than the ACP in order to meet their compliance obligation and avoid ACP payments. The revenue generated from ACPs is used to fund other clean energy projects throughout the Commonwealth.

In June 2015, in order to comply with these requirements, Eversource, in conjunction with other electric distribution companies, sought proposals for the supply of electric energy and/or Renewable Energy Certificates (“RECs”) from newly developed, small, emerging or diverse renewable energy distributed generation facilities under long-term power purchase agreements pursuant to Section 83A of the Green Communities Act (“Section 83A”). Preferred bidders were selected and contracts sent for DPU approval in early 2016. This shows the RPS and APS compliance system in operation and how these technologies are incentivized.

Energy efficiency is also planned and incentivized for in Massachusetts. Currently there is a state-wide energy efficiency plan for 2016-2018, which follows on from the 2013-2015 Three Year Plan, and was developed in collaboration with the Energy Efficiency Advisory Council (EEAC) and approved by the Massachusetts Department of Public Utilities[30]. This plan sets annual savings levels for both electricity (2.93% of retail sales) and gas (1.24% of retail sales)[31]. The proposed plan also ensures continued growth of energy efficiency in MA with year over year increases in annual and lifetime savings goals for both electric and gas.

Mass Save is contracted by numerous energy supply companies (including Eversource) to administer energy efficiency incentives. Under Mass Save, the Massachusetts Program Administrators (PAs) offer financial incentives and technical assistance to commercial, industrial, and institutional customers who are building new facilities or undergoing a major renovation; adding capacity; or replacing or upgrading equipment. They provide technical assistance and incentives to help optimize energy efficiency investment. Mass Save also provide assistance to home owners to incentivize energy efficiency in the home.

[29] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/renewable-thermal/eligible-technologies-alternative-portfolio-std-rulemaking.html

[30] http://ma-eeac.org/plans-updates/

[31] http://www.mass.gov/eea/pr-2015/energy-efficiency-plan-proposed-in-massachusetts.html

The Database of State Incentives for Renewables and Efficiency (DSIRE) website lists 163 programs that offer incentives, policies or technical resources to promote distributed generation, including those offered by small municipals and cooperatives for the state of Massachusetts.

2.4.1.4 Grid Organization

Massachusetts has implemented **Integrated Resource Planning** to structure its grid supply. By incorporating least-cost and integrated resource planning (IRP), a utility is required to report its load and resource forecast for a specified period, and utilize the least-cost resource mix, including both supply and demand-side options. Because energy efficiency is such a low-cost resource, proper utilization of IRP tends to result in the incorporation of energy efficiency as a utility system resource and reduce the need for additional supply resources. This also reduces total resource costs for utilities.

The impact of this for Massachusetts (and for Cambridge as a part of the state) is to have Eversource objectively analyze the potential of all its available resources – supply and demand – and identify the mix of resources that produces a least-cost, reliable resource plan.

2.4.1.5 Grid Modernization

In June, 2014, the Department of Public Utilities issued order D.P.U. 12-76-B requiring each electric distribution company to develop and implement a ten-year grid modernization plan. The Department determined that grid modernization will provide several benefits including:

- Empowering customers to better manage and reduce electricity costs;
- Enhancing the reliability and resiliency of electricity service in the face of increasingly extreme weather;
- Encouraging innovation and investment in new technology and infrastructure;
- Addressing climate change and meeting clean energy requirements.

In January 2017, Eversource filed a $400 million grid modernization plan with state regulators as part of a broader rate case application, proposing significant investment in energy storage, electric vehicle infrastructure as well as an extensive grid management and resource integration system. Proposed changes are expected to increase monthly bills on average by 7% based on 2016 usage and could come into effect in January 2018. The City of Cambridge has obtained status as an Intervenor and is seeking to influence the outcome of the rate case to benefit Cambridge rate payers and support energy efficiency and renewable energy investment.

Approximately 25% of the proposed grid modernization budget is to be spent on Storage, 10% on electric vehicle charging and 65% on distribution automation. The plan also includes implementing a performance-based ratemaking mechanism that would adjust rates annually in step with a revenue-cap formula approved by regulators.

2.4.2 Heating/Cooling

2.4.2.1 Regulation of Water Based Heating and Cooling Supply

District energy systems supplied by hot or chilled water are not specifically regulated through the Department of Public Utilities.

Supply of steam for heating is however regulated in Massachusetts according to 220 CMR 20.00, excluding design, fabrication, and installation of piping downstream of the customer's property line. This regulation covers the following headings:

20.01: Purpose and Scope
20.02: Definitions
20.03: Compliance with Standard Code
20.04: Notification of Construction
20.05: Operating and Maintenance Plan
20.06: Emergency Plan
20.07: Customer Education and Information Program
20.08: Employee Training
20.09: Periodic Inspections
20.10: Welding - Qualification and Nondestructive Testing
20.11: Leaks and Vapor Conditions
20.12: Logging and Analysis of Steam Emergency Event Report
20.13: Reports of Incidents and Interruptions
20.14: Facility Failure Investigation
20.15: Corporate Filings
20.16: Department Examinations and Investigations; Fines
20.17: Records
20.18: Miscellaneous

2.4.2.2 Incentives available for thermal energy supplies

The Massachusetts Department of Energy Resources (DOER) is preparing draft regulations to include Renewable Thermal in the Massachusetts Alternative Portfolio Standard (APS 225 CMR 16.00) discussed above and pursuant to Chapter 251 of the Acts of 2014.[32] These draft regulations were put out for consultation with oral hearings in June 2016 and July 2017.

Waste heat usage from Energy from Waste or combined Heat and Power plants is incentivized through the Alternative Energy Portfolio Standard (APS) discussed above.

Additionally, the Massachusetts Clean Energy Center (MassCEC) in partnership with the Massachusetts Department of Energy Resources (DOER) run the Clean Heating and Cooling program[33]. This provides renewable heat incentives for residential, business, commercial and industrial heat consumers. These incentives relate to rebates/subsidies towards wood pellet boilers/stoves, air source heat pumps, ground source heat pumps, heat pump water heaters and solar water heating.

2.4.2.3 Heating and Cooling System Regulation in Buildings

Cooling and heating system allowances and limitations for the City of Cambridge are defined by the Massachusetts Building Code: 9th[34] Edition Base Code (780 CMR). The technical content of the Massachusetts Basic Building Code is based on the 2015 International Code Council (ICC) International Building Code.

2.4.3 Natural Gas

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[32] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/renewable-thermal/eligible-technologies-alternative-portfolio-std-rulemaking.html
[33] http://www.masscec.com/residential/clean-heating-and-cooling
[34] https://www.mass.gov/service-details/ninth-edition-of-the-ma-state-building-code

Regulation 220 CMR 14.00 outlines how the unbundled gas network in Massachusetts is to provide services related to the provision of natural gas. The Department of Public Utilities' Gas Division ensures that gas companies provide their customers with the most reliable resource at the lowest possible cost.

The Gas Division is responsible for the regulation of the eight investor-owned gas distribution companies in Massachusetts. The regulation of the natural gas industry requires the Gas Division to, among other requirements, review forecast and supply plan filings, long-term supply contracts, numerous non-tariffed contracts for the sale and transportation of natural gas, energy efficiency programs as well as all Cost of Gas Adjustment filings that determine the rates customers are charged for the gas commodity.

In addition, the Gas Division monitors the market at the regional and national level to ensure that the Massachusetts consumers continue to receive the economic and environmental benefits that natural gas has to offer. The Gas Division is in charge of ensuring that the natural gas market in Massachusetts remains competitive at the retail level.

Eversource is the gas supplier in Cambridge.

220 CMR 101.00 through 113.00 outline the Gas Distribution Code for Massachusetts and are designed to ensure safe operating practices for persons engaged in the storage, transportation and distribution of gas. The Code is to apply to all new construction and new installations made subsequent to the effective date of the code.

2.4.4 Energy Storage

In May of 2015, Massachusetts launched the Energy Storage Initiative, with the goal of advancing energy storage capability within the state by attracting storage companies, accelerating technology development, expanding markets and progressing policies, regulations and programs that promote energy storage.

The program was later expanded in August of 2016 via ‘An Act Relative to Energy Diversity’ which opened public and stakeholder comment to set energy storage goals. These energy storage targets are now set at 200MW by 2020[35].

Electricity currently has the least amount of storage capacity in its supply chain and thus has become the focus for future energy storage development projects. Recent studies estimate that Massachusetts has the capability to generate upwards of 600 MW of advanced energy storage by 2025 (ESI Study, Mass.gov[36]).

To date, energy storage in Massachusetts has been primarily concentrated on pumped hydro-storage. This technology is commonly used and therefore, minimal advancement to existing and/or new pumped hydro infrastructure is expected in the future.

Other, more conventional energy storage applications include batteries, ice storage and heat-based thermal storage. ‘Advanced’ applications have also come to the forefront, such as compressed air energy storage, flywheel and flow batteries.

Massachusetts currently offers a number of incentives for energy storage applications. New incentives and programs launched in 2017 should further develop the energy storage market in Massachusetts. As part of the SMART program discussed above, energy storage will be compensated via a variable

[35] http://www.mass.gov/eea/pr-2017/doer-sets-200-megawatt-hour-energy-storage-target.html

[36] http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf

adder system which is based on the ratio of storage capacity to solar capacity as well as the duration of the storage. This will incentivize storage capacity in tandem with solar generation in the state.

Additionally, DOER and MassCEC have requested proposals for energy storage demonstration projects in Massachusetts. The projects proposed should provide solutions to the barriers and technical challenges storage deployment face in Massachusetts.

2.4.5 New Energy Facility Construction

The Energy Facilities Siting Board ("Siting Board ") is a nine-member review board charged with ensuring a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The Siting Board's primary function is to license the construction of major energy infrastructure in Massachusetts, including large power plants, electric transmission lines, natural gas pipelines and natural gas storage facilities.

3. TECHNICAL CONSIDERATIONS

3.1 Alternative Energy Sources and Technologies in Cambridge

Outlined below are the alternative energy sources and applicable technologies for Cambridge identified and refined through the course of the work packages. These are described here to facilitate ease of reading and understanding of the individual scenario analysis in the following sections.

3.1.1 Geothermal Potential of Cambridge

3.1.1.1 Deep Geothermal

Based on discussions and information contained in Appendix 4, the potential for deep geothermal (greater than 1km) is assessed to be low.

3.1.1.2 Shallow Geothermal

Shallow geothermal is discussed further in conjunction with Aquifer Thermal Energy Storage (ATES) and heat pumps in the sections below.

3.1.2 Heat Pumps

Heat pumps and chillers are sometimes confused as being separate technologies but are in fact one machine. Regardless of the type of the heat pump (ground source, air or other) the basic function is similar for all types. Heat pumps extract energy (low temperature) from one source and supply the energy to another source (higher temperature) or vice versa.

Only electrical driven heat pumps are addressed here.

A refrigerator gives a common example of a how a heat pump operates. In a refrigerator the heat source is the air inside the refrigerator. A coil filled with fluid runs through the back of the refrigerator. The fluid absorbs the heat energy from the air in the refrigerator resulting in cooling of the air and releases the heat energy to the room via a series of spirals (the condenser). The heat exchanging fluid is kept in motion by an electrically driven pump. The process can be seen in Figure 11 below.

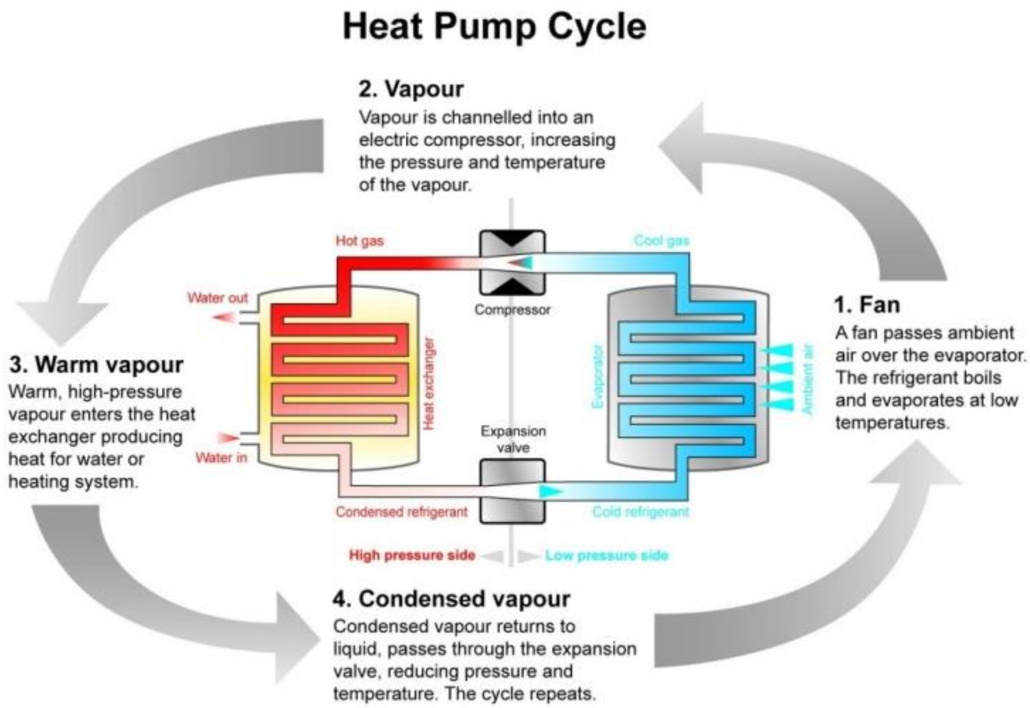

Figure 11 Heat Pump Cycle

Electrically driven heat pumps absorb low grade heat from a source such as the air, ground or water body and upgrade it via an electrically driven vapor compression circuit to provide space heating and hot water. Figure 12 describes the vapor compression circuit that operates within an air source heat pump.

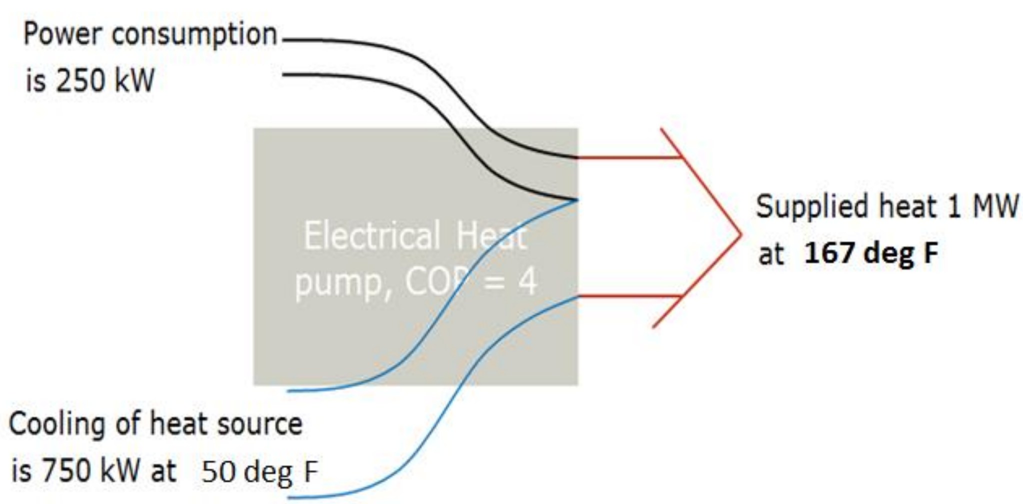

Figure 12 Vapor Compression Circuit with COP explained

The Coefficient of Performance (CoP) is defined as the total heat output from the heat pump divided by the necessary power input to the compressor. Therefore, the heat pump above has a CoP of 1,000 kW (thermal) / 250 kW (electric) = 4.0 as can be seen in Figure 13.

3.1.2.1 Efficiency of heat pumps

The higher the temperature of the heat source, the higher the efficiency it is possible to achieve for a given required supply temperature. Air or river/pond water could be a viable source during summer but the low temperatures during the winter period will lead to a lower efficiency.

Additional information on heat pump efficiencies can be found in Appendix 4.

3.1.2.2 Heat source for heat pumps

Depending on the heat source and the supply temperature for the heating demand, the heat pump design and efficiency can vary. In general the efficiency is higher the higher the energy source temperature is.

For this project the following heat sources have been studied:

- River or pond
- Ambient air
- Air-to-air (small split-unit)
- Air-to-water (VRF)
- Ground Source Heat Pump (GSHP) with vertical loops (Closed system)
- Aquifer Thermal Energy Storage (ATES) heat pump (Open system)
- Sewage

If there is an area or building where a heat pump is not feasible due to limitations in available space for installation or the available energy source, an electrical boiler can be used.

3.1.2.3 Integration of heat pumps

Overall power grids have previously exclusively had to handle production from very stable production sources of electricity. With the increasing interest in utilizing renewable sources as wind and solar, the power grids need to be able to handle power from these intermittent sources.

The higher the share of electricity from intermittent sources the higher the requirements are for the electrical grid, which would be required to distribute larger amounts of energy from different production sources and locations from time to time. The higher the share of intermittent electricity the greater the need becomes to utilize the electricity immediately or to store the energy.

Battery technologies are being developed but are still very far from being able to store larger amounts of electricity for longer periods. A high proportion of flexible heat pumps / chillers in an electrical system increases the share of intermittent electricity that can be accommodated in the energy system. In such a situation, excess RES production can be utilized by the heat pumps or chillers for production of cost-effective heating and cooling provided there is a demand for heat or cooling in a district energy network, or available thermal storage thus preventing electricity waste or wind turbine shut down.

Pumped storage is an alternative to battery technologies (if there is access to it) and is very efficient. During periods with high production from intermittent sources water is pumped up to the storage, which is typically at a height (utilizing an old quarry for instance) to create potential energy. When production is limited from intermittent sources or from fossil sources, the stored water will be released creating kinetic energy to move hydro-electric turbines to create electricity. Energy storage is further discussed in the sections below.

3.1.2.4 River or pond as heat source

Potential fresh water heat sources within the Cambridge area include Fresh Pond, the Charles River and the Mystic River. Extracting heat from the Mystic River was considered as a potential opportunity under this study and not the Charles River due to its shallow depth and capacity for freezing over or the Fresh Pond due to its limited size and resulting viability as a source. Based on the table below from the Massachusetts Water Resources Authority, it is concluded that normally the Mystic River isn't frozen.

Since the efficiency for a heat pump is mainly dependent on the temperature difference between the heat source and the supply temperature (in this case approx. 41 °F (5 °C) from Mystic River in the coldest months and 185 °F (85 °C) in supply temperature for the district heating) it is not expected that the COP will exceed 2.5 during winter. However, in summer and spring the efficiency would potentially be around 4.5.

Temperatures and water depths from Mystic River are indicated in Table 8 below.

	Average Temperature	Average Depth
	°F	Ft
January	38.1	19.6
February	35.8	20.2
March	38.9	19.5
April	45.2	19.5
May	53.0	19.7
June	59.6	18.6
July	63.2	19.2
August	65.6	19.4
September	64.2	19.4
October	57.8	19.8
November	49.8	20.4
December	42.6	20.9

Table 8 Mystic River Temperatures[37]

The temperatures are too cold for heat pumps in January to March. In December the achievable temperature difference is approx. 5.4 °F (3 °C). The average temperature is approx. 42.8 °F (6 °C) and the minimum temperature required for the heat pumps to avoid icing is approx. 37.4 °F (3 °C).

Under the assumption of a flow of water of maximum 925 gallons per second to the heat pumps and temperature difference of 5.4 °F (3 °C) in December and at least 50 °F (10 °C) in summer, it would be possible to supply a capacity of nearly 256 MMBtu/h (75 MW thermal) in December and 682 MMBtu/h (200 MW) thermal during summer.

The average COP efficiency of the heat pump would be approximately 3.

Capital costs for the installation of heat pump extracting water from Mystic River is estimated to $1 million per MW heat installed (all included) but there are many factors influencing the price; e.g. necessary lengths of the piping installation but also the access to local supply of electricity. Larger heat pump installation would require a higher voltage level and potentially it is necessary to include local substations.

[37] http://www.mwra.state.ma.us/harbor/html/wq_data.htm

A Mystic River Heat Pump installation with the above data would potentially be able produce approximately 40 % of the annual heat demand for Zone 1.

3.1.2.5 Air-to-Air Heat Pump

There are two types of air source heat pumps (ASHP), these are air-to-air and air-to-water. Air source heat pumps use the ambient outside air as the heat source, air-to-air heat pumps create warm air and air-to-water heat pump produces warm water.

Air-to-air heat pumps are only able to cover the demand for space heating whereas air-to-water heat pumps can cover the demand for domestic hot water as well.

Production of domestic hot water from air-to-air heat pumps would often be based on an electric boiler included in the heat pump installation. The consequence is that air-to-air has much lower efficiencies (when producing space heat and hot water) but investment costs are low as well. For residential buildings capital expenditure (CapEx) for air-to-water heat pumps is approx. 4-6 times higher than air-to-air heat pumps.

If a building's insulation standard is poor and it is necessary to supply heat at high temperatures during winter, a heat pump will be less suited since an electrical boiler will be necessary to supplement the production – either to increase the temperature or to produce the entire demand during low outside temperatures. It is assumed in this study that insulation concerns will be addressed through planned upgrades in accordance with the Net Zero Action Plan.

An air-to-air heat pump is typically installed in a residential buildings, but can be used for other purposes. The installation is simple and relatively low cost. The air-to-air heat pump uses air as the energy source on the evaporator side and warms the air inside the building with the condenser side.

For higher capacity requirements the evaporator units are quite large and could produce noise. The evaporators often occupy the roof tops in cities which otherwise could have been used for alternative purposes – e.g. green roofs or solar panels.

For smaller installations e.g. in residential buildings an ASHP is a good solution due to the low price of the installation. This type of heat pump is typically placed on the side of the building as one single unit. Therefore, we have used a capacity limit of 4-5 tons (15 kW) for air source heat pumps. For other building types, other technologies are preferred. The annually weighed efficiency (COP) is 2.5. SCOP is defined as weighted annual average of COP.

The air-to-water heat pump is more efficient and can be made with larger capacities. Large capacities require a large air intake that can be handled by for example dry coolers or cooling towers. The space requirements for this type are large as a result. The dry coolers or cooling towers can for example be placed on the roof top of a large building.

The plausible capacities for air-to-water heat pump for this project are estimated to be from the range of 9 tons (30 kW) to 34 tons (120 kW). The annual average efficiency (CoP) is estimated to be 3.

3.1.2.6 Ground source heat pump – closed loop

A ground source heat pump uses the warm shallow underground as an energy source. Tubes are drilled into the ground and heat is exchanged between the underground soil and a brine fluid in the tubes. A loop is typically 1 ton (2-3 kW) of capacity and the length is 500 ft.

A distance between two boreholes should be 16-23 ft. (5-7 m) and therefore a large available land area is required (approx. 270 ft.^{2}/borehole), which is why the potential in the densely populated built out part of the city is limited.

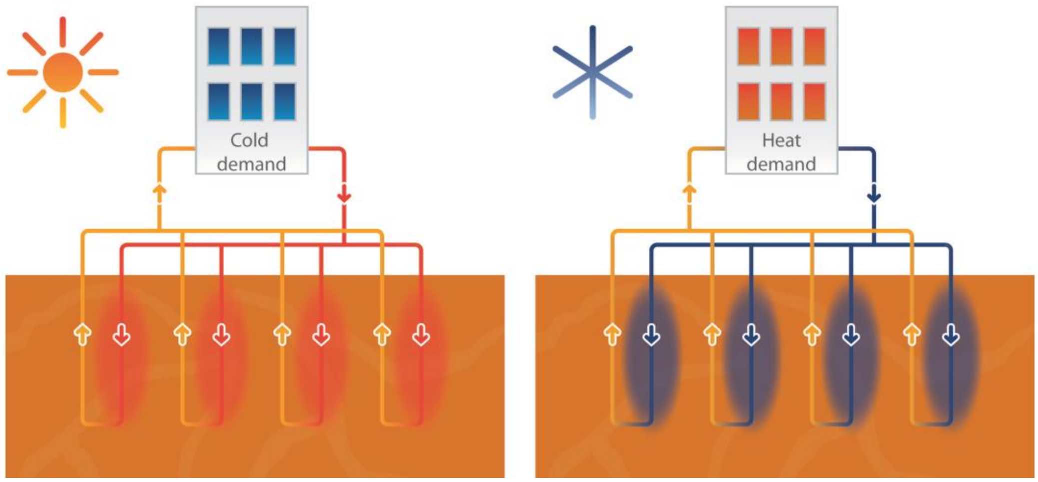

Figure 13 Ground Source Heat Pump System

Ground source heat pumps will have an average annually efficiency of approx. 3.5.

3.1.2.7 Aquifer Thermal Energy Storage – open loop system

The heat source for a heat pump could be the excess heat from cooling the buildings during the summer period. Since the demand for heating is limited typically to hot water usage during the summer period, seasonal storage would be necessary. In the following, aquifer thermal energy storage is explained.

In an Aquifer Thermal Energy Storage (ATES) system energy is stored in aquifers from 65 ft. to 1000 ft. below the surface. Water is pumped up from an aquifer, heat is extracted and relatively cold water is re-infiltrated in the same aquifer. A cold groundwater zone (41 to 50°F) develops around the infiltration well, which can be used for cooling in the summer. This water then absorbs heat from the building and energy can be stored in a corresponding warm water zone (60 to 86°F) and used to heat the building in winter. For heating in general a heat pump (not shown) will be used to boost the temperature for the in the building's loop. The principle of this technology is illustrated in Figure 14.

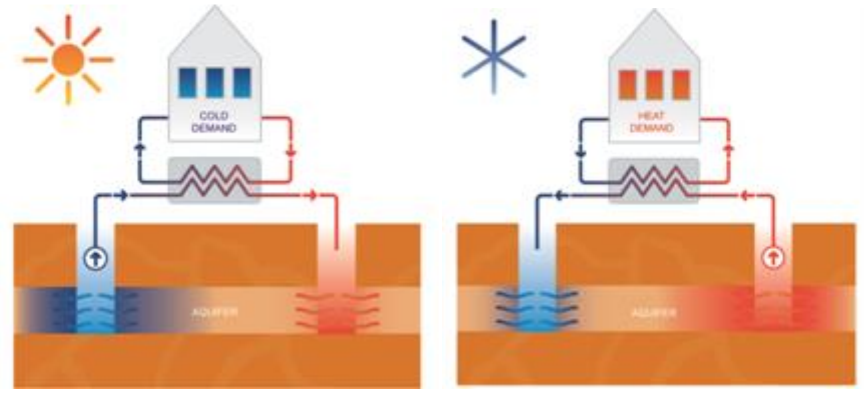

Figure 14 ATES Summer and Winter Season Examples

Characteristics of ATES

- Seasonal storage of energy, resulting in a "free" supply of heat and cold.
- Open loop system, but separated from the building circuit by a heat exchanger. This prevents pollution of the groundwater.
- Groundwater is extracted and infiltrated simultaneously: no net water depletion.
- Applicable depth: 65 to 1000 ft.
- High energy savings possible: up to 90% in cooling mode; 60% in heating mode.
- Average energy saving based on many realized systems: 50 – 70%.
- Average CO_2-emission reduction: 50 - 90 %.
- ATES is a very economically sustainable energy technology
- 90 US gal/min flow rate of a well can generate about 120 kW heating and/or cooling power.

As discussed in the sections above, the potential of an ATES system is very dependent on the underground structure. The underground of Cambridge is not optimal for ATES and therefore a low flow from each borehole is expected. However the flow is estimated to be 90 US gal/min (20 m3/hr) which could generate a heating capacity of 120kW per well. As a result this has been included within the scenario analysis where possible.

ATES is the heat pump solution with the highest efficiency, but also the highest investment cost.

3.1.2.8 Sewage

Waste heat from sewers can provide a low grade heat source when combined with a heat pump. The main benefit compared to other heat sources is that the temperature constantly is above approx. 50 °F (10 °C) which would provide a quite high efficiency for the heat pump.

Ramboll received sewer and pump station data from the City to identify areas of high volume sewer flow where heat could be extracted from the sewers. Two high volume flow areas were identified and the flow data was assessed for these. The volumes at these high volume points for the City of Cambridge will provide less than 6.8 MMBtu/h thermal (2 MW thermal) of heat and so are not included as a potential heat source going forward due to this limited potential compared to the cost of implementation.

Therefore, we have not considered sewage water as part of the energy system in this study.

3.1.3 Electric boilers

Electric boilers are very simple units for heat production and would be comparable with a simple household cooker.

The main advantages with an electric boiler compared to e.g. a heat pump is that it does not require any heat source for operation, they can operate even during periods of low external temperatures as long as they are supplied by electricity. They are very simple and inexpensive. The COP is 1 which means that the amount of electricity to the boiler corresponds to the thermal output. A heat pump uses 3 to 4 times less electrical demand compared to the thermal demand (COP of 3-4).

In the scenarios electric boilers are used when it is very cold outside, and there is limited or no sources for the heat pumps. Electric boilers are necessary in Zone 1 when the capacity requirements are high. Electric boilers are also used for backup production purposes to the district heating system when heat pumps unexpectedly are out of operation.

3.1.4 Biomass cogeneration

Biomass cogeneration is an appropriate technology for district energy. Under the RPS scheme (225 CMR 14.00), plants which generate heat and power with an efficiency of 50% receive one half of a renewable energy credit (REC), while those with 60% will receive a full credit. It is possible to reach a high efficiency far in excess of 60% in the energy plant with biomass, thus qualifying for REC credits in Massachusetts and making biomass an accepted renewable energy fuel by the state. Significant additional discussion in Cambridge is necessary to determine whether biomass should be considered a carbon-neutral fuel source (see Section 6). Due to the production of electricity it will additionally reduce the dependency of electricity imported to Cambridge.

