The Impact of Distributed Energy Resources (DERs) in Integrated Gas-Electricity Energy Systems

by

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Submitted to the Institute for Data, Systems, and Society
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Abstract

Our gas and power energy systems are interconnected, which makes the decision to provide energy a non-trivial one for consumers and the system as a whole. The focus of this thesis is on the long-term planning of integrated electricity and natural gas infrastructures at the distribution (low voltage) level. This research explores the question on how pricing relates to the coupling of a gas-electricity system given an expected greater consumer participation at the residential level.

I developed a long-term planning tool that is able to consider the interaction between the integrated natural gas-electric energy system. In the first component of the tool, I formulated a mixed integer linear program, Z-DRE, as a proxy for the rational consumer. Given commodity prices, investment costs and demand profiles, Z-DRE would decide which distributed energy resource (DER) equipment or conventional equipment to invest in as well as when to run these equipment to meet its demand. The results of this program would determine what demand profile (or supply profile) the electrical and natural gas grids would need to meet. A model electrical grid and a model natural gas grid were simulated with these demands in order to determine if any reinforcement was needed. If reinforcements were needed, a heuristic was used to determine where the reinforcement should be placed in the grid and iteratively continued this process until a 99% reliability was achieved. I considered two pricing incentives to determine what effect pricing could have on the individual consumer and the spillover effects to the overall grid. The two pricing strategies was (1) a static feed-in-tariff combined with a static residential consumption tariff and (2) a dynamic feed-in-tariff and a dynamic residential consumption rate, both pegged to the market rate of electricity.

In the context of New England, I found that adoption of Combined Heat and Power (CHP) units was unlikely to occur without generous electricity feed-in-tariffs which would require a wealth transfer. As a result, it is anticipated that the integrated gas-electric network to be only loosely coupled for New England at the distribution

level. I also considered what effect using prices that tracked the wholesale rate of electricity might have on CHP adoption and came to the similar conclusion that the electricity prices in New England are too low to spur CHP investment.

I note that over-adoption of CHP units from extremely high feed-in-tariffs (in the cases of both the static feed-in-tariff and the dynamic feed-in-tariffs) caused an extraordinary need for electricity grid reinforcement in order to accommodate the enormous backward power flow back into the high voltage grid. However, the grid also needed moderate reinforcements when there was a low or no feed-in-tariff. I found the reinforcement cost minimum (and total cost minimum) can be found with a tariff that encourages only a portion of the population to purchase CHPs since the locally generated power could now be consumed within the distribution network. This lowered the need for capacity between the primary feeders of the high voltage network and the secondary distribution network.

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Contents

List of Figures

List of Tables

Nomenclature

ACOPF	Alternating currrent optimal power flow
CHP	Combined heat and power
DER	Distributed energy resource
EES	Electrochemical energy storage
FERC	Federal Energy Regulatory Commission
GMD	Geometric mean distance
GMR	Geometric mean radius
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
ISO-NE	Independent System Operator - New England
MILP	Mixed integer linear programming
MISOCP	Mixed integer second order cone problem
NERC	North American Electricity Reliability Corporation
PUC	Public Utility Commission
PV	Photovoltaic
Z-DRE	Z-Distributed Resources Economics

Chapter 1

Introduction

1.1 Motivation

Energy systems are changing rapidly. Climate change policies, more affordable renewables, and information and communication technology (ICT) development are leading to and enabling a new power system structure in which end-consumers are active players, with decisions that are impacting the operation and further development of electricity systems. This process is allowing the installation of distributed energy resources (DERs) and microgrids, and the formation of energy communities in which consumers contribute and cooperate to secure their on-site energy procurement. However, this energy system is a complex environment where on the one hand hundreds of active nodes connect millions of active producers, consumers, and prosumers; and on the other hand several energy vectors, i.e. heat, electricity and gas, are interconnected making the decision to provide energy a non-trivial one for consumers and the system as a whole. For instance, co-generation systems - also known as combined heat and power (CHP) - have direct impacts in both the natural gas networks as well as the electricity networks, by putting demand on the former and providing supply in the latter. In addition to generating electricity, CHP systems produce usable heat for industrial processes, and space heating and cooling in residential and commercial contexts.

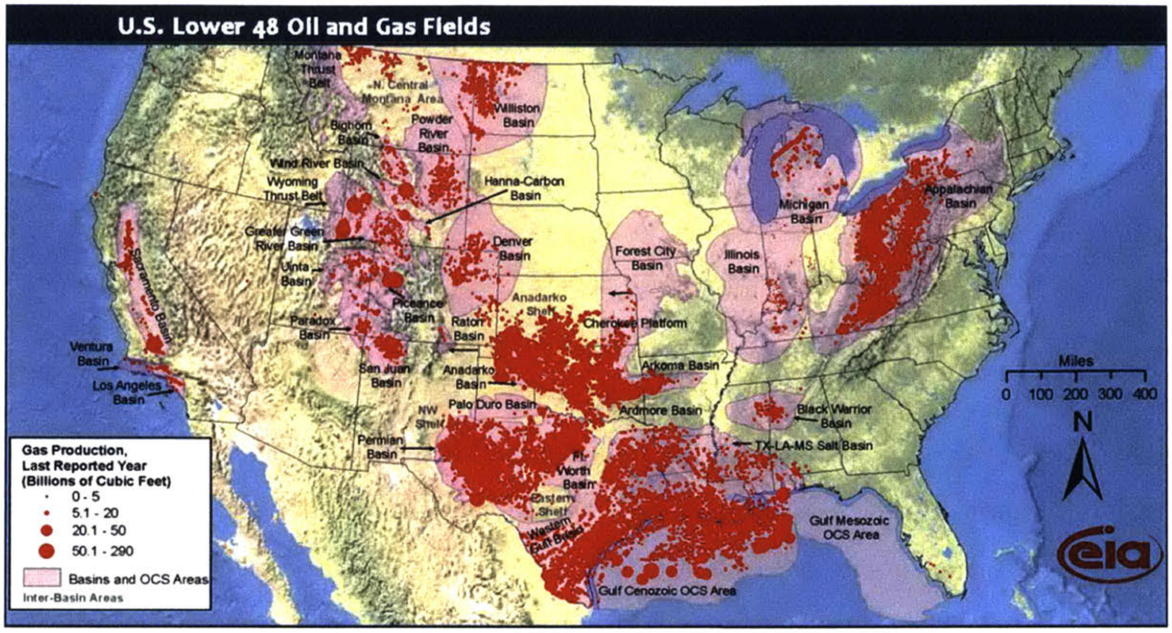
1.1.1 Market Interdependencies

Electricity, being a secondary form of energy, relies on the upstream supply chains of its primary energy fuel sources. As a result, the electricity market is directly impacted by its ability to manage the inflowing supply in order to meet demand. In the most extreme cases where there is no ability to control the supply of primary energy, significant uncertainty is introduced into the electricity market; such is the case for technologies that rely on solar or wind primary energy. The intermittency that is inherent in the usage of these renewables introduces grid problems such as greater requirements for ramping and ancillary services. The supply chain for hydro-generating stations with reservoirs have short-term control, but are still reliant on medium-term precipitation trends.

Natural gas-fired generation has generally been considered firm capacity due to the implied assumption that there will always be natural gas available. The events in February 2011 relating to the polar vortex shattered this notion when disruptions in the natural gas supply chain cascaded onto reliability concerns on the grid. However, low natural gas prices spurred by the availability of shale gas has made natural-gas fired generation economically attractive. Furthermore, the lower environmental impacts relative to other fossil fuels such as coal in regards to carbon dioxide, SOx, NOx and particulate matter makes it an ideal transition fuel [2]. In 2016, natural gas-fired plants generated 33.8% of electricity generation at utility-scale in the United States[3] and due to the aforementioned economic and environmental factors, one can assume that this trend will continue for the near-future.

Natural Gas Networks

To understand the dynamics between the two systems, consideration must be made to how each are operated. The natural gas network draws many parallels to the electricity grid. As a gas, its most economical land transport system is the pipeline. The flow of natural gas is governed by pressures which are controlled through compressor stations. Unlike electricity, natural gas can be stored in underground reservoirs,



Source: EIA based on data from HPDI, IN Geological Survey, USGS, April 8, 2009

Figure 1-1: Distribution of Gas Wells across the United States [1]

storage facilities and the pipeline itself can store some natural gas (known as line pack) [4]. Pressure must be maintained within a certain bandwidth to ensure that the network does not fail.

The Federal Energy Regulatory Commission (FERC) oversees the monopolies of pipeline transmission and distribution of natural gas by setting tariffs and requiring open access to market participants. Pipeline transmission companies are prohibited from selling or buying natural gas [5]. Otherwise, FERC does not regulate activities outside of gas transport, instead letting competitive market forces establish a price. Within the United States, there is a glut of supply contained in the regions of the Gulf Coast, the Southwest and the Appalachian Basin. Table 1.1 outlines the 5 states with the most wells and Figure 1 illustrates the distribution of wells in the United States. They show that the supply of gas, is not necessarily well located to demand and therefore requires significant transport systems.

Table 1.1: Number of wells in top 5 states [1]

State	Number of gas wells
Texas	93,507
Pennsylvania	57,356
West Virginia	50,602
New Mexico	44,784
Oklahoma	43,600

Natural Gas Markets

Natural gas is a commodity traded on regional markets. It has uses in electricity generation, industrial processes and heating (commercial and residential). It is estimated that 25% of primary energy needs are met through natural gas in the United States [6]. At the bulk level, firm contracts and non-firm contracts help dictate the priority of delivery of gas to customers. Wholesale customers are expected to nominate gas ahead of time and are charged based on real-time consumption. Local gas distribution companies are responsible for nominating sufficient gas for its end consumers, but also typically hold firm delivery contracts.

1.1.2 Transmission Level Interaction

At the high voltage level and bulk transmission level of electricity and natural gas, the connection between the two networks is natural gas-fired electricity generation. These can take the form of cogeneration units, simple cycle generation units and more modern combined cycle generation units. In addition, the compressors in the natural gas network rely on the electricity network, but they often have uninterruptible power supplies (UPS) in case of power loss.

The Advantages and Disadvantages of Natural Gas Generation

In a sense, gas-fired generation is machinery that converts a product from one market to another market. However the peculiar characteristics of these generators does not make it a straightforward transaction. Specifically, there are constraints on how they can be operated, their costs are non-convex and their efficiency is non-linear which make offering a representation of their costs to the market difficult.

Startup costs represent the cost of fuel burn as well as operation costs that are expended to transition the generating unit from an off state to a stable operating state. Mathematically, they represent a non-convexity in the cost function of a generator which makes the calculation of the Lagrange multiplier (generator shadow price) from the relaxed linear program less meaningful. The marginal cost captured here does not consider the startup cost in the calculation of optimal states [7].

Next, the efficiency of energy conversion is a non-constant parameter. Instead, the efficiency is dependent on the electrical output of the unit and the efficiency tends to be much lower at low operating points. Once again, this can add non-convexities to the solving of the least cost solution of the system. In addition, these non-linearities in efficiency can result in operating states that are difficult to mechanically control. Therefore, a minimum generating limit is imposed when the unit is in operation which in itself is a non-convexity.

The combination of the minimum generation requirement and the startup costs often, although not always, created an impetus to maintain minimum run times for generators. That is, under normal operation, a gas generator can be expected to operate a certain number of hours after startup regardless of the price during individual hours, but with due consideration of the set of prices during those hours. This requires significant planning and coordination over larger time periods than a dispatch period which make day-ahead markets a key tool for gas generators to secure financial hedges to the real-time prices. In addition, out-of-market uplifts help guarantee sufficient revenues to cover their non-marginal costs (startup costs) and their losses in hours where the electricity price is insufficient [7].

Despite these undesirable characteristics, natural gas generation offers a slew of valuable and needed services on the grid. Often, they are employed as peaking units for systems to meet demand during high consumption periods of the day. They can also provide operating reserves, ramping services and frequency control (automatic generation control). Their dispatchability is a boon in an era where intermittency is introducing increasing uncertainty and generation swings to the grid. Most of all, their attractive economics due to their efficiency and low fuel costs has made them the preferred thermal plant. Their combined economic advantage, dispatch flexibility and firm generation capacity makes them an extremely useful tool in the operation of a power system.

Operation in Two Markets

On the side of the generator operator, an issue arises from the coordination of buying from one market and selling into another. Day-ahead bidding windows for electricity and nomination windows for natural gas rarely align. This is the avenue that disruptions in the natural gas network will manifest into disruptions into the power network.

Natural gas purchasing in the United States occurs at hubs- major pipeline intersections - and then transportation is also purchased in a process known as *nomination.* Natural gas generators rarely purchase firm delivery of natural gas unless they are a baseload plant; instead they opt for interruptible (swing) service. Even with firm delivery services, in the event of emergency operation of the natural gas network electricity generation is amongst the lowest priority loads and are the most likely to be cut first [1]. Gas nomination for interruptible service is rarely an issue on an unstressed gas grid. However, in times of scarcity, the natural gas dispatch prioritizes not based on the willingness to pay, but based upon the regulatory requirements.

The gas market posts hub day-ahead prices at 9am CT for gas purchases for the following day. However, the first nomination cycle known as "timely" nomination closes at 1pm CT. There are further nomination cycles ("evening" nomination closing at 6pm CT and 3 intraday nomination periods) that enable parties to revise their nominations, but there are restrictions on how much the original nomination can be modified down.