Eligible biomass is defined by using the Biomass Eligibility and Certificate Guideline published by the DOER in August 2012[38]. These guidelines state amongst others, that in order to receive REC's, biomass projects must utilize Massachusetts available biomass resources, demonstrate significant reductions in greenhouse gas emissions and protect forests. As a result to comply with the City's goals, any biomass CHP should have efficiency in excess of 60% and a biomass supply from Massachusetts which meets the eligibility guidelines. The Siting Board may also require an Environmental Impact Report to be prepared when site location, fuel source and technologies are selected.

It is good practice to locate energy production facilities at the outskirts of the cities to reduce environmental impacts within the city boundaries while still providing the benefits of local generation. Other benefits associated with locating plants on city outskirts are: improved access for fuel supply and the potential to exploit synergies with other production facilities.

If all in-city production were moved to the city outskirts, the land currently occupied by these facilities would become available for future development. This would mean an increase in land values in these areas.

The Mystic River plant location is already in existence and used as a power plant, has potential infrastructure that could be re-used such as cooling water intakes, and has good fuel delivery potential due to its proximity to the river. Available space for fuel storage or plant expansion may also be possible at this site but needs to be explored further. It is therefore considered to locate the plant near the Mystic River plant and supply neighboring cities with heat and power due to the limited available space within the City of Cambridge and limited fuel supply delivery options. This location is considered as a potential option for progression in this study due to the above conditions, but would require relevant stakeholder consultation and further studies to understand the realistic potential of such a site.

Biomass for the plant would most likely be supplied by large ships which are able to use the existing harbor facilities (or with limited extensions).

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[38] http://www.mass.gov/eea/docs/doer/renewables/biomass/biomass-eligibility-and-certificate-guideline.xlsx

Table 9 shows the different vessels for biomass transportation.

Table 9 Different vessels used for biomass transportation

Type of Vessel	Draft	Length	Width	Volume	Cargo size	Cargo Size 1
		LOA	Beam		Wood Chips	Wood Pellets
	Ft	Ft	Ft	US Barrel	ton	ton
Coasters	13-20	328-394	42-49	10-63,000	2-3,000	3-6,000
Barge	13-23	360-650	49-65	95-190,000	5-10,000	10-20,000
Handysize	10-11	500-650	65-82	220-280,000	10-15,000	20-30,000
Handymax	33-36	500-650	82-115	380-470,000	20,25,000	40-50,000
Panamax	43-49	720-750	100-130	500-700,000	25-35,000	50-70,000

With an approx. consumption of 500,000 tons biomass (wood chips) (based on heat capacity of approx. 500 MMBtu/h (150 MW thermal) per year a vessel with the capacity 15,000 to 25,000 would be necessary 2-3 times per month on average. Smaller vessel might however also come into consideration. It might be necessary to increase the depth of the harbor. This is however not assessed further in this study.

Based on 500,000 tons of biomass a biomass cogeneration plant with a capacity of 500 MMBtu/h would be able to supply most of Cambridge with heat (in combination with other technologies) and electricity. Such a plant could however be sized to supply the areas surrounding it in addition to Cambridge with heat and power.

For further considerations about the capacity of the plant see Section 5 below.

3.1.5 Biomass heat only

Small or large heat only plants are much simpler than cogeneration plants and are more flexible when a suitable location is found. As with the larger plants, it will be difficult to locate larger biomass heat only boilers in Cambridge due to the limited space and necessary transportation of fuel for the plant.

3.1.6 Waste to Energy Plants

Waste-to-energy plants are waste management facilities which combust solid waste to produce electricity and heat through cogeneration. Modern waste-to-energy plants are very energy efficient. Waste-to-energy plants are designed to reduce the emission of air pollutants in the flue gases exhausted to the atmosphere, such as nitrogen oxides, sulfur oxides and particulates, and to destroy pollutants already present in the waste, using pollution control measures such as baghouses, scrubbers, and electrostatic precipitators. However, due to the limited volumes of waste generated in Cambridge, a WtE facility is not deemed viable.

Similarly Anaerobic Digestion plants which use the anaerobic digestion process to generate methane gas were not considered further as the volume of biodegradable waste is only a fraction of the total solid waste generated within the City and therefore insufficient to meet the fuel demand.

3.1.6 Water Based District Energy networks

A district energy system consists of central energy production in the forms of hot water or chilled water, a water pipe network distribution system of the energy and finally a heat exchanger station (also called "Energy Transfer Station" or ETS) located at the consumer. The network is thus a carrier of the energy produced centrally. Furthermore, there is often a large thermal energy storage connected to the network to enable independent production of electricity and heat, if the production technology is based on cogeneration. The networks are often city wide and supply several thousand consumers with hot or chilled water.

Some of the benefits are:

- Lower investment costs. Although it is necessary to invest in a network the total capital costs will often be lower due to economies of scale for the production units
- Lower necessary capacity since heat (or chilled water) is not needed at the same time
- Environmentally friendly since it is possible to integrate alternative generation sources such as solar PV and wind using thermal storage when electricity production is high
- Lower operation and maintenance costs than traditional steam networks
- Facilitates the use of both heat and power from CHP plants, thus providing highly efficient energy generation
- Allows for the incorporation of low temperature waste heat sources

3.1.6.7 Design of district energy networks

As this is high level assessment of the energy system in Cambridge no detailed design has been developed. When the phrase "Design" is used in this report it refers to a high level masterplan for potential networks in Cambridge.

Since we don't know the condition, extent, age and design data for the existing steam based district heating systems in Cambridge it has not been possible to evaluate whether any of the existing infrastructure can be reused in a district heating hot water network[39]. All evaluations are based on entirely new networks.

The district heating hot water network is designed for supplying of heat for space heating as well as domestic hot water. The district cooling networks (consisting of several smaller networks) will supply chilled water.

District heating networks are designed for the heating demand in the short and medium term within the relevant city zones. The long term forecast for Cambridge predicts a significant reduction in heat demand in the city due to more energy efficient buildings and a warmer climate. This long term assessment is based upon a number of estimates with significant uncertainty and there is a risk that if networks are designed for long term reduction in demand the network may not be capable of meeting the medium energy demand. As the network is built out over time change in demand projections will become more certain and planning can be carried out on a phased basis.

The demand for cooling is predicted to increase over the planning period and the design for a district cooling network is based on the projected demand in 2040. Again this is to avoid a situation where the infrastructure is not capable of supplying all customers.

District energy network pipe sizing is dependent on the difference in temperature between the hot water supply to a building and the temperature of the return water. The larger the difference between the two temperatures, the smaller and cheaper the pipes will be. For this reason a key

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[39] Steam district energy networks consist of a flow pipe and a condensate return pipe. Sometimes there is no return pipe or it is far smaller than a hot water return pipe. In most instances retrofit from steam for hot water use is not possible for optimal design.

aspect of network design is to ensure the efficient operation of buildings where the return temperatures can be reduced.

Building conversions from non-hydronic to hydronic systems will be required in Cambridge to meet temperature requirements for a district energy network should this be found to be the preferred option. More details are outlined in Section 3.3.

District energy requires district heating systems to strive for low system temperatures and district cooling to achieve higher system temperatures. Higher temperature district cooling increases the efficiency of chillers connected to the network.

Low temperature heating would allow for greater utilization of waste or excess heating sources in the city (as e.g. industrial heat or surplus heat from chillers). This would lead to an overall improvement in the efficiency of the thermal production plants in the city.

Since conversion of internal heating systems to hydronic systems would take a long time it is necessary to initially design the district heating network to have adequate capacity to supply the city buildings which are suitable for immediate connection due to their existing internal heating system configurations. The heating network will be further built out gradually. Over time an increasing number of buildings will have modernized their internal systems and there should be a gradual reduction in the demand due to climate change and more efficient buildings.

Key design parameters for the DHC networks:

- Maximum temperature of heating network of 212°F (100°C)
- Maximum operating temperatures will be designed for 185°F (85°C)
- Temperature difference of heating network is designed for 36°F
- Design supply temperature of the cooling network is assumed 43°F and return temperature is assumed 61°F

District heating and cooling can take advantage of the variance in heat demand profiles between a large number of building types. This has the effect of smoothing out the overall demand profile and therefore reducing the required peak capacity of thermal energy plants and distribution networks without any losses to customers in terms of the quality of service.

3.1.6.8 Peaking and backup supply

A district energy system will be supplied by several production units. Such production units have high investment costs but low variable operating costs. These plants should be used for the base load production. Since these plants have high capital costs they should not be designed for peak production.

Peak production units instead have very low capital and high operational costs. They should only be in operation for peak production for a limited number of hours per year. Often, peaking units will produce between 2 and 15 % of the annual heat demand. These boilers should be used for backup purposes to provide resiliency in case the base load production units fail. For this reason they require a reliable fuel source in terms of availability, transport and production.

It is recommended to have more than one peaking / backup boiler available. Since capital costs are low this redundancy provides a good guarantee that heat can be supplied in all situations.

For chilled water supply, chillers are in general used both for base load and peaking / backup.

3.1.6.9 Service pipes

Service pipes are the pipes connecting the consumer with the main pipe in the street. These should be designed for maximum capacity to the consumer.

3.1.6.10 Technical lifetime of district energy networks

District heating hot water networks will have a very long technical lifetime of more than 50 to 60 years. Due to the lower temperature in the networks and the modern insulation materials the insulating capacity will be maintained throughout the technical lifetime.

When doing financial analysis it is important to take the long technical lifetime into account. Often, and also in this case, the estimates are conducted over a planning period of 20 years. Therefore, there will be a significant residual value in the network by the end of the period. This will figure as a negative cost in year 20 in the calculations. The residual value is estimated from a linear depreciation of the initial costs.

The same methodology is used for other technical appliances with a technical lifetime of more than 20 years.

3.1.6.11 Substations

For the Cambridge system it is recommended to install Energy Transfer Substations (ETS) in the buildings where district energy is to be installed. These units maintain a separation between the district energy network and the buildings, providing a commercial interface with cost and technical protection for both the building owner and the network operator/owner.

If areas of the City are to be enabled with district energy, all the existing installations (boilers etc.) need to be removed and a new ETS installation needs to be installed. The required space for an ETS installation will typically be far less than for a boiler. The change would happen gradually from year 2020 to year 2040 as areas are converted and consumers chose to connect.

In areas of the city which are not to be enabled with district energy, existing installations at the end of their useful life should be considered for replacement with heat pump technology alternatives. One or two family building types can be equipped with an air source heat pump (ASHP) whereas larger building types in the residential areas can be supplied by ground source heat pumps (GSHP) where the space is available as discussed in Sections 3.1.2.5, 3.1.2.6 and Section 5.

When converting from existing installations (e.g. natural gas boiler) to district heating the boiler must be removed and the boiler room should be prepared for the ETS installation. This should be done in as economic a manner as possible, with ETS installation at the end of the design life of the existing domestic heating installations.

3.1.6.12 Thermal storage

Thermal energy storage in this case refers to tank storage where thermal energy (hot or cold) is produced at times of low demand in the network and stored until periods of high demand to smooth peaks in the demand profile from the network. This can have the effect of increasing the utilization of base plant, lowering the overall operating costs.

Thermal storage tanks for district heating contain cold water in the bottom (corresponding to the return temperature) and warm water in the top (corresponding to the supply temperature). There is no mechanical separation between the cold and the warm water. What separates the two is the difference in the specific density of the water due to the different temperatures. Normally, the separation layer is less than a couple of feet in height and within this height the temperature changes from e.g. 50 °C to 95 °C.

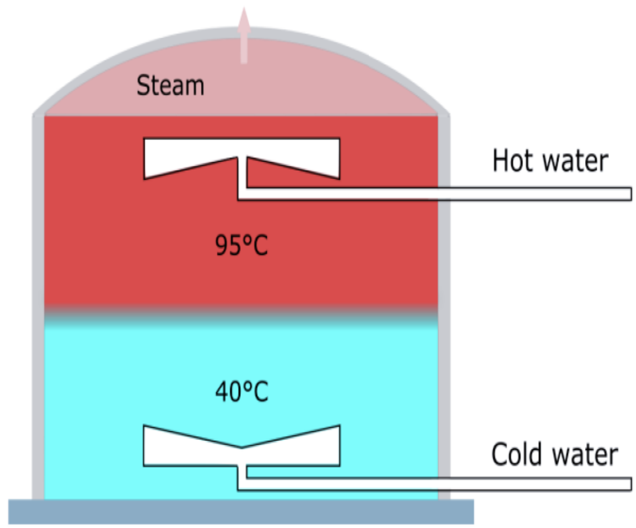

Figure 15 Illustration of a Thermal Energy Storage tank

The water level in the tank will not vary noticeably.

A thermal storage tank would be insulated to maintain a surface temperature according to applicable standards. Chilled water stores have very low surface temperatures which cause moisture to condense. Therefore, cooling storage should be insulated as well but with air tight insulation keeping out the moisture of the surrounding air.

Atmospheric tank thermal energy storage with the relevant capacity for a Cambridge project will have specific costs of approx. $180/m3 or 0.70 $/gallon including internal mechanical equipment, connections, insulation and foundations. The sizing and location of thermal storage tanks is dependent on the site of the energy generation station.

3.1.7 Photovoltaic (PV)

In terms of renewable energy generation, the City has limited space for large scale solar PV within the City boundary. However, solar PV panels can still be located on building roofs inside the city. Solar thermal can equally be installed on building rooftops, however this will increase the electricity required to be supplied from outside of the City of Cambridge. This analysis therefore prioritizes roofspace for solar PV.

It has not been investigated if the local electricity grid can withstand the increased solar PV production; however maximum deployment of solar PV within the city boundary is assumed to show how much PV electricity can be generated from roof top solar.

Floating PV on Fresh Pond

As decentralized renewable energy electricity generation is limited within the City, all surface areas where PV can be installed should be considered to contribute to the demand required. Fresh Pond could provide a large surface area for floating solar panels.[40] To demonstrate the potential, it is assumed arbitrarily that 30% of the surface area of the pond is covered with floating PV, then

[40] https://www.nrel.gov/technical-assistance/blog/posts/floating-solar-photovoltaics-gaining-ground.html

approximately 1.4% of the City's total electricity demand forecasted for 2040 (1,151 GWh) could be met. If this is increased to 60% of pond surface area, this would double the electrical output to 2.8%. The capital, environmental and social costs and benefits of the use of this open water source compared to investment in wind farms or other generation solutions external to the city should be considered further prior to proceeding with such an option.

3.1.8 Wind turbines

The wind potential and available locations for wind turbines has also been identified as limited inside the city. However, buying REC's from existing wind farms or investing in wind turbines outside the city is an option for the City to meet its low carbon objective. This is discussed further in the sections below.

3.1.9 Microgrids

Microgrids can save on distribution costs (as the micro-grid owner does not have to pay grid operator their set tariff) and provide resilience in black out situations; however they are considered an enabling technology and not a low carbon energy supply technology. Microgrids enable electricity generating plants to achieve better rates for the electricity they generate. Typically microgrids would be considered as a way to add value and contribute towards the business case for a combined heat and power or renewable energy plant. In a situation where dual located networks (microgrid and existing grid) are operating, energy losses from supply can be increased as both networks are losing energy through distribution losses as they distribute electrical energy within the same area in parallel. Consideration of microgrids in this project will be driven by the identified supply technologies in their finally decided locations and the technical and economic requirements needed to realize these supply options.

3.1.10 Battery technologies

Battery storage is still very expensive compared to market competitive storage technologies and can store a limited amount of electricity. In the last decade the technology has only slightly improved. A successor to the Lithium-ion technology is in development but this new technology still needs to prove its capabilities and be tested at scale. Following this it will most likely take numerous years before the costs are on an acceptable level compared to competitive technologies.

As an example, the world's largest combined solar PV plant and battery storage is planned to be commissioned by the end of 2017. The capacity of the solar PV plant is 300 MW and the capacity of the battery storage, consisting of 1.1 million batteries provided by TESLA, is 100 MW and 400 MWh i.e. it can supply 100 MW of electricity for 4 hours. The costs for the plant are expected to be $1 billion. As a comparison the average Cambridge consumption (electrical appliances) is close to 200 MW electric. This is without heat pumps, chillers, electric boilers, electric vehicles etc. Thus, the total demand would only be covered for a very short time at a significant cost.

Battery storage can be used for reducing the smaller fluctuations in the frequency from intermittent renewable technologies such as e.g. from wind farms. However, other technologies such as electric boilers (and likely chillers and heat pumps as well) supplying thermal storage will be able to provide a similar function. These technologies have significantly lower costs than battery storage.

Battery storage is often used in residential buildings for short term storing of excess electricity from solar PV units or micro wind turbines. However, these storage costs would be significantly lower if the electricity could be stored by the local distributor and not the consumer as the storage is at scale.

As said above, battery technology is useful for providing peak shaving in periods of high electricity demand and frequency stability, but contributions to a low carbon energy supply are limited by storage durations and the low carbon electricity still has to be generated.

Chemical battery technology today at the scale required for Cambridge is currently prohibitively expensive and would require significant amount of space for a city scale project. The technology costs and space requirements are expected to continue to decrease, however the Lithium technology behind this is not expected to improve in order to meet the demand of the City in the course of the next 2020+ years. However, battery technology may also act as a technology enabler, facilitating more PV generated electricity utilization for instance, and will form part of the low carbon energy supply transformation process.

3.1.11 Waste heat from MBTA subway system:

This has been examined and ruled out a source of low grade heat, as it is a minor heat source in Cambridge with limited potential compared to the cost of implementation.

3.2 Conversion of buildings from non-hydronic to hydronic heating

To enable modern low temperature district heating in the buildings, internal building mechanical installations need to be converted to allow for temperature reductions in the buildings. The buildings which are non-hydronic need to be converted to hydronic heating with modern radiators.

From the energy demand database it is estimated that approximately 8.7 million square feet of buildings need to be converted.

We have assumed a cost of $12.9/sq. ft. for conversion based on project data compared against the RS Means construction cost database.

The total costs for converting from non-hydronic to hydronic are estimated to be $112 million. This figure is exclusively for buildings in the "Potential District Heating" zones.

The technical lifetime of the building conversion is estimated to be 50 years, so for the internal building installation the residual value will be significant as well.

3.3 Reinforcing the overall electrical grid

In a full electrification scenario it is assumed that individual electrical heating units are located in each building (heat pumps and/or electric boilers). In a full electrification scenario with district energy supply it is assumed that district energy networks are located where economically feasible.

The main thought concept behind any level of electrification is that the electric system is moving towards increased renewable energy integration. In addition electricity is easy to transport and has an established distribution system.

Converting the existing production from fossil fuel boilers to full electricity would have significant consequences for the overall electric system. Some parts of the grid may be able to transport an large increased amount of electricity but the margin at which the grid will fail will decrease, meaning brownouts and blackouts in these areas may be more frequent. All power lines including substations serving the city will need to be redesigned as will all internal distribution within the city. The costs of such a conversion is difficult to determine and any estimate would be subject to significant uncertainty. This uncertainty is exacerbated by a lack of available information as to the strength and capacity of the existing network.

Ramboll has experience in reinforcing the electrical grid for a larger city in the UK. We have used specific costs which were determined for this project, factored for the US. One should always be careful using information from project to project since the external assumptions, codes and regulations can be very different. However, without specific estimates from Eversource and for this high level of planning we consider this to be adequate.

Under a business as usual scenario, a large proportion of building owners (especially in residential areas) would likely consider buying heat pumps, even without any further incentives from the city, as the technology becomes more familiar and cost competitive. This is a situation that Eversource could be expected to be planning for. This would mean that they would need to take action to reinforce parts of the grid to accommodate this increase thermal electrical load, notwithstanding the actions of the city in moving towards a fully electrified scenario. Additionally, there will likely be increased demand on the electrical grid due to electrification of transport. This is not considered in any of the scenarios as it is outside the scope of this study.

Eversource cannot, however, be expected to be planning for full electrification of the city's heating system. Costs which should be included in the calculations are exclusively the added costs as a consequence of the city moving towards full electrification.

The potential for establishing large scale heat pumps in the densely populated areas of the city is limited. Therefore, it is assumed that Eversource has not planned for any (or very limited) increase in the necessary capacity increase. Therefore, the entire necessary capacity increase should be included in the cost estimates.

Based on the experience of Ramboll's project in the UK it is assumed that the specific reinforcement costs are $2.2 million per MW electric capacity. This figure is used for determining the total costs for reinforcing the overall grid and the internal city electrical grid from higher voltage level to lowest connected to the buildings.

All costs are within the city limits from high voltage substations to the lowest voltage level. There are thus no costs included in reinforcing high voltage lines (transmission) connecting to the substations. These costs should be taken into consideration as well. It is assumed that these costs amount to 10 % of the cost for reinforcing the internal city grid.

3.4 Carbon Offsets, Renewable Energy Certificates, Power Purchase Agreements and similar approaches

Due to the limited available space and renewable energy sources in a developed urban space such as the City of Cambridge, there is limited potential for energy generation within the city's boundaries. As a result, no matter which scenario is selected, there will be a need for the City of Cambridge to import electricity in order to meet its energy demand as it does today.

This dependence on external supply means that the City has limited control over the carbon intensity of the electricity supplied to the city, and will be reliant on the greening of the New England Power Pool (NEPOOL).

Figure 16 below is based on ISO-NE presentations and shows the forecast for renewable energy supply in the New England region, forecasted linearly towards 2050. By 2040, it is expected that NEPOOL will be supplied by 38% renewable energy. Based on this projection, for every unit of electricity imported by the City, it would need to compensate carbon emissions from 62% of this amount through Carbon offsets or Renewable Energy Certificates in order to be carbon neutral.

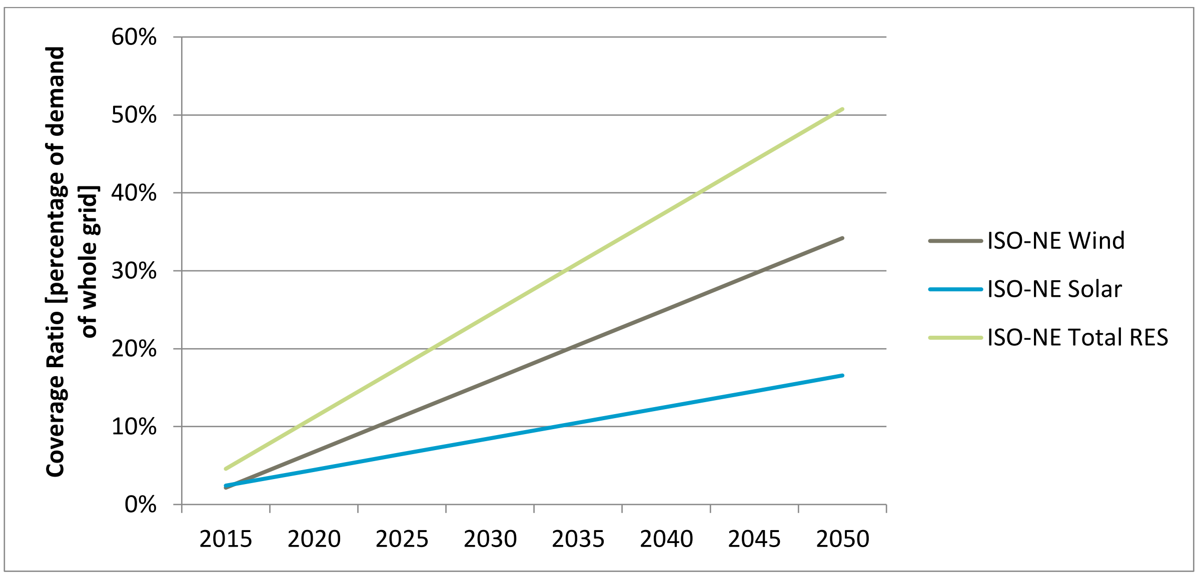

Figure 16 Forecast for renewable energy supply in the New England

3.4.1 Carbon Offset

Carbon offsets can be bought on global markets based on different emission mitigation projects.

One approach is to buy CO_2 quotas in the Regional Greenhouse Gas Initiative (RGGI) or European Union Emissions Trading Scheme (EU ETS) and take them off the market. In the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont a Regional Greenhouse Gas Initiative (RGGI) is operated, which corresponds to the EU ETS. An option for Cambridge would be to buy RGGI certificates without reselling.

Still, consideration should be given by the City as to whether this approach meets the goals of the City's net zero ambition, as the amount of CO_2 allowances available in RGGI are adjusted in a political process. Currently this process allows for additional allowances to be added if a cap is triggered, without these allowances being borrowed from future years, as is the situation in other allowance reserve system programs. Lately it was seen that when the prices rose too high (high demand, low supply), new allowances were put back into the market. This decouples the supply and demand market pricing, thus maintaining a level of cost for the quotas while demand rises. As a mechanism this does not significantly increase the viability or incentivize renewable projects versus traditional fossil fuel projects, as the quota price for carbon is increasing in a very controlled manner.

The operation of such quota schemes should be considered by the City when deciding to invest in them, as not all of the purchase price of the quota goes towards renewable projects or carbon abatement due to administrative fees or similar, as illustrated in Table 10. Additionally, the effectiveness or value for investment of the projects developed is outside the City's control.

Table 10 Estimated allocation of Auction Revenues by Category ($ millions) 2008 - 2014[41]

State	Energy Efficiency	Direct Bill Assistance	GHG Abatement	Clean and Renewable Energy	Administration	RGGI, Inc.	State Budget Deficit Reduction	Committed to 2015 and Future Programs	Total
Connecticut	74			25	8	1		16	124
Delaware	16	2	3	3	2	<1		37	63
Maine	34		1		1	<1		17	53
Maryland	87	177	16	26	13	3		53	375
Massachusetts	244		40	15	6	3		12	320
New Hampshire	46	24			1	>1	3	1	75
New Jersey (2008-2011)	44		10		5		65		124
New York	242		107	79	30	5	90	172	725
Rhode Island	13			>1	1	<1		21	35
Vermont	14				<1	<1		<1	14
Total	814	203	177	148	67	12	158	329	1,908

[41] https://fas.org/sgp/crs/misc/R41836.pdf

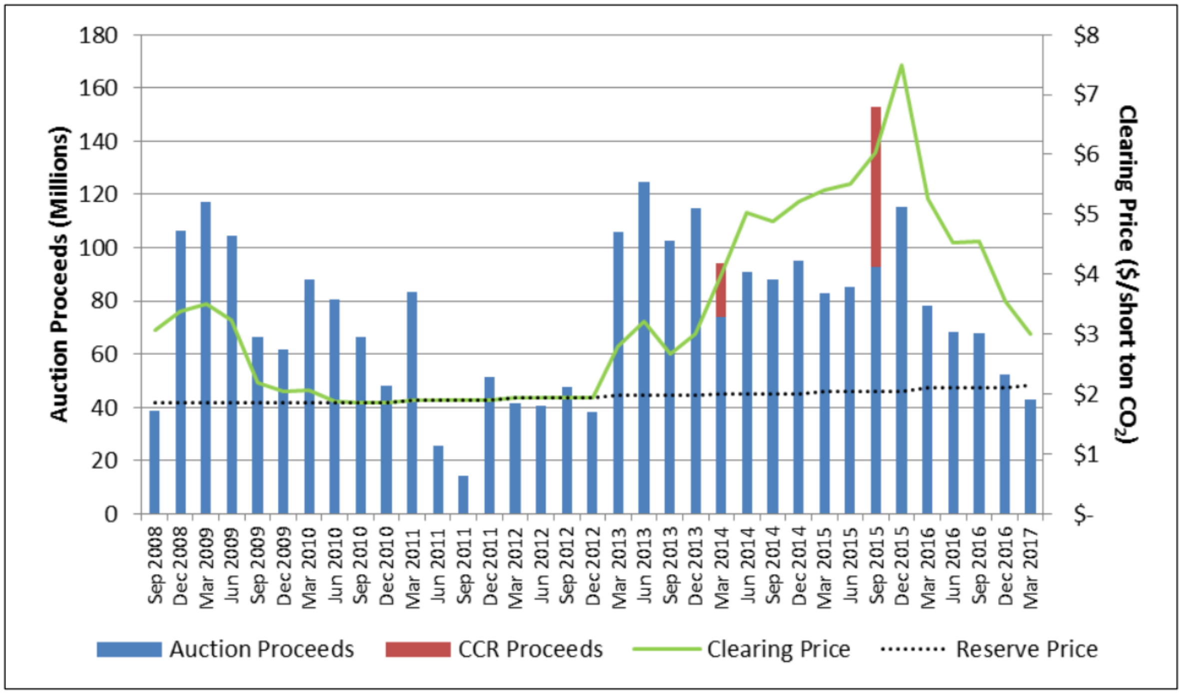

Figure 17 RGGI Auctions Proceeds and Clearing Prices 2008 – 2017

The estimated cost of buying RGGI certificates for Cambridge in 2040 is uncertain. Figure 17 shows the clearing prices experienced in recent years, with \$3/ton CO_2 being a recent auction price, but this has been as high as \$7 ton CO_2. The quantity of certificates will ultimately depend on the scenario selected for implementation and the emissions resulting in the year 2040 and onward. Estimations for each scenario are given in Section 5.

This carbon offset approach can be an expensive and unpredictable process impacting energy costs for consumers as the funding for such quota purchases will likely derive from energy consumption bills.

3.4.2 Renewable Energy Certificates

Unlike carbon offsets, the Renewable Energy Certificates (RECs) do not guarantee a CO_2 reduction directly. Instead, the CO_2 reduction is indirect assuming that renewable energy does not emit any CO_2.

Renewable Energy Certificates are traded on national markets in the US and are used to subsidize electricity generated from renewable energy sources. RECs represent proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource.

Large companies are known to buy these certificates to have a green profile and the same certificates are used by energy distribution companies to comply with state renewable portfolio standards (RPS). It should be considered if investing in these certificates introduces the equivalent amount of new renewable energy into the market to compensate for fossil fuel derived energy consumed within Cambridge.

In terms of prices there are essentially two REC markets; the compliance market and the voluntary market. In states with RPS, the renewable energy generators can sell their RECs to electric utilities, who must purchase these (compliance market). In states without RPS, the renewable energy producers can sell their REC to voluntary purchasers like private companies and often at a much lower price.

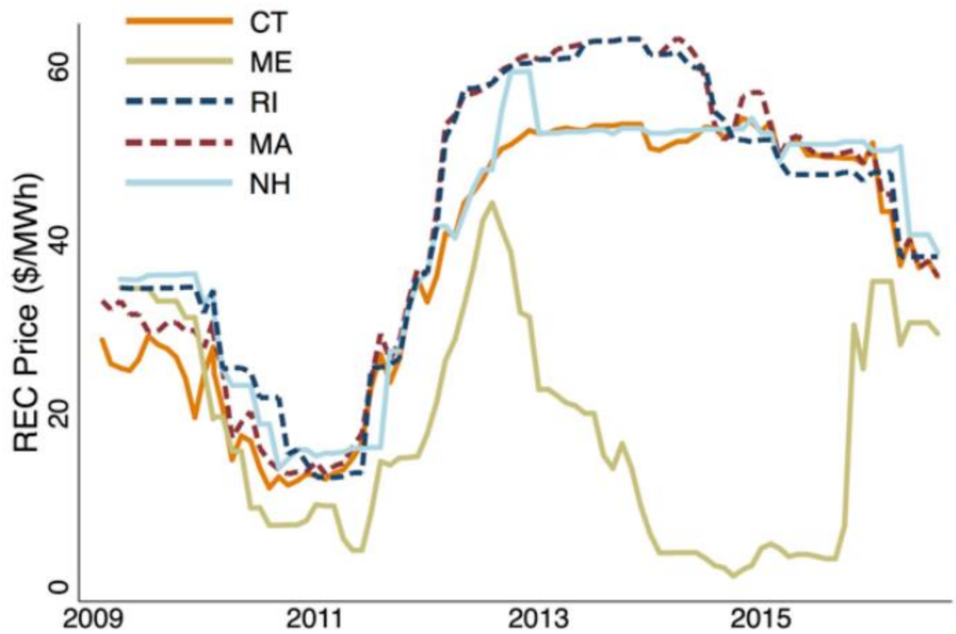

Figure 18 Compliance REC prices (excluding SRECs)[42]

As can be seen in Figure 18 above, the REC price in Massachusetts is approximately $35/MWh in January 2016 in the compliance market (this excludes the Solar REC (SREC) which currently has a higher price). However, the voluntary market price shown in Figure 19 is approximately $0.5/MWh, which is significantly lower. Cambridge does not have to comply with the RPS, so they could buy RECs in the voluntary market from other states.

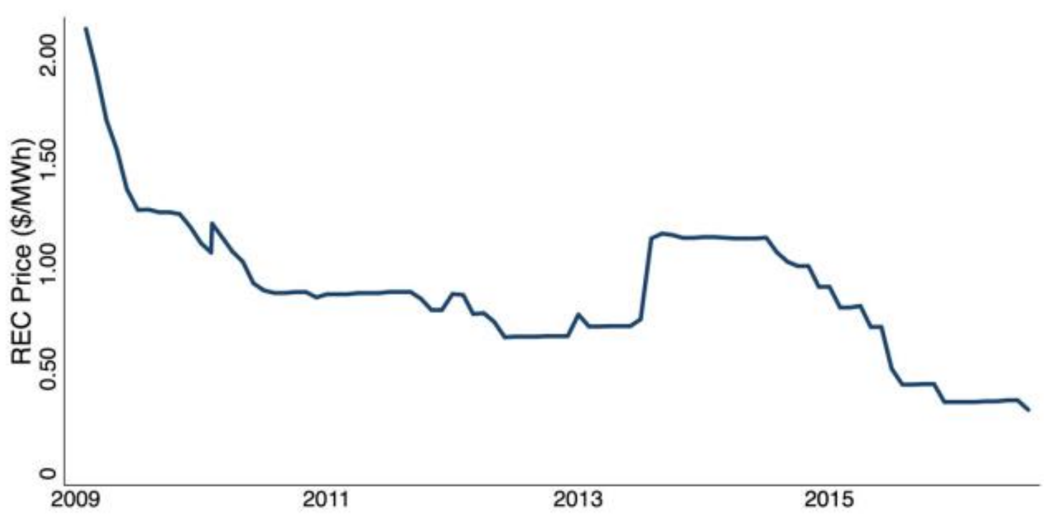

Figure 19 Voluntary national REC prices[43]

In a very conservative estimate we assumed a price of $30/MWh to evaluate a potential annual cost for purchasing RECs.

The quantity of RECs required will ultimately depend on the scenario selected for implementation and the quantity of non-renewable energy used by the City in the year 2040 and onward. Estimations for each scenario are given in Section 5.

[42] https://www.nrel.gov/docs/fy17osti/67147.pdf

[43] https://www.nrel.gov/docs/fy17osti/67147.pdf

Some certificates can be cheaper than others depending on the type of production facility, location and state initiatives. Because the Renewable Energy Certificate functions as a subsidy to renewable energy producers, the price is higher than the RGGI CO_2 price. However, any offset/REC purchases would have to satisfy City criteria of additionality to be considered legitimate.

3.4.3 Power Purchase Agreement (PPA)

Another option is to engage in a Power Purchase Agreement (PPA) where the REC is retained by the purchaser (ie. City of Cambridge). This is where a customer enters into a long term contract with a generator to buy electricity, and when it is from a qualifying renewable source this electricity can be accompanied by the REC per MWh purchased.

3.4.4 Community Choice Aggregation (CCA)[44]

Massachusetts[45] is one of seven states to date that have passed legislation (Massachusetts General Law c. 164, § 134) which authorizes municipalities to aggregate the electrical load of customers within their borders to form community choice aggregations (CCA) to procure a competitive (or renewable) supply of electricity.

Where such an aggregation is established, individual electricity customers can be automatically enrolled into the electricity service selected by the CCA, and customers can opt out if they don’t want to participate.

The current process for a Municipality to create a Municipal Aggregation Program is as follows:

1. A municipality must vote to initiate the municipal aggregation program.
2. A municipal aggregation plan is prepared in consultation with the Department of Energy Resources.
3. Citizen review period for the municipal aggregation plan.
4. Submit a municipal aggregation plan to the Department of Public Utilities for review and approval

Sustainable Westchester[46] is an example of a community of 110,000 homes in New York which formed a CCA to purchase 100% renewable electricity in 2016.

PPAs or CCAs can provide the financial basis for private renewable energy project developers to proceed with new renewable projects which are external to the boundaries of the City of Cambridge, allowing the City have more control over its electricity source while not having the generation within the City.

Cambridge currently signed an 18 month contract with Agera Energy in July 2017 to provide renewable electricity under a Community Electricity program. Under this Community Electricity Program Eversource will continue to deliver electricity to Cambridge, but the City will now use a competitive bid process to choose its own electricity supplier. Options within this program allow residents of Cambridge to receive 25% more solar energy than required by the state by default, or 100% renewable electricity if they choose to opt-in[47].

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[44] https://www.nrel.gov/docs/fy17osti/67147.pdf
[45] http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/electric-market-info/muni-agg.html
[46] http://sustainablewestchester.org/
[47] http://www.masspowerchoice.com/cambridge

4. SCENARIO DEVELOPMENT AND SHORTLISTING PROCESS (WORK PACKAGE 2)

Following Work Package 1 which established the baseline situation for energy demand, supply and regulations as discussed in the section above, Ramboll proceeded with Work Package 2 (WP2). The objective of WP2 was to develop 1-3 low carbon energy supply scenarios for detailed analysis under Work Package 4[48].

This section outlines the process that was undertaken in order to develop the shortlisted scenarios and a high-level overview of each scenario considered. Additional information on the process and information provided during this work package can be found in Appendix 2.

Figure 20 below gives a visual representation of the iterative process that was undertaken in order to select scenarios for further evaluation. The City's energy supply goals (as outlined in Section 1.2) were used to qualitatively assess the scenarios throughout the WP2 process.

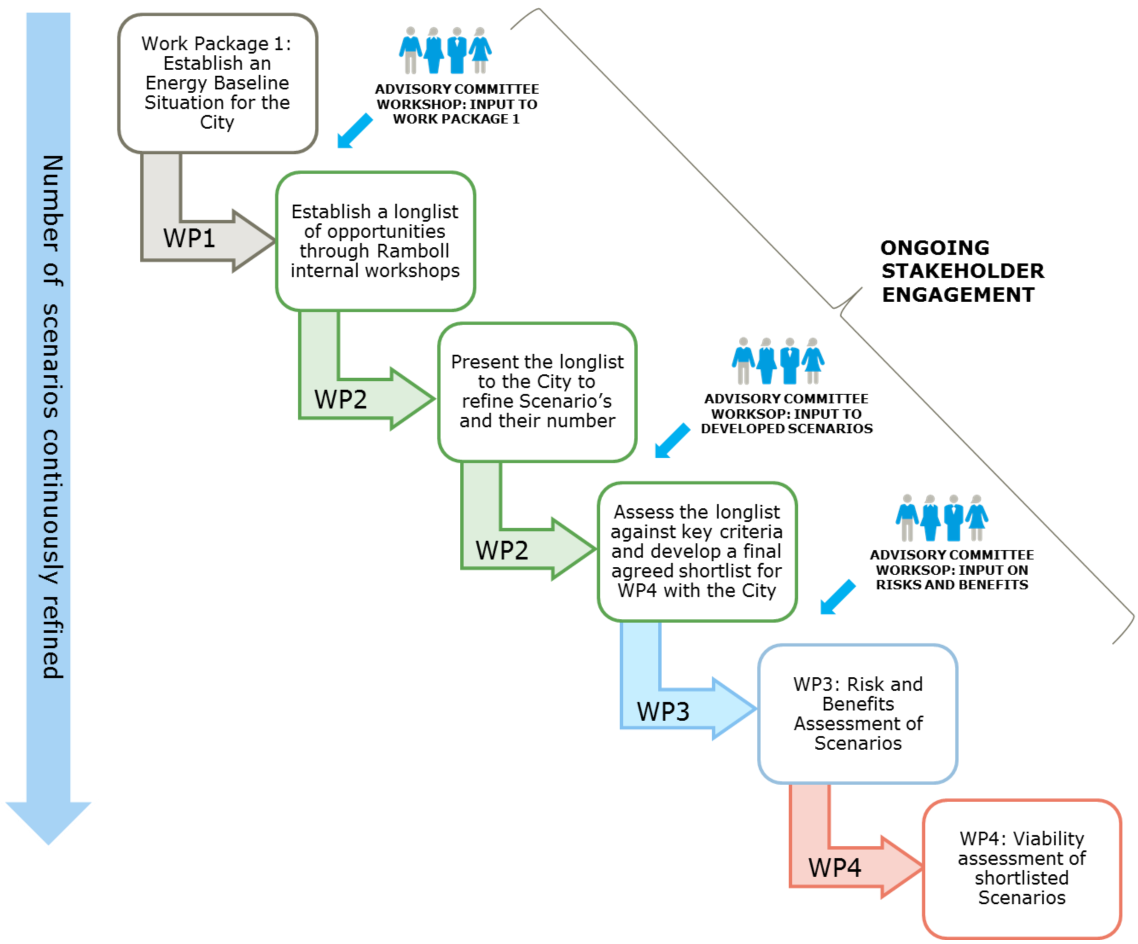

Figure 20 Scenario Selection Process

The City objective is to be on the path to Net Zero emissions from buildings by 2040. To achieve this it is critically important to bring all stakeholders into the process in order to build consensus on the process outcome.

[48] Work package 3 is the change and benefit management work package which ran in parallel to work package 4

As a result an Advisory Committee (AC) was created to evaluate and encourage engagement on the solutions developed under this study as representatives of the community of the City of Cambridge to ensure all stakeholder voices were considered in this process. The AC has provided input and guidance to the City on the deliverables prepared by the Consultant throughout this project. Table 11 lists the stakeholders and representatives which made up the Advisory Committee.

Table 11 Advisory Committee Participants

Institution	Participant	Institution	Participant
Harvard	Mary Smith	City of Cambridge Community Development Dept.	Susanne Rasmussen
MIT	Emma Corbalan		Seth Federspiel
	Steve Lanou		Melissa Peters
Eversource	James Cater		John Bolduc
Veolia	Patrick Haswell		Bronwyn Cooke
Climate Protection Action Committee	Melissa Chan		
Compact for a Sustainable Future	Ben Myers	City of Cambridge Housing Authority	Tina Miller
City of Boston	Adam Jacobs, Brad Swing	City of Somerville	Oliver Sellers Garcia
MA Department of Energy Resources	Samantha Meserve	City of Cambridge Department of Public Works	Ellen Katz
MassCEC	Amy Barad, Galen Nelson		Owen O'Riordan
Boston Green Ribbon Commission	John Cleveland	City of Cambridge Electrical Department	Steve Lenkauskas

4.1 Process Step 1: Advisory Committee Workshop on WP1

Following completion of Work Package 1 (WP1), the findings were presented to the AC for their consultation and input.

During this workshop, the AC was divided into 3 teams and two working group sessions were conducted. The participants of the first working group session were provided with a list of current and potential energy supply sources for Cambridge and Figure 21 below. Participants were then asked to consider the following questions:

- What is missing from supply map / list of energy supply sources?
- What does the team foresee as being difficult / barriers to low carbon energy supply implementation in Cambridge?

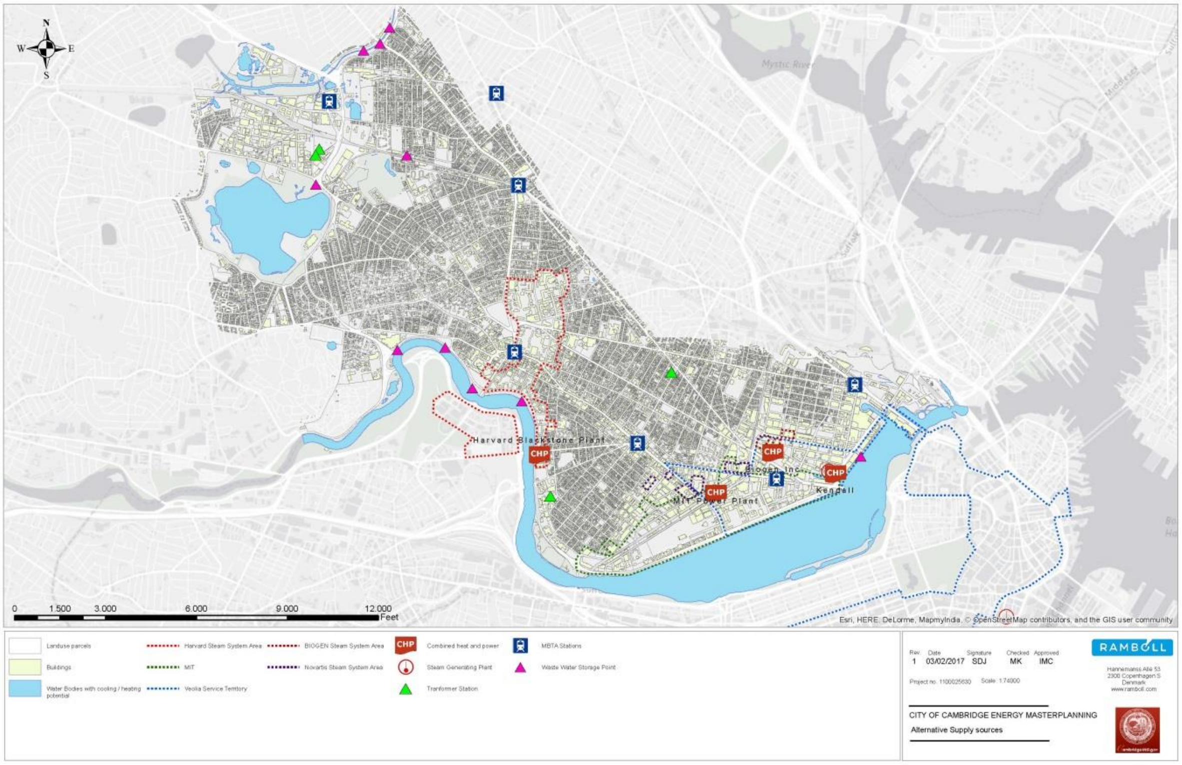

Figure 21 AC Workshop on WP1 Supply Map

The second advisory committee session involved each team building their own low carbon energy supply strategy. Pictogram stickers as shown in Figure 22 were supplied to the teams for them to indicate and draw on the maps their ideas for a low carbon energy supply for Cambridge.

The objective of this advisory committee process was to bring better understanding to the stakeholders of the challenge being faced by the City, engage them in the process and to identify any gaps or ideas in the analysis.

Additionally, this process was to bring the understanding that this is a challenge that needs to be addressed together and not by one stakeholder alone. Figure 23 and Figure 24 show examples of the advisory committee outcome.

The comments and inputs provided by the AC at this workshop and following it were then integrated into the final WP1 report.

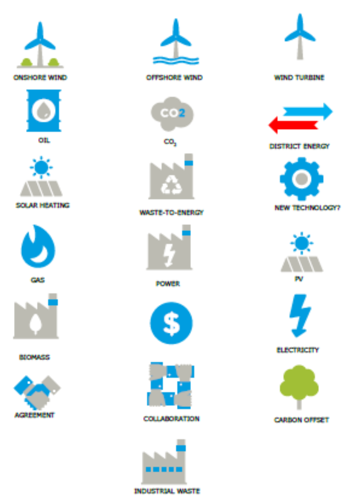

Figure 22 Pictogram Stickers

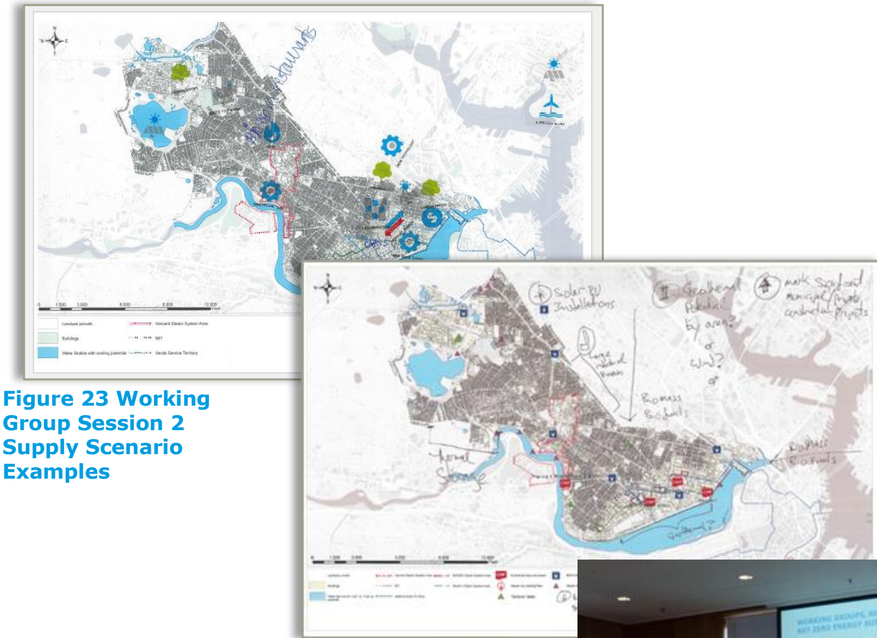

Figure 23 Working Group Session 2 Supply Scenario Examples

Figure 24 Working Groups developing their own low carbon supply scenarios

4.2 Process Step 2: Scenario Longlist Developed

4.2.1 City Zone Mapping Process

In order to understand the consumption of energy within the City, Ramboll divided the City into zones based on heat consumption. As heating and cooling accounted for 60 % of the city's energy consumption in 2016, it is important to understand where this is specifically being consumed within the City. This spatial analysis facilitates the consideration of alternative methods of supplying this demand.

The maps produced distinguished the zones based on:

- Energy consumption (kBTU) per consumer. This is the total demand within a zone divided by the total number of consumers (connection) within the zone.
- The total thermal usage within a zone divided by the zones area in hectares (ha).

Following the analysis of the energy data, the City was divided into various zones based on existing consumption. These zones are outlined in Figure 25 below. The scenarios developed were based on the zones defined and how to meet the required demand for each zone with low carbon alternatives. It can be seen from this figure than Zone 1 has the highest heat density, with Zones 3 and 4 having potential for high heat density as they are development areas. Zone 2 has a lower heat density and is primarily low rise residential areas.

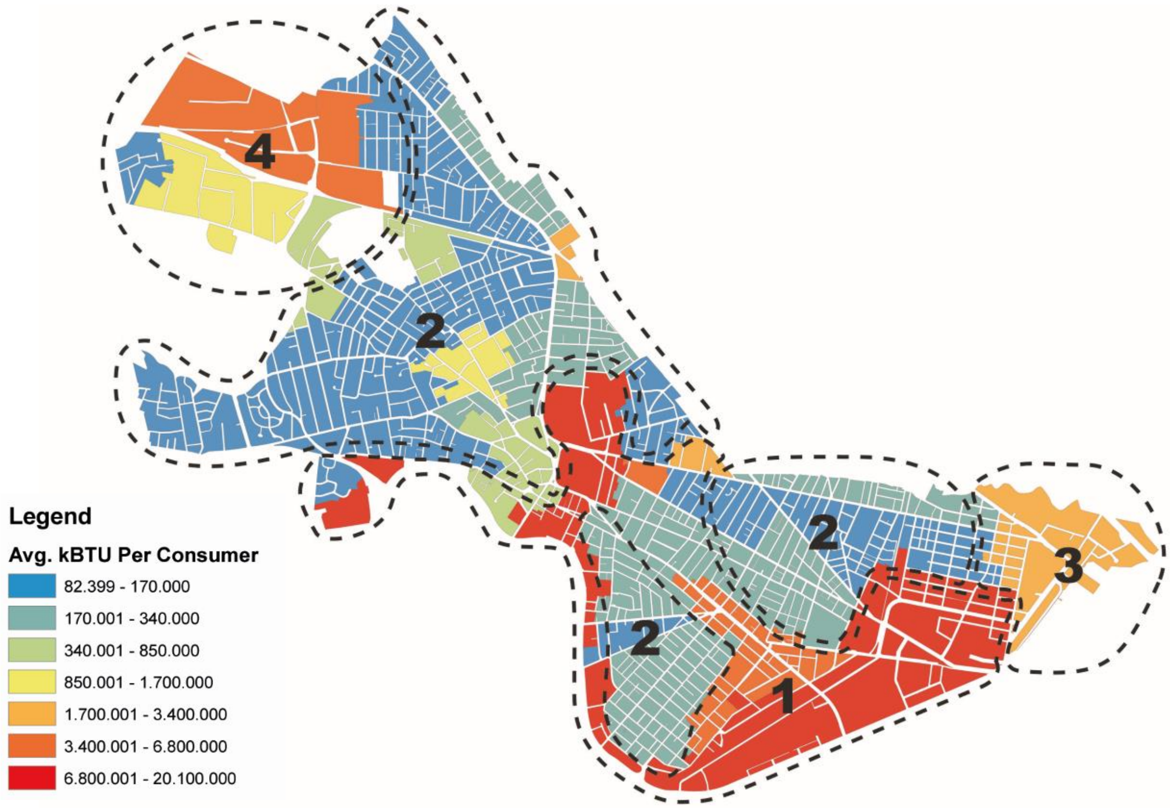

Figure 25 City Energy Demand Zone Map

4.2.2 Scenario Development Process

Based on the energy supply sources identified and the energy demand in each zone, the project team developed a range of potential low carbon energy supply scenarios that could meet the projected energy demand in all zones. This section outlines the long list of scenarios initially identified by the project team following internal workshops as follows:

- Scenario 1: Individual Electrification
- Scenario 2: District Energy Electrification
- Scenario 3: Electrification in Clusters
- Scenario 4a: District Heating and Cooling Systems with Biomass CHP Generation
- Scenario 4b: District Heating and Cooling Systems with Biomass Boiler Generation
- Scenario 4c: District Heating and Cooling Systems with Waste to Energy
- Scenario 4d: District Heating and Cooling Systems with Geothermal Supply
- Scenario 5: Hydrogen City with District Heating and Cooling Systems
- Scenario 6: Hydrogen City with Fuel Cells at building level

Further information on the developed scenarios can be found in Appendix 2.

4.2.2.1 Scenario 1: Individual Electrification

This scenario consists of building level electrification of thermal energy and cooling demand for all zones and building types. The only alternative heat production technology considered (in addition to electric boilers) is a heat pump utilizing a low grade heat source, which is upgraded to building operating temperatures by use of electricity. The cooling technologies are individual chillers and air conditioning units, also supplied by electricity.

The electricity supply will be dependent on an external supply of renewable electricity through greening of the New England Power Pool (NEPOOL), RECs and/or through investing in a renewable generating facility outside the city border. Maximum deployment of solar PV within the city boundary is assumed.

Figure 26 is a visual representation of Scenario 1. Locations of pictograms in all such figures in this section are only to indicate supply technologies proposed for each zone, and do not take into account existing plant and are not representative of actual proposed locations.

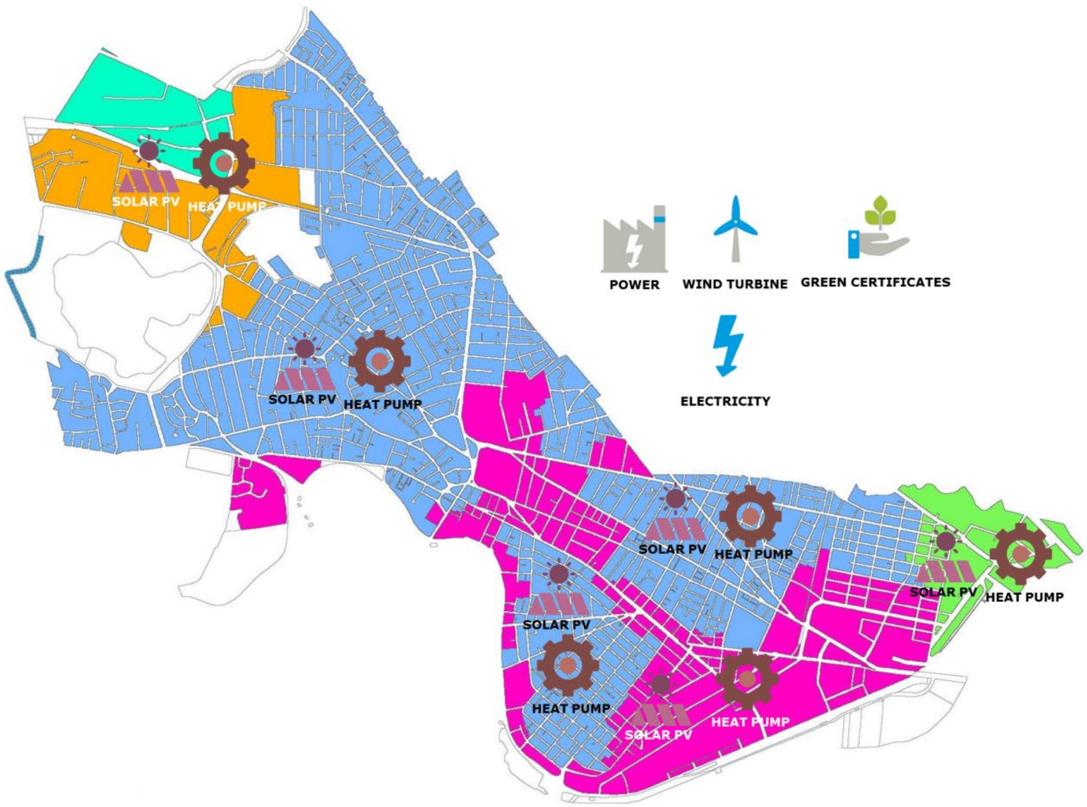

Figure 26 Visual Representation of Scenario 1

4.2.2.2 Scenario 2: District Energy Electrification

This scenario is a further development of Scenario 1. However, in this scenario, the buildings in Zone 1 and eventually Zone 3 and Zone 4 will be supplied by a district heating and cooling (DH&C) system supplied by heat pumps, electric boilers and chillers – all with thermal storage included.