Electricity markets' day ahead bidding windows are different based on jurisdiction. However, consideration of market clearing coordination is a concern to Independent System Operator's (ISO) as well as to FERC. FERC did change the "timely" nomination deadline by moving it back to 1pm CT from 11:30am CT, as a compromise

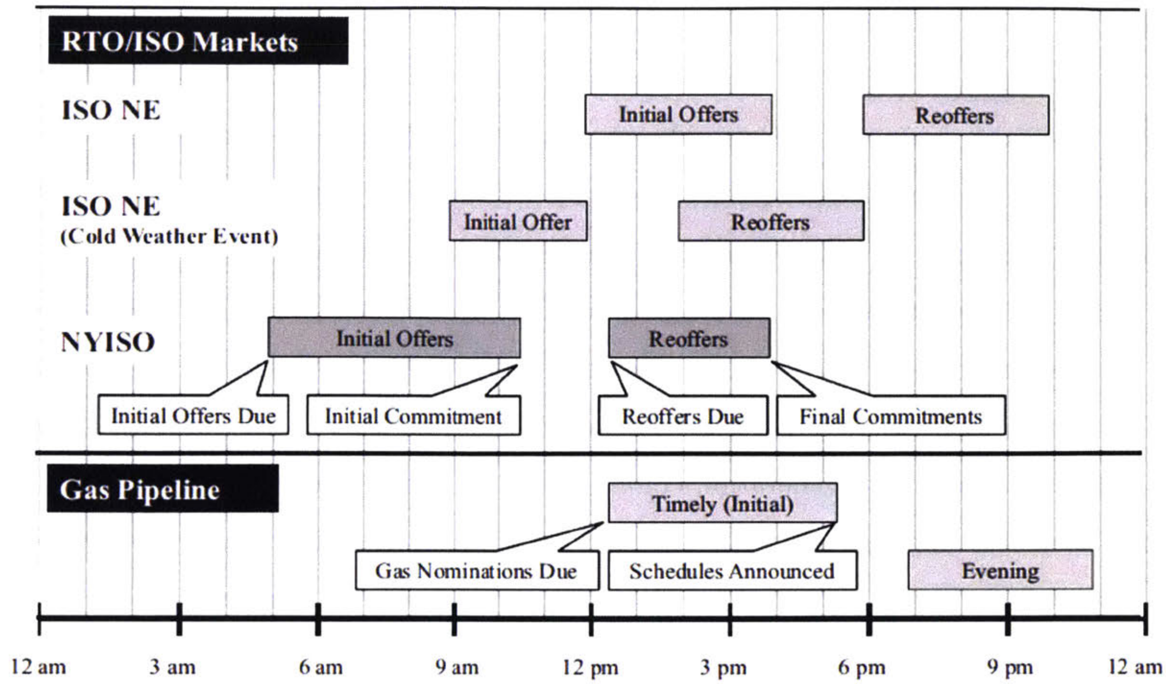


Figure 1-2: Example of two ISO timelines compared to gas timeline [2]

between the electricity industry who wished for the gas market to be cleared at 4am and the gas industry [8] [9].

> *"We're trying to figure out how to balance the risk. If I close the nominations for the electric market at 8 a.m. then I do not know tomorrow's gas price, but I have to close it at 8 a.m. to make the 1 p.m. nomination for the gas market. So there's a lot of debate going on not just here but at the other RTOs about what's the right balance of risk."*
>
> Richard Dillon, SPP Director of Market Design [9]

The above quotation illustrates the two competing scheduling issues in the current environment. Without alignment of these schedules, either the system operator will force generators to offer into the electricity market without knowing the gas price or to nominate gas without having a firm schedule to provide electricity. Figure 1-2 illustrates the nomination window for gas in the eastern United States with the timetable of two electric systems' day ahead bidding windows. In the case of New York, gas generator offers are due at 5am which means generator operators must offer into the day-ahead electricity market without knowing their fuel costs; on the other hand, they are able to nominate an appropriate scheduling of gas in the timely window. In the case of New England, gas plants are able to offer into the electricity market with the knowledge of their fuel costs at 9am CT, but they are not able to nominate their gas schedule with a commitment from the electricity market.

While it is rare that a gas generator would not be able to secure a gas contract for its generation needs, when the gas network is under stress they may be either placed in a position where they must purchase gas contracts at a loss or are wholly unable to meet their electricity generation commitment. While this may not pose a risk to the system if a single generator is unable to perform in real-time, there is cause for concern if a significant portion of the natural gas fleet is unable to produce electricity; especially during periods where electricity usage spikes with natural gas usage. In effect, this is a market coordination issue between two interrelated markets. A solution would be to widen the time between the announcement of natural gas prices and the closing of the timely nomination window so that ISO's are able to run their day-ahead co-optimization engines and offer financial commitments to generators. However, the natural gas sector has resisted such propositions thus far [9].

1.1.3 Distribution Level Interactions

The effect of natural gas at the electricity distribution level is not currently readily apparent. Heating load at the residential load represents a significant proportion (22%) of the total natural gas consumption [1]. Society would be more efficient if it were able to convert the high grade heat energy into electricity prior to using the low grade for heating needs. Fuel cells and combined heat and power (CHP) offer an avenue towards this idea. In the United States, less than 10% of electricity is derived from CHP units, but Finland and Denmark both have over 30% of their electricity delivered through CHP [10].

Increasingly, distributed energy resources (DERs) are becoming more popular and prevalent. Distributed generation can take the form of solar photovoltaics (PV) or wind turbines, but also through fuel cells, gas micro combined heat and power or community CHP units. Natural gas distributed generation can and will provide many of the same benefits that they do at the transmission level, namely controllable power output and ancillary services. However, the market incentives that prospective distributed generation owners face need to be aligned to provide the optimal amount of investment in such technologies. In addition, regulated electricity and natural gas rates have been the norm at the distribution level and are rarely dynamic. Therefore natural gas rates and electricity rates must be coordinated in a fashion that respects the interdependence of both systems.

1.2 Objectives

The broad objective of this thesis is to investigate how modifying the pricing conditions of natural gas and electricity will affect the long-term planning of low-voltage distribution networks. More specifically, I delve into how changing the retail electricity prices seen by consumers will affect their equipment purchasing decisions. The resulting residential gas and electricity demand will have cascading effects on their respective distribution networks. These networks will then need to be reinforced to accommodate any additional flows. I aim to determine how retail electricity and natural gas pricing can affect the electricity costs, gas costs, consumer investment costs and distributor investment costs of an integrated gas-electric system.

1.3 Thesis Outline

In Chapter 2, I review the literature regarding integrated electric-gas systems. I outline the available research at the bulk and transmission levels for the two systems and how this can be made applicable to the distribution level. I continue on to the research that has been done at the distribution level on integrated electric-gas systems and how DERs can affect the grid. I also look into current policy regarding rate setting at the distribution level.

In Chapter 3, I explain the methodology and the underlying models used in this thesis. Specifically, I explain the Z-Distributed Resources Economics (Z-DRE) model, the power flow simulations and the cost finding algorithm that calculates the costs of reinforcements. I also outline the sets of scenarios that were considered in the various experiments with the (Z-DRE) model.

In Chapter 4, I present the results of the experiments in a New England setting and hypothesize on how these results came to be. I discuss the notable trends in the results and then extrapolate these trends to hypothesize how the electric-gas system would interact in other contexts.

In Chapter 5, I provide a summary of the work performed. I explain the implications of the results for real-world rate-making and also the caveats that must be considered when applying its results to the real-world. Finally, I point out how it might be improved in the future.

Chapter 2

Literature Review

2.1 Bulk Transmission

The study of the interdependencies between the natural gas network and the electricity grid is well established at the bulk/transmission level. The North American Electricity Reliability Corporation (NERC) released a report in 2004 that examined the impact of losing the natural gas supply at key nodes on the electricity grid. They foresaw the rise in natural gas-fired generation capacity and the accompanying increase in reliance of the power grid on the natural gas system. The report considered the specific implication that the largest contingency of the electricity grid may not be in the network itself, but within the upstream supply of natural gas to key fractions of the generating fleet. It noted that ISOs should conduct studies to investigate the degree that they relied on the natural gas system and establish clear lines of communications with the natural gas utility. [11]

Modelling and simulation of the power grid with consideration of the dynamics of the gas network has been presented in the literature. Correa-Posada and Sanchez-Martin [12] create a mixed integer linear programming formulation (MILP) which considers both networks by linearization of equations. They consider the short-term transient behavior of the system with a granularity of one hour. Their objective function aims to minimize the cost incurred from start-up, shutdown, non-served power, gas production, gas storage and non-served energy. In order to model gas flow, they use an equation derived from general equations for continuity and momentum in gas flow, generally known as the Weymouth equation.

The gas flow formulation in the Weymouth equation is both non-convex and non-linear which is why Correa-Posada and Sanchez-Martin [12] linearize the squared terms in flow and pressure in order to maintain the order of complexity of a MILP. Overall, their work concluded that a) linearizing the equation and integrating the gas flow equation into an optimal power flow model can be used to guarantee global optimality within predefined tolerances and b) linepack (gas that is transiently stored within the pipes themselves) can have significant ramifications on gas adequacy levels at the bulk/transmission level. They go on in further research to show that this MILP formulation can also be adapted for security-constrained optimal power and gas flow problems whose solutions are robust against $n-1$ contingencies [13]. Furthermore, they expand the model to consider security-constrained unit commitment of natural gas units [14].

In the high-voltage grid, the DC power flow approximation can be used. This is what Correa-Posada and Sanchez-Martin[12] use in their power flow modeling. Such an approximation cannot be used in distribution lines as voltage angles may vary significantly, which violates the small angle approximation implicit in the DC power flow approximation; therefore the full AC power flow must be solved in distribution networks. An optimal AC power flow problem can only be posed as a second-order cone problem (SOCP) at best with some simplifying assumptions and a quadratically constrained quadratic problem (QCQP) at worse in its full formulation[15].

Back in 2005, Shahidehpour et al. [6] performed a similar study where they analyzed security-constrained unit commitment schedules in systems with high combined-cycle natural gas fired generation. They consider a 118-bus IEEE model system connected to a natural gas network through 12 combined-cycle generators. They also consider the effect of having solar PV and energy storage on this system. Through their case studies they arrive to some notable conclusions: (1) combined-cycle generation present economic advantages over other thermal generation that they replace, (2) this economic advantage is dependent on having a steady supply of natural gas and (3) fuel diversity in an electricity network is important to mitigate effects from failures in the natural gas system.

Martinez-Mares and Fuerte-Esquivel [16] conducted steady-state flow simulation studies of an electric power system coupled with a natural gas grid. Like Shahidehpour et al., they used the 118-bus IEEE model system. For the gas network, they used a 15-node natural gas network based on a part of the Belgian gas network. They perform the steady state analysis on both systems simultaneously using a single Newton-Raphson formulation. The two systems are coupled by natural-gas fired generators, a portion of which also acts as distributed slack generators in the electrical system. As slack generators, their actual power output differs from their power output setpoints; this divergence has an effect on the natural gas network since power output is some function of natural gas consumption. Therefore any energy balancing on the grid will affect the power output of these generators which will cascade over to the natural gas grid in a dynamic natural gas consumption. They found that the initialization of the Newton-Raphson method is important. The electrical system's voltages can be initalized at 1 p.u. without any issue, but initializing the gas nodal pressures at identical values will yield a null-diagonal Jacobian (ill-suited for inversion). They suggest a 5%-10% difference in nodal pressures between the sending and receiving nodes.

2.2 Distribution Level

The research of the interplay between the natural gas network and the electricity network at the distribution/low voltage level has slowly developed in recent years as distributed generation becomes a larger part of our energy systems.

Vendewalle and D'haeseleer [17] examined the effect of high penetration of CHP DERs in a distribution network on gas adequacy and control strategies to manage these DERs at the individual level. In their model, they simulate a household with heating demand that is fulfilled by a boiler, a CHP and/or a thermal storage tank. A cost-based optimization that contemplates the natural gas prices, electricity prices and forecasted heating needs is used to make control decisions on these units. Then, Vendewalle and D'haeseleer take the results of the natural gas consumption at the individual level and consider the impacts of these decisions in a scenario with high penetration (80%) of CHP DERs. Overall, they found that even under the high penetration scenario, the gas network is not likely to have issues under peak demand from DERs, although they note it may spur new investment if it is nearly congested at the peak. They also found that a well sized-storage system plays a significant part in managing peak gas loads. In a different scenario, they consider the impact of the sell-back tariff of electricity on short-term operation, but do not comment on its role in the purchasing decision of CHPs.

Similarly, Acha and Hernandez-Aramburo [18] formulated an integrated model of gas and electricity networks at the distribution level with high CHP penetration. Instead of optimizing, they perform three case studies with penetrations of 10%, 25% and 50%. They employed the Weymouth equation for gas flow and the AC power flow equation for electricity. They solved both using the Newton-Rhapson method. The results from the case studies showed that implementation of CHP technology increased strain on the gas network since they had a lower thermal efficiency than the boilers they replaced. An opposite decrease was found in the strain on the electricity network. Overall these changes to the network were small and they found that even in the high-penetration scenario of 50%, the operability of the gas and electricity network was not threatened.