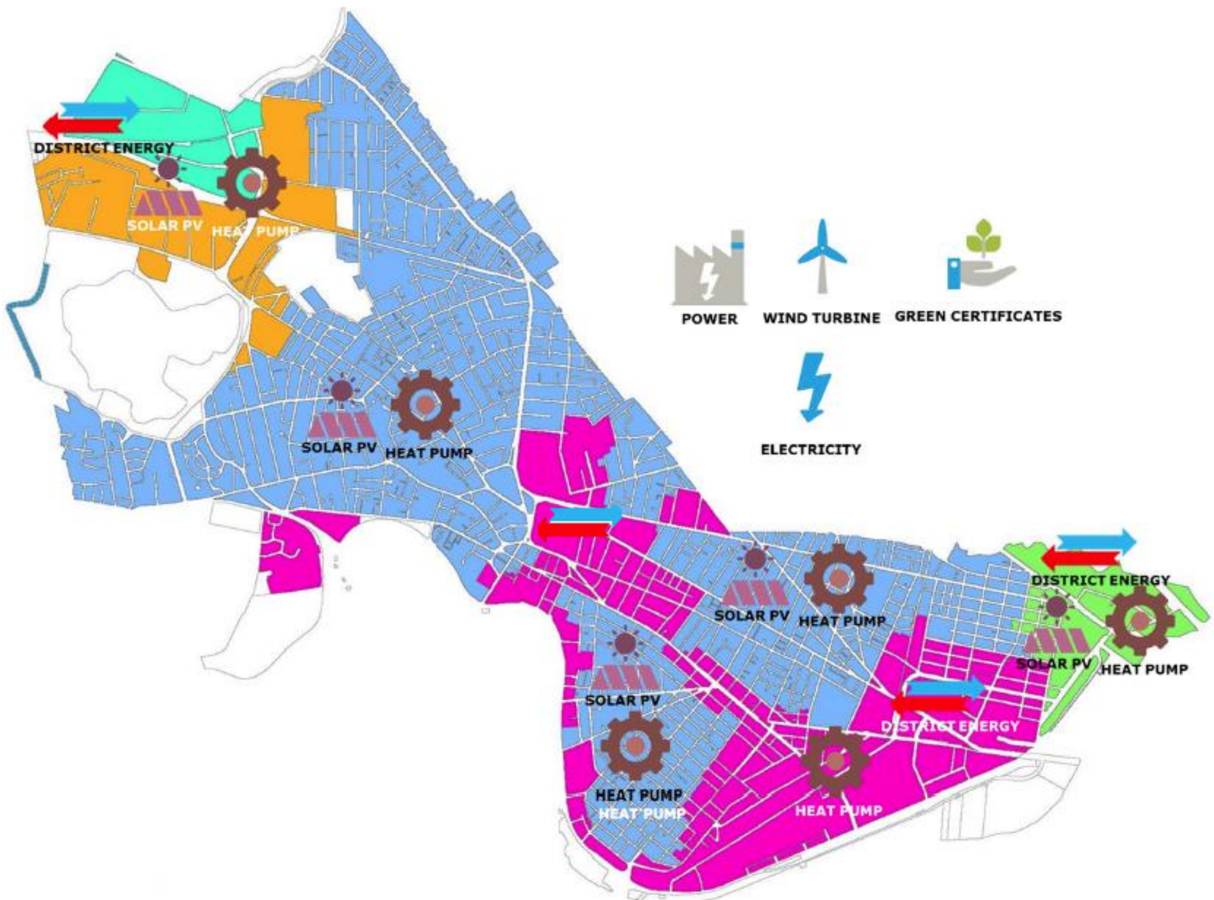

Figure 27 Visual Representation of Scenario 2

The city will still be dependent on external supply from the external electricity grid. The greening of New England Power Pool (NEPOOL), RECs and/or investments in renewable generating facilities outside the city border will be required. Maximum deployment of solar PV within the city boundary is assumed. Figure 27 displays the overall structure of Scenario 2. Electricity will be supplied by the external electricity grid with production from both conventional and renewable power stations.

Electrical consumption will increase with the introduction of electrically driven heat pumps as a replacement for gas boilers and furnaces. It is assumed that chillers will provide cooling for these buildings. The smaller buildings will still be supplied by individual heat pumps, but the larger buildings with a higher heat density will be supplied from centralized DH&C systems.

4.2.2.3 Scenario 3: Electrification in Clusters

The production units in this scenario are similar to Scenario 2. However, instead of a centralized production with a large conventional district heating network[49], this scenario proposes an extra low temperature network distributing both heating and cooling to decentralized production of DH&C in clusters. The heat source for the heat pump production at individual clusters is a low temperature network, which can have an inlet temperature of 68°F (20°C) and outlet temperature of 50°F (10°C). This scenario allows the low temperature network to redistribute waste heating from cooling consumers and waste cooling from heat customers. Thermal energy (either heating or cooling) may

[49] Conventional district heating, including operating temperatures is described in Section 3.1.6.

be boosted centrally by a large heat pump using heat from the river, pond, air, sewers, Aquifer Thermal Energy Storage (ATES) or waste heat from industry.

Similar to Scenarios 1 and 2, the electricity supply must be converted to renewable energy for this scenario to be a low carbon sustainable option. Solar PV located on the rooftops within the city can also contribute. The principle is outlined in Figure 28. A centrally located heat pump will supply heat at 68ºF (20ºC) source to smaller heat pumps located in clusters; this will allow these smaller units to operate with a higher efficiency. The solution will not differ much from Scenario 2, with the main difference being the size and type of distribution network and the size and location of heat pumps. The same buildings supplied by DH&C in Scenario 2 will also be supplied in this scenario.

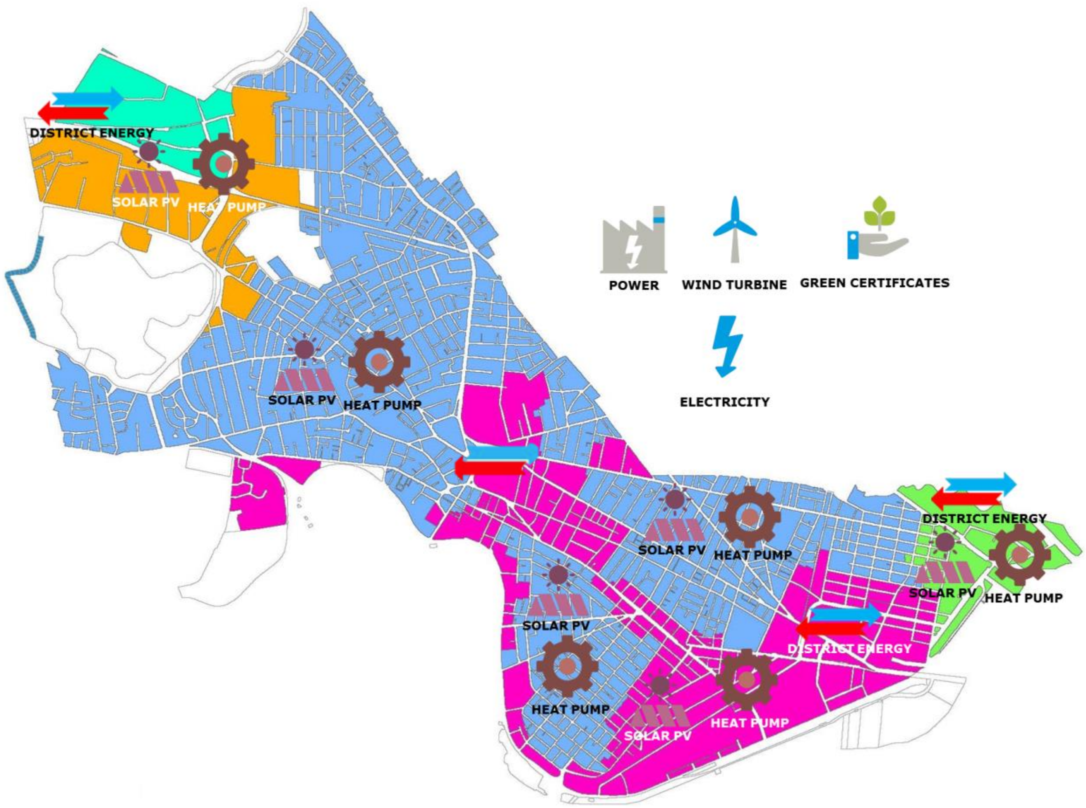

Figure 28 Visual Representation of Scenario 3

4.2.2.4 Scenario 4: District Heating and Cooling Systems

Scenario 4 consists of 4 variations (a, b, c & d) of heat production technologies. These scenarios consist of providing district heating and cooling to most of the city. Heat pumps, biomass plants and waste-to-energy plants are considered for delivery of district heating. The heat pumps will provide district cooling in cooperation with chillers. Thermal energy storage for both heating and cooling is included.

Heat pumps and chillers are centralized in the district cooling system. An ATES system is also included in all scenarios to utilize the synergies between district heating and cooling systems. The electric boiler is a cheap solution for producing heat based on excess renewable electricity production in this scenario.

Scenarios 4a, 4c and 4d all have a central district heating system established. In scenario 4b, it is assumed that lengthy network connections are not viable. Therefore, district heating is only established in clusters of high heat density supplied by biomass boilers.

The district cooling system will in all scenarios be constructed in clusters of high cooling density supplied by heat pumps using an ATES system and chillers. The electricity consumption will be supplied as outlined under Scenario 1, supplemented by biomass and waste-to-energy plants which will also produce electricity through co-generation technology. Solar PV mounted on each building is still an option for increased local electricity production. The expansion of district heating and cooling (DH&C) into the zones displayed on Figure 29 is divided as stated below. Scenario 4b is an exception, where district heating is only established in clusters instead of central systems.

- **Zone 1**: DH&C network supplied by a mix of centralized heat pumps and chillers, biomass CHP or waste to energy CHP or geothermal with thermal storage. Electric boilers can also serve to provide peak production in the district heating system, when renewable energy production is high and electricity prices equally low. The thermal storage can consist of storage tanks or an ATES system. It is estimated that approximately 70-80 % of the consumers in the zone can profitably be supplied by DH&C.
- **Zone 2:** All consumers are supplied by individual heat pumps or by block heating systems, when profitable. The heat- and cold density is not immediately high enough to establish a district heating network and district cooling network respectively.
- **Zone 3:** Ultimately to be supplied like Zone 1 with a DH&C system.
- **Zone 4:** Ultimately to be supplied like Zone 1 with a DH&C system.

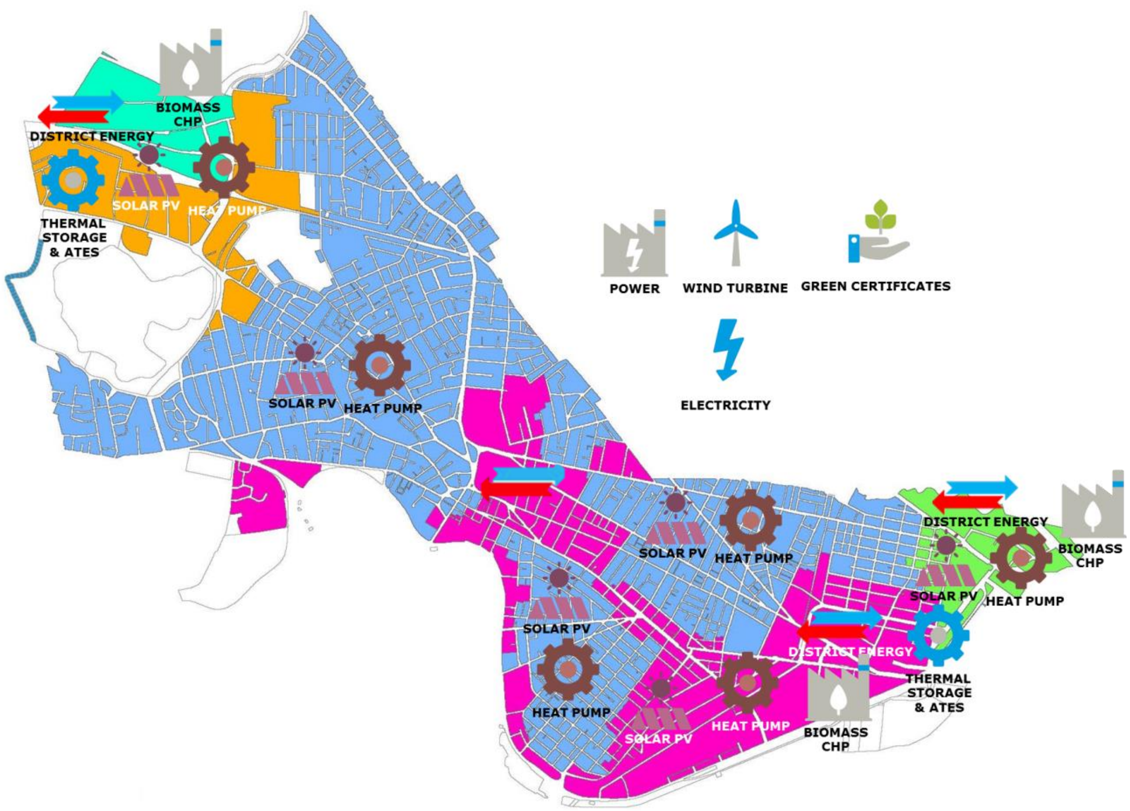

Figure 29 Scenario 4a Biomass CHP Generation

Local solar PV production mounted on rooftops is included in all scenarios. The electrical network may need strengthening to serve Zone 2. Figures 29, 30, 31, and 32 outline the visual representation of each scenario.

Biomass is the primary fuel considered under this scenario, however a Waste to Energy (WtE) plant is considered if sufficient volumes of waste can be secured. It should also be kept in mind that the WtE plant can be designed as a co-generation facility generating electricity locally within the city.

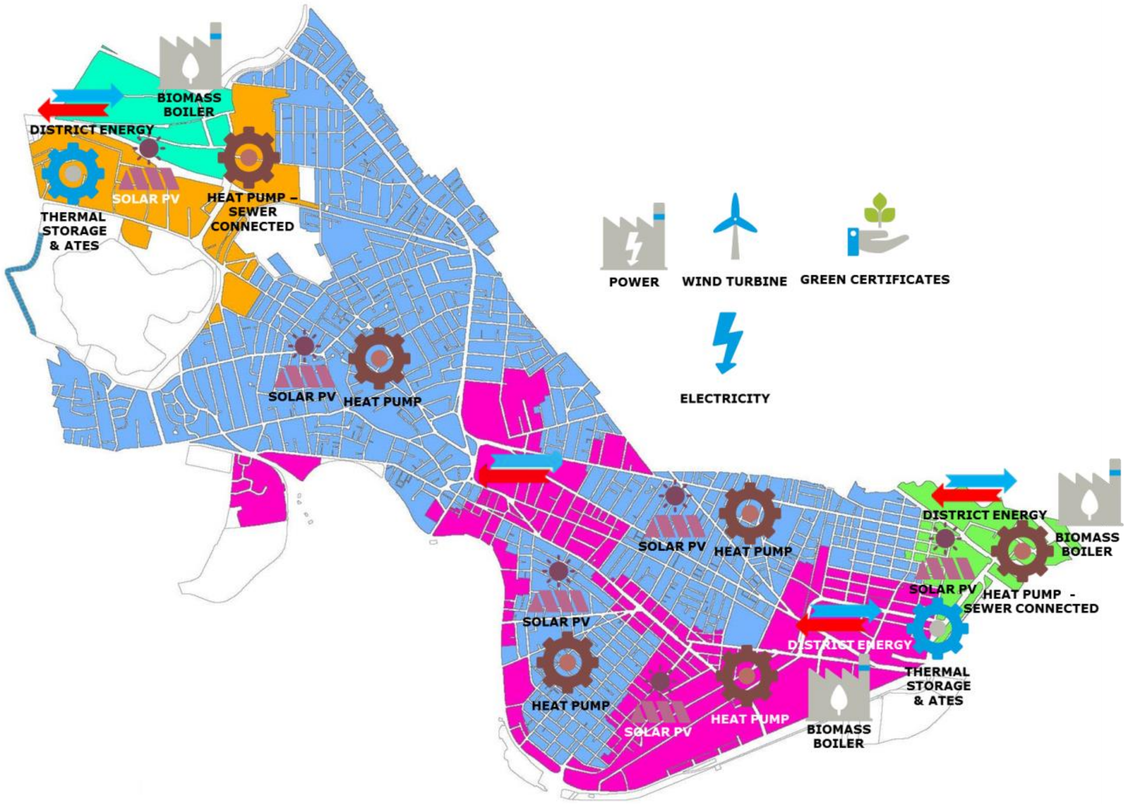

Figure 30 Scenario 4b Biomass Boiler Generation

The relationship between thermal energy storage used for both district heating and cooling is displayed in the form of tank thermal energy storage and an ATES system. All plausible technologies for production of electricity, district heating and district cooling are displayed.

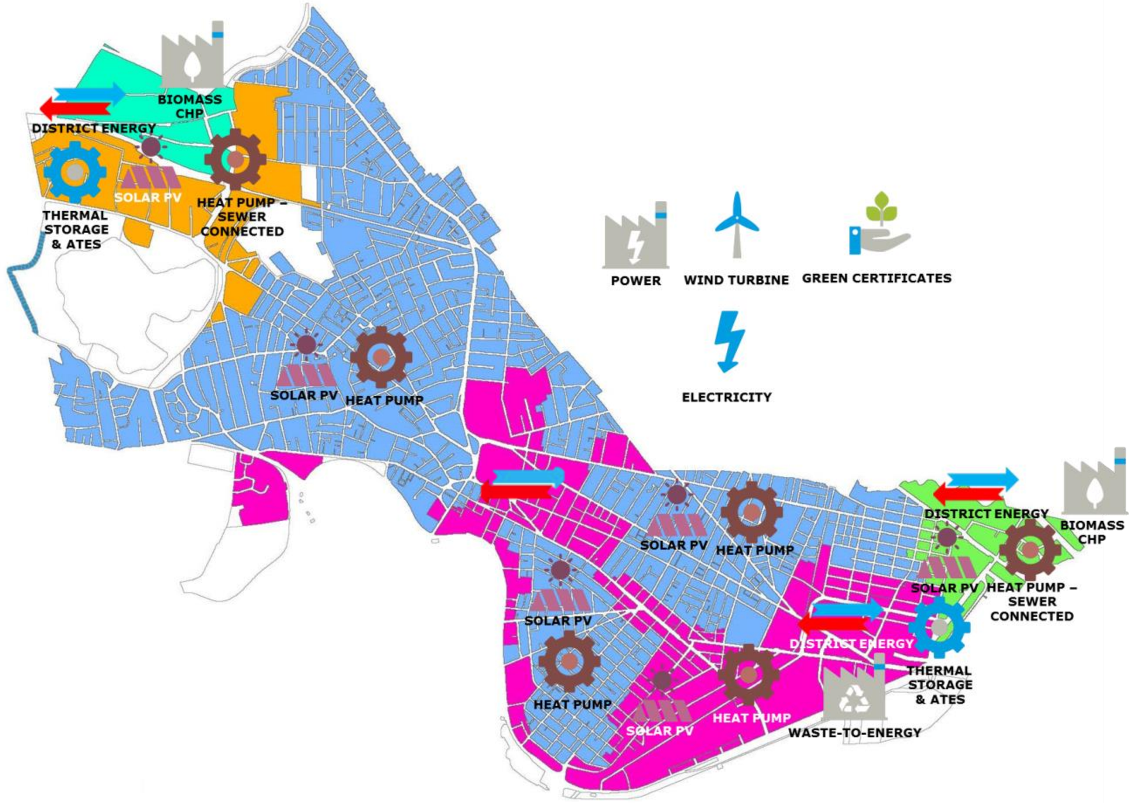

Figure 31 Scenario 4c Waste to Energy

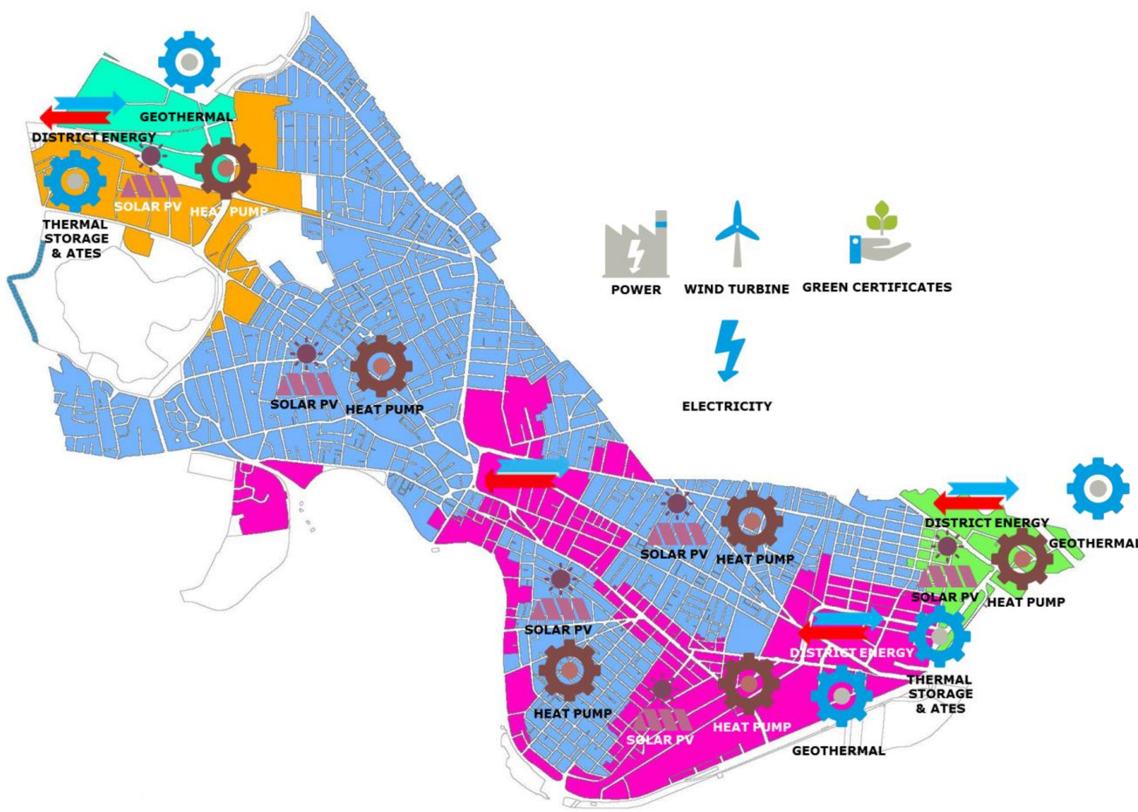

Figure 32 Scenario 4d Geothermal Supply

4.2.2.5 Scenario 5: Hydrogen City with DH&C

This scenario consists of a restructuring of Cambridge to be a hydrogen powered city. The main benefit of using hydrogen is that it allows conversion of renewable energy into a medium that allows large scale storage with relatively high energy density. Hydrogen is a flexible fuel and can be converted back into electricity, heat and also used as a renewable, low emission, transport fuel. Hydrogen fuel also offers the potential to be transported in existing gas networks (subject to suitability of the existing gas network installation, compliance and appropriate amendment to regulations) and also be compressed for transport in trailers.

Some of the technologies required are relatively immature and still in early commercialization phases. Furthermore, the conversion of electricity to hydrogen and back to electricity has a significant loss of energy. The solution would require significant expense, but could remove all emissions from the city and be a low carbon solution provided a renewable electricity supply.

The principle of this scenario is shown Figure 33. Solar PV and wind turbines located outside the city produce hydrogen through an electrolyzer, which is converted back to electricity by a fuel cell located in the city to supply the electricity network and DH&C production facilities.

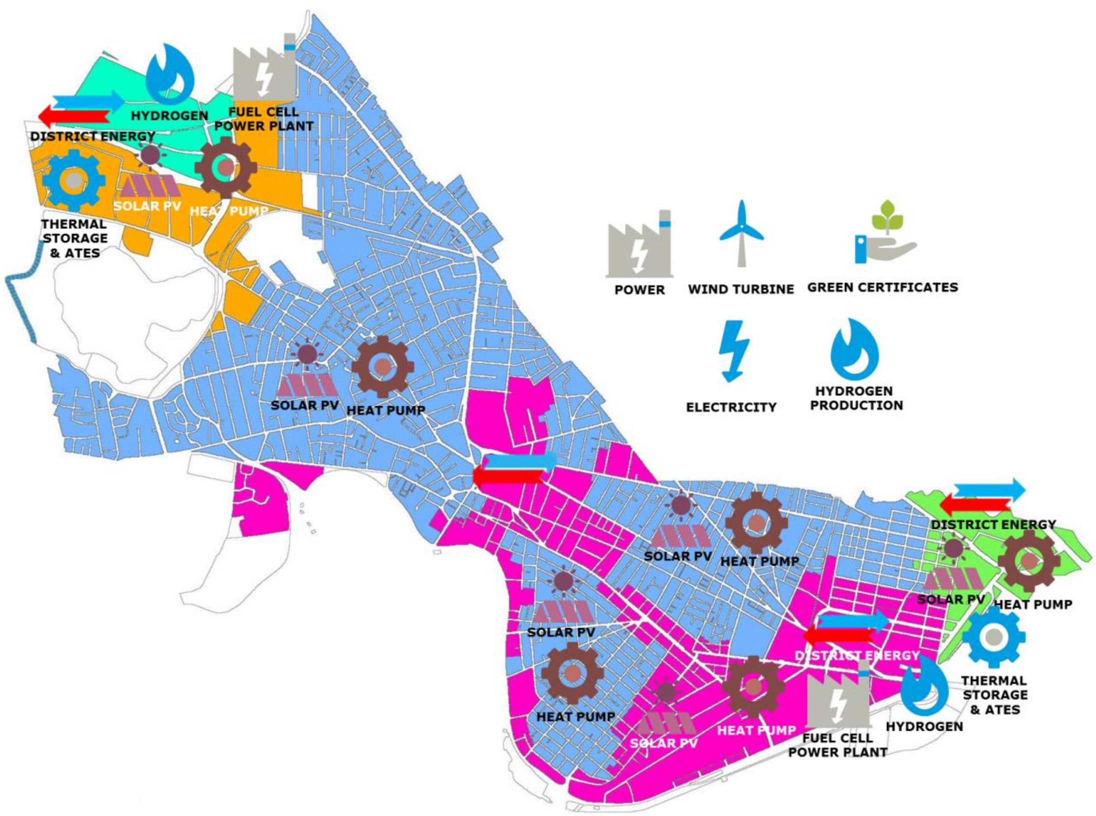

Figure 33 Scenario 5 Hydrogen City

The basis of this scenario is the ability to support the deployment of large scale renewable energy technologies within and external to Cambridge and to smooth imbalanced profiles of supply and demand through hydrogen storage. These technologies do not always produce their energy at required times and so often the full potential of these technologies cannot be realized. This can be minimized by using the excess electricity to produce hydrogen when the electricity demand is low, which can be stored and later converted to usable energy via a fuel cell to provide heat and electricity or transport.

The hydrogen would then be transported (in the gas network or by tanker) to a fuel cell location where both heat and electricity would be produced and supplied to a district energy network with power exported to NEPOOL.

The hydrogen production, compression and daily storage could be located in Cambridge. Large scale seasonal storage could be located external to the City with hydrogen stored in subterranean stores or in above ground tanks.

The proposal works in conjunction with district heating solutions previously discussed in Scenario 4. This would be supplied by a combination of fuel cells and heat pumps. The areas where district heating is not deemed to be viable (low density heat demand areas such as Zone 2) are assumed to be supplied by individual electric heat pumps (this is the significant difference between Scenario 5 and 6).

The daily production of the electrolysis plant would need to be of the order of 35 tons of hydrogen per day. The fuel cell plant could be located within the city boundary for resiliency purposes, the indicative capacity of the fuel cell could be 185 MW.

The remaining heat demand would be made up from large scale heat pump technology utilizing the most appropriate energy sources, and using renewable energy produced external to the city in addition to the full solar PV roll out.

In this scenario chillers are utilized as the primary cooling supply in all scenarios.
Figure 34 below shows the concept for this Scenario in flow chart format. The blue line represents electricity, the red line represents district energy and the green line represents hydrogen.

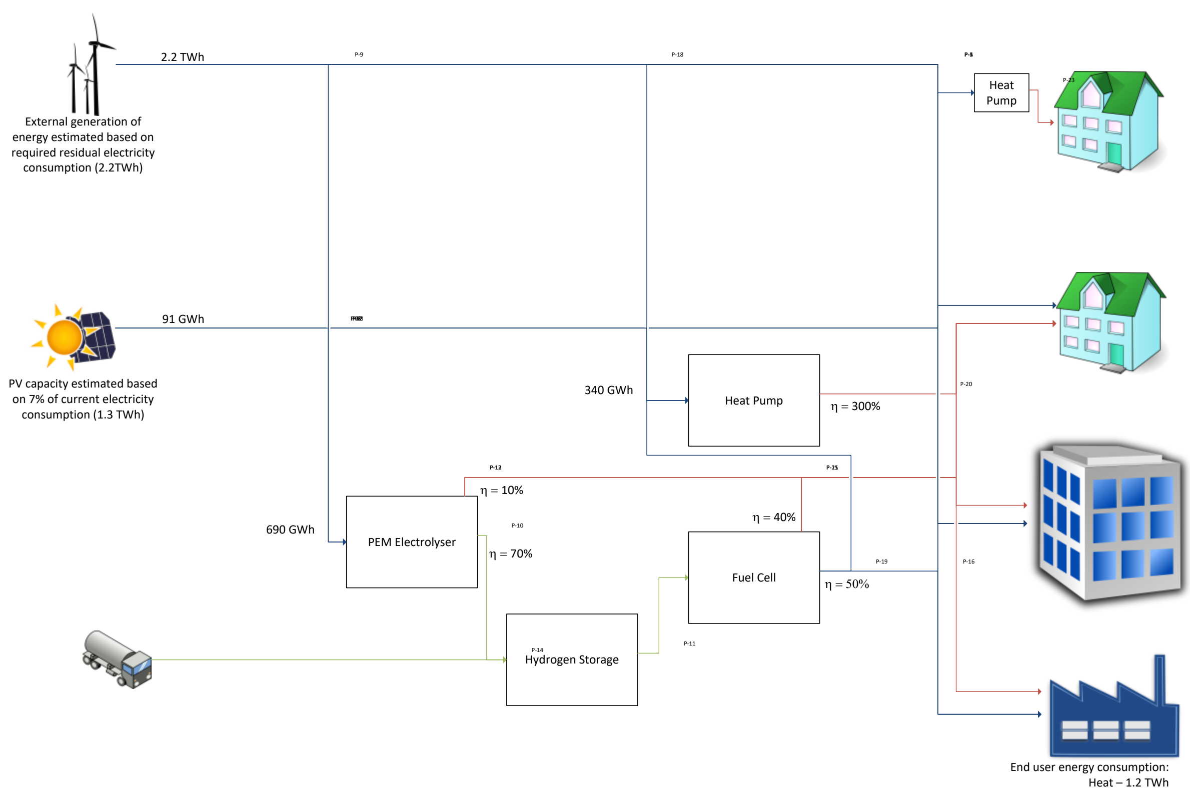

Figure 34 Hydrogen City Scenario flow chart

Hydrogen electrolysis and stationary fuel cell technology are still developing at the scale that is required for the transformation of the city of Cambridge. Costs for the entire system are very high and are uncompetitive with other generation technologies at the moment. While some smaller applications have been successful under specific circumstances in other areas, these have been at a much smaller scale and have had a readily available hydrogen source or other enabling factors.