Zhang et al [19] considered the optimal placement of CHP machines in a distribution system with regard to the natural gas, electric and water networks. With the addition of the water network, CHP placement is constrained by the ability of the water network to supply sufficient water for waste heat absorption. They formulate the problem as an AC optimal power flow (ACOPF) over a IEEE 123 node test feeder system. They discovered that their solutions to the non-linear problem were often local optima and sometimes they were unable to determine a feasible solution. In the solutions examined, they determined that CHPs could not be employed at every node due to insufficient water supply for the recovery of waste heat.

2.2.1 Rate Setting

Electric rate setting at the distribution level is heavily dependent on the jurisdiction. In some countries with a retail market such as the United Kingdom (UK), the retail tariff is determined through competition[1] and a network usage charge for distributors[2] is determined by regulators. In these cases the distributor and retailer are separate entities. While in other jurisdictions such as Massachusetts, a regulated monopoly (a single entity known as the distributor-regulator) has its entire rate set by a regulator (in the case of the USA, it is the state Public Utility Commission (PUC) though the name varies by state). Similarly, natural gas distribution regulation also falls under the purview of state PUCs. [20]

Cost of service regulation has been the norm for the past decades where utilities present their costs to the regulatory commissions and are given a remuneration[3] that would compensate them for those costs plus an acceptable rate of return. However, a direct application of cost of service regulation does not provide any incentive to find cost reductions while encouraging over-building. The subjective standard of 'acceptable' rate of return is also controversial. The Federal Power Act establishes the PUC's authority to assign discretionary 'just and reasonable' rates. It is up to the PUCs to determine rates that are neither confiscatory to the utilities nor overly burdensome for the consumers. There have been several high-profile court cases regarding these rates, perhaps notably *Jersey Central Power & Light v. FERC.* In this 1984 case, the 2nd D.C. Circuit Court prevented Jersey Central Power and Light Company from filing an electricity rate increase based on the costs of a canceled nuclear plant. This order was telling that even cost of service regulation will not remunerate all costs incurred. [21]

Incentive based regulation is an improvement over cost of service regulation whereby regulators set a volumetric price cap or revenue cap for utilities over a 4-5 year period

[1] Consumers have a choice of which energy retailer to purchase energy from and they will usually select the retailer that is most economically favourable for their demand profile.

[2] Distributors are the companies that maintain the physical infrastructure that deliver electricity. They are considered a regulated monopoly.

[3] A tariff is calculated so that distributors will be able to recoup remuneration.

based on their historical costs. Utilities are able to extract profits by becoming more efficient and reducing costs. There are still misaligned incentives, as the quality of service could be reduced in the name of cost reduction. In addition cost shifting may occur between operarting expenses (OPEX) and capital expenses (CAPEX) lines of a utility's business in order to deflate their profits on paper. [20]

There has also been some innovation in rate setting. Jenkins [22] proposes a model where utility rates are determined partly through a benchmark reference network model. The utility is given a menu of contracts that stipulate ex post sharing of profits. The contract menu is on a sliding scale of how much of that profit is shared.

Furthermore, Perez-Arriaga et al. [23] advocate that tariffs should be more reflective of the cost of energy at the time and place that it is consumed. Specifically, it prescribes that rates and incentives should be strictly of the value of energy at the node and should not take into account how that energy is generated (device agnostic). One of its main findings is that 'Flat, volumetric tariffs are no longer adequate for today's power systems and are already responsible for inefficient investment, consumption, and operational decisions.'

2.3 Distributed Energy Resources

Distributed Energy Resources (DERs) continue to play a greater role in our energy systems. They harness energy in many different ways and have unique characteristics. However, they all share the fact that they are capable of providing electricity services to the distribution system.

2.3.1 Solar Photovoltaics

Solar photovoltaics (PV) convert sunlight into electricity by harnessing a photon's energy to excite electrons to a higher energy potential through the photovoltaic effect. A strong advantage for solar PV technologies is the lack of a fuel requirement and therefore having negligible variable costs (maintenance is still needed).

Tamimi et al [24] compared the effect of solar PV on the high voltage grid's transient stability when the solar PV technology is implemented in centralized farms or distributed in networks. Using Ontario, Canada as a reference model, they investigated the system loadability and ability to survive a three-phase fault under these scenarios. They found that distributed solar PV resources outperformed the centralized PV scenario when considering these two metrics.

On the other hand, Katiraei and Aguero [25] outlined that solar PV integration still faces many challenges. Unlike controllable DERs, the variability of distributed PV 'can significantly affect volt/var control, power quality, and system operation.' Major other steady-state concerns include reverse power-flow at locations that are not designed to handle such flows, voltage fluctuations, capacitor interactions, reactive power fluctuations, modification of feeder section loading and potentially increased power losses. Most of these issues arise from the need to manage reactive power at the distributed level.

2.3.2 Battery Technology

Electrochemical Energy Storage (EES) or battery technology is the most commonly thought of method of electricity storage. EES is merely an energy arbitrage tool meant to store energy at low cost/low demand periods to discharge that same energy during high cost/high demand periods. It incurs a 'round-trip' loss as some energy that is stored in the battery is not recoverable when discharged.

Tant et al [26] have done research in the implementation of batteries as a resource to balance solar PV's fluctuation at the distribution level. They investigate the trade-off between using batteries for voltage control or peak-shaving. In addition, they look at the location where batteries should be ideally situated. The batteries used are Li-ion or Pb-acid batteries. They determine that battery installation can help facilitate further PV integration in distribution networks when such networks are dealing with voltage deviation or overvoltage issues.

2.3.3 Micro-CHP

Combined Heat and Power (CHP) units utilize fossil fuels (typically natural gas or diesel) to generate electricity and using the waste heat for residential, commercial or industrial heating needs. This has the added bonus of increasing the chemical energy that is useable. Electricity generation from combustion engines are inherently limited by the Carnot efficiency (2.1).[4] While the electrical efficiency of CHPs are still constrained by this limit, the usable energy that a CHP provides also encompasses the heating it can extract from the waste heat of the electricity generation process.

$$\eta_{Carnot} = 1 - \frac{T_{amb}}{T_{comb}} \tag{2.1}$$

Where:

T_{amb}: Ambient temperature in Kelvin

T_{comb}: Temperature of combustion in Kelvin

Thomson and Infield [27] used a distribution network in the UK to model the effect that micro-CHP penetration had on such a network. They based their micro-CHP on the WhisperGen Stirling engine rated at 1.2 kWe. In addition, they considered scenarios where solar PV had a high penetration as well. They discovered that micro-CHPs dramatically reduce power losses when the network is under stress but only marginally when the network is functioning nominally. However, when combined with solar PV, the voltage rose to alarming levels.

2.4 Heating and Cooling Equipment

The ability to maintain comfort in a dwelling can be accomplished through various means. In this thesis, I consider four types of heating and cooling systems: condensing boilers combined with an electric air condition system, air-source heat pumps, ground-

[4] The Carnot efficiency is the upper technical limit of the amount of work that can be achieved per unit of heat input with a heat engine. However, there are further losses from non-ideal conditions which means that actual heat engines always operate below this efficiency.

source heat pumps and CHP.

There have been comparisons made between the economics and carbon costs between conventional and condensing boilers in existing research. A condensing boiler is able to extract the heat from the exit flue gas in order to generate usable heat. The condensing aspect of the boiler comes from the extraction of the latent heat of water vapour in the flue gas by reducing its temperature and therefore condensing it. There is also heat recovery in the sensible heat of the gas. This increases the overall efficiency of the boiler by reducing the amount of fuel needed to maintain a certain temperature set point. However, this entails the extra capital cost of a heat exchanger which will generate savings in reduced fuel purchases in the future. The size, materials and sophistication of the heat exchanger will determine how much extra heat it can extract from the flue gas; Che et al [28] estimated that a carbon steel heat exchanger had the lowest payback period and reduces the flue gas temperature to around 50° C. The efficiency of the boiler can be increased as high as 10% from the addition of the heat exchanger. Comakli [29] showed through a life cycle analysis that a condensing boiler could reduce the carbon footprint of space heating by 8% and that the life cycle cost is lower for condensing boilers.

Reversible heat pumps operate on the principle of inducing heat exchange through mechanical work. This heat exchange often occurs against the gradient of natural heat flow (i.e. they are moving heat from low temperatures to high), although heat pumps can still operate in the same direction of natural heat flow if needed. The mechanical work takes place in the compressor where the refrigerant (or air) has an increase in pressure and temperature. Heat is exchanged with the heat sink, while the refrigerant is cooled before it has its pressure reduced through an expansion valve. It will then absorb heat from the heat source until it reaches the compressor again where the cycle begins anew. In the case of heating, the indoors is the heat sink and the ambient outdoors is the heat source; it is vice versa when cooling. A reversible heat pump's efficiency can be increased through multistage compression, improved compressor performance, ejector systems and newer refrigerants. [30]

Air sourced heat pumps use the outdoor air as the heat source and heat sink for heating and cooling respectively. They use electricity to power the compressor and have been commonly used in air conditioning systems. However a reversible air sourced heat pump is needed in order to provide heating as well. Modern research on air-sourced heat pumps focus on efficiency improvements that can be achieved through multi-stage compression arranged with either an intercooler, an economizer or set up in a cascade style. [31]

Ground sourced heat operate in a similar fashion to air-sourced heat pump, but use the earth as a heat sink or source. The earth has less temperature fluctuation and will often present a lower temperature gradient. This generally reduces the work required to move heat across the gradient. However, ground sourced heat pumps require extensive excavation to install the piping in depths that would offer stable temperatures. This entails high capital costs; a closed loop system is estimated to cost \$20,000 (relative to the cost of air sourced heat pumps which can be around \$3200 [32]). However using electricity generated from green sources and a ground sourced heat pump can reduce carbon emissions by up to 0.21 kgCO2/kWh when compared to a condensing boiler. [33]

Chapter 3

Methodology

3.1 Overview

I created a long-term planning model that aims to incorporate consumer decision making based on price inputs, physical power and gas flows and macro-level grid reinforcements. The overall goal of this model is to calculate the system costs (both grid-level reinforcement costs and consumer-level investment costs) for a given set of electricity and natural gas prices. In the Results section, we dissect any trends of these costs in relation to the electricity and natural gas costs.

First, the Z-Distributed Resource Economics (Z-DRE) model takes the perspective of the rational consumer by trying to arrive at the lowest (annual) cost solution of meeting one's electricity and heating loads. It considers the investment cost of a menu of equipment, the electricity prices and natural gas prices. Using this information, it chooses a set of equipment for purchase and ex-ante operation of these units that arrive at the least cost. It is formulated as a mixed integer linear programming problem. Each equipment type has different characteristics and these are modeled by a governing set of constraints. Within each equipment type grouping, the specific equipment are all uniquely defined by their set of parameters (i.e. efficiency, capacity). Each Z-DRE run represents the choices of a single consumer.

The power flow and gas flow simulation takes the injections and withdrawals of active power, reactive power and gas from the results of multiple Z-DRE runs (e.g.

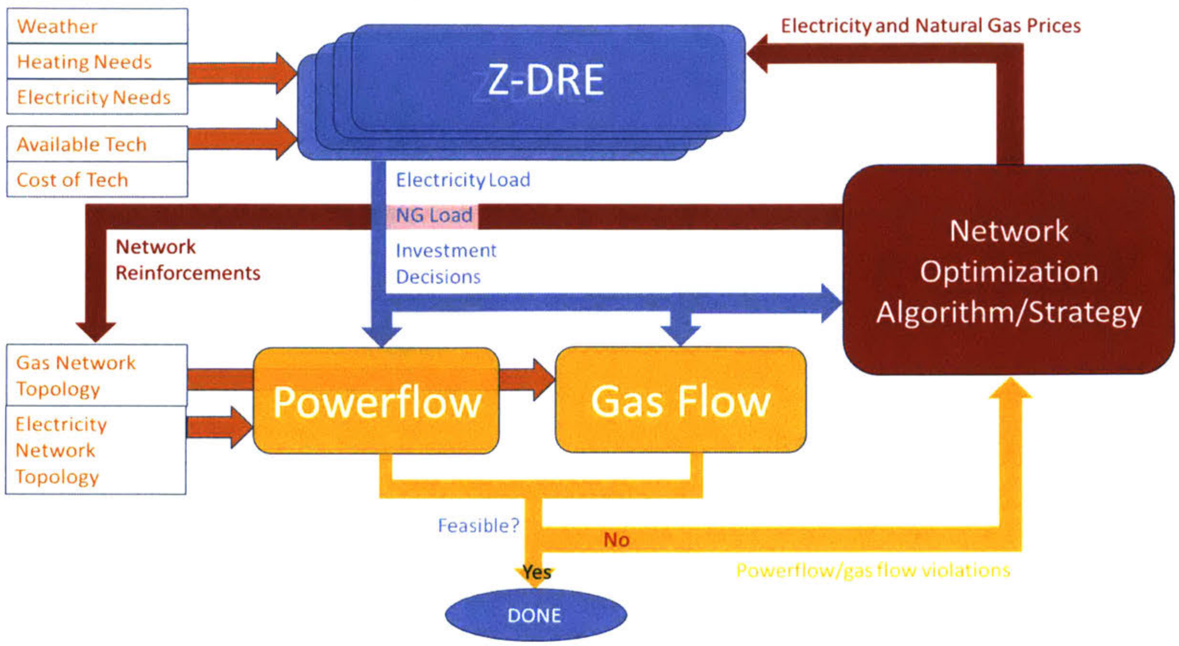


Figure 3-1: Flow Diagram of Model

the aggregated results of multiple consumers) and calculates the power flows and gas flows in the system. Given a set of injections and withdrawals in both systems, I applied Newton's method to arrive at a set of voltages and pressures. Using these voltages and pressures, I was able to calculate the power and natural gas flows. These flows are then passed to the cost finding algorithm.

The cost finding algorithm determines the reinforcement costs of the network. It does this by iteratively adding more reinforcements until the system is operating reliably 99% of the time. In between iterations, the power and gas flow simulations are rerun in order to recalculate the new flows. Once there are no more violations, it reruns Z-DRE for another set of electricity and gas prices.

3.1.1 Z-Distributed Resources Economics Model

Z-DRE is a mixed integer linear programming problem (MILP) that models the economics and behaviour of candidate HVAC, CHP, PV and battery DER investments. It is constrained by building temperature constraints, electricity demand requirements and an investment budget. The objective function (3.1) takes the form of a cost minimization of the total costs at the consumer level (investment costs, electricity purchases, gas puchases and feed-in-tariff electricity revenues). It aims to minimize the capital costs and operational costs of the chosen equipment. The capital costs are annualized over the lifetime of the equipment based on an interest rate of 6%.[1] The operational costs are extrapolated to a value representative of the cost of one year's worth of hours or 8760 hours (the optimization only considers 672 hours).

$$\min_{\mathbf{x},\mathbf{y}} \quad \sum_{g\in G, t\in T} \alpha_{g,t} x_{g,t} + \sum_{g\in G} \beta_g y_g \tag{3.1}$$

Where:

$x_{g,t}$:	Consumption of fuel for technology/commodity g at time t
y_t:	Investment decision of technology g
$\alpha_{g,t}$:	Parameter, Variable cost of technology/commodity g at time t
β_t:	Parameter, Capital cost of technology g
G:	Set of all possible investments
T:	Set of all hours

The technologies considered in the model include conventional heating, ventilation and air conditioning (HVAC) systems, stand-alone water heaters, CHPs, solar PV and energy storage technologies. Each of them represented by their main technical characteristics and physical constraints in the following subsections. In addition, physical building constraints such as heating losses and load balance are also presented.

[1]Interest rates on loans can vary wildly based on the creditworthiness of the applicant. In addition, special governmental loan programs can be used as an incentive to adopt specific types of equipment. For the 6% figure, I used modern mortgage rates and added 2% as a premium since these loans are unsecured.

Heating, Ventilation and Air Conditioning Systems

Heating, ventilation and air conditioning (HVAC) systems that run on electricity are constrained by their total rated electricity capacity $\zeta_{g,p}$. The amount of heat they are able to transfer in an hour[2] is linearly scaled to their electricity consumption by a coefficient of performance $\kappa_{g,p}$. All operations are constrained by the investment decision y. If $y = 0$, the units output will always be zero.

$$\begin{aligned}
v_{t,HVAC} &= \textstyle\sum_{g \in HVAC}(\kappa_{g,heat} q_{g,t,Heat} - \kappa_{g,cool} q_{g,t,Cool}) && \\
\tfrac{q_{g,t,Heat}}{\zeta_{g,Heat}} &\leq y_g, && g \in \text{HVAC} \\
\tfrac{q_{g,t,Cool}}{\zeta_{g,Cool}} &\leq y_g, && g \in \text{HVAC}
\end{aligned} \tag{3.2}$$

$$\begin{array}{lllll}
0 & \leq & q_{g,t,Heat} & \leq \zeta_{g,Heat}, & g \in \text{HVAC} \\
0 & \leq & q_{g,t,Cool} & \leq \zeta_{g,Cool}, & g \in \text{HVAC} \\
0 & \leq & y_g & \in \{0, 1\}, & g \in \text{HVAC}
\end{array} \tag{3.3}$$

Where:

$q_{g,t,p}$:	HVAC Heating/cooling electricity usage for technology g at time t
$v_{t,HVAC}$:	Heat increase/decrease from HVAC at time t
y_t:	Investment decision of technology g
$\kappa_{g,p}$:	Coefficient of performance for technology g for energy type p
$\zeta_{g,p}$:	Maximum output of energy type p for HVAC g
G:	Set of all possible investments
T:	Set of all hours

[2]It is assumed that the HVAC system can only be turned on/off. Linearity in the efficiency can be assumed because the HVAC system can be cycled between an on state (where it achieves its rated efficiency) and off state throughout the hourly period.

Water Heaters

Water heaters have a state variable $u_{g,t}$ tracking its energy state. The state variable $u_{g,t}$ are constrained between 0 and 1 because they represent the unitary state of charge (decimal amount); it is proportionally scaled to the capacity of the unit.[3] The transition from $u_{g,t-1}$ state to the next $u_{g,t}$ state is only modified from withdrawn heat $z_{g,t}$ and input heat from electricity consumed $q_{g,t}$. The electricity input is scaled to heat by the coefficient of performance $\kappa_{g,p}$ (or efficiency if $\kappa_{g,p} < 1$). I assumed that storage losses were negligible.

$$\begin{aligned}
w_{t,WH} &= \textstyle\sum_{g \in WH}(z_{g,t}) & \\
u_{g,t} &\leq y_g, & g \in \text{HW} \\
\theta_g(u_{g,t} - u_{g,t-1}) &= \kappa_{g,p} q_{g,t} - z_{g,t}, & g \in \text{HW} \\
\tfrac{z_{g,t}}{\theta_g} &\leq y_g, & g \in \text{HW} \\
\tfrac{q_{g,t}}{\zeta_g} &\leq y_g, & g \in \text{HW}
\end{aligned} \tag{3.4}$$

$$\begin{aligned}
0 \leq\; & u_{g,t} && \leq 1, g \in \text{HW} \\
0 \leq\; & z_{g,t} && \leq \theta_g, g \in \text{HW} \\
0 \leq\; & q_{g,t} && \leq \zeta_g, g \in \text{HW} \\
0 \leq\; & y_g && \in \{0,1\}, g \in \text{HW}
\end{aligned} \tag{3.5}$$

[3]For example, a 10 kWh unit that holds 7.5 kWh of heat would have $u = 0.75$.

Where:

$q_{g,t}$: Electricity used by technology g at time t

$u_{g,t}$: Unitary state of storage for technology g at time t

$w_{t,HW}$: Hot water heat transfer to demand t

y_t: Investment decision of technology g

$z_{g,t}$: Hot water heat used for demand of technology g at time t

$\kappa_{g,p}$: Coefficient of performance for technology g for energy type p

θ_g: Maximum capacity of technology g

ζ_g: Maximum input rate of energy for HW g

G: Set of all possible investments

T: Set of all hours

CHP and Boilers

CHPs are capable of producing electricity $q_{g,t,p}$, generating heat v_t, removing heat (if a chiller is attached) and generating hot water $w_{t,HW}$ while consuming natural gas $x_{g,t}$. I assumed that heat can bypass the heat exchanger and be rejected to the ambient environment which means that the CHP can run in an electricity-only mode or produce usable heat below what the heat-to-power ratio would nominally suggest. However, the opposite is not assumed to be true; heat cannot be generated without the appropriate amount of electricity suggested by the heat-to-power ratio as the turbine must spin when the gas is combusted.

The equations primarily revolve around the unitary power or per-unit power output $u_{g,t}$.[4] In the case of a boiler this number is fictitious since it does not produce electricity. The equations for boilers are worked out in such a way that it leaves only a heat conversion between gas energy to heat energy through a coefficient of performance $\kappa_{g,p}$ (or in the boiler's case an efficiency since $\kappa_{g,p} \leq 1$).

The CHP is able to produce active and reactive power and would regularly be constrained by the two norm (a unit semi-circle). The two-norm would change the prob-

[4] $u_{g,t}$ is scaled from 0 to 1 with the maximum 'electrical' capability of the CHP/boiler being the scale

lem from a MILP to a mixed integer second order cone problem which increases computational complexity. To avoid this, I generate a piecewise inner-circle approximation by linearizing the semi-circle boundaries. It may operate in only the quadrant of positive active power and positive reactive power for to reduce the computational load.[5] The linearization uses 5 operating points on the unit circle ($\angle 0°, \angle 15°, \angle 45°, \angle 75°$ and $\angle 90°$).

$$\begin{aligned}
&w_{t,CHP} && = \textstyle\sum_{g \in CHP}(\kappa_{g,hotwater}\zeta_{g,elec}u_{g,t}) && \\
&w_{t,Boiler} && = \textstyle\sum_{g \in Boiler}(\kappa_{g,hotwater}\zeta_{g,elec}u_{g,t}) && \\
&v_{t,CHP} && = \textstyle\sum_{g \in CHP}(\kappa_{g,heat}\zeta_{g,elec}u_{g,t} - \kappa_{g,cool}\zeta_{g,elec}u_{g,t}) && \\
&v_{t,Boiler} && = \textstyle\sum_{g \in Boiler}(\kappa_{g,heat}z_{g,t,Heat}) && \\
&0.97x_{g,t} && \geq \tfrac{q_{g,t,reactive}}{\eta_g}, && g \in \text{CHP} \\
&1.12x_{g,t} && \geq \tfrac{0.58q_{g,t,active}+q_{g,t,reactive}}{\eta_g}, && g \in \text{CHP} \\
&1.93x_{g,t} && \geq \tfrac{1.73q_{g,t,active}+q_{g,t,reactive}}{\eta_g}, && g \in \text{CHP} \\
&0.97x_{g,t} && \geq \tfrac{q_{g,t,reactive}}{\eta_g}, && g \in \text{CHP} \\
&u_{g,t} && \geq \tfrac{|\{q_{g,t,active},q_{g,t,reactive}\}|2}{\zeta_{g,elec}}, && g \in \text{CHP,Boiler} \\
&u_{g,t} && \leq y_g, && g \in \text{CHP,Boiler} \\
&\Omega_g u_{g,t} && \geq z_{g,t,heat} + z_{g,t,hotwater} + z_{g,t,cool}, && g \in \text{CHP,Boiler} \\
&\Omega_g b_{g,t} && \geq z_{g,t,heat}, && g \in \text{CHP,Boiler} \\
&\omega_g(1-b_{g,t}) && \geq z_{g,t,heat}, && g \in \text{CHP} \\
&q_{g,t} && = 0, && g \in \text{Boilers}
\end{aligned} \tag{3.6}$$

[5]The CHP should be able to operate in two quadrants (positive active power and positive/negative reactive power), but it is limited to one quadrant to reduce the computational complexity of the problem. In addition, it is unlikely that the grid will produce excess reactive power since overhead lines are dominated by the inductance term relative to the capacitative term. This makes the grid a reactive power consumer.

$$
\begin{array}{llllll}
0 & \leq & q_{g,t,active} & \leq \zeta_{g,elec}, & g \in \text{CHP} \\
-\zeta_{g,elec} & \leq & q_{g,t,reactive} & \leq \zeta_{g,elec}, & g \in \text{CHP} \\
0 & \leq & z_{g,t,heat} & \leq \zeta_{g,heat}, & g \in \text{CHP,Boilers} \\
0 & \leq & z_{g,t,cool} & \leq \zeta_{g,cool}, & g \in \text{CHP} \\
0 & \leq & z_{g,t,hotwater} & \leq \zeta_{g,hotwater}, & g \in \text{CHP,Boilers} \\
0 & \leq & u_{g,t} & \leq 1, & g \in \text{CHP} \\
 & & y_g \in \{0,1\}, & & g \in \text{CHP}
\end{array}
\tag{3.7}
$$

Where:

$b_{g,t}$:	Binary variable for heating (1) or cooling (0) for technology g at time t
$q_{g,t,p}$:	Electricity of type p generated by technology g at time t
$u_{g,t}$:	Unitary power of technology g at time t
$v_{t,CHP}$:	Heat increase/decrease from CHP at time t
$v_{t,Boiler}$:	Heat increase/decrease from Boiler at time t
$w_{t,HW}$:	Hot water heat transfer to demand t
$x_{g,t}$:	Consumption of fuel for technology g at time t
y_g:	Investment decision of technology g
$z_{g,t,p}$:	heat of technology g at time t
$\kappa_{g,p}$:	Coefficient of performance for technology g for energy type p
Ω_g:	Heat to power ratio for CHP g
ω_g:	Cooling to power ratio for CHP g
$\zeta_{g,p}$:	Maximum output of energy type p for CHP g
G:	Set of all possible investments
T:	Set of all hours

PV

Solar PV is the only equipment that is allowed to have multiple modules installed; the installation variable is a non-negative integer as opposed to a binary variable. Photovoltaics modules are limited by the total available area A with the total number limited to $floor(\frac{A}{\Psi_g})$ where Ψ_g is the area required per module. In addition, a module's output is limited by the given insolation ρ times its efficiency η.

$$\begin{aligned} q_{g,t} &\leq \rho_g \eta_g y_{g,t} & g \in \text{PV} \\ y_g &\leq \tfrac{A}{\Psi_g} & g \in \text{PV} \end{aligned} \tag{3.8}$$

$$\begin{aligned} 0 \leq \quad & q_{g,t} \quad \leq \zeta_g, & g \in \text{PV} \\ 0 \leq y_g \quad & \in \mathbb{Z}, & g \in \text{PV} \end{aligned} \tag{3.9}$$