For context the current global fuel cell capacity installed in 2016 was 262MW[50], the application proposed in Cambridge the required capacity would be just under 200 MW. Sizing is based on the hydrogen system being utilized as a means to store renewable energy such as wind and solar power.

Plans for the largest electrolysis plant in the world have just been given the go ahead for a facility to be constructed in Linz, France[51]. This will be a 60 MW facility and thus just over a quarter of the size required for Cambridge. The proposed plant will be based on the same technology proposed here.

Similar to battery technology fuel cell technology is expected to develop rapidly in the near future, however this rapid development and subsequent lowering of costs has been expected for some time now and has yet to materialize[52].

2025 is referenced in some quarters as the expected date by when fuel cell technology will have become more established[50]. There is however no consensus on how the technology and market will develop.

4.2.2.6 Scenario 6: Hydrogen City with Fuel Cells at building level

Scenario 6 is a variation of 5 whereby instead of properties in non-district heating areas (such as Zone 2) being supplied by electric heat pumps, individual buildings have hydrogen boilers or fuel cells installed as direct replacement for existing gas boilers. This is outlined in Figure 35.

[50] https://www.navigantresearch.com/research/stationary-fuel-cells

[51] https://www.gasworld.com/areva-h2gen-unveils-electrolysis-plant-concept/2012679.article

[52] https://www.greentechmedia.com/articles/read/Fuel-Cells-2016-Within-Striking-Distance-of-Profitability

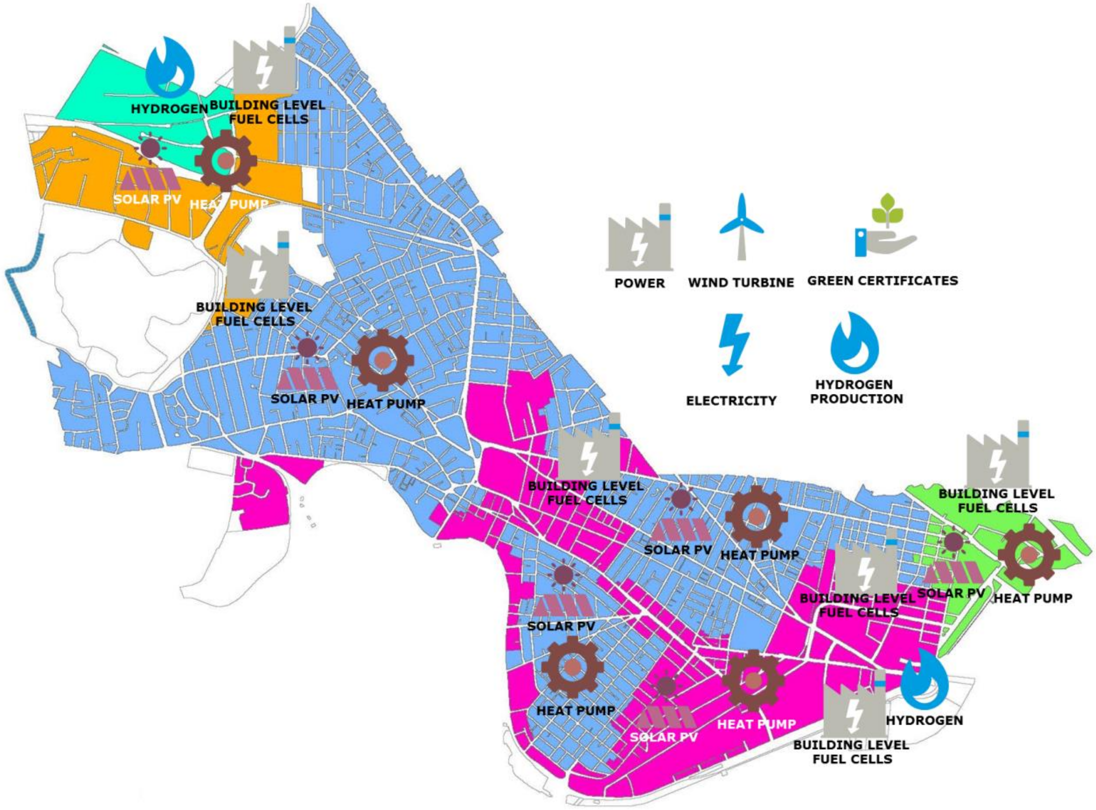

Figure 35 Visual representation of Scenario 6

Hydrogen is still utilized as a means of balancing electricity production from renewable energy sources. District heating remains in this scenario for the high demand zones, however it may be considered appropriate to exclude district heating and fully convert to hydrogen across the gas network.

Hydrogen distribution in the gas network could be phased by blending in early years with natural gas and over time changing the ratio of gas in the network. Regulatory barriers would need to be overcome to allow hydrogen to be conveyed in gas networks and to ensure safety and licensing concerns are properly addressed. The effects of this on network capacity, network materials, energy losses and customer interface and boiler suitability would require greater work. There has been research on this approach in a number of European Countries.

Figure 36 shows the concept for this scenario in flow chart format. The blue line represents electricity, the red line represents district energy and the green line represents hydrogen.

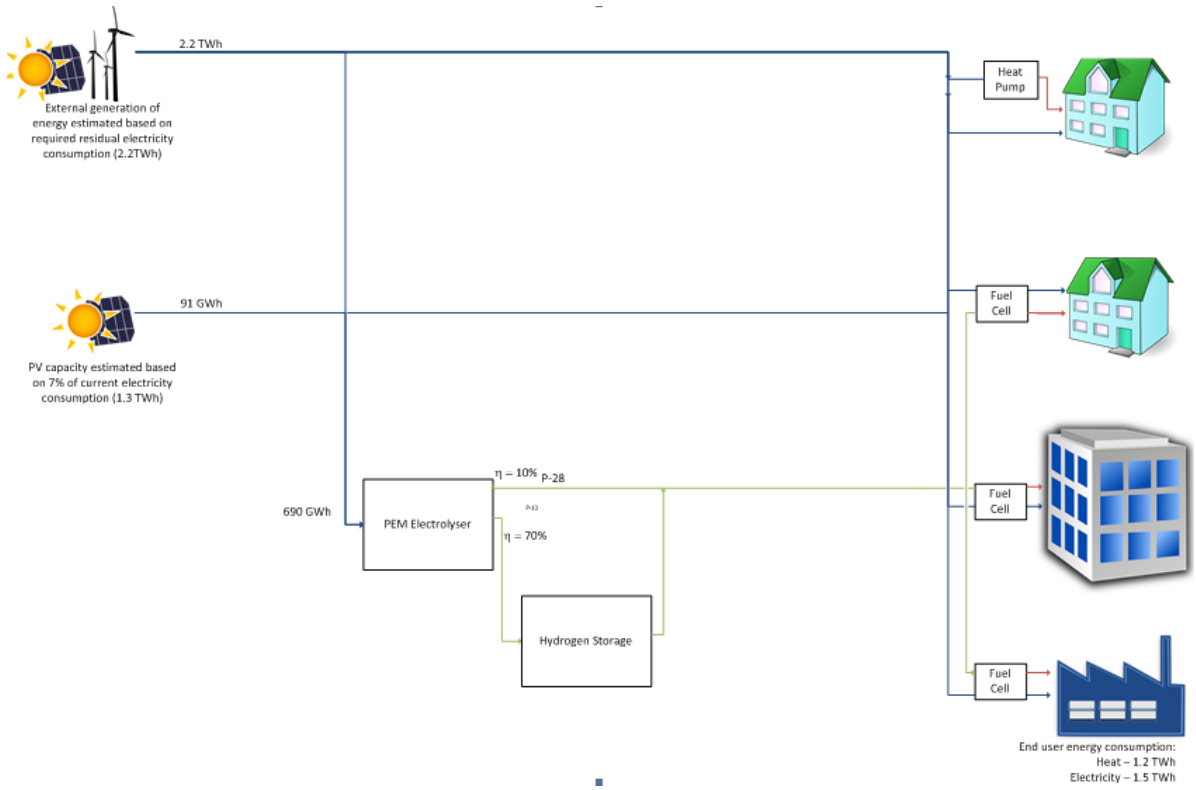

Figure 36 Scenario 6 Variation of Hydrogen option with building level fuel cells

The size and cost of hydrogen production, compression and storage would remain the same in this scenario. Additional costs would be incurred by the increased hydrogen network and the scale of fuel cell installation if DH&C is not included.

4.3 Process Step 3: Advisory Committee Workshop on Developed Scenarios

The 9 scenarios described above were then presented to the City at a meeting on April 25th 2017. The objective of the meeting was for the City to score the scenarios to focus the scenarios into a short list and for the Consultant to receive feedback on the concepts put forward for further elaboration. Scenarios 1, 2, 4 a, b & c and 5 were selected by the City for further development and presentation to the Advisory Committee[53].

In advance of the AC workshop on May 16th 2017, the stakeholders were sent a memo on the scenarios prepared along with a scenario scoring template to evaluate the scenarios in accordance with the City's goals in advance of the workshop. In this memo, the energy demand density zones were further defined as shown in Figure 37 below.

The objective of this workshop was to present and explain the scenarios to ensure full understanding by all stakeholders of what was being proposed. Participants were encouraged to ask questions to further their understanding.

This fostered some very interesting conversations and ideas and all input was considered. The comments from the AC meeting were then taken on board by the City for further shortlisting of the scenarios proposed for more detailed assessment under Work Packages 3 and 4.

[53] Scenario 3 was merged into Scenario 2 and Scenario 4d was deemed technically unviable due to the lack of deep geothermal resources in Cambridge; See appendix 2 for additional detail

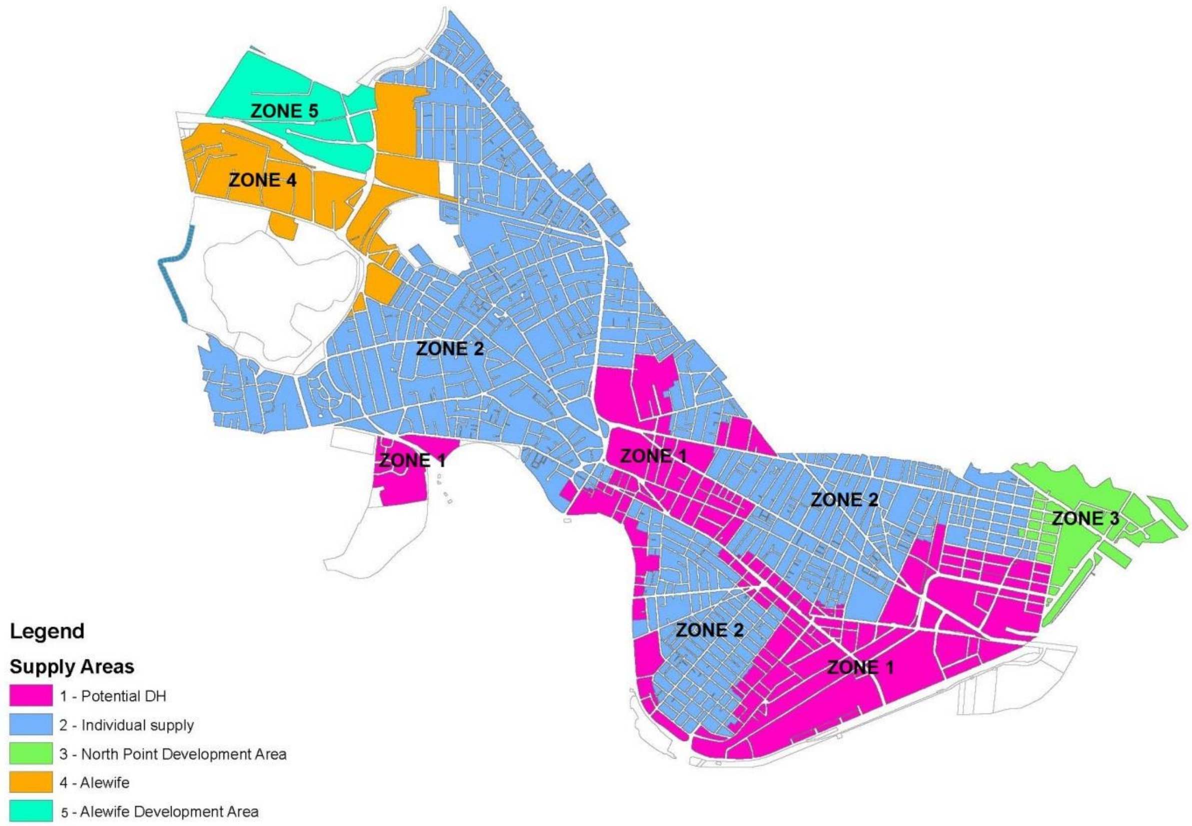

Figure 37 Energy Demand Density Zones

The zones indicated in the above figure have heating loads as outlined in Table 12 below.

Table 12 Total zone thermal demand

Zone	Existing Thermal Demand (kBTU)	Existing Cooling Demand (kBTU)	Existing Electric Demand in MWh
1	4,801,777,544	805,937,507	1,092,193
2	2,212,318,931	65,030,481	299,033
3	290,720,538	28,666,396	89,480
4	207,040,709	19,856,336	66,799
5	122,941,619	26,363,062	49,419

4.4 Process Step 4: Agree on Shortlisted Scenarios with City

Following the AC committee meeting a Decision Gate meeting was held with the City's project steering group to finalize the scenarios for further progression and agree on the criteria under which these scenarios should be evaluated.

4.4.1 Assessment Criteria Review

The goals of the City were reviewed with a focus on the relevance of these goals for assessing projects. Some of the City's goals were agreed to be subjective rather than objective key performance indicators suitable for project assessment. As a result, the goals agreed with the Steering Group to be best utilized as a means of quantitative assessment are the "Clean" and "Affordable" goals.

"Clean" can be measured in terms of Green House Gas emissions and other pollutants.

"Affordable" can be measured in terms of capital costs, ongoing cost, net present value and internal rate of return amongst others.

The other City goals for the future energy supply will be considered in a narrative, qualitative form providing valuable information for the City to consider in selecting preferred solutions.

4.4.2 Scenario assessment summary WP2

Scenario 1 and 2

The steering group agreed that the concentration on resiliency had been given too much weight in the electrification scenario. Other options for mitigating the impact of grid downtime such as emergency shelter areas could address this.

In light of this it was agreed that it would be beneficial to take another look at Scenario 1 – full electrification at a building level in addition to Scenario 2.

Scenario 5 and 6

Further consideration of hydrogen at this scale was ruled out by the steering group as the technology is not currently at a sufficiently advanced commercial scale to be viable. The opportunity for hydrogen was identified as its ability to store excess renewable electricity generation and thus increase overall penetration and utilization of renewable electricity into the energy mix. Hydrogen will continue to be considered as a future opportunity only and shall be dealt with in the narrative through future-proofing and safeguarding considerations.

Scenario 4a and 4b

The Steering Group agreed that the similarities of Scenario 4a and 4b were such that these should be considered variations of a single opportunity and progressed to WP4. Special consideration will be given to emissions issues, plant locations and the impact that this would have on Cambridge. Transportation of fuel and the available supply chain will be further considered.

4.4.3 City decisions made on scenarios to be brought forward to WP4:

1. Scenario 1 – Full electrification at a building level
2. Scenario 2 - Electrification with centralized electrical DH&C generation and distribution
3. Scenario 4 - District energy utilizing either biomass or waste to energy with heat pumps working off low grade heat sources.

Further details of the full scenario shortlisting process with accompanying minutes of meetings can be found in Appendix 2.

4.5 Process Step 5: Workshops on Risks and Benefits of Scenarios

Work Package 3 is the Change and Benefit Management section of the project and includes stakeholder engagement and development of approaches for change and benefit management. The objective of this change and benefit management process is to develop a strategy for securing the required change for the proposed new energy supply.

To identify the changes necessary for successful implementation, the proposed scenario and the solutions it incorporates must be evaluated from a risks perspective. By identifying what the risks are to implementation, a risk mitigation plan which encompasses the change required to realize the proposed scenario is realized. In order to ensure all risks are identified, it is important to take different stakeholder perspectives into account, which is why stakeholder engagement is an important aspect of this process.

4.5.1 Identifying Risks and Benefits

In order to identify the risks and benefits associated with the shortlisted scenarios, Ramboll conducted two workshops, one with the City of Cambridge inclusive of the Department of Public Works, and one with the Advisory Committee inclusive representatives of the State Department of Energy Resources.

The workshop process facilitated further evaluation and discussion of the shortlisted scenarios amongst the stakeholders, bringing further understanding of the City's ambition to all participants. Additionally the workshops allowed for real stakeholder risks and issues to be identified for resolution as the selected scenario is progressed.

To identify the project benefits, the teams were asked to consider their assigned scenarios and the benefits this scenario posed for the City of Cambridge in relation to the City goals as per Section 1.2.

Benefits were written down by the team on "post-its" and posted to the poster template provided as shown in Figure 39 below.

Following the collaboration period, each team presented their discussion on the benefits they determined.

Multiple benefits were identified for each scenario. Significant benefits identified during the City workshop and the AC workshops are highlighted below.

Figure 38 Scenario 4 WtE Team Consider Scenario Benefits

Figure 39 Scenario 1 Benefits Identified

Following this group process, the teams considered the risks associated with implementing each respective scenario proposed. As discussed above, by identifying what the risks are to implementation, a risk mitigation plan which encompasses the change required to realize the proposed scenario can be realized. The risks of significant interest from the City workshop and the AC workshops are highlighted below.

Collaboration and involvement was excellent throughout the workshop and demonstrated strong understanding of the proposed scenarios and willingness to progress the project process for to a successful conclusion.

See Appendix 3 for the full list of risks and benefits identified by the Advisory Committee. The risks and benefits of the shortlisted scenarios along with a risk mitigation plan are further elaborated in Sections 5 and 6.

5. SCENARIO ASSESSMENT (WORK PACKAGE 4)

The Scenarios are evaluated following a standard cost-benefit analysis method. The sum of all costs in each Scenario are returned to a net present value (NPV) for comparison. The Scenarios are also evaluated based on an emissions analysis. Ramboll have not evaluated the socio-economic implications factoring in costs of emissions.

5.1 Considerations for modelling the energy supply options in Cambridge

Ramboll built a model specifically for this project. To achieve the largest extent of flexibility and to enable an open model in which all assumptions and methodologies are directly visible, we found Excel to be best suited. The model can handle large amounts of data and estimations from each Scenario and Zone. The model consists of five sheets:

1. ***Input;*** All main assumptions such as energy prices, technology specific cost estimates and main input parameters.
2. ***Energy;*** All inputs from the LCESS master dataset containing data from the data gathering process such as demands for heating, cooling and electricity
3. ***Emissions;*** Calculated emissions
4. ***Economy;*** Economic calculations
5. ***Results;*** All final results from the calculations.

5.2 Assumptions

In this section, the assumptions applied in the modelling are explained. Not all of the cost estimates are shown, but these can be found in Appendix 5.

The financial estimates include fuel costs, variable operation and maintenance costs (costs directly related to energy production), fixed operation and maintenance cost (staffing and expected reinvestments in equipment) and capital cost (investments and reinvestments)

For the final result, the NPV is calculated for all costs per year in the 20-year planning period. The heat demand in Zone 1 is the highest, with a share of more than 60 % of the total heat demand. For both the cooling and the electricity demand, the share is more than 70 %.

5.2.1 Energy demand and forecast

An assessment of the energy demand and a forecast of expected future energy demands were developed during Work Package 1. The same forecast is applied in the economic evaluation.

5.2.2 Fuel prices

The fuel prices applied in the economic evaluation can be found in Appendix 5. The reader should notice the different price levels for residential and commercial fuels. Large commercial plants can buy cheaper energy than smaller residential households[54] [55] [56] [57] [58].

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[54] World Energy Outlook, International Energy Agency, 2016.

[55] District Heating Assessment Tool, Danish Energy Agency, 2016: https://ens.dk/en/our-responsibilities/global-cooperation/district-heating-assessment-tool-dhat

[56] Socio economic analysis prerequisites, Danish Energy Agency, 2016:https://ens.dk/service/fremskrivninger-analyser-modeller/samfundsoekonomiske-analysemetoder

[57] Annual energy outlook 2017, EIA, 2017:https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-1&cases=ref2017&start=2015&end=2050&f=A&linechart=ref2017-d120816a.3-3-AEO2017.1-1~~~~&map=ref2017-d120816a.4-3-AEO2017.1-1&sourcekey=0

[58] Analysis prerequisites, Energinet.dk, 2017:https://energinet.dk/Analyse-og-Forskning/Analyseforudsaetninger/Analyseforudsaetninger-2017

5.2.3 Electricity prices

Two electricity price levels are applied; residential and commercial consumers respectively.

5.2.4 Solar PV and solar thermal

It is assumed that production from solar PV in Cambridge will increase up to 107.3 GWh/year in 2030, which is evaluated as both the technical and economically feasible level possible for the city by the Zapotec Energy report produced for the Net Zero Task Force.[59]. It is not investigated whether it would be beneficial to develop solar thermal in favour of solar PV at different locations because of the priority to generate electrical energy (see Section 3). The implementation of solar PV is included in all Scenarios.

An alternative option that was not included in the scenarios is to develop floating solar PV panels on Fresh Pond. Based on the same solar PV production potential as used in the model, approximate production potential was calculated. The results are shown in Table 13 and the production is compared to the projected energy demands in 2040, as seen in Figure 40. Calculations have not been performed on the economic viability of installing solar PV on the pond, only the generation potential.

Table 13 Solar PV development on Fresh Pond[60]

	30 % pond coverage	60 % pond coverage
Annual solar PV production	16.3 GWh	32.6 GWh
Percentage Coverage of annual total demand (2,735 GWh)	0.6 %	1.2 %
Percentage Coverage of annual electricity demand (1,151 GWh)	1.4 %	2.8 %

[59] Potential for solar power development in Cambridge, Zapotec Energy, 2014. The Net Zero Task Force process established revised targets of 60MW by 2020 and 160 MW by 2040 of installed solar capacity in the City of Cambridge since the Zapotec report. This additional electricity generation capacity within the city displaces imported electricity imported from the electrical grid in all scenarios modelled. As a result, this additional solar capacity saves the emissions related to the creation of this electricity which would be imported from the grid. Over the period between 2020-2040, this equates to a further emissions reduction of 35kton CO2 on each scenario. To compare this to total emissions, this equates to a further 0.25% reduction on the total CO2 emissions for the Scenario 0 / BaU case. While a small difference in emissions, using the Net Zero solar targets would result in a notable increase in the proportion of electricity that could be generated locally, from approximately 10% to approximately 15%. The use of Fresh Pond for floating solar panels would add to this local generation potential.

[60] The pond size is approximately 0.3 sq. miles, but only 30-60 % is covered by solar PV. The calculation is based on a solar PV production of 70 kWh/m^2/year. A ground coverage ratio factor of 0.6 is included for ground/pond installed PV systems. If one solar panel is 240 W/1.6 m^2 then around 90,000 solar panels is needed for 30 % coverage.

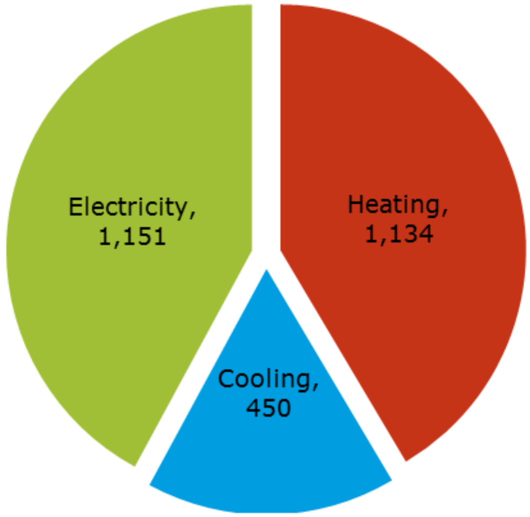

Figure 40 Division between energy demands in Cambridge City in 2040 (GWh)

5.2.5 Capital cost, operational cost and technical assumptions

The capital cost, operational cost and technical assumptions can be found in Appendix 5 [61] [62] [63] [64] [65].

5.2.6 Economic assumptions

The planning period is from 2020-40 and the applied discount rate is 7 %.

5.2.7 Hydronic conversions

The specific costs for conversion of non-hydronic buildings is estimated to be 12.9 $/ft^2$ [66]. In Zone 1 it is estimated that 1,200 out of 3,500 buildings are converted at a total cost of $112M.

5.2.8 District heating network

Where included, it is assumed that district heating networks would be gradually expanded. The main district heating lines installed should have adequate capacity for a fully built out network.

It is assumed that the district heating network in the Kendall Square area is expanded gradually from 2020 and finalized in 2040.

It is assumed that the expansion of the hot water system in other areas of Zone 1 will happen from the year 2030 to 2040.

Production from alternative hot water production sources is assumed to gradually take over production from steam. In line with this, production from the Kendall Cogeneration steam plant to supply Cambridge is reduced.

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[61] Updated technology data for energy plants, Danish Energy Agency, 2016: https://ens.dk/sites/ens.dk/files/Analyser/update_-_technology_data_catalogue_for_energy_plants_-_aug_2016.pdf

[62] Technology data for energy plants, individual heating plants and energy transport, Danish Energy Agency, 2016: https://ens.dk/sites/ens.dk/files/Analyser/old_technology_data_for_individual_heating_plants_and_energy_transport_aug2016.pdf

[63] Technology data for individual heating plants and energy transport updated chapters, Danish Energy Agency, 2016: https://ens.dk/sites/ens.dk/files/Analyser/technology_catalogue_individual_heating_plants_energy_transport_aug16.pdf

[64] Cost and performance data for power generation technologies, NREL, 2012: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

[65] Projected costs of generating electricity, International Energy Agency, 2015:https://www.oecd-nea.org/ndd/pubs/2015/7057-proj-costs-electricity-2015.pdf

[66] Hydronic conversion cost, Hydronic Heating, 2017:http://www.hydronicheating.net/costs.html

Although the district heating network is gradually built out, the main district piping is initially designed for full capacity to ensure what is installed in the next ten years can supply the capacity required in 20 years.

For the district heating network, it is assumed that the capital costs will gradually be reduced due to increased experience with hot water systems in America. Planning prices are shown in Appendix 5. All costs for the network are included, such as capital costs for the pipes, excavation, commissioning, nuisance avoidance etc. and are based on our empirical experience.

For a steam based district heating network a loss of 35 % is applied, and for a hot water based district heating network a loss of 15 % is applied.

5.2.9 Thermal storage

Thermal storage is used for both heating and cooling. The sizes are varied per Scenario. In Scenarios 2 and 3, the hot and cold storage are each about 90,000 m^3 in total. In reality, the storage volume will depend on the electricity price difference between peak and off-peak.

5.2.10 Emissions

For each year in the planning period emissions are estimated from; CO_2, CH_4, N_2O, SO_2, NO_X and $PM_{2.5}$. Included in the total emissions are emissions from production of heating, cooling and also imported electricity. CH_4 and N_2O emissions are in the category of greenhouse gasses and both have a higher greenhouse gas effect than CO_2. Therefore, these emissions are included as CO_2 equivalents. The emissions from the imported electricity are based on a presentation from ARUP Engineers regarding the New England carbon emissions in 2016[67]. The RGGI scheme reduces their number of allowances by 2.5 % per year towards 2020 and 30% total from 2020-2030[68]. A reduction of 3 % per year is applied throughout the entire period. The CO_2 content of imported electricity is shown in Figure 41. Remaining emission estimates are based on technology specific standards[69] [56].