Where:

y_t:	Number of photovoltaic modules of PV g
q_t:	Electricity output of technology g at time t
η_g:	Electrical efficiency of photovoltaic module g
Ψ_g:	Area required per photovoltaic module
ρ_g:	Maximum output of electricity for PV g based on insolation
ζ_g:	Maximum output of electricity for PV g based on capacity
A:	Area suitable for PV
G:	Set of all possible investments
T:	Set of all hours

Energy Storage

Electrochemical energy storage (EES) has an energy state variable $u_{g,t}$ similar to the water heater which tracks its charge level scaled from 0 to 1. Its charge q_{up} and discharge q_{down} capability is linked to this energy state and are hampered by efficiency factors η in either direction.

$$\begin{aligned} u_{g,t} &\leq y_g, & g \in \text{EES} \\ \theta_g(u_{g,t} - u_{g,t-1}) &= \eta_{g,in} q_{g,t,up} - \tfrac{q_{g,t,down}}{\eta_{g,out}}, & g \in \text{EES} \end{aligned} \tag{3.10}$$

$$
\begin{array}{lllll}
0 & \leq & u_{g,t} & \leq 1, & g \in \text{EES} \\
0 & \leq & q_{g,t,up} & \leq \zeta_{g,up}, & g \in \text{EES} \\
0 & \leq & q_{g,t,down} & \leq \zeta_{g,down}, & g \in \text{EES} \\
0 & \leq & y_g & \in \{0,1\}, & g \in \text{EES}
\end{array}
\tag{3.11}
$$

Where:

$u_{g,t}$:	Unitary state of charge for technology g at time t
y_t:	Investment decision of technology g
$q_{g,t,d}$:	Electricity charge($d = up$)/discharge($d = down$) of technology g at time t
$\eta_{g,in}$:	Charge efficiency of technology g
$\eta_{g,out}$:	Discharge efficiency of technology g
θ_g:	Maximum capacity of technology g
$\zeta_{g,t,up}$:	Maximum output of electricity for EES g
$\zeta_{g,t,down}$:	Maximum input of electricity for EES g
G:	Set of all possible investments
T:	Set of all hours

Capacitive Building Model

The capacitive building model considers a thermal mass which loses (or gains) heat naturally from its environment and it is dependent on the temperature difference between the interior temperature and the ambient (external) temperature. I applied the analogy of an electrical circuit with resistance and capacitance where energy transfer is analogous to current, temperature difference is akin to voltage potential and insulation is similar to resistance. There is a resistor between the building and equipment R_1 denoting internal heat losses in the equipment as well as a resistor R_2 between the building and the environment for heat losses through a building's walls and roof. A capacitor C_1 dictates the capability of a building to store energy.[6] [34]

[6]A building with a high capacitance will be able to hold more heat than a lower capacitance building at the same temperature. On the other hand, high capacitance buildings require more heat

$$
\begin{aligned}
h_t &\leq \nu_{t,max} \\
h_t &\geq \nu_{t,min} \\
h_t - h_{t-1} &= \tfrac{1}{R_1 C_1}(\nu_{t,amb} - h_{t-1}) \\
&+R_1(v_{t,HVAC} + v_{t,CHP} + v_{t,Boiler}) \\
&+(\tfrac{R_1+R_2}{R2C1} - R1)(v_{t-1,HVAC} + v_{t-1,CHP} + v_{t-1,Boiler})
\end{aligned} \tag{3.12}
$$

$$
0 \leq h_t \tag{3.13}
$$

Where:

h_t: Temperature state at time t

$v_{t,HVAC}$: HVAC heat contribution/removal at time t

$v_{t,CHP}$: CHP heat contribution/removal at time t

$v_{t,Boiler}$: Boiler heat contribution at time t

$\nu_{t,max}$: Temperature maximum at time t

$\nu_{t,min}$: Temperature maximum at time t

$\nu_{t,amb}$: Ambient temperature at time t

R_1: Thermal Resistance between building environment and equipment

R_2: Thermal Resistance between building environment and ambient environment

C_1: Thermal Capacitance of building

Energy Balance

The building must balance its electrical load with injections/withdrawals from the grid, its own local generation and potentially non-served energy. Hot water demand is met through a boiler and/or CHP output so they are summed. The local electrical demand is the sum of the non-heating/non-cooling related demand $\phi_{t,elec}$ and the electricity consumption of all equipment (HVAC, water heaters and batteries that are charging). The local electricity generation is the sum of the production of all

to raise its temperature than a lower capacitance building.

equipment (CHP, PV and discharging batteries). The reactive power generation is only the sum of all reactive power production from the CHPs. Finally, I calculate the amount of electricity demand as seen from the grid. If it is a positive demand, then the imported electricity is positive $x_{ElecImp,t} > 0$. If the demand is negative then exported electricity term is positive $x_{ElecExpP,t} > 0$. The non-served energy $x_{NSE,t}$ is a slack term if the $x_{ElecImp,t}$ is constrained in some way.

$$\begin{aligned}
& w_{t,CHP} + w_{t,Boiler} && = \phi_{t,HW} \\
& \phi_{t,elec} + \textstyle\sum_{g\in HVAC}(q_{g,t,Cool} + q_{g,t,Heat}) + \sum_{g\in WH} q_{g,t} + \sum_{g\in ESS} q_{g,t,in} && = z_{ElecDem,t} \\
& \textstyle\sum_{g\in CHP} q_{g,t,active} + \sum_{g\in PV} q_{g,t} + \sum_{g\in ESS} q_{g,t,out} && = z_{ElecGenAct,t} \\
& \textstyle\sum_{g\in CHP} q_{g,t,reactive} && = x_{ElecExpQ,t} \\
& x_{NSE,t} + x_{ElecImp,t} + z_{ElecGenAct,t} && = x_{ElecExpP,t} + z_{ElecDem,t}
\end{aligned} \tag{3.14}$$

$$\begin{aligned}
0 & \leq x_{ElecImp,t} \\
0 & \leq x_{ElecExpP,t} \\
0 & \leq x_{NSE,t} \\
0 & \leq z_{ElecGenAct,t} \\
0 & \leq z_{ElecDem,t}
\end{aligned} \tag{3.15}$$

Where:

$w_{t,CHP}$:	CHP hot water contribution at time t
$w_{t,Boiler}$:	Boiler hot water contribution at time t
$\phi_{t,p}$:	Demand for product p at time t
$x_{ElecImp,t}$:	Imported electricity from grid at time t
$x_{ElecExpP,t}$:	Exported electricity (active power) to grid at time t
$x_{ElecExpQ,t}$:	Exported electricity (reactive power) to grid at time t
$x_{NSE,t}$:	Non-served energy at time t
$z_{ElecGenAct,t}$:	Total local active power generated at time t
$z_{ElecDem,t}$:	Total local active power consumed at time t

3.1.2 Powerflow and Gas Flow Simulation

Load Calculation

I run the Z-DRE model for three different demand profiles: HIGH, BASE, and LOW. I scaled the resulting electric and natural gas requirements from these demand profiles by a set of three random multipliers $k_{d,i}$ at each node (to represent multiple houses in one node). Each multiplier $k_{d,i}$ represents the number of houses of demand type d at node i. These gas and electric loads are the input for the power and gas flow simulations.

$$\begin{aligned} &P_{wth,i,t} = \sum_{d \in \mathbf{D}} k_{d,i} p_{d,t} \\ &G_{wth,j,t} = \sum_{d \in \mathbf{D}} k_{d,j} g_{d,t} \\ &\sum_{d \in \mathbf{D}, k \in \mathbf{K}} k_{d,k} = \sum_{d \in \mathbf{D}, j \in \mathbf{J}} k_{d,j} \end{aligned} \tag{3.16}$$

Where:

$P_{wth,i,t}$: Power withdrawn at node i at time t

$q_{wth,k,t}$: Gas withdrawn at point k at time t

$k_{d,i}$: Randomly determined number of houses connected to node i with demand profile d

$k_{d,j}$: Randomly determined numberof houses connected to point j with demand profile d

$p_{d,t}$: Result of Z-DRE, net power consumption of consumer with demand profile d at time t

$g_{d,t}$: Result of Z-DRE, gas consumption of consumer with demand profile d at time t

$\mathbf{D}$: {HIGH, BASE, LOW}

$\mathbf{I}$: Set of all nodes in the electrical system

$\mathbf{J}$: Set of all points in the gas system

In the experiments I generated the number of houses from a uniform distribution at each node $k_{d,i}$. I assigned each node to a point in the gas system $i \in \mathbf{J}_p$. Then I summed the number of houses $k_{d,i}$ contained in all nodes that belonged to that point $i \in \mathbf{J}_p$ to calculate the number of houses at a given point of the gas system $k_{d,j}$.

$$\begin{aligned} k_{d,i} &\sim \text{floor}(U(0,6)) \\ k_{d,j} &= \textstyle\sum_{i \in \mathbf{J}_p} k_{d,i} \end{aligned} \tag{3.17}$$

Where:

$k_{d,i}$: Randomly determined number of houses connected to node i with demand profile d

$k_{d,j}$: Randomly determined number of houses connected to point j with demand profile d

$U(a,b)$: A random variable selected from the uniform distribution bounded a and b

$\mathbf{D}$: {HIGH, BASE, LOW}

$\mathbf{I}$: Set of all nodes in the electrical system

$\mathbf{J}_p$: Set of all nodes assigned to node j

Newton's Method

In both cases of power flow and gas flow calculations, I utilized Newton's method to converge a system of non-linear equations so that the nodal balances are zero. Newton's method [35] is an iterative process which takes an initial value and determines a step that moves it closer to the target values. For simplicity, I applied Newton's method twice, once for each system, since these systems have no flow interactions[7].

1. Take a function $f(x)$ and a target vector y

2. Take an initial guess x_0

3. Calculate the Jacobian $J(x_i)$ of $f(x)$ evaluated at x_i

4. Invert the Jacobian $J(x_i)^{-1}$

5. Calculate the step vector $\Delta x = J(x_i)^{-1}(f(x_i) - y)$

6. Update the x vector, $x_{i+1} = x_i + \Delta x$

7. Evaluate the function at the new vector, $f(x_{i+1})$

8. If $|f(x_{i+1}) - y|_m \geq \epsilon$ for some specified tolerance ϵ and norm m, then increment i and return to step 3.

9. Return x_{i+1} as the solution to $f(x) = y$.

AC Powerflow

There are three types of buses considered in the AC powerflow equation: a slack bus, load buses and voltage controlled buses. The slack bus, also known as an infinite bus, has constant voltage magnitude of 1 and a reference voltage angle of 0. It is able to supply any amount of power, both active and reactive, as needed. A load bus, also known as a PQ bus, has known active power P and reactive power Q quantities that are injected or withdrawn from the bus. A PQ bus has two equations to solve for the voltage magnitude $|V|$ and voltage angles δ. A voltage controlled bus has known active power injection/withdrawal P and voltage magnitude V quantities, but

[7]Unlike the analysis done by Martinez-Mares and Fuerte-Esquivel [16] (all interactions of the gas and electric system are at the building level in the Z-DRE model), I did not use any of the CHP generators as swing generators; so there is no coupling of the systems for the purposes of the power and gas flow simulations.

has two equations that can be solved for the voltage angle δ and reactive power injection/withdrawal Q quantity.

Assuming a balanced 3-phase load, the apparent power flow S to node k is governed by the fundamental complex power equation (3.18).

$$S_k = P_k + jQ_k = V_k I_k^* \tag{3.18}$$

$$S_k = V_k Y_{kj}^* V_j^* \tag{3.19}$$

Where:

S_k: Apparent power at node k

P_k: Active power at node k

Q_k: Reactive power at node k

V_k: Voltage phasor at node k

Y_{kj}: Admittance between bus k and bus j

As active power P and reactive power Q are perpendicular quantities, I could separate the real and imaginary parts of the equation. Conservation of both active and reactive power must be respected meaning that the power flows and the injected/withdrawn power must sum to 0 at every node. I summed all of the power flows for all lines $\mathbf{L}$ that connect to the node k with the power injected and withdrawn at that node.

$$0 = real\{V_k \sum_{\{k,j\}\in\mathbf{L}} Y_{kj}^* V_j^*\} - P_{inj,k} + P_{wth,k} \tag{3.20}$$

$$0 = imag\{V_k \sum_{\{k,j\}\in\mathbf{L}} Y_{kj}^* V_j^*\} - Q_{inj,k} + Q_{wth,k} \tag{3.21}$$

Where:

$P_{inj,k}$:	Injected active power at node k
$P_{inj,k}$:	Withdrawn active power at node k
$Q_{inj,k}$:	Injected reactive power at node k
$Q_{inj,k}$:	Withdrawn reactive power at node k
V_k:	Voltage phasor at node k
Y_{kj}:	Admittance between bus k and bus j
$\mathbf{L}$:	Set of all lines

I note that equation 3.21 can be solved for Q trivially since the terms $-Q_{inj,k} + Q_{wth,k}$ are not given, but rather chosen so that the equation balances. Therefore PV buses only have one equation to solve with any difficulty.

To apply Newton's method, I built the $\mathbf{x}$, $\mathbf{y}$ and $\mathbf{f}(\mathbf{x})$ below:

$$\mathbf{x} = \begin{bmatrix} V_2 \\ \vdots \\ V_n \\ \delta_2 \\ \vdots \\ \delta_n \end{bmatrix}, \mathbf{y} = \begin{bmatrix} P_{inj,2} - P_{wth,2} \\ \vdots \\ P_{inj,n} - P_{wth,n} \\ Q_{inj,2} - Q_{wth,2} \\ \vdots \\ Q_{inj,n} - Q_{wth,n} \end{bmatrix}, \mathbf{f}(\mathbf{x}) = \begin{bmatrix} real\{V_2 \sum_{\{2,j\}\in\mathbf{L}} Y_{2j}^* V_j^*\} \\ \vdots \\ real\{V_n \sum_{\{n,j\}\in\mathbf{L}} Y_{nj}^* V_j^*\} \\ imag\{V_2 \sum_{\{2,j\}\in\mathbf{L}} Y_{2j}^* V_j^*\} \\ \vdots \\ imag\{V_n \sum_{\{n,j\}\in\mathbf{L}} Y_{nj}^* V_j^*\} \end{bmatrix} \tag{3.22}$$

The Jacobian $\mathbf{J}(\mathbf{x})$ is constructed as follows:

$$\mathbf{J}(\mathbf{x}) = \begin{bmatrix} \frac{\partial P_2}{\partial V_2} & \cdots & \frac{\partial P_2}{\partial V_n} & \frac{\partial P_2}{\partial \delta_2} & \cdots & \frac{\partial P_2}{\partial \delta_n} \\ \vdots & & \vdots & \vdots & & \vdots \\ \frac{\partial P_n}{\partial V_2} & \cdots & \frac{\partial P_n}{\partial V_n} & \frac{\partial P_n}{\partial \delta_2} & \cdots & \frac{\partial P_n}{\partial \delta_n} \\ \frac{\partial Q_2}{\partial V_2} & \cdots & \frac{\partial Q_2}{\partial V_n} & \frac{\partial Q_2}{\partial \delta_2} & \cdots & \frac{\partial Q_2}{\partial \delta_n} \\ \vdots & & \vdots & \vdots & & \vdots \\ \frac{\partial Q_n}{\partial V_2} & \cdots & \frac{\partial Q_n}{\partial V_n} & \frac{\partial Q_n}{\partial \delta_2} & \cdots & \frac{\partial Q_n}{\partial \delta_n} \end{bmatrix} \tag{3.23}$$

The partial differentials are derived as follows:

$$\frac{\partial P_k}{\partial V_j} = \begin{cases} |V_k||Y_{kj}|cos(\delta_k - delta_j - \theta_{kj}), & k \neq j \\ |V_k||Y_{kk}|cos(\theta_{kk}) + \sum_{j=1}^{n} |V_j||Y_{kj}|cos(\delta_k - delta_j - \theta_{kj}), & k = j \end{cases} \tag{3.24}$$

$$\frac{\partial P_k}{\partial \delta_j} = \begin{cases} |V_k||Y_{kj}||V_j|sin(\delta_k - \delta_j - \theta_{kj}), & k \neq j \\ -|V_k| \sum_{j=1, j\neq k}^{n} |Y_{kj}||V_j|sin(\delta_k - \delta_j - \theta_{kj}), & k = j \end{cases} \tag{3.25}$$

$$\frac{\partial Q_k}{\partial V_j} = \begin{cases} |V_k||Y_{kj}|sin(\delta_k - delta_j - \theta_{kj}), & k \neq j \\ -|V_k||Y_{kk}|sin(\theta_{kk}) + \sum_{j=1}^{n} |V_j||Y_{kj}|sin(\delta_k - delta_j - \theta_{kj}), & k = j \end{cases} \tag{3.26}$$

$$\frac{\partial Q_k}{\partial \delta_j} = \begin{cases} -|V_k||Y_{kj}||V_j|cos(\delta_k - \delta_j - \theta_{kj}), & k \neq j \\ |V_k| \sum_{j=1, j\neq k}^{n} |Y_{kj}||V_j|cos(\delta_k - \delta_j - \theta_{kj}), & k = j \end{cases} \tag{3.27}$$

where $\theta_{kj} = \angle Y_{kj}$

For this thesis, I used the IEEE 342 node Low Voltage Distribution Network[36]. The network is connected to a 230kV high voltage network through two delta-delta step-down transformers. These two transformers bring the voltage down to 13.2kV line-to-neutral and supply 8 radial primary distribution feeders. The 13.2kV network (red in Figure 3-2) consists of 150 nodes.

The low voltage network (blue in Figure 3-2) operates at 120/208V and is a wye grounded grid network. It has 192 nodes and is supplied from the 13.2kV feeder network through 48 delta wye step down transformers. While the network is originally meshed, I adapted the network into a radial configuration by removing any loops. Line characteristics and data can be found in Figures 3-3, 3-4 and 3-5.

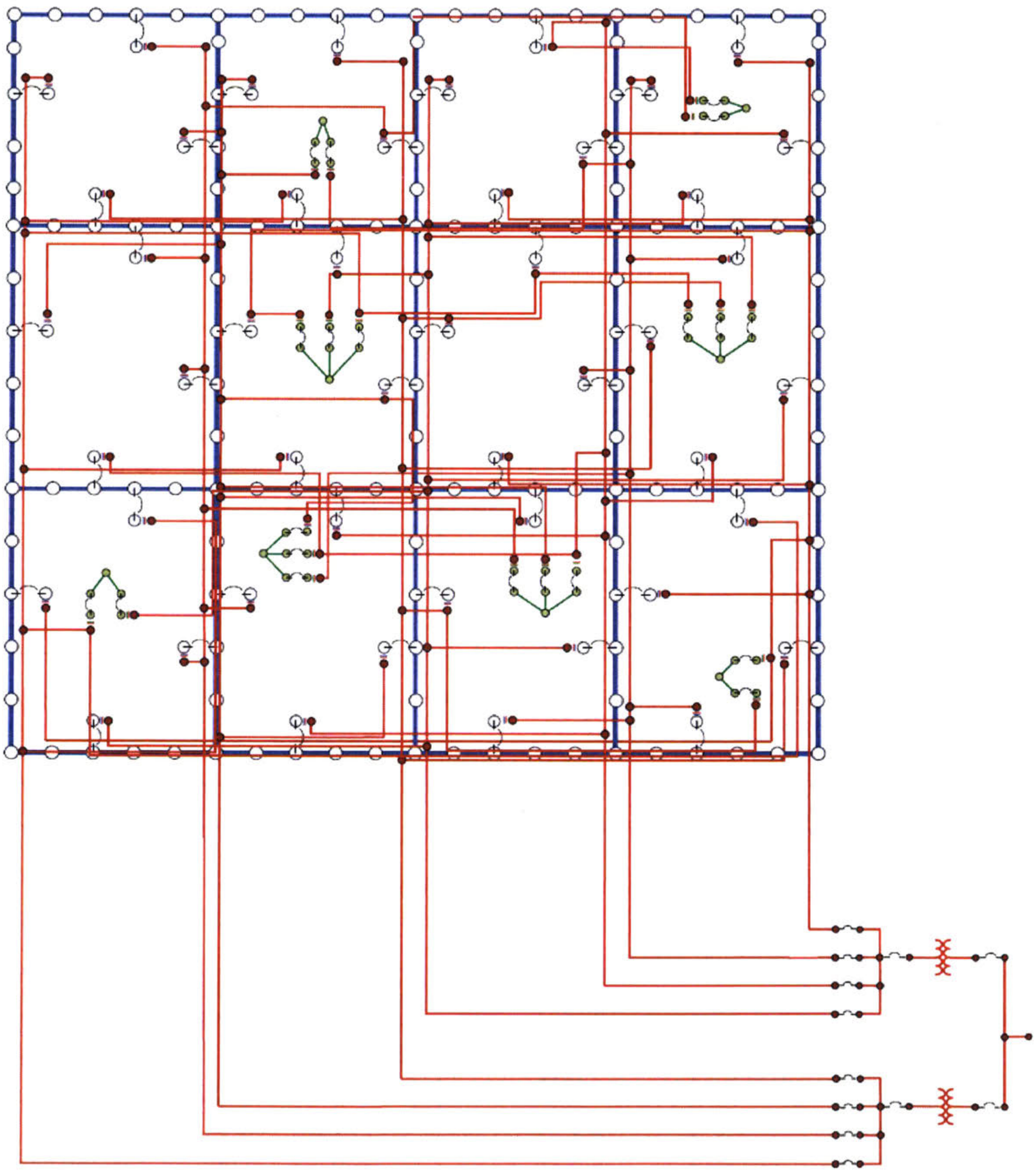


Figure 3-2: IEEE 342 node Low Voltage Distribution Network

Line Configurations			
Configuration	Trans	Pri	Sec
Phasing	AB C	AB C	AB C N
Phase Conductor	397.5 kcmil AA	1000 kcmil AA	500 kcmil Cu
Neutral Conductor	397.5 kcmil AA	1000 kcmil AA	500 kcmil Cu
Spacing	101	102	103
OH/UG	OH	UG	UG
Rating (A)	594	615	430

Figure 3-3: Line Characteristics [1/3]

Conductor Data			
Conductor	397.5 kcmil	1000 kcmil	500 kcmil
GMR (ft.)	0.0277	0.04683	0.026
R (Ω/mile)	0.0477	0.1214	0.206
Rating (A)	594	615	430
Outer Dia. (in)	N/A	2.08	N/A
Conductor Dia. (in)	N/A	1.124	N/A
Neutral GMR (ft.)	N/A	0.0365	N/A
Neutral R (Ω/mile)	N/A	0.1809	N/A
Neutral Dia. (in.)	N/A	0.1285	N/A
Neutral strands	N/A	21	N/A

Figure 3-4: Line Characteristics [2/3]

Conductor Spacing			
Spacing	101	102	103
AB	10 ft.	3.0 in.	3.0 in.
AC	20 ft.	6.0 in.	4.424 in.
BC	10 ft.	3.0 in.	3.0 in.
AN	N/A	N/A	3.0 in.
BN	N/A	N/A	4.424 in.
CN	N/A	N/A	3.0 in.

Figure 3-5: Line Characteristics [3/3]

Calculation of the Admittance Matrix Y values

A line l generally has three lines spaced apart at distances $\{d_{ab}, d_{ac}, d_{bc}\}$ each with voltages $\{v_a, v_b, v_c\}$ and carrying currents $\{i_a, i_b, i_c\}$. These lines have resistances which can be calculated by using the per-unit length resistances provided by the conductor manufacturer. However, the reactance of the line is dependent on both the conductor material as well as the spacial placement of lines relative to one another. A line will have characteristics known as the geometric mean radius (GMR) and the geometric mean distance (GMD). The GMR is dependent on the material in the lines, the cross-sectional shape of the lines and the relative distance between lines of the same phase (if multiple lines for the same phase exist). The GMR can generally be looked up from a manufacturer's table for transmission systems with one line per phase. However the GMD is entirely dependent on the distance between lines. In this case with a single line per phase, it is the third root of the product of the distances. [35]

$$GMD = \sqrt[3]{d_{ab}d_{ac}d_{bc}} \tag{3.28}$$

The reactance of the line is calculated as follows:

$$X_l = \frac{\mu_0}{2\pi}(2\pi f)(L)\log\frac{GMD}{GMR} \tag{3.29}$$

Where:

μ_0: Permeability of free space, $4\pi \times 10^{-7}$

f: Electrical frequency of system in Hertz (60Hz in these cases)

L: Length of transmission line

The admittance of a line γ_l is simply the inverse of the impedance:

$$\gamma_{kj} = \frac{1}{R_{kj} + jX_{kj}}, \{j, k\} \in \mathbf{L} \tag{3.30}$$

Each element of the bus admittance matrix Y is constructed based on the grid topology. Specifically, the off-diagonal elements of the Y are the negative admittance value of line l between nodes if a line l exists between those two nodes (otherwise the value is 0). For diagonal terms, the element is the sum of the admittances of all lines that connect to that node. [35]

$$Y_{kj} = \begin{cases} -\gamma_{kj}, & k \neq j \cap \{j,k\} \in \mathbf{L} \\ 0, & k \neq j \cap \{j,k\} \notin \mathbf{L} \\ \sum_{\{j,n\} \in \mathbf{L}} \gamma_{nj}, & k = j \end{cases} \tag{3.31}$$

Gas Flow

For the function to be employed in Newton's method for the gas network, I considered the mass balance equation at each node.[8] I applied the Weymouth gas flow equation. [37]

$$\tilde{q}_{ij}|\tilde{q}_{ij}| = (\frac{\pi}{4})^2 \frac{D_{ij}^5}{\Delta x_{ij} F_{ij} R T Z \rho_0^2}(p_i^2 - p_j^2) \tag{3.32}$$

[8] I assume that there are no leaks in any pipelines.