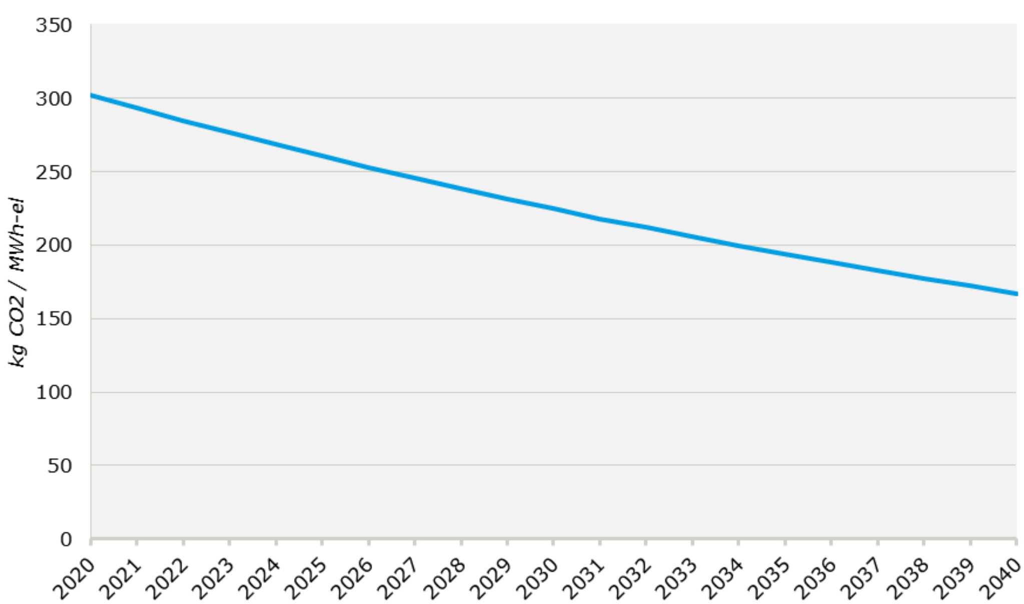


Figure 41 Assumed CO_2 content from imported electricity

[67] Electricity grid development in New England, ARUP engineers, 2016.

[68] Regional greenhouse gas initiative (RGGI), 2016:https://www.rggi.org/

[69] Emission limits in EU, European Union, 2017: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017D1442&from=EN

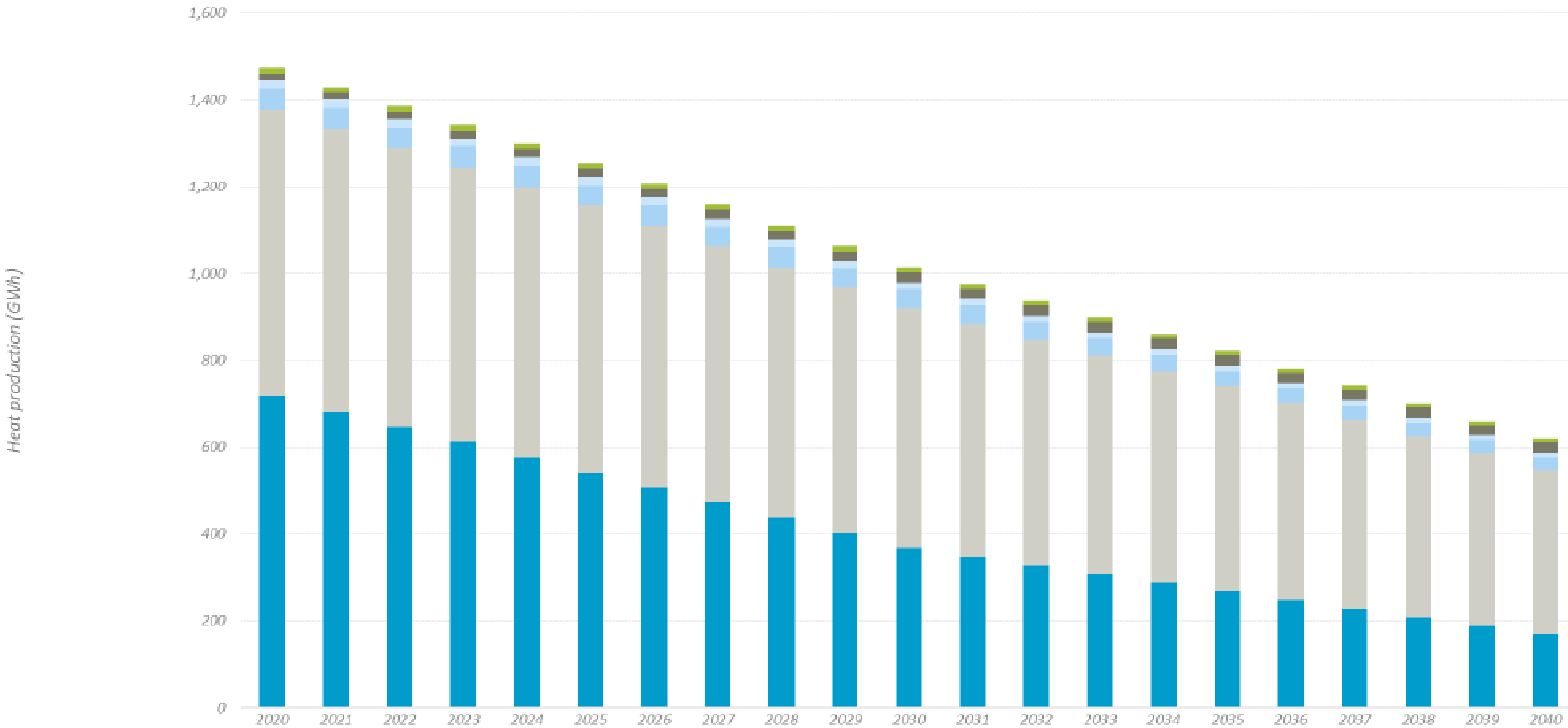
5.3 Scenario 0: Business as Usual

In this Scenario, the city continues with the technologies in use today – without any new incentives. The production of heat is based on continuous operation of the existing individual technologies such as air source heat pumps, gas boilers, oil boilers and steam based district heating. For cooling, the production will be based on electrical chillers and reversible heat pumps. Electricity is produced at the CHP plants, solar PV plants and imported from the grid.

The main capital expenditure includes reinvesting in heating and cooling units, as they reach the end of their useful lifetimes but also includes the investment costs for solar PV panels. It is assumed that reinvestments in the cogeneration plants at MIT, Blackstone and Kendall are recently completed. Thus, any reinvestment costs are excluded in these plants. This is very likely the case for MIT, but there might be reinvestments in the other plants.

Another uncertainty is the reinvestments in the electricity and gas networks. The distribution company, Eversource, will under all circumstances have a plan for reinforcement and replacement of the existing energy system, as per the grid modernisation plan. It is assumed that the investments are made in all Scenarios, as Ramboll currently do not have detailed data on Eversource´s plans. Thus additional investment costs beyond BAU are only included for electricity grid reinforcements in Scenario 1 and 2, where a full electrification of the city is undertaken. It is clear that by developing district heating and cooling systems some of the planned investments in the electricity and gas grid may not be necessary. However, this potential benefit is not included in our later economic evaluation of Scenario 2 and 4.

Figure 42 shows the development of heat demand and production in Zone 1 for Scenario 0. The figure is read from the bottom up. For example, the *District Heating (CHP-gas)* is displayed at the bottom of both the table and the figure, and so forth with the remaining technologies.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Electric boiler	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1
Gas fired absorption heat pump	12	12	12	12	12	12	12	12	11	11	11	11	10	10	10	9	9	8	8	7	7
Ground source heat pump	14	15	16	17	19	20	21	21	21	22	22	23	23	24	24	24	24	24	24	24	24
Oil boiler	21	20	20	19	19	18	18	17	17	16	16	15	15	14	14	13	12	12	11	11	10
Air source heat pump	50	50	49	49	48	47	47	46	46	45	44	43	41	40	38	36	35	33	32	30	28
Gas boiler	659	650	641	632	623	614	602	589	577	565	552	536	520	503	487	471	453	435	417	399	381
District Heating (CHP-gas)	716	682	647	612	577	542	507	472	438	403	368	348	328	308	288	268	247	227	207	187	167

Figure 42 Development of heat demand and production in Zone 1 for Scenario 0 (***This is an assumed future energy production based on the modelled Scenario and is not reflective of current stakeholder plans***)

The financial results are shown in Table 14. The highest expense is buying fuels, which accounts for more than 90 % of the total costs. The capital expenditure may be underestimated, as information about any reinvestment costs in the steam networks at the universities and the power plants is unavailable. Therefore, the capital expenditure only represents the estimated reinvestment costs in the existing individual units and forecast solar PV installations. Table 15 shows the emissions in the first year, last year and over the entire evaluation period. Notice that the CO2 emissions are given in kton, SO_2 and NO_X emissions in tonnes and $PM_{2.5}$ emissions in kg. The CO2 emissions are dominant.

Table 14 Financial result of Scenario 0

Financial result	NPV (M$)
Fuel costs	4,111
Variable operation & maintenance	72
Fixed operation & maintenance	112
Capital expenditures (CAPEX)	600
Total	**4,896**

Table 15 Emissions in Scenario 0

Emissions	Emissions (20 year total)	Emissions (first year)	Emissions (last year)
CO_2 equivalent (kton)	14,157	983	387
SO_2 emissions (ton)	919	58	27
NO_X emissions (ton)	10,772	763	286
$PM_{2.5}$ emissions (kg)	38,065	2,448	1,126

Arguably, changes in fuel prices will have a great influence on the financial result. Since the households are primarily supplied with heat from individual natural gas boilers and heat pumps, a sensitivity analysis is performed on the natural gas and electricity prices. The gas- and electricity price will also influence the costs of operating the CHP plants. The prices are increased and decreased by a factor. The results are displayed Table 16. An increase in the natural gas price leads to a higher cost than an equivalent increase in the electricity price.

Table 16 Sensitivity analysis of Scenario 0

Sensitivity analysis NPV (M$)		Natural gas price factor		
		0.9	1	1.1
Electricity price factor	0.9	4,494 (92 %)	4,776 (98 %)	5,058 (103 %)
	1	4,614 (94 %)	4,896 (100 %)	5,178 (106 %)
	1.1	4,734 (97 %)	5,017 (102 %)	5,299 (108 %)

In the following Scenarios, three proposals are investigated as to how the city can become a low carbon city. All Scenarios can be compared to this Scenario – business as usual.

It should be emphasized that the cost in this Scenario has been evaluated conservatively. It is likely that the cost of reinvestment in existing units has been underestimated, both for individual and central plants. Also, the costs of reinvestment have been excluded in the existing steam networks and natural gas networks. Some of these costs can be avoided in the following Scenarios, but this potential benefit is not included. This conservative approach should be kept in mind when comparing the following Scenarios to Business as Usual.

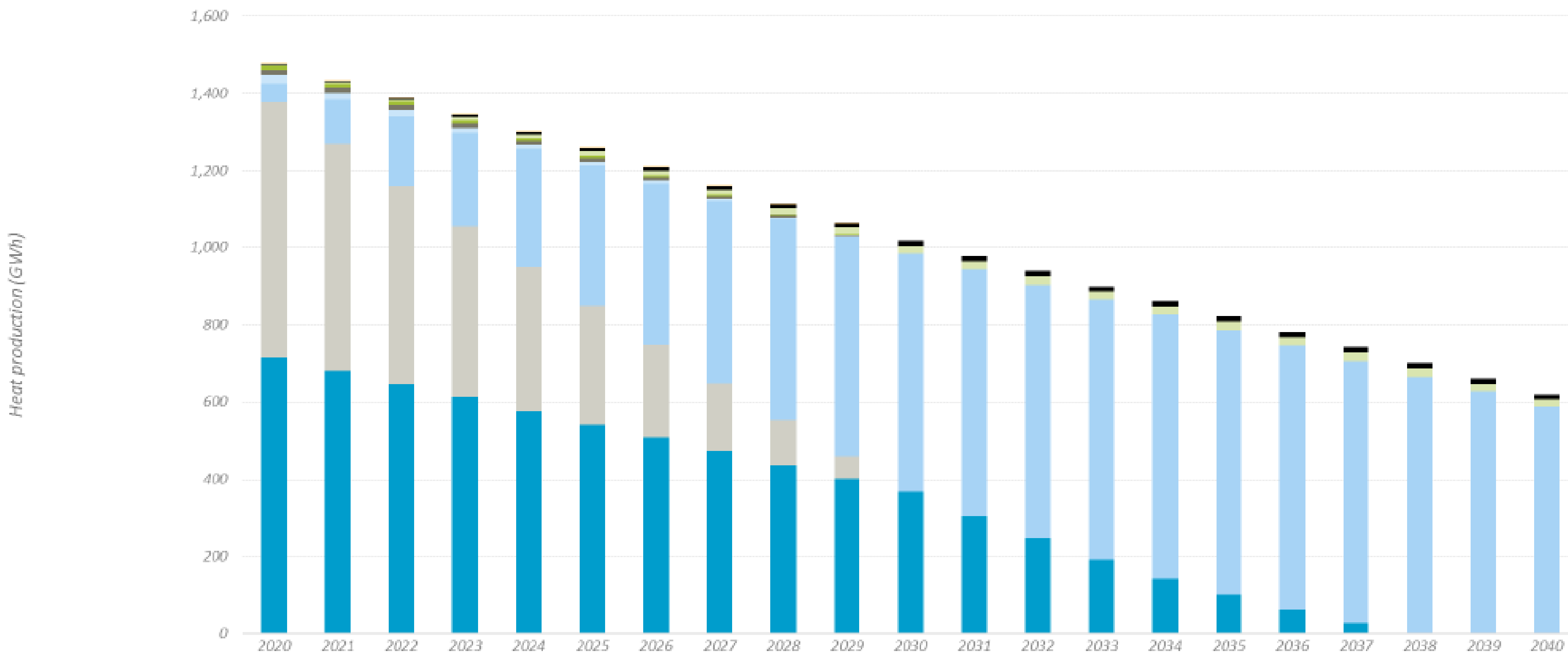
5.4 Scenario 1: City wide electrification

This Scenario involves conversion of all fossil fuel boilers and furnaces, cogeneration units and cooling units to individual electricity driven production units – heat pumps, electric boilers and chillers. The existing steam networks could be supplied from large scale steam electric boilers, but it is assumed also that the steam networks will be gradually substituted by individual electric boilers. The individual heat production technologies will be heat pumps with different heat sources and electric boilers.

In the high heat density areas, there are limited options for choosing heat pumps, due to the lack of good heat sources. Therefore, in Zone 1, electric boilers will be widely used in buildings with a high heat demand. Heat pumps can operate even during the coldest winter days, but will have an efficiency close to that of an electric boiler. This implies that the total capacity of electricity consumption will be noticeably higher than today, and that the internal electricity grid in Cambridge, as well as the external supply lines to the city, must be reinforced. Since heat production technologies are individual it is necessary to reinforce the grid from the high voltage substations supplying the city to the lower voltage grid supplying end consumers. The cooling demand will be supplied from individual electric chillers.

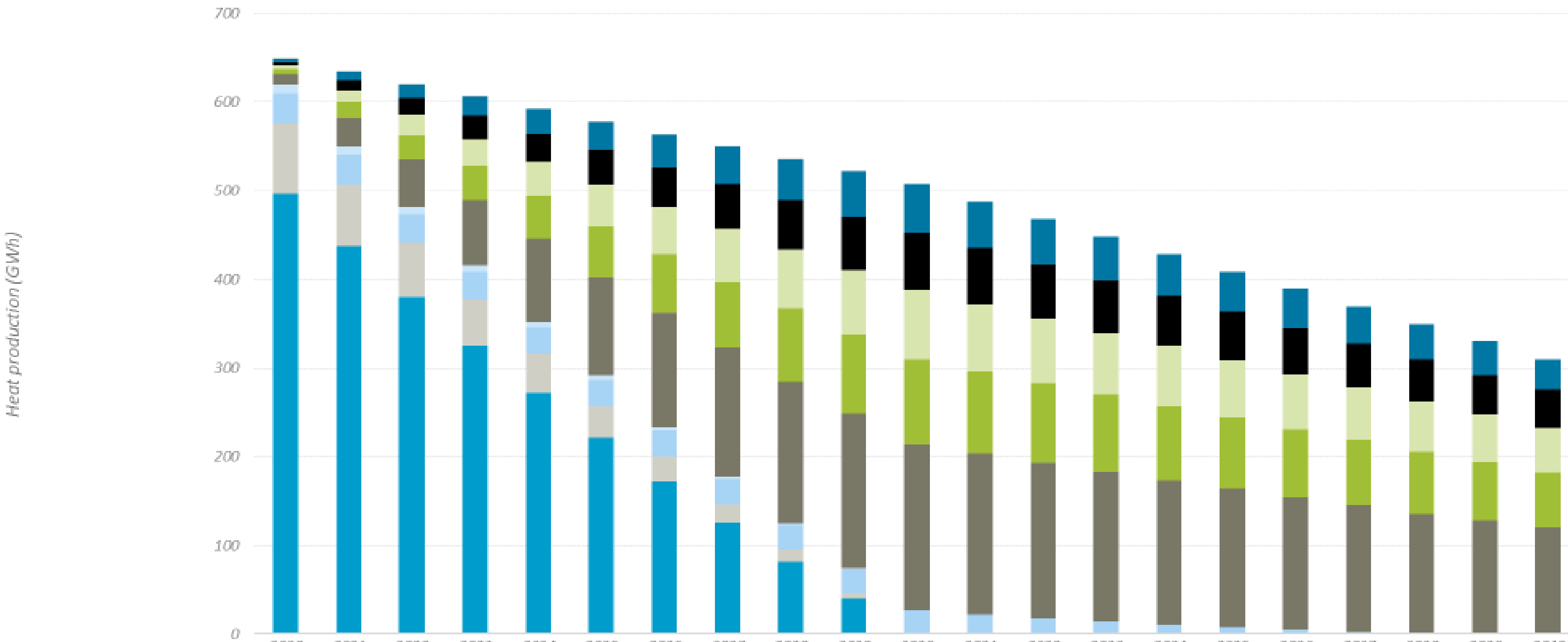
Also, the heat production from the main cogeneration plants at Kendall, MIT and Blackstone will be converted to individual technologies, which will convert the production of electricity and heat to a significant demand for electricity. The production of electricity from inside the city in 2040 is only from the solar PV systems. The city is fully reliant on imported electricity. As shown on Figure 43, the heat production in 2040 will be from electric boilers, air source heat pumps and ground source heat pumps in Zone 1. Similarly, Figure 44 shows the development of heat demand and production for Zone 2 in Scenarios 1, 2 and 4. In 2040, the heat production will be based on air source heat pumps, vertical ground source heat pumps, electric heating, ATES and air to water heat pumps.

The cooling production is based on air cooled chillers and air source heat pumps. Like the heating production no cooling is distributed in district cooling networks – cooling is only produced on individual plants.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Oil fired absorption heat pump	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Water source heat pump	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Air source heat pump	1	2	4	5	6	8	9	10	11	12	13	13	14	14	14	14	14	14	14	13	12
Air-to-water heat pump	2	4	6	8	10	11	13	15	16	18	19	20	21	21	22	22	22	21	21	20	19
Gas fired absorption heat pump	12	11	10	8	7	6	5	3	2	1	0	0	0	0	0	0	0	0	0	0	0
Ground source heat pump	14	13	13	12	11	10	8	6	4	2	0	0	0	0	0	0	0	0	0	0	0
Oil boiler	21	18	16	13	11	9	7	5	3	2	0	0	0	0	0	0	0	0	0	0	0
Electric boiler	50	116	180	242	303	363	418	471	522	570	616	640	659	673	682	687	685	678	666	627	589
Gas boiler	659	585	513	443	374	307	241	177	115	56	0	0	0	0	0	0	0	0	0	0	0
District Heating (CHP-gas)	716	682	647	612	577	542	507	472	438	403	368	304	246	192	144	100	62	28	0	0	0

Figure 43 Development of heat demand and production in Zone 1 for Scenario 1 (*This is an assumed future energy production based on the modelled Scenario and is not reflective of current stakeholder plans*)



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Wood pellet boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ATES-heat	3	10	16	22	27	32	37	42	46	51	54	53	51	49	47	45	43	41	39	37	35
Air-to-water heat pump	4	11	19	26	33	39	45	51	56	61	65	63	61	59	57	55	52	50	48	45	42
Electric boiler	4	14	22	31	39	46	53	60	67	72	78	75	73	70	68	65	62	59	57	53	50
Vertical ground source heat pump	6	17	28	38	48	57	66	74	82	89	96	93	90	87	83	80	77	73	70	66	62
Air source heat pump	11	33	54	74	93	111	128	145	160	174	187	181	175	169	162	156	149	143	136	128	121
Gas fired absorption heat pump	11	10	8	7	6	5	4	3	2	1	0	0	0	0	0	0	0	0	0	0	0
District Heating (CHP-gas)	34	33	32	32	31	30	29	29	28	27	27	22	18	15	11	8	5	2	0	0	0
Oil boiler	80	70	61	52	44	35	28	20	13	6	0	0	0	0	0	0	0	0	0	0	0
Gas boiler	496	437	380	325	272	221	173	126	82	40	0	0	0	0	0	0	0	0	0	0	0

Figure 44 Development of heat demand and production in Zone 2 for Scenario 1 (***This is an assumed future energy production based on the modelled Scenario and is not reflective of current stakeholder plans***)

Because production is based entirely on imported electricity (bar that produced by roof top installed PV which is expected to account for approximately 10% of the annual electricity consumption in 2040.) there is no flexibility in the choice of fuels. If the electricity grid blackouts, the city will be without heating, domestic hot water and cooling along with electricity. In the case the security of supply of the electricity grid is low there is a risk that large consumers may establish their own fossil fuel based production of heat and/or electricity, which will be inefficient and expensive. Local emissions and associated nuisances would follow as a result.

Following this path, it will be expensive to change the decision later, as investments are already made for new production facilities, and the existing facilities are replaced. The financial result is shown in Table 17. The fuel costs still represent the majority of the total costs. However, the capital expenditure is much higher than in Scenario 0. The major investments are that of reinforcing the electricity grid and replacing a majority of the heating and cooling units.

Table 17 Financial result of Scenario 1

Financial result	NPV (M$)
Fuel costs	5,637
Variable operation & maintenance	74
Fixed operation & maintenance	67
Capital expenditures (CAPEX)	2,942
Total	**8,721**

Table 18 shows the emissions in the first year, last year and over the entire evaluation period. The carbon emissions decrease compared to Scenario 0 (BaU Case expected for the grid), if the city should choose a full electrification with individual heating and cooling supply. Table 8 below compares the CO2 emissions should the electrical grid achieve decarbonisation by 2035, which would achieve a 20-year reduction of 21% of CO2 emissions compared to the current grid emissions trajectory.

Table 18 Emissions in Scenario 1

Emissions	Emissions (20 year total)	Emissions (first year)	Emissions (last year)
CO_2 equivalent (kton)	11,524	991	162
SO_2 emissions (ton)	338	58	1
NO_X emissions (ton)	8,815	769	112
$PM_{2.5}$ emissions (kg)	19,986	2,462	211

The capital expenditure is far greater than in Scenario 0 (BaU). Thus, we include a sensitivity analysis on both the fuel costs and the capital costs, which primarily stems from the costs of reinforcing the grid. The technical lifetime of grid investments is estimated to be 60 years and will therefore have a significant residual value in year 2040. The total investment in reinforcing the grid is estimated to be around $2,250 million, but due to the residual value the net investment is around $1,850 million. The sensitivity analysis results are shown in Tables 19 and 20.

Table 19 Sensitivity analysis of Scenario 1

Sensitivity analysis NPV (M$)		Natural gas price factor		
		0.9	1	1.1
Electricity price factor	0.9	8,160 (94 %)	8,649 (99 %)	9,139 (105 %)
	1	8,231 (94 %	8,721 (100 %)	9,210 (106 %)
	1.1	8,302 (95 %)	8,792 (101 %)	9,281 (106 %)

Table 20 Sensitivity analysis on electricity grid investment cost in Scenario 1

Sensitivity analysis						
Marginal investment cost of additional electricity grid	M$/MW	1.8	2.0	2.2	2.4	2.6
Total investment cost of additional electricity grid	M$	1,532	1,702	1,872	2,043	2,213
Total project cost (NPV)	M$	8,380	8,550	8,721	8,891	9,061

By choosing a full electrification Scenario for the city, the carbon emissions are dependent on the power plants that produce the electricity. The assumed decarbonisation of the electricity grid applied in the calculation is shown in Figure 41. However, should the unlikely happen that the electricity grid is fully decarbonized in 2035 emissions from the city would be closer to that presented in Table 21. We applied a linear reduction of emissions from 2020 to 2035.

Table 21 Emissions in Scenario 1 (decarbonized electricity grid in 2035)

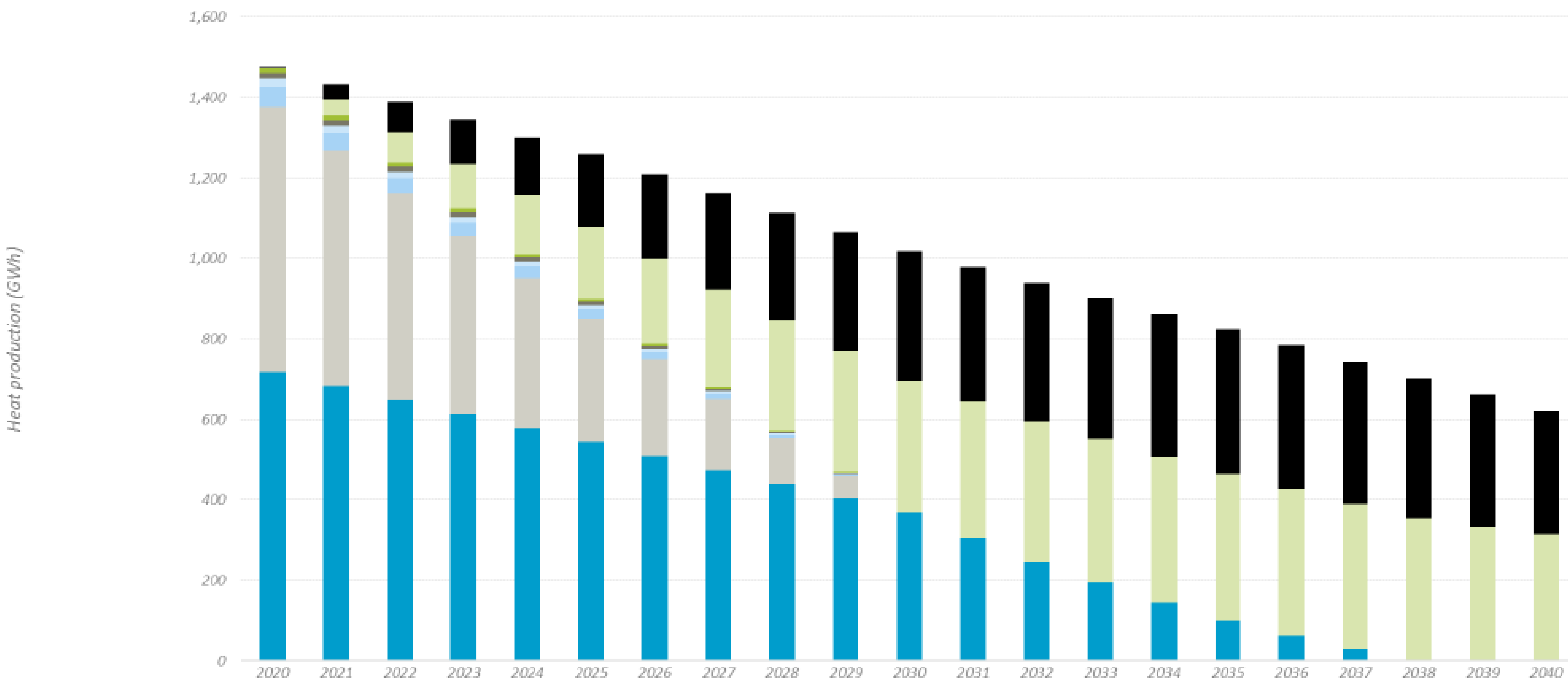
Emissions	Emissions (20 year total)	Emissions (first year)	Emissions (last year)
CO_2 equivalent (kton)	9,106	991	0
Comparison (kton)	-2,418	0	-162
Reduction (%)	~21 %	---	---

A full individual electrification of the heating and cooling supply in the city would therefore lead to higher costs but lower emissions compared to the business as usual case.

5.5 Scenario 2: City wide electrification with district heating and cooling

The main difference between Scenario 2 and Scenario 1 is that in Zone 1, 3 and 4 district heating and cooling networks are established in Scenario 2. In Zone 2 there are no changes compared to Scenario 1. In Zone 1 and 3, the heat production will be based on large electric heat pumps and electric boilers. It is assumed that the heat pump station is located near the Mystic River power plant utilizing the energy in the river as heat source (see Section 3.1.4). The peaking plants (electric or gas[70] boilers) are located at Kendall and Blackstone. The production in Zone 4 is based on ground source heat pumps and electric boilers. During the coldest months it is necessary to supply the heat demand from the electric boilers. The district heating networks are connected to end consumers by energy transfer stations (ETS). The ETS stations convert the district heating into space heating as well as domestic hot water.

[70] Gas boilers are used temporarily to supply the peak load and backup supply heat demand in the initial development period up to 2040.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Oil fired absorption heat pump	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric boiler	1	38	74	110	144	177	209	239	267	295	321	333	343	351	355	358	357	353	347	327	307
Water source heat pump	1	39	76	112	147	181	213	244	273	301	327	340	350	358	363	365	364	360	354	333	313
Gas fired absorption heat pump	12	11	10	8	7	6	5	3	2	1	0	0	0	0	0	0	0	0	0	0	0
Ground source heat pump	14	13	13	12	11	10	8	6	4	2	0	0	0	0	0	0	0	0	0	0	0
Oil boiler	21	18	16	13	11	9	7	5	3	2	0	0	0	0	0	0	0	0	0	0	0
Air source heat pump	50	45	39	34	29	24	19	14	9	5	0	0	0	0	0	0	0	0	0	0	0
Gas boiler	659	585	513	443	374	307	241	177	115	56	0	0	0	0	0	0	0	0	0	0	0
District Heating (CHP-gas)	716	682	647	612	577	542	507	472	438	403	368	304	246	192	144	100	62	28	0	0	0

Figure 45 Development of heat demand and production in Zone 1 for Scenario 2 (***This is an assumed future energy production based on the modelled Scenario and is not reflective of current stakeholder plans***)

Unlike the previous Scenario 1, it is not necessary to reinforce the entire electricity grid, but only the main high voltage lines to the locations of the energy plants in Zone 1. It is assumed that the cost of reinforcing the grid to Zone 1 is 20 % of that in the previous Scenario. Thus, the reinforcement costs are significantly lower than in Scenario 1.