Where:

$\tilde{q}_{ij}$: In and outflow gas rate from point i to j

$q_{inj,i}$: Natural gas injected at point i

$q_{wth,i}$: Natural gas withdrawn at point i

D_{ij}: Diameter of pipe

Δx_{ij}: Length of pipe

F_{ij}: Pipeline friction coefficient I adapted it as

R: Specific gas constant

T: Temperature

Z: Compressibility factor

ρ_0: Gas density under standard conditions

p_i: Pressure at point i

$\mathbf{P}$: Set of all pipelines

$$\tilde{q}_{ij} = \text{sign}(p_i^2 - p_j^2) K_{ij} \sqrt{|p_i^2 - p_j^2|} \tag{3.33}$$

Where $K_{ij} = \sqrt{(\frac{\pi}{4})^2 \frac{D_{ij}^5}{\Delta x_{ij} F_{ij} RTZ\rho_0^2}}$

Using conservation of mass and a network of pipelines $\mathbf{P}$

$$0 = \sum_{\{i,j\} \in \mathbf{P}} (\tilde{q}_{ij}) - q_{inj,i} + q_{wth,i} \tag{3.34}$$

$$0 = \sum_{\{i,j\} \in \mathbf{P}} (\text{sign}(p_i^2 - p_j^2) K_{ij} \sqrt{|p_i^2 - p_j^2|}) - q_{inj,i} + q_{wth,i} \tag{3.35}$$

To apply Newton's method, I built the $\mathbf{x}$, $\mathbf{y}$ and $\mathbf{f}(\mathbf{x})$ below. Once again, I assumed a 'slack bus' exists (indexed at 1) that can supply or absorb any amount of gas.

$$\mathbf{x} = \begin{bmatrix} p_2 \\ \vdots \\ p_n \end{bmatrix}, \mathbf{y} = \begin{bmatrix} q_{inj,2} - q_{wth,2} \\ \vdots \\ q_{inj,n} - q_{wth,n} \end{bmatrix}, \mathbf{f(x)} = \begin{bmatrix} \sum_{\{2,j\}\in\mathbf{P}} \mathrm{sign}(p_2^2 - p_j^2) K_{2j} \sqrt{|p_2^2 - p_j^2|} \\ \vdots \\ \sum_{\{n,j\}\in\mathbf{P}} \mathrm{sign}(p_n^2 - p_j^2) K_{nj} \sqrt{|p_n^2 - p_j^2|} \end{bmatrix} \tag{3.36}$$

The Jacobian $\mathbf{J}(\mathbf{x})$ formulation and partial differentials are below:

$$\mathbf{J}(\mathbf{x}) = \begin{bmatrix} \frac{\partial q_2}{\partial p_2} & \cdots & \frac{\partial q_2}{\partial p_n} \\ \vdots & & \vdots \\ \frac{\partial q_n}{\partial p_2} & \cdots & \frac{\partial q_n}{\partial p_n} \end{bmatrix} \tag{3.37}$$

$$\frac{\partial q_j}{\partial p_i} = \begin{cases} \sum_{\{j,n\}\in\mathbf{P}} \frac{K_{jn} p_i}{\sqrt{|p_i^2 - p_n^2|}}, & i = j \\ -\frac{K_{ij} p_j}{\sqrt{|p_j^2 - p_i^2|}}, & i \neq j \cap \{i,j\} \in \mathbf{P} \\ 0, & i \neq j \cap \{i,j\} \notin \mathbf{P} \end{cases} \tag{3.38}$$

I noted that the function has an infinite slope whenever $P_i = P_j$ and that the Jacobian terms approach zero when $P_i >> P_j$. To allow for a greater chance of convergence, I implemented additional steps in Newton's method to prevent the iterations of $\mathbf{x_i}$ from moving further away from the correct solution or cause computational errors. Specifically, I applied a decaying maximum step size α_i^m at each step i. The original limiting step size τ is an arbitrarily chosen large number. For hours without any gas demand (which could happen with no CHP units in the summer), I did not run the gas simulations as the Jacobian would be singular. Instead, I used the trivial solution of $q_{i,j} = 0 \forall \{i,j\} \in \mathbf{P}$ and the pressures were all identical to the gate pressure of the distribution network.

$$\alpha_i^m = \frac{\min(\tau i^{-0.5}, abs(\Delta x_i^m))}{\Delta x_i^m} \tag{3.39}$$

$$\Delta x_{i,steplimited}^m = \alpha_i^m \Delta x_i^m \tag{3.40}$$

3.1.3 Cost Finding Algorithm

In terms of cost finding, I employed two nested loops. In the outer loop, Z-DRE calculates the optimal equipment selection as well as the load profile for electricity consumption/generation and natural gas consumption for a given set of prices, equipment costs and local electricity demand[9]. Z-DRE runs three times in each outer loop iteration: once for a HIGH, BASE and LOW electricity demand profile. The results of each Z-DRE result are multiplied by the number of houses at each node to determine the electricity and gas that is withdrawn from the grid (See Section 3.1.2 for the methodology on how the load is calculated).

In the inner loop I found the minimum transmission and gas expansion costs for these electricity and gas withdrawals with the particular constraint of 99% reliability. The grid is considered operating reliably when all power flows and gas flows are below the rated capacity of the respective line and pipeline. Anytime there is a power flow or gas flow violation, the entire grid is considered in an unreliable operating state and that hour is counted towards the 1% downtime. [10] I reached this 99% reliability by determining which elements[11] in each network are violated the most during failure hours. I reinforced these parts of the network by adding an identical line/pipeline in parallel and run the simulation again to calculate any changes in flows (since expansion of the network also causes changes in impedances which will affect power

[9]The local electricity demand is all of household electricity demand that is unrelated to space heating, space cooling and domestic water heating.

[10]For a simulation of 672 hours, this means that I only allowed 6 hours to have power flow or gas flow violations

[11]I only considered line and pipeline elements in each system.

flows). I then checked if this new network reaches a 99% reliability. I continued adding reinforcement elements to the network until a violation rate of less than 1% is reached. Figure 3-6 shows a visual representation of this algorithm.

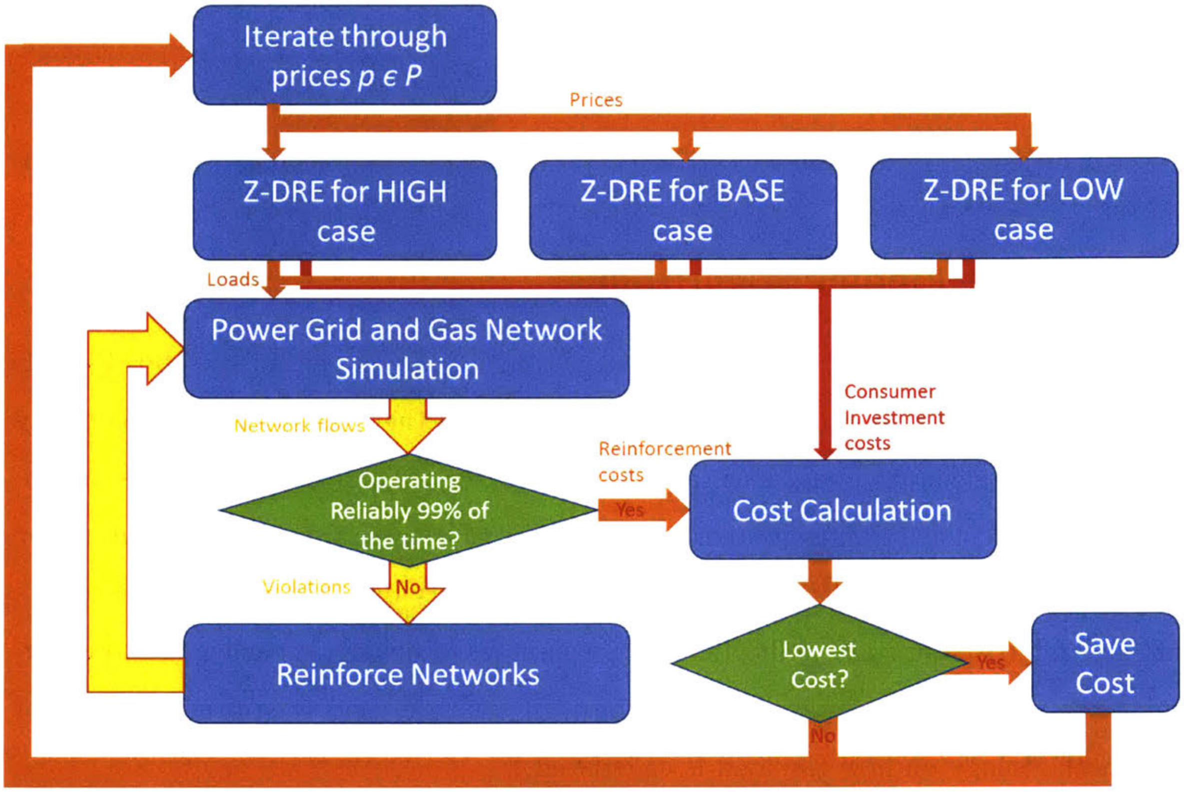


Figure 3-6: Flow Diagram of Cost Finding Algorithm Implementation

I calculated reinforcement costs on a per-unit-length basis for both the electricity and natural gas network. [12] Network reinforcements used the same type of line, transformer or pipeline as the original network element (i.e. a secondary 120V line is reinforced by a 120V secondary line); I assumed that I could run reinforcements in parallel or 'twin' the pipeline.

3.1.4 Data

I used data primarily sourced in the New England area. Local retail gas and electricity prices were used at the retail level while wholesale prices were sourced from the Henry Hub spot market and the Independent System Operator of New England (ISONE).

[12]See Appendix A for the exact costs used and the sources that they are derived from.

For the most part, all of the data inputed was added without any changes. The only exception was for the HIGH, BASE and LOW electricity demand cases. The United States Department of Energy provides simulated electricity and natural gas profiles for a typical meteorological year as well as the a breakdown of the components of what makes up that profile. Instead of using the number that is pre-aggregated by the Department of Energy, I summed all of the components that were unrelated to heating, cooling and domestic water generation. I did this since Z-DRE will calculate these values itself.

See Appendix A for the exact sources of my information.

I modeled the system on 4 representative weeks; the first weeks of February, May, August and November. All costs are annualized from the 672 hours by extrapolating these costs to a full 8760 hour year.

3.2 Scenarios

I considered 3 cases with the tool. In each case (except the base case), I applied a different formula that determines the retail purchase tariffs for electricity and feed-in-tariffs. Within each case, I tested out multiple scenarios using this formula to see how the system trends when prices are varied. I had a base case using current (static) prices with no feed-in-tariff, a case that uses static tariffs with a non-zero feed-in-tariff and a case that uses tariffs based on the market rate of electricity.

3.2.1 Case 1: Base case

In the base case, I applied standard single volumetric gas and electricity rates, but set the feed-in-tariff of electricity at \$0. This is to reflect the distribution regime where prices are time-insensitive and the regulator does not contemplate DERs generating electricity for neighbourhood use. The only method remedying grid violations is to reinforce the networks which further increases the reliance on the upstream feeder.

3.2.2 Case 2: The Static Tariffs Case

In the second case, I considered scenarios where the regulator chooses to set a non-zero static feed-in-tariff. This scenario is primarily looking at how a static feed-in tariff will affect investment decisions which will, in turn, affect reinforcement costs. The retail electricity purchase price started as the same price as in the base case, but it was increased when feed-in-tariff became larger than the price used in the base case. The retail electricity purchase price was always greater than the feed-in-tariff. The purpose of this constraint is to avoid an unbounded solution in Z-DRE.

3.2.3 Case 3: The Market-based Tariffs Case

In the third case, I expose the consumers to tariffs that are pegged against the market rates. Both the feed-in-tariff FiT and retail purchase tariff RPT are calculated by taking the market rate[13] MR and then adding a premium $c_{tariff} > 0$ or discount $c_{tariff} < 0$ onto said market rates.

$$\begin{aligned} \text{FiT} &= MR + c_{FiT} \\ \text{RPT} &= MR + c_{RPT} \\ c_{RPT} &\geq c_{FiT} \end{aligned} \tag{3.41}$$

[13] I considered the market rate to be the locational market price of the high voltage grid.

Chapter 4

Results and Discussion

In this chapter, I present the results from the modeling tool broken down by the different pricing scheme cases that were investigated:

1. The base case where there is no feed-in-tariff and the residential tariff is static
2. The case where feed-in-tariffs are static and the residential purchase tariff is static
3. The case where the feed-in-tariff and the residential purchase tariff are both pegged against the market rate

4.1 Metrics Used

The results in the following chapter are broken down by costs from various items within the system. I present the calculation of these metrics below.