Since all consumers do not consume energy at the same time, the peak demand is reduced by a diversity factor of 0.8. Consequently, installing the same capacity as in the previous Scenario 1 is not required. In addition, large heat pumps are also more efficient than small individual heat pumps and the resulting specific investment is significantly lower. Thus, the total investment cost in new production units is lower.

The district cooling clusters expected to be developed are shown in Figure 46. The clusters are located in areas where we find a cooling density high enough to develop district cooling networks. A network was designed for distribution of cooling in each cluster. As seen, the most district cooling networks are located in Zone 1. The cooling production is based on air cooled chillers and air source heat pumps. The same production technologies and district cooling systems are also evaluated in Scenario 4.

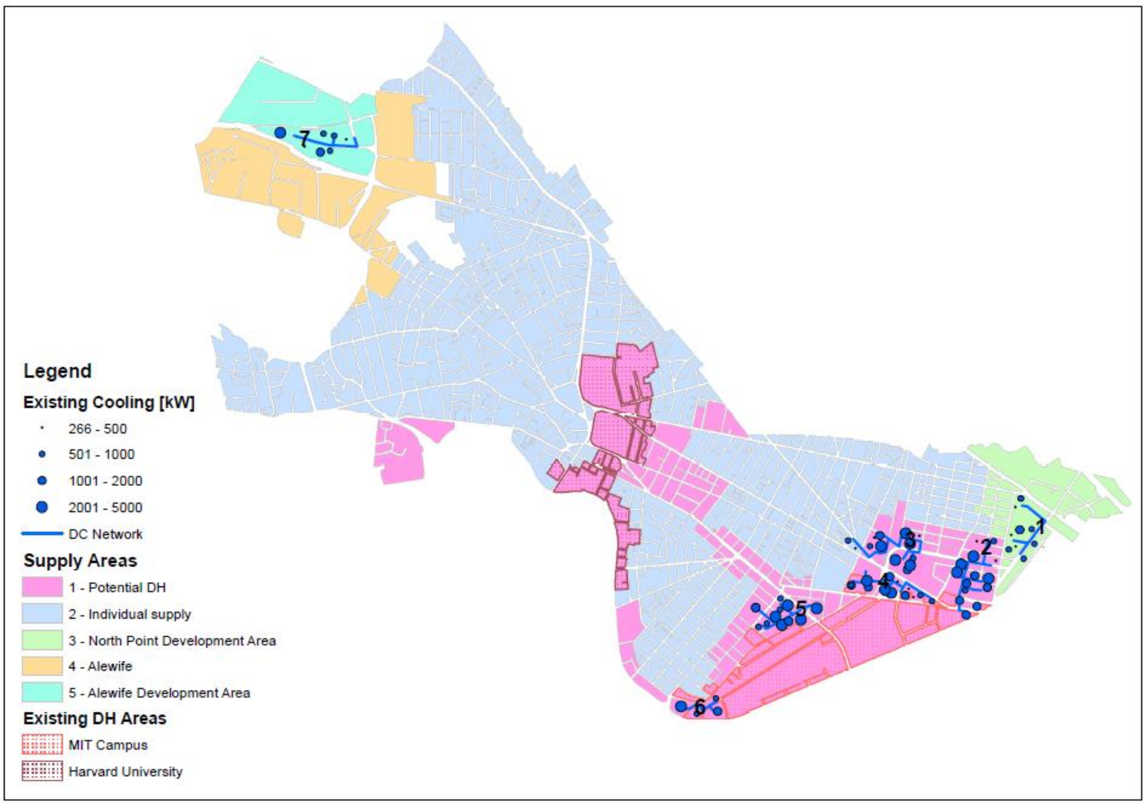


Figure 46 Potential cooling clusters in Cambridge City

An advantage of developing district energy systems – heating and cooling – is the possibility of minimizing the costs of production better than with individual systems. Thermal storage can be used to minimize production costs from heat pumps and electric boilers utilizing varying electricity prices. The heat duration curve for the proposed district heating system in Zone 1 is displayed on Figure 47. The thermal storage is used to supply both the peak demand and parts of the minimum demand during summer. The heat pump is base load and the remaining demand is supplied with electric boilers. The heat pump production depends on the available energy in the Mystic River or ground respectively, which is reduced during winter time. The curve is shown without production of excess heat from cooling production.

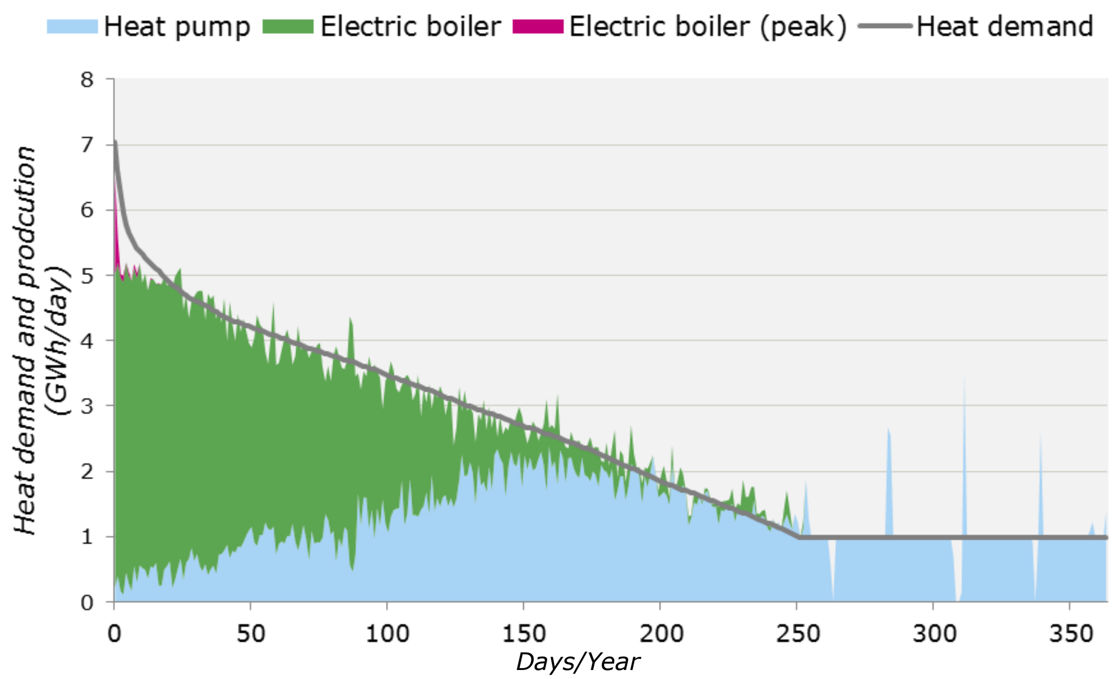


Figure 47 Heat duration curve; Scenario 2 in Zone 1 and 3 at full expansion of the district heating network

The financial result is shown in Table 22. As expected, the capital expenditure is lower than in Scenario 1, even though district heating and cooling networks are established, because the costs of reinforcing the electricity grid are reduced. The fuel costs are also lower, as the district heating and cooling production is more efficient than individual production.

Table 22 Financial result of Scenario 2

Financial result	NPV (M$)
Fuel costs	4,618
Variable operation & maintenance	86
Fixed operation & maintenance	56
Capital expenditures (CAPEX)	1,689
Total	**6,449**

Table 23 shows the emissions in the first year, last year and over the entire evaluation period.

Table 23 Emissions in Scenario 2

Emissions	Emissions (20 year total)	Emissions (first year)	Emissions (last year)
CO_2 equivalent (kton)	10,901	980	137
SO_2 emissions (ton)	335	58	1
NO_X emissions (ton)	8,340	761	92
$PM_{2.5}$ emissions (kg)	18,905	2,446	165

The same sensitivity analysis as performed in the previous scenario is also made here. The results from varying the electricity price, gas price and electricity grid investment costs are shown in Table 24 and 25. The potential carbon emission savings were also evaluated if the electricity grid is decarbonized in 2035 as shown in Table 26.

Table 24 Sensitivity analysis of Scenario 2

Sensitivity analysis NPV (M$)		Natural gas price factor		
		0.9	1	1.1
Electricity price factor	0.9	5,991 (93 %)	6,378 (99 %)	6,766 (105 %)
	1	6,062 (94 %)	6,449 (100 %	6,837 (106 %)
	1.1	6,133 (95 %)	6,520 (101 %)	6,908 (107 %)

Table 25 Sensitivity analysis on electricity grid investment cost in Scenario 2

Sensitivity analysis						
Marginal investment cost of additional electricity grid	M$/MW	1.8	2.0	2.2	2.4	2.6
Total investment cost of additional electricity grid	M$	500	555	611	666	722
Total project cost (NPV)	M$	6,338	6,394	6,449	6,505	6,560

Table 26 Emissions in Scenario 2 (decarbonized electricity grid in 2035)

Emissions	Emissions (20 year total)	Emissions (first year)	Emissions (last year)
CO_2 equivalent (kton)	8,866	980	0
Comparison (kton)	-2,035	0	-137
Reduction (%)	~19 %	---	---

Comparing this scenario to the previous Scenario 1 it can be concluded that it is less expensive to develop district heating and cooling than continuing with individual supply, when deciding for full electrification. Still, comparing to the Business as Usual this scenario is more expensive.

Additionally, the resilience is still low in this scenario. Production will be based on electricity generated outside the City border, therefore there is no backup of electricity production for vital electricity users in the city (e.g. from biomass or fossil fuel) or to the heating systems (from e.g. very reliable heat only boilers).

However, the flexibility is much higher in this scenario. Since heat is supplied through a district heating network it is very easy to change the production from one source to another when new technologies emerge. Heat supplied from centralized heat pumps can easily and with limited costs (compared to Scenario 1) be changed to another source. Buildings would not need to have their internal systems updated when new technologies emerge and the costs for new technologies must be expected to have large economies of scale which further reduces the costs.

Another large advantage of this scenario compared to Scenario 1 is that when district heating networks are part of the energy system it will be possible to actively make use of it during energy production to maximize efficiency. Large scale thermal storage is connected to the network enabling the production of heat from electricity when prices are close to zero, meaning a surplus of intermittent renewable electricity in the networks. This will most likely not be the situation in the coming 5 to 10 years but as more and more renewable intermittent electricity is entering the grid it is important to have as flexible a system as possible and thus being able to closely integrate the different energy supplies.

Therefore, we would also recommend that considering a longer perspective, large scale heat pumps should definitely play a significant role in the energy system. Electrical large scale heat pumps are the link between the electric grid and the heating system, but a district heating network is required to facilitate distribution to consumers of the heat generated.

5.6 Scenario 4: District heating and cooling with a new biomass cogeneration plant

In Scenario 2 it was the overall objective that all production should be based on electrically driven technologies. Therefore, large scale heat pumps were an important technology. However, going full electric will have the consequence that the overall consumption of electricity will increase. Since electricity bought from the grid may still include a significant carbon content many years after 2040 this causes resulting emissions. An alternative would be large scale biomass cogeneration, which is a well proven technology either as new build or alternatively as a conversion of existing fossil fuel plants.

The efficiency of a large-scale biomass cogeneration plant is more than 85 % (based on lower heating value[71]) and would be eligible for renewable energy credits. This means that the variable production costs will be very low for the biomass cogeneration plant. Furthermore, it was decided not to include large scale heat pumps in the district heating technology mix in the initial planning, as they will replace operation on the biomass cogeneration plant and thus increase the specific investment. At a subsequent phase in the conversion of the city, it can be considered to include this or other technologies. In the interim, gas boilers are used to supply the peak load and backup supply in the initial development period up to 2040. It is important that the backup is very reliable and there are no restrictions on the fuel supply. It is therefore that it is recommended that these boilers (heat only) are based on either natural gas or oil. Emissions and costs are incorporated in the assessment. Post 2040, a decision should be made on the choice of back up supply, whether this should be provided by fossil fuels or other technology.

Additionally, the amount of available residual waste in Cambridge is too small for a viable waste to energy facility. The investments and economies of scale in these facilities are significant. Therefore, they should operate with a high capacity factor and be able to sell all produced heat and electricity. If the city planned for a facility in cooperation with the neighbouring cities, the amounts of available waste could possibly substitute fossil fuels. This has not been investigated further and the technology has been rejected for a Cambridge-only scenario.

Instead, a biomass cogeneration plant has been included with a capacity that enables it to reach an annual share of more than 90 % of the total heat demand in Zone 1 and 3. The district heating production in Zone 4 is still based on the same technologies as in the previous scenario – ground source heat pumps and electric boilers.

The total heat demand over the 20 year period of the city is decreasing, but the district heating demand will increase as the network develops and connects more consumers. Therefore, it is not recommended to plan a full capacity production facility from the beginning. In a subsequent detailed design phase it can be considered to modify the capacity of the plant, and if the plant should be one plant or two or more plants. The plant is designed with capacities shown in Table 27. The plant can be designed with a slightly higher efficiency, but this potential has not been included at this point and a more conservative estimate is utilized.

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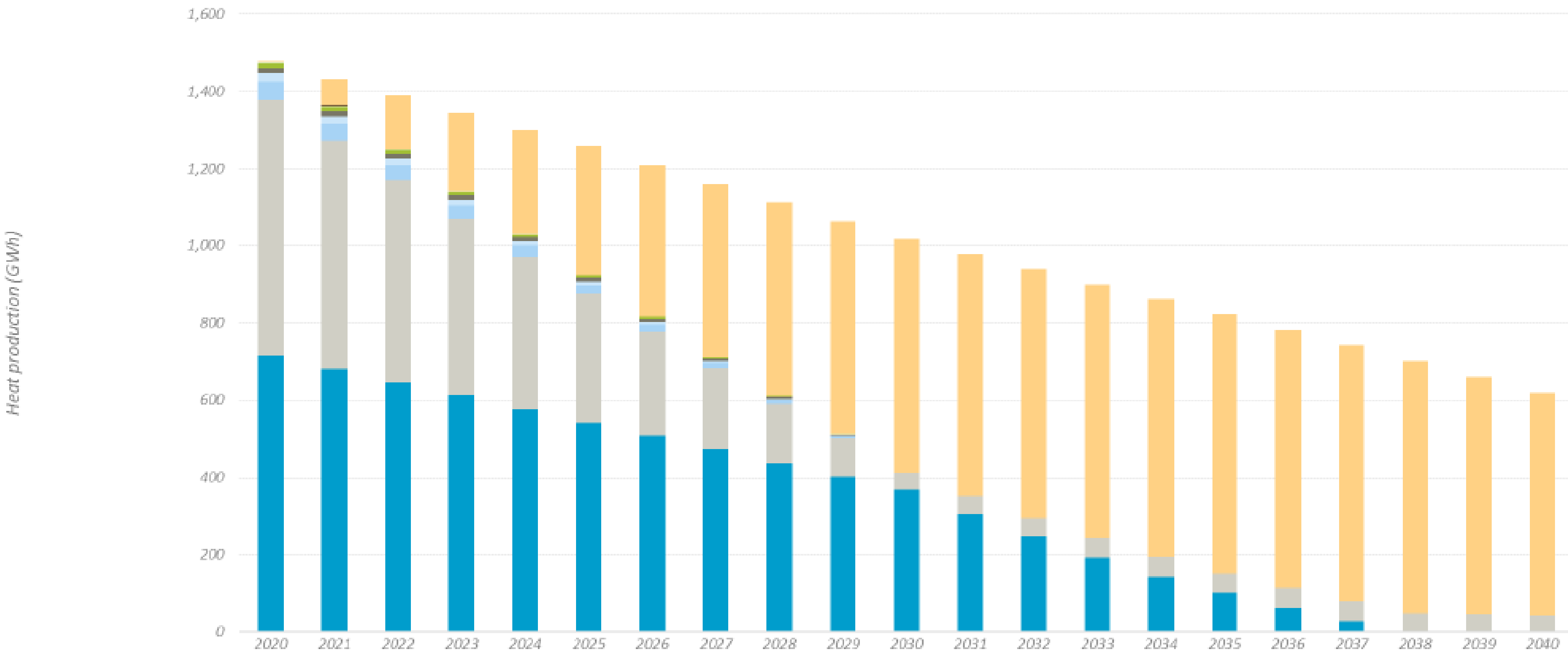
[71] The lower heating value (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C, which assumes the latent heat of vaporization of water in the reaction products is not recovered. In contrast, the higher heating value (also known gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C, which takes into account the latent heat of vaporization of water in the combustion products. (https://www.h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels)

Table 27 New biomass cogeneration plant

	Maximum heat capacity	Maximum electric capacity	Maximum fuel use
Biomass plant	150 MW-h	75 MW-el	250 MW-fuel

On an annual basis, the consumed fuel can be up to 500,000 tons of wood chips. The same number for imported tons of wood pellets would be around 60 % of that for wood chips. This is a large amount of biomass and the potential sourcing must be considered thoroughly through a more detailed feasibility study of the viability of such a plant. A very important aspect is that the biomass must be based on wood from sustainable forestry. It is very important to ensure appropriate requirements for the wood, so it complies with *25 cmr 14.00 Reg DOER 081712 RPS Biomass Regulation for Massachusetts*.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
District Heating (CHP-bio)	0	70	138	204	269	332	391	448	502	554	603	626	645	659	668	672	670	663	652	614	576
Oil fired absorption heat pump	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Water source heat pump	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric boiler	2	2	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas fired absorption heat pump	12	11	10	8	7	6	5	3	2	1	0	0	0	0	0	0	0	0	0	0	0
Ground source heat pump	14	13	13	12	11	10	8	6	4	2	0	0	0	0	0	0	0	0	0	0	0
Oil boiler	21	18	16	13	11	9	7	5	3	2	0	0	0	0	0	0	0	0	0	0	0
Air source heat pump	50	45	39	34	29	24	19	14	9	5	0	0	0	0	0	0	0	0	0	0	0
Gas boiler	659	590	523	458	394	332	270	211	153	98	45	47	49	50	50	51	50	50	49	46	43
District Heating (CHP-gas)	716	682	647	612	577	542	507	472	438	403	368	304	246	192	144	100	62	28	0	0	0

Figure 48 Development of the heat production in Zone 1 for Scenario 4 (*This is an assumed future energy production based on the modelled Scenario and is not reflective of current stakeholder plans*)

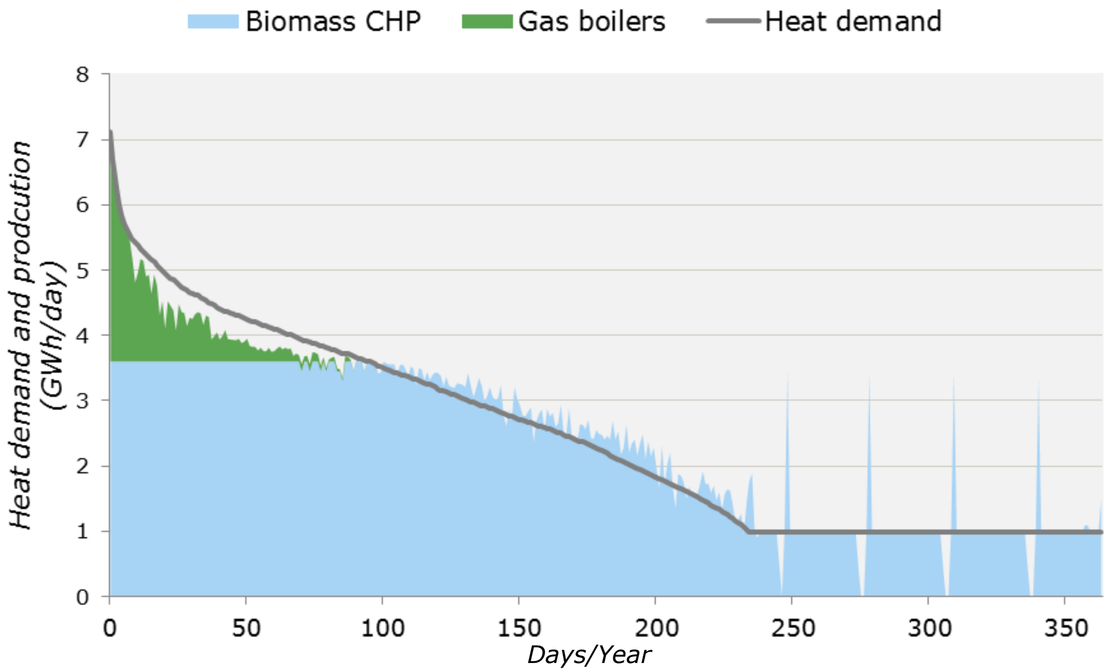


Figure 49 Heat duration curve; Scenario 4 in Zone 1 and 3 at full expansion of the district heating network

The heat duration curve for the district heating system at full expansion is shown in Figure 49. The curve is shown without production of excess heat which is a bi-product of cooling production. Parts of the production from the biomass cogeneration plant can be replaced by this excess heat production. Nevertheless, we did not investigate the economic implications further.

The financial result is shown in Table 28. Here, the fuel costs and capital expenditure are lower than the two previous scenarios. It should be kept in mind that the only change in this scenario compared to Scenario 2 is that the district heating system is supplied from a new biomass cogeneration plant instead of heat pumps and electric boilers. Thus, the investment costs of reinforcing the electricity grid are not included in areas where district heating is established.

Table 28 Financial result of Scenario 4

Financial result	NPV (M$)
Fuel costs	3,531
Variable operation & maintenance	91
Fixed operation & maintenance	171
Capital expenditures (CAPEX)	1,386
Total	**5,180**

Table 29 shows the emissions in the first year, last year and over the entire evaluation period. As discussed in Sections 3 and 6, further consideration of the carbon neutrality of biomass must be made before proceeding with the scenario; biomass is considered carbon neutral for this analysis. The particulate (PM2.5) emissions level indicated for the biomass facility is based on Best Available Technology standards for emission control in the Industry Emissions Directive in Europe.[72] This emissions level can be further reduced, but the costs increase significantly to do this and this level of emissions is deemed acceptable across Europe for emissions from industrial plants. To give further context to this, the current permit for the Kendall Square plant shows a limit of 86.3 TPY (tonnes per year) or 86,300 kg/year total PM emissions (PM10+PM2.5) based on their permit.[73]

[72] http://ec.europa.eu/environment/industry/stationary/ied/legislation.htm

[73] MBR-00-COM- 029: https://www.mass.gov/files/documents/2016/08/ta/op-kendallgreen.pdf

Table 29 Emissions in Scenario 4

Emissions	Emissions (20 year total)	Emissions (first year)	Emissions (last year)
CO_2 equivalent (kton)	9,210	980	63
SO_2 emissions (ton)	985	58	38
NO_X emissions (ton)	9,838	761	193
$PM_{2.5}$ emissions (kg)	109,851	2,446	5,456

The biomass- and electricity prices are also varied in the sensitivity analysis in Table 30.

Table 30 Sensitivity analysis of Scenario 4

Sensitivity analysis NPV (M$)		Biomass (wood chips) price factor		
		0.9	1	1.1
Electricity price factor	0.9	4,903 (95 %)	5,150 (99 %)	5,397 (104 %)
	1	4,933 (95 %)	5,180 (100 %)	5,427 (105 %)
	1.1	4,963 (96 %)	5,210 (101 %)	5,458 (105 %)

In this scenario it is shown that there is not an economic benefit of implementing a district heating scheme for the city as a whole – based on the selected technologies – but rather just for Zones 1 and 3. However, the results also show that this scenario is less expensive than the previous two scenarios.

5.7 Conclusion

The least expensive way to convert Cambridge City to a low carbon city is by developing biomass-based district heating and cooling where viable and base the remaining individual heating and cooling on electricity. Outlined in the table below are the economic assessment of the scenarios as discussed above. Table 31 shows the final economic result for the investigated scenarios.

Table 31 Final economic results of all scenarios (NPV; M$)

Financial result	Scenario 0	Scenario 1	Scenario 2	Scenario 4
Fuel costs	4,111	5,637	4,618	3,531
Variable operation & maintenance	72	74	86	91
Fixed operation & maintenance	112	67	56	171
Capital expenditures (CAPEX)	600	2,942	1,689	1,386
Total	**4,896**	**8,721**	**6,449**	**5,180**
Additional cost compared to business-as-usual	---	+3,825	+1,553	+284

The total costs are high in Scenario 1. This is because all heat demand is supplied from individual technologies. Even the existing steam networks are gradually substituted by individual electric boilers. Consequently, the costs of electricity grid reinforcements are high. If alternatively, the existing steam network is reused and electric boilers supply the steam network centrally both the capital costs for heating units and the electricity grid reinforcement costs will be reduced, as seen in Scenario 2.

The fuel costs in Scenario 4 are significantly lower than in the other Scenarios, but may still be considered conservative. Here, the main uncertainties is the biomass price. A wood chip price projection is used from the International Energy Agency, who expect a price of 27 $/MWh in 2020. However, Ramboll have already experienced prices that are half this level in New England which would bring the total Scenario costs well below BAU. A further analysis of locally available resources and expected prices is necessary as part of an overall biomass facility feasibility study before proceeding.

A further concern for Scenario 2 and 4 is the investment costs in the district heating network. Nonetheless, it is considered that the applied pipe prices are high compared to Ramboll's experience from projects in USA and Canada.

The emissions per scenario are shown in Table 32 together with the cost of offsetting the carbon emissions by buying CO2 credits in 2040.

Table 32 Emissions per Scenario in 2040

Item	Scenario 0	Scenario 1	Scenario 2	Scenario 4
CO_2 equivalent (kton)	387	162	137	63
SO_2 emissions (ton)	27	1	1	38
NO_X emissions (ton)	286	112	92	193
$PM_{2.5}$ emissions (kg)	1,126	211	165	5,456
Cost of off-setting carbon emissions with a carbon price of 50 $/ton (M$)	19.35	8.1	6.9	3.2

Emissions of CO_2 in Scenario 1 and Scenario 2 are lower than in Scenario 0 because heat pumps and electric boilers are used to supply the entire heat demand with emissions related to the carbon content of imported electricity. A faster decarbonisation of the electricity grid would reduce the emissions as shown in the sensitivity analysis. Much of the carbon emissions in Scenario 4 are also stemming from the carbon content in the imported electricity, as the district heating network is only established in Zone 1, 2 and 4. Additionally the heat production in Zone 4 is based on heat pumps and electric boilers in Scenario 4. The use of biomass will indeed reduce the CO_2 emissions, but also increase the emissions of $PM_{2.5}$, which are fine dust particles. The emissions of SO_2, NO_x and $PM_{2.5}$ are based on European requirements for new biomass plants and are far below those permitted for power generation within Cambridge today[74]. Nonetheless, the emissions can be reduced further at an extra cost of improved flue gas cleaning.

Based on the analysis it can be concluded that Scenario 4 is the least expensive option for converting Cambridge to a low carbon city. The conclusions are however different for each Zone. The following conclusions have been drawn for each zone based on results shown in Table 33 and Table 34:

- Zone 1: A district heating network supplied from a biomass cogeneration plant is the least expensive option. Further, it is recommended that district cooling is developed in clusters. Developing a district heating system is less expensive than continuing with the existing energy supply system.
- Zone 2: Electrification is more expensive than continuous operation of the existing energy system. However, electrification will reduce the CO_2 emissions, as the existing heating supply is mostly based on gas and oil boilers and CO_2 emissions from imported electricity are lower.
- Zone 3: The district heating system supplying Zone 1 should be expanded into this zone where financially viable using the same production technologies.
- Zone 4: A district heating network should be established for the entire zone including the development areas. Less expensive production facilities than the investigated ground source heat pumps and electric boilers can likely reduce the costs.

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[74] Current permit for the Kendall Square plant shows a limit of 86.3 TPY (tonnes per year) or 86,300 kg/year total PM emissions (PM10+PM2.5) based on their permit MBR-00-COM- 029: https://www.mass.gov/files/documents/2016/08/ta/op-kendallgreen.pdf

Table 33 Economic result per Zone (NPV; M$)

Economic result per Zone	Zone 1	Zone 2	Zone 3	Zone 4	Sum
Scenario 0	2,671	1,380	369	476	4,896
Scenario 1	5,429	1,819	586	886	8,721
Scenario 2	3,715	1,819	380	535	6,449
Scenario 4	2,568	1,819	257	535	5,180

Table 34 CO2-equivalent emissions per Zone in 2040 (kton)

CO_2 emissions per Zone	Zone 1	Zone 2	Zone 3	Zone 4	Sum
Scenario 0	254	87	15	31	387
Scenario 1	115	20	11	16	162
Scenario 2	92	20	9	15	137
Scenario 4	26	20	2	15	63

5.7.1 Development Zones

For the development Zones, it has been shown that developing district heating and cooling is the most cost-efficient solution. In Table 34 it is observed that the emissions will decrease in Zone 3 (North Point Development Area) and in Zone 4 (Alewife) compared to business as usual, when developing district heating and cooling. However, if instead other technologies than heat pumps and electric boilers are selected in Zone 4, the result may be different.

In the North Point Development Area, it is recommended that a district heating network is developed together with that in Zone 1, where the heat will be supplied from the same production facilities. it is also recommended that all new buildings are prepared for low temperature district heating.

In the Alewife Area, there is already today a noticeable heat demand. Therefore, it is recommended to establish a separate district heating system partly supplying the existing buildings and the new development area. This can ensure a flexible and reliable supply of energy, with potential of using available low temperature heat sources. The existing buildings will likely require a higher supply temperature than new buildings, which it is recommended are prepared for low temperature district heating. Later, it can be investigated if the return water supplying existing building can be used as supply for the new buildings, which can further increase the efficiency.

It is also recommended to develop the district cooling clusters identified in both areas as illustrated in Figure 46 (Section 5.5). It will be possible to utilize the excess heat from the production of cooling in the district heating system.

6. CHANGE MANAGEMENT: LOW CARBON SUPPLY IMPLEMENTATION ACTION PLAN

6.1 Introduction: Technical Basis for a Low Carbon Energy Supply

Achieving the Carbon Neutral objective of the City of Cambridge by 2050 is a challenging task. This study outlines the significant challenges that must be addressed in order to change the current energy supply of the City to a low carbon alternative. This section outlines the steps that need to be taken to address some of these challenges and start implementing the change necessary to meet the Carbon Neutral objective.

This study has investigated, assessed and modeled numerous energy supply scenarios involving multiple technologies for Cambridge in order to determine the best path forward towards the Net Zero target for its energy supply. The study provides a menu of solutions and arguments as to how to proceed, which can be used as a template regionally to build regional solutions for achieving a low carbon energy supply. The reality of their implementation will be somewhat different to the hypothetical scenarios outlined here, as commercial considerations, regulatory conditions, spatial considerations, future societal and environmental changes, and human behavior will impact upon what the low carbon energy supply of Cambridge is by mid-century.

The commercial viability of the technologies will drive some of their implementation via the competitive market; however for large scale technology change in such a short timeframe, there will be the need for external drivers to act further on the market. For electrification in residential areas, for example, this could be by providing economic incentives for electrical boilers, heat pumps and chillers. For hot water district heating utility establishment, it could be working to establish favorable conditions for development. To implement such change, a regional approach will likely be most effective to scaling up the conclusions made in the Cambridge study and seeking solutions to challenges through collaboration with neighboring communities and regional and state stakeholders.

The below sections discuss next steps for further development of each technology area outlined in the scenarios above to guide regional collaboration on a route to progress towards the low carbon energy supply objective.

6.2 Electrification Implementation

Electrification will form part of any future low carbon energy supply. Certain parts of the city such as Zone 2 residential areas are not suited to district energy supply due to their low heat density and so electricity will be used in combination with efficient technologies such as heat pumps to deliver the thermal loads which are met in these city areas today by fossil fuels.

6.2.1 Grid Level Considerations

Grid strengthening and modernization (within and external to Cambridge) will likely be required in order for the electrical grid to take on a proportion (or all) of the thermal load currently met by fossil fuels. The Integrated Resource Planning (discussed in 2.4.1.4) and Grid Modernization Planning (GMP) (discussed in 2.4.1.5) requirements which Eversource need to comply with should provide the tools to facilitate the introduction and planning for any proposed changes in demand which the electrical grid will need to meet. Such proposals for GMP are ultimately approved by the DPU, so this again highlights the importance of their buy-in to any plans put forward for low carbon energy supply implementation.

Such processes and approvals of GMP is complex and will take time to affect change. To outline an example, the 10-year GMP submitted in August 2015 by Eversource for approval is still under investigation by the DPU.[75] and requires the consideration of many parties' submissions prior to

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[75] http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/grid-mod/grid-modernization.html

agreement. The objectives of the DPU and Eversource in this initial GMP process do not specifically include incorporation or consideration of accommodating the existing thermal load of the city currently met by fossil fuels.

DPU objectives for grid modernization (including its objectives related to Advanced Metering Functionality ("AMF") and Time Varying Rates ("TVR") are:

- Reducing the effects of outages;
- Optimizing demand; which includes reducing system and customer costs;
- Integrating distributed resources; and
- Improving workforce and asset management.

Eversource considers that a modern grid must be smart, integrated and resilient; and facilitate customer engagement. As a result they proposed four broad categories for their Short Term Investment Plan designed to achieve a smarter and more integrated grid:

- Grid Wide Situational Awareness;
- Advanced Analytics;
- Real Time Flexible Grid Action; and
- Dynamic Distributed Energy Resources ("DER") Integration.

Electrical grid strengthening costs for Cambridge will ultimately filter down to be paid via the electrical bills of electricity consumers of Massachusetts, and not specifically Cambridge consumers. How the costs for grid strengthening in specific locations would be shared equitably across the consumer base will be deliberated through rate setting overseen by the DPU.

6.2.2 Building Level Considerations

For electrification of thermal supply at the building level in many cases there will be a need to modify the technologies employed at the building level and potentially the distribution grid infrastructure outside the building. At building level this will, in many instances, involve the removal of gas or oil boilers in exchange for air or water source heat pump and electric boiler installations. There may also be a need for internal modification of buildings, consisting of upgrading radiators, internal piping, installing a new heat pump-compatible hot water cylinder and increased insulation measures. Older properties may also require upgrades to the electrical installation.

The building stock to be electrified should be studied further using the parameters outlined in Section 3.1.2 to ascertain which property types are suitable for water source heat pumps, air source heat pumps and electric boilers. It additionally needs to be understood what building modifications are required to facilitate electrification in the different building stock types identified in the city. Based on this information, it should be considered how best to incentivize the switch from the existing fossil fuel technologies to the electrical alternatives for each property type. Any incentives provided should be accompanied by a communication campaign to educate the residents on why these changes are necessary, how the technologies work and will improve their quality of life, and the incentives available. It is understood the City has started to investigate some of these issues.[76]

Consideration should be given to the potential to deter the replacement or new installation of gas or oil boilers. This would result in the gradual phasing in of electric heat pumps at the end of life of existing boilers.

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[76] See "The Potential for Air Source Heat Pumps within Cambridge Residential Buildings," Cambridge Community Development Department, September 2017

6.3 District Heating and Cooling Implementation

District energy can facilitate many of the goals (see Section 1.2) which the city has identified for their future low carbon energy supply. The installation of such systems internationally has often been reliant on stakeholders identifying an opportune time to act. This can be when a clear champion for district energy has emerged, or when external events have catalyzed the urgency to act.

In this report, the viability of district energy in the city has been demonstrated for specific areas. In order to progress with district heating and cooling hot water networks, a coherent vision needs to be set for district energy city zones, and then stakeholders mobilized accordingly.

By providing an alternative to fossil fuel heating and cooling, district energy can be an important mechanism to facilitate change.

Below are outlined eight key steps to support the development of a policy and investment road map for a district energy system and their relevance to Cambridge currently. These steps are drawn from the United Nations Environment Programme report, District Energy in Cities.[77], which is an excellent resource tool to assist in the development of a district energy utility.

6.3.1 Step 1: Assess existing energy and climate policy objectives, strategies and targets, and identify catalysts

The City has set a 2050 target for reaching carbon neutrality. A technical analysis has been undertaken, demonstrating the viability of district energy in current or emerging high-energy demand districts. This should be built upon to ensure there is clear understanding and agreement by relevant stakeholders for progression with district energy in the city.

6.3.2 Step 2: Map local energy demand and evaluate local energy resources

This step has been carried out within this study and provides a clear indication of the areas within the city which are viable for district energy. This information can be used to progress to the next level of mapping required to determine all technically viable consumer connections for a new network within each viable area identified.

Additionally the potential local energy resources, however limited, have been assessed within this study. This gives a strong understanding of the city's potential with regard to local energy resources and as a result a good indication of the environmental and operational costs of operating such a system in Cambridge.

Further detailed district energy system planning should be carried out as described in Step 5.

6.3.3 Step 3: Strengthen or develop the institutional multi-stakeholder coordination framework

The Advisory Committee assembled under this study has provided significant input and opinion to develop this study. For the realization of a district energy utility, there would be a need for multiple stakeholders to be assembled to work within a coordinated framework. This will involve different stakeholders meeting to initially develop a coordination framework and then to provide input and discussion at various steps in the utilities development as described below; however they should be all unified under the same objective.

Such stakeholders could include:

- City of Cambridge, DPW
- City of Cambridge, Community Development Department

[77] http://staging.unep.org/energy/districtenergyincities

- The Massachusetts Department of Public Utilities
- The Massachusetts Department of Energy Resources
- The Massachusetts Attorney General's Office
- Eversource (Gas and Electric representatives) with representatives from the network operation departments
- Veolia, including representatives from the plant and network operation departments
- Harvard University, including representatives from the facilities departments
- MIT, including with representatives from the facilities departments

The role of project management and coordination of this stakeholder group will need to be filled by a change champion, tasked with driving this process forward to creation of a district energy utility.

6.3.4 Step 4: Determine relevant regulatory and policy design considerations and integrate district energy standards into state and/or local energy strategy and planning

Water based district energy is not an established utility in the city today and no regulatory framework exists at the state level, although the benefits and economic viability exist to support its establishment. In order to catalyze its establishment as a utility there will be a need for well-considered state and local policy and regulatory design to encourage and enable its establishment. There are many options available for policy design to establish a new utility, and this should be studied further to develop policy which best fits end objective. Some options are briefly discussed below to give some examples of what could be done.

Policy design should consider both the existing developed zones and proposed zones for development. Such policy design should consider connection policy options to encourage and enable consumers to connect to the new utility. Options for mandatory connections for new development should be considered unless it can be demonstrated by a project proponent that the district energy solution is not cost effective.

Regulatory policy should also be established for water based district energy, incorporating policy for protection of customers and oversight of tariff settings and addressing potential barriers such as franchise rules. Such policy will give structure as to how heat producers can sell excess heat to third parties and consumers can purchase such heat and what licenses are required to do so.

Such policy design should also consider the existing incentives for CHP establishment under the APS scheme and how district energy can best be incorporated into building efficiency standards.

The City's role as a large energy consumer and real-estate owner should also be taken into account. If the City decides to connect all its suitable buildings to a district energy network it could help encourage development of the network. The location of the City's buildings in relation to proposed district energy networks needs to be studied further to assess the viability of this, in conjunction with any future plans of the city to locate their buildings and facilities in the coming 25 years.

Policy design can be done in collaboration with the Department of Public Utilities, neighboring communities, Eversource as indirect suppliers of heating (via gas and electricity) and cooling (electricity for air conditioning) and Veolia as heat suppliers (via their district energy network and electrical supply). This collaboration will be dependent on how heating and cooling currently affects their business model, such as leading to grid constraints and blackouts on the network for air conditioning. Initially identifying how district energy can relieve constraints on the electricity grid or the burden of replacing/installing new gas infrastructure can lead to fruitful collaboration and first steps in developing a district energy network.

The establishment of such design standards and regulations in collaboration with the Department of Public Utilities is an important first step in the development of the utility to ensure uniformity of utility implementation throughout the city and that best design practice, energy and emissions savings are achieved. Best practice standards for other jurisdictions are available and which have been tried and tested over significant operational periods. Such standards as used in the European Union (EN13941, EN253) could be assessed for harmonizing with existing ASME pressure piping standard (B31.1-2010) in Massachusetts.

It is recommended that district energy with relevant modern standards also be incorporated into citywide planning recommendations and that, long-term, any necessary changes be made to the municipal zoning ordinance to enable and encourage its adoption in the zones highlighted within this report. The City could consider establishing a "twinning" relationship with other cities nationally and internationally who have successfully established district energy networks to learn and benefit from their experiences.

6.3.5 Step 5: Carry out project feasibility and viability

Under the coordination framework established under Step 3 above, the stakeholders should agree how the utility could be initially established. Once some options are agreed upon, they should be defined as individual projects via a more detailed planning phase which considers the energy source today and in 2040. The feasibility of these district heating projects should then be determined to assess where, if and when they should be proceeded with.

Specific district energy network boundaries within recommended zones should be based on assessment of all technically viable connections or consumers for a new network within these zone. The assessment should consider (i) whether the building is hydronic or not (ii) whether the building has sufficient energy demand to make connection viable (iii) the existing technology in place in the building and the benefits of district heating connection

Implementation approaches and considerations could include:

- A network to initially supply the City owned buildings in the city with potential to expand as discussed above
- High heat density building clusters which can form initial heat network clusters throughout the city
- High cooling density building clusters which can form initial cooling network clusters throughout the city
- Assess the excess heat capacity from the existing district energy networks in Harvard, MIT and Veolia and how this could be utilized to supply new areas of the city in the vicinity of these networks with hot water district energy.
- Assess whether it is possible to reuse some of the existing infrastructure, such as steam lines, as part of a hot water network.
- Establishing new hot water networks in the Alewife area.
- Establishing new hot water networks in the Northpoint area.
- Converting the Mystic River plant to renewable energy or siting a new plant at this location.
- Biomass supply chain and delivery via the Boston Main Channel and harbor.

The feasibility assessment of these projects should include an economic viability model which considers: available incentives at that time to support the utilities installation; how gas consumers will be switched over; and the approach to degasification. Currently the APS (Alternative Energy Portfolio Standard) is the most applicable incentive; however under Step 4 above there may be policies implemented which further assist the establishment of a district energy utility.

6.3.6 Step 6: Develop business plan and financing approach

Once a viable project or projects have been identified, a business plan will need to be developed. A business plan consists of a set of documents prepared by project initiators to summarize the project's operational and financial objectives for the future and how they will be achieved over time. It serves as a blueprint to guide and supervise the project's objectives, policies and strategies.

Although all stakeholders may be in agreement on the way forward, the interests of the financing parties may be very different with respect to the required rate of return, risk-appetite, timing or with respect to the preferred legal terms and conditions of their involvement in the project. A well-structured and thorough business plan is key to getting project finance and getting unified stakeholder agreement to progress, in addition to deciding the best business model for implementation.

To achieve a successful modelling phase, it is important that business models are open for all stakeholders thereby enabling all to see the specific assumptions and final results for each stakeholder's part. This will avoid sub-optimization and accusations of hidden agendas in the modelling. Furthermore, an open model will visualize the distribution of the benefits in the system for all stakeholders and thus who should be compensated. This will facilitate the negotiation process.

Many business models for district energy involve the public sector to some degree, and in many cases the public sector has partial or full ownership of the project. The degree to which the public sector is involved is determined in part by how much it may wish to steer a district energy project towards a variety of local objectives. A business model which is replicable and scalable both technically and financially at the district level will be key to the acceleration of district energy in the city.

Some business model options include:

- **The "wholly public" business model**

This is the most common globally. This is where a municipality has full ownership of the system, which allows it to have complete control of the project and makes it possible to deliver broader social objectives (such as the carbon neutral objective) and the alleviation of fuel poverty through tariff control.

- **The "hybrid public and private" business models**

These have a rate of return that will attract the private sector, but where a municipality is still willing to invest in the project and retain some control.

These business models can include:

- ➢ A municipality and private entity joint venture where investment is provided by both parties that are creating a district energy company, or where the municipality and private entity finance different assets in the district energy system (e.g., production of heat/cooling versus transmission and distribution);

- ➢ A concession contract where a municipality is involved in the design and development of a project, which is then developed, financed and operated by the private sector, and the municipality usually has the option to buy back the project in the future; and

- ➢ A community-owned not-for-profit or cooperative business model where a municipality establishes a district energy system as a mutual, community-owned not-for-profit or cooperative. In this model, the municipality would take on higher risk initially in development and if it underwrites any finance to the project.

- **The "wholly private" business models**

These are pursued where there is a high rate of return for the private sector and require limited public sector support. They are developed as a wholly privately owned Special Purpose Vehicle but may benefit from guaranteed demand from the public sector or a subsidy or local incentives.

Full or majority private ownership can impact the affordability of a network as profit margins as the private owners tend to have different interests to municipalities for the operation of the system in terms of profitability. Private ownership reduces the municipality's ability to control the networks development. A district heating system is a long term investment which is not compatible with short term profit. Experience from Denmark is that when a public district heating system is sold to a private investor the cost of heat increases significantly to facilitate the profits required. Such increased costs can prevent further development of the system and, instead of encouraging new consumers to connect, it can result in disconnections from the system.

Financing will very much depend on the business plan developed and the model proposed for implementation. With all investment, the lower the risk and the higher the return, the more attractive an investment is. By de-risking the project, the more available financing will be.

For district energy projects, capital is typically invested prior to the connection of customer buildings; thus, the greatest risk in system deployment is load uncertainty, i.e. how many consumers will be connected to the system within e.g. 10 years. This is difficult to forecast if it is not required to connect to the system and if the tariffs are high compared to the alternative production. To provide investor security and alleviate financial risks, local governments can use land-use and connection policies or designate district energy high-priority and opportunity zones.

To reduce risk and project cost, smaller systems can be interconnected over time as a district system. This allows the system to be built out as load is connected, reducing the risk of not being able to connect sufficient demand.

6.3.7 Step 7: Analyze procurement options

Once a project has been defined and the business model and plan are established, the preferred method of Utility Operator procurement should be assessed. This is primarily applicable where the municipality plans to maintain ultimate ownership of the utility, whether through a concession contract or some form of Public Private Partnership (P3).

6.3.8 Step 8: Set measurable, reportable and verifiable project indicators

This is an important step for the City of Cambridge in order to attain its Carbon Neutral objective by 2050. If a district energy utility is agreed to play a significant role in achieving this as an alternative to fossil fuel supplied thermal energy, it will be important to work backwards from 2050 to establish a critical path timeline for district energy implementation, identifying key milestones and their associated indicators which need to be addressed to indicate progress in line with the timeline.

As with all projects, it is important that the milestones and their associated indicators identified are measurable and verifiable to facilitate reporting and progress or issue understanding. To establish a new utility which is in direct competition with existing utilities will be a complex task which will encounter challenges as the project progresses. These issues need to be identified as they occur in order to resolve and not delay project progression. Appropriate and measurable indicators are key to timely identification and should be agreed with the stakeholders in line with the critical path for utility implementation.

6.4 Siting Large Generation Plants

If it is decided to pursue siting any large low carbon intensity energy generation plants within or near the city, it will be necessary to meet with the Energy Facilities Siting Board ("Siting Board"). The Siting Board is within but not under the supervision or control of the Department of Public Utilities. This is a nine-member review board charged with ensuring a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. The Siting Board's primary function is to license the construction of major energy infrastructure in Massachusetts, including large power plants, electric transmission lines, natural gas pipelines and natural gas storage facilities.

If it is decided to progress a large biomass Combined Heat and Power plant it should be designed to meet the requirements of 225 CMR 14.00 to ensure the plant falls under the RPS scheme. Plants which generate heat and power with an efficiency of 50% receive one half of a renewable energy credit (REC), while those equal or greater to 60% will receive a full credit. Eligible biomass is defined by using the Biomass Eligibility and Certificate Guideline published by the DOER in August 2012. These guidelines state amongst others, that in order to receive RECs, biomass projects must utilize Massachusetts available biomass resources, demonstrate significant reductions in greenhouse gas emissions and protect forests.[78] As a result to comply with the City’s goals, any biomass CHP should have efficiency in excess of 60% and a biomass supply from Massachusetts which meets the eligibility guidelines. The siting board may also require an Environmental Impact Report to be prepared when site location, fuel source and technologies are selected.

Once a consensus is reached on the trajectory that should be taken to achieve a low carbon energy supply and what generation is required within the city, a project should be established and the feasibility for this plant should be further assessed to facilitate its development.

6.5 Roof top Photovoltaic

Due to the limited capacity to generate renewable electricity within the City of Cambridge, full roll out of Photovoltaic and Solar Thermal technologies in available roof top space within the city will not make a significant effect on the renewable energy demand of the city. As significant work has been completed with regard to driving PV installation in Massachusetts and Cambridge, including the Solar Massachusetts Renewable Target (SMART) program and the Sunny Cambridge program, these programs should continue to be promoted, but additional subsidies to the existing state subsidies for PV and solar thermal will not make a significant impact on the City’s net zero objective.

Investigation of larger solar sites in Cambridge such as Fresh Pond and support for state policies to bring more solar and other sources of renewable energy onto the regional electricity grid can make a larger impact on decarbonizing the electricity supply to Cambridge.

6.6 Heat Pumps

Heat pumps will likely play a key role in decarbonizing the heat supply of the residential Zone 2 and in other city zones where district energy connection is not viable. Under the recently adopted APS regulation, ground and air source heat pumps are included for subsidies. Incentivizing of these technologies should be structured in such a way to encourage ground source heat pump installation over air source heat pumps when the option is available due to available land. These are more efficient than air-source heat pumps and as the heat source is the ground they have a higher

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[78] Further discussion of the carbon neutrality and availability of biomass in Massachusetts is needed before proceeding with this strategy, as identified in the questions in Section 6.10.2 below

efficiency during the coldest months which also influences the necessary electricity capacity to power them. However, ground source heat pumps require more space and the associated installation have a higher capital cost and so may not be invested in by consumers.

6.7 Degasification – Develop Transition Process Plan

The City has stated its desire to move away from high carbon intensity energy to renewable and low carbon alternatives. As a result, there is a desire to move away from natural gas, oil and coal supplied thermal energy. There is an existing natural gas network and supplier in the City of Cambridge, and so the transition process to alternative supplies and the process for effecting this change will need to be considered. The transition process developed should consider the existing consumers and the practical elements of their fuel switching, the existing gas network, its on-going maintenance and expansion, the need for reliable backup systems, and the gas supply company in operation today.

A utility cannot operate without consumers. Consumers connect to a utility for numerous reasons, such as it fulfills a need, is available in the locality, is economically competitive, is secure and reliable, and more frequently because they are a sustainable supplier. By providing an economic, sustainable alternative to natural gas, this will encourage customer switching and reduce the viability of a natural gas supply.

Consumer switching will need to be additionally supported as generally consumers are resistant to change and are comfortable with what they know (in this case natural gas or oil). Additionally natural gas is considered to be a "green" fuel, so an educational effort should be incorporated as to the rationale and benefit of the alternative low carbon thermal supply. The role of gas as a potential "transition" fuel, such as in the case of powering combined heat and power facilities which could help capitalize development of district energy networks should also be discussed.

Under Regulation 220 CMR 14.00 the Department of Public Utilities' Gas Division is responsible for the regulation of Eversource's natural gas supply to Cambridge and their long-term supply contracts. The DPU monitors the market at the regional and national level to ensure that the Massachusetts consumers continue to receive the economic and environmental benefits that natural gas has to offer. Recommendations of this report should be discussed with the DPU and how they see these affecting the economic and environmental impacts of natural gas to Cambridge and regional consumers.

Based on this discussion, a regional transition process plan and timeline for degasification should be developed and then brought for further discussion with relevant stakeholders and the DPU. Any degasification plan should consider consumer behavior and the need for an economic and environmentally sustainable alternative to be available. The plan should also incorporate measurable, reportable and verifiable indicators to track the progression of this process to ensure it keeps pace with increases in the low carbon energy supply.

6.8 Carbon Offsetting

By 2050 there may be a need for the City to utilize a suitable carbon offsetting mechanism to fully reduce the carbon intensity of its electrical energy supply and thermal peaking / backup boilers in accordance with the carbon neutral target. Options for this include to establishing a renewable electricity project outside the City boundaries, Power Purchase Agreements (PPAs) or Community Choice Aggregation (CCA).

PPAs or CCAs can provide the financial basis for private renewable energy project developers to proceed with new renewable projects which are external to the boundaries of the city of Cambridge, allowing the city to have more control over its electricity supply while not having the generation within the city. The exact approach to decarbonize the remaining electrical supply should be considered further approaching mid-century, assessing the conditions and mechanisms in existence at that time.

6.9 Regional Collaboration

The challenge faced by the City of Cambridge to achieve net zero is further complicated by being situated in a densely developed urban area which is bordered by other dense urban areas. This reduces the available space for renewable energy projects and makes siting of such projects difficult as all suitable siting areas of the city have neighbors or neighboring cities. Further to this, the solutions developed for this study indicate that the supply challenge can be better addressed by cross city and stakeholder collaboration regionally and not planning in isolation.

This is something that should be prioritized between the neighboring cities of Cambridge (Boston and Somerville) to ensure that optimal cross city solutions are developed which benefit each city and draw on the optimum alternative resources available from each city. Such consideration could be utilization of waterways and ports for biomass supply, utilization of remote siting locations for large scale renewable energy generation and industrial waste heat utilization.

The Metropolitan Mayors Coalition may be a vehicle for stakeholder collaboration, given its commitment to net zero / carbon neutrality by 2050. In addition, engagement with DOER, DPU, MassCEC, MassDEP, the Office of the Attorney General and other state-level entities is important in addition to local utilities and major local energy generators such as MIT and Harvard. Such a stakeholder group can include members from and build off of the study Advisory Committee. The Metropolitan Area Planning Council (MAPC) could be a chair to coordinate stakeholders for such a regional approach to energy supply decarbonization in the Metropolitan Boston area.

The Massachusetts Department of Public Utilities (DPU) is responsible for the structure and control of energy provision in the Commonwealth of Massachusetts; monitoring service quality; regulating safety in the transportation and gas pipeline areas; and for the siting of energy facilities. As stated above, decarbonization of the energy supply system is a significant challenge to be addressed, and one that is very complex with many stakeholders who will be affected in different ways. The DPU is a key player in enabling the transition to a low carbon energy supply.

Areas of interest to the DPU are outlined below. At this early stage of development, the answers to these questions may not be known, but will need to be understood in detail as the plan progresses.

- How will utility consumers be provided with the most reliable service at the lowest possible cost by the proposal being proposed?
- What are the public safety concerns identified by this proposal and how are these addressed?
- What locations are being considered for new energy generation, or utility lines, and what are the issues arising from these proposals?
- How will the proposal protect ratepayers' rights and ensure a responsible sustainable future energy supply?

The Attorney General’s Office (AGO) also fulfills a key role in enabling the transition to a low carbon energy supply as proposals issued to the DPU are also reviewed by the AGO. As a result, their early engagement on proposals for progression is very important to structure proposals for their understanding and to allow them to identify any initial issues they may foresee with any proposal.

6.10 Next Steps

Outlined below are recommendations for additional actions and investigation to build on the conclusions and outstanding questions raised above. The risks and mitigation strategies identified for each recommendation made here are discussed further in Appendix 6.

6.10.1 District Energy Utility

Next steps should consider a more detailed analysis of a district energy utility establishment in Cambridge investigating the following points:

- Determination of all technically viable connections or consumers for a new network within Zone 1. The assessment should consider (i) whether the building is hydronic or not, (ii) whether the building has sufficient energy demand to make connection viable, and (iii) the existing technology in place in the building and the benefits of district heating connection.
- Based on the identified potential consumers, district heating network clusters could be developed.
- District heating clusters proposed should take account of planned natural gas rehabilitation works to consider if such consumers could be converted to district heating now prior to investment in new gas networks.
- Based on the clusters developed, it would be possible to make agreements with consumers for connection to the proposed district energy network, providing a future customer base and cash flow.
- Consider adding an additional line item to the Building Energy Use Disclosure Ordinance (BEUDO) to request small CHP operators to disclose any additional capacity they may have. Such sources could be considered for supply to a district energy network in the short term, whether for back up or peak load supply.
- Laying district energy pipes in Cambridge will require space, and so an understanding of the existing utilities and available space or lack thereof is needed. This method of installation of piping and depth required to install will impact the cost of network installation. In order to improve the understanding of available space and where utilities are located in the city, GIS tagging of all utilities as a standard during ongoing roadworks works where utilities are exposed should be considered. Additionally, Non-Destructive Testing surveying (or Ground Penetrating Radar surveys) should be completed in city streets prior to detailed network design.
- Once a district energy network is planned, consideration should be given to storage, and the potential for Aquifer Thermal Energy Storage in the vicinity of the network. This will require a more detailed study into the specific geology of that area of the city.
- The steps outlined in Section 6.4 above should be implemented if it is decided to start on the path to establishing a district energy utility for Cambridge.

6.10.2 Biomass CHP

- Complete further study and stakeholder engagement on the potential for biomass to be considered a carbon-neutral fuel in context of the Massachusetts RPS.
- Consider completing a siting study for a new biomass CHP generation plant capable of supplying a regional district energy network. Such a study should consider emission plumes from such a plant and their impact, if any, on the environs to the plant. The resulting required chimney stack height should also be considered and access routes for biomass supply.
- A study to assess the viability of a biomass supply chain including the practical logistics and development of a biomass market to supply a plant of the scale proposed in this study should be conducted.

6.10.3 Heat Pumps

- Consideration should be given to launching an informative marketing campaign on heat pump technologies and the benefits of these to home owners, especially targeting the low-density areas of the city.

6.10.4 Regional Implementation

As discussed above, regional collaboration is an important next step for Cambridge due to its build-out nature with limited alternative energy sources and available space, and its location which is bound by other cities. State and regional planning organizations are a potential mechanism to identify and address the key questions, barriers, and next steps outlined in this study in a coordinated manner. Elements to consider in this regard are:

- The state planning processes and what allowance they make for municipal collaboration
- What form regional project organization for implementation would take and who would lead such efforts regionally?
- What are the enabling factors for regional approaches to challenges raised above?

APPENDIX 1
WORK PACKAGE 1 REPORT

APPENDIX 2
WORK PACKAGE 2

APPENDIX 3
WORK PACKAGE 3

APPENDIX 4
ADDITIONAL TECHNOLOGY INFORMATION

APPENDIX 5
MODEL ASSUMPTIONS

APPENDIX 6
LOW CARBON SUPPLY IMPLEMENTATION RISKS