To calculate the **reinforcement costs** I took the number of reinforcements in both networks required for a 99% reliability. I then multiplied the number of these reinforcements $n_{w,i}$ by the annualized capital cost r_w of the type of line w that needs to be reinforced.[1]

[1]The annualized capital cost is a function of the type of line/pipeline and the length of that line/pipeline. I scaled the costs linearly on a per-unit-length basis.

$$
\begin{aligned}
C_{elec,rein} &= \textstyle\sum_{i \in \mathbf{L}} n_{w,i} \times r_w \times l_i \\
C_{gas,rein} &= \textstyle\sum_{j \in \mathbf{P}} n_{w,j} \times r_w \times l_j
\end{aligned} \tag{4.1}
$$

Where:

$C_{elec,rein}$:	Electrical Grid Reinforcement Cost
$C_{Gas,rein}$:	Gas Network Reinforcement Cost
$n_{w,i}$:	Number of reinforcing lines/pipelines at element i of line/pipeline type w
r_w:	Per-unit length cost of line/pipeline type w
l_i:	Length of element i

To calculate the **equipment costs**, I used the investment decisions y_t from Z-DRE from each demand profile d. I multiplied the annualized capital costs a_t of the equipment selected $y_t = 1$ by the number of houses of that demand type $k_{i,d}$. I summed these costs over all equipment of the same type (i.e. all CHP investments are summed together),

$$
A_{\mathbf{T}} = \sum_{d \in \mathbf{D}} \sum_{t \in \mathbf{T}} y_t \times a_t \times \sum_{i \in \mathbf{I}} k_{i,d} \tag{4.2}
$$

Where:

$A_{\mathbf{T}}$:	Investment costs for equipment of type $\mathbf{T}$
y_t:	Z-DRE investment decision for technology t
a_t:	Annualized capital costs of technology t
$k_{i,d}$:	Number of houses of demand type d at node i
$\mathbf{D}$:	{HIGH, BASE, LOW}
$\mathbf{I}$:	Set of all nodes
$\mathbf{T}$:	{CHP, Hot Water, PV, Electrical Storage, HVAC}

To calculate the **distributor-retailer's**[2] **electricity consumer revenue**[3], I first determined the revenue (or loss) that a single house of demand type d generates for the distributor-retailer. This is done by multiplying the withdrawn electricity $p_{wth,d,s}$ and the residential purchase tariff α_s at time s and subtracting the product of the (net) injected electricity from local generation $p_{inj,d,s}$ and the feed-in-tariff β_s at time s.[4] These values are summed over all of the calculated hours $\mathbf{S}$. This value is multiplied by the number of houses $k_{d,i}$ of type d at node i. With the total electricity demand by demand type and node, I summed all of the electricity consumption across nodes $i \in \mathbf{I}$ and demand types $d \in \mathbf{I}$. Finally, I extrapolated these values to annual values by scaling from the 672 hours in the simulation to the 8760 hours in a year.

$$R_{elec} = \tfrac{8760}{672} \textstyle\sum_{s \in \mathbf{S}} \sum_{i \in \mathbf{I}} \sum_{d \in \mathbf{D}} (\alpha_s k_{d,i} p_{wth,d,s} - \beta_s k_{d,i} p_{inj,d,s}) \tag{4.3}$$

[2]There exists market structures where the distributor and retailer are separate entities as described in Section 2.2.1. Distributors are regulated monopolies who are charged with maintaining the distribution infrastructure. Retailers are financial parties who purchase electricity/gas at market rates and sell their respective commodity to consumers at a competitive retail rate. Such an arrangement is uncommon in the USA. For the purposes of this thesis, we consider the American perspective where a distributor and a retailer are one entity which much maintain the physical infrastructure as well as act as the intermediary between the wholesale and retail levels of consumption.

[3]While I call these cash flows as 'distributor-retailer's electricity consumer revenues', a more accurate description would be 'amount of money received from or paid to consumers.' In the traditional scenarios where there is only one way flow of electricity, this value will always be positive and therefore will be seen as revenue for the distributor/retailer. When this value becomes negative (due to the fact that money paid to cover feed-in-tariffs is greater than the amount of money collected from residential purchase tariffs), this value is a cost to the distributor-retailer rather than the 'revenue' that I refer to it as.

[4]Only $p_{wth,d,s}$ or $p_{inj,d,s}$ can be non-zero at any given s.

Where:

R_{elec}: A distributor-retailer's electricity consumer revenues

α_s: Retail purchase tariff at time s

β_s: Feed-in-tariff at time s

$k_{i,d}$: Number of houses of demand type d at node i

$p_{wth,d,s}$: Power withdrawn by house of type d at time s

$p_{inj,d,s}$: Power injected by house of type d at time s

$\mathbf{D}$: {HIGH, BASE, LOW}

$\mathbf{I}$: Set of all nodes

$\mathbf{S}$: Set of all hours

The **gas consumer revenue** calculation for distributors is very similar to the electricity consumer revenue calculation. However, there are only gas withdrawal from the grid as opposed to the two-way flow that is possible in the electricity grid. Gas demands for a single house of demand d are multiplied by the respective gas price at time s and all of these products are summed over the modeled time period S. This is multiplied by the number of houses of that type at specific point. Subsequently, the demand is aggregated by summing all of these products over all withdrawal points and demand types. I linearly extrapolated this cost for a full year.

$$R_{gas} = \frac{8760}{672} \sum_{s\in\mathbf{S}} \sum_{j\in\mathbf{J}} \sum_{d\in\mathbf{D}} \gamma_s k_{d,j} g_{d,s} \tag{4.4}$$

Where:

R_{gas}: A distributor-retailer's gas consumer revenues

γ_s: Retail gas price at time s

$k_{j,d}$: Number of houses of demand type d at withdrawal point j

$g_{d,s}$: Gas withdrawn by house of type d at time s

$\mathbf{D}$: {HIGH, BASE, LOW}

$\mathbf{J}$: Set of all points

$\mathbf{S}$: Set of all hours

For the **gas distribution costs**, I multiplied the total withdrawal each hour from the bulk/high pressure grid G_s with the wholesale market price π_s and sum the products. For the **electricity distribution costs**[5], I used the total withdrawn amount from the primary feeder P_s at time s with the wholesale market price for electricity ρ_s. I knew both withdrawal quantities from the simulation as they are the values of the slack variables in their respective network. Once again, I prorated the cost for a full year.

$$\begin{aligned} C_{gas} &= \tfrac{8760}{672} \textstyle\sum_{s \in \mathbf{S}} \pi_s G_s \\ C_{elec} &= \tfrac{8760}{672} \textstyle\sum_{s \in \mathbf{S}} \rho_s P_s \end{aligned} \tag{4.5}$$

Where:

C_{gas}:	A distributor-retailer's gas costs
C_{elec}:	A distributor-retailer's electricity costs
π_s:	Wholesale gas price at time s
ρ_s:	Wholesale electricity price at time s
$k_{j,d}$:	Number of houses of demand type d at withdrawal point j
G_s:	Gas withdrawn from bulk transmission network at time s
P_s:	Power withdrawn from high voltage feeder at time s
$\mathbf{S}$:	Set of all hours

4.2 Base Case

In the base case results under flat volumetric tariffs, residential consumers are best advised to install electric air-source heat pumps for cooling, electric water heaters for domestic hot water and gas condensing boilers for heating. While the air-source heat pump is capable of heating a home, the low price of natural gas and efficiency makes the condensing boiler the economic choice for heating purposes. The lower capital

[5]Similar to the electricity consumer 'revenue', the 'cost' category may be more accurately described as 'cost or revenue from purchases on the electricity market.' When it is positive, it is a cost on the distributor-retailer. When it is negative, it represents the revenue that a distributor-retailer earns when injecting electricity to the high-voltage grid.

cost of an electric water heater helps it edge out the natural gas water heater.[6]

In Table 4.1, I found no difference in equipment selection in any of the HIGH, BASE and LOW demand electricity cases. In fact, aside from electricity consumption, nothing varies between these scenarios. This is a recurring theme across scenarios and cases since the investment decisions are all discrete; from this I could infer that equipment selection is a piecewise function of the exogenous variables such as local demand and prices. Therefore I would only expect to see step changes in equipment selection over certain thresholds[7] and that equipment selection will be identical for certain ranges of inputs.[8] In the case of HIGH, BASE and LOW demand electricity cases, only the electricity demand changes and I found that they are not sufficiently varied to merit the installation of different types of equipment.

The electricity demand from the Z-DRE base case comes from the air-source heat pump and electric water heater in addition to local electricity needs[9]. The natural gas demand originates only from the condensing boiler. When these demands are simulated on the 342-IEEE network and gas grid models, I determined that the electrical network needed about \$29,400/year[10] in grid reinforcements while the current gas network was sufficient to handle the demand. All of the electricity grid reinforcements were at the secondary 120V/208V network on five lines that connected to the step-down transformers.

4.3 Static Feed-in-Tariffs

With the ability to sell electricity to the grid, consumers have an increased incentive to purchase energy generating DERs since they can offset some of the investment costs

[6]The condensing boiler is prevented from supplying hot water in the model, although this may differ from reality.

[7]These thresholds are likely to be affine functions of the inputs meaning they take the form of $g(x, y, z) = Ax + By + Cz + d$. This implies that the threshold is only passed once while traveling on any axis.

[8]These ranges are convex if the thresholds are affine functions since these affine functions can be represented as hyperplanes that constrain a polytope.

[9]Local electricity needs constitute lighting loads (both interior and exterior), appliance loads and miscellaneous loads

[10]This figure is in annualized capital costs over the lifetime of the distribution line

Table 4.1: Base Case Results

<table>
<tr><td rowspan="5">Z-DRE (Individual)</td><td>Demand Type</td><td>Equipment Selected</td><td>Net Electricity Injected (kWh)</td><td>Total Electricity Consumed (kWh)</td><td>Natural Gas Consumed (kWh)</td></tr>
<tr><td>LOW</td><td rowspan="3">Air-Source Heat Pump
Electric Water Heater
Condensing Boiler</td><td>0</td><td>4,790</td><td>2.26</td></tr>
<tr><td>BASE</td><td>0</td><td>8,670</td><td>2.26</td></tr>
<tr><td>HIGH</td><td>0</td><td>11,368</td><td>2.26</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td rowspan="3">Networks</td><td>Grid</td><td colspan="2">Reinforcement Cost ($/year)</td><td colspan="2">Network Violations (/672 hours)</td></tr>
<tr><td>Electricity</td><td colspan="2">29,400</td><td colspan="2">0</td></tr>
<tr><td>Natural Gas</td><td colspan="2">0</td><td colspan="2">0</td></tr>
</table>

by selling their excess electricity. However for a DER to be economic, it must receive a feed-in-tariff that allows it to run profitably in order to recover its investment cost (plus a rate of return) and/or the electricity retail purchase price must be high enough so that the avoided costs of grid purchases recover the investment costs. However for a DER with a variable cost such as CHP, the feed-in-tariff must also be high enough to cover the fuel cost. Figure 4-1 shows that the static feed-in-tariff must be at least 14 cent/kWh (and the retail purchase price must be around that price as well) for a CHP to be able to overcome its fuel costs and become capable in covering its investment cost. Before the 14 cent/kWh threshold, a residential customer's purchase decisions are exactly the same as the Base Case; this is due to the fact that the feed-in-tariff is too small to allow any CHPs to run profitably and recoup their capital costs.

Figure 4-1 shows the different costs and revenues that are incurred for various scenarios. The scenarios take place across a spectrum of feed-in-tariff pricing ranging from 0 cent/kWh to 20c/kWh. The graph shows that there are 3 basic outcomes from the Z-DRE model when considering static feed-in-tariffs which are separated into different coloured boxes (denoted as Outcome 1, Outcome 2 and Outcome 3).

From 0 cent/kWh to 12 cent/kWh, distributor-retailer electricity consumer revenues and costs are positive[11], since the distribution grid as a whole relies on the high

[11]The electricity consumer revenues and costs being positive indicate that the traditional 'buy from the grid and sell to the consumer' one-way power flow is being adhered to. A positive revenue indicates that the amount collected in retail electricity tariffs is greater than the costs incurred by the feed-in-tariff. Similarly a positive cost indicates that the distribution grid is purchasing electricity

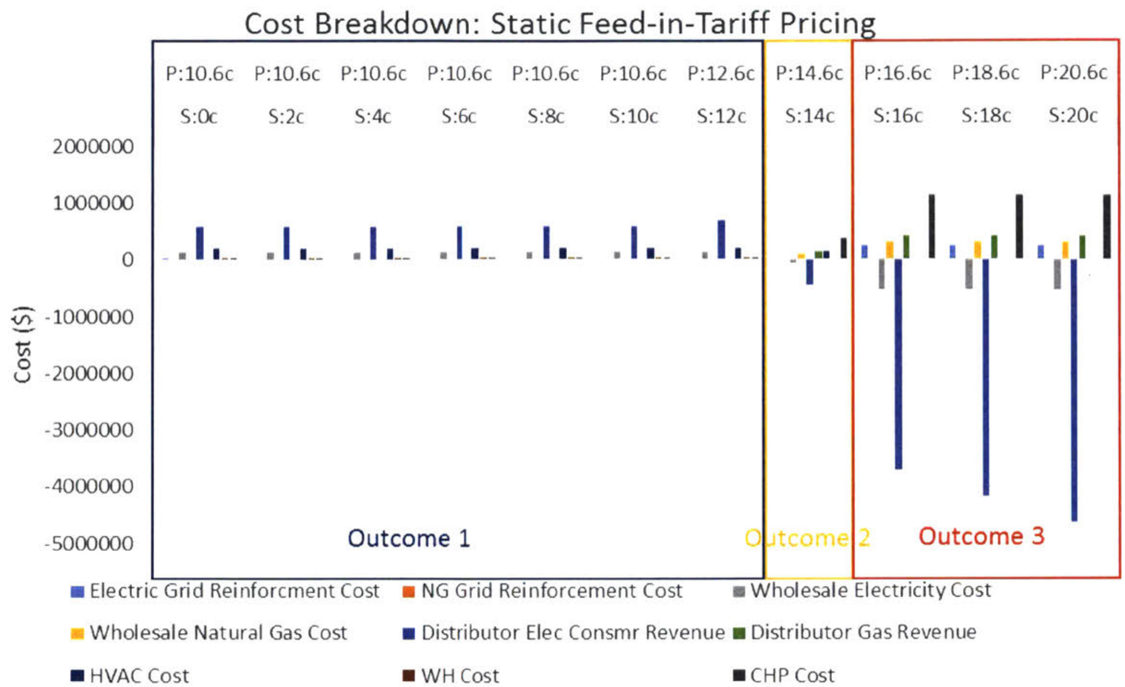


Figure 4-1: Cost Breakdown: Static Feed-in-Tariff
P: Retail Purchase Price, S: Feed-in-tariff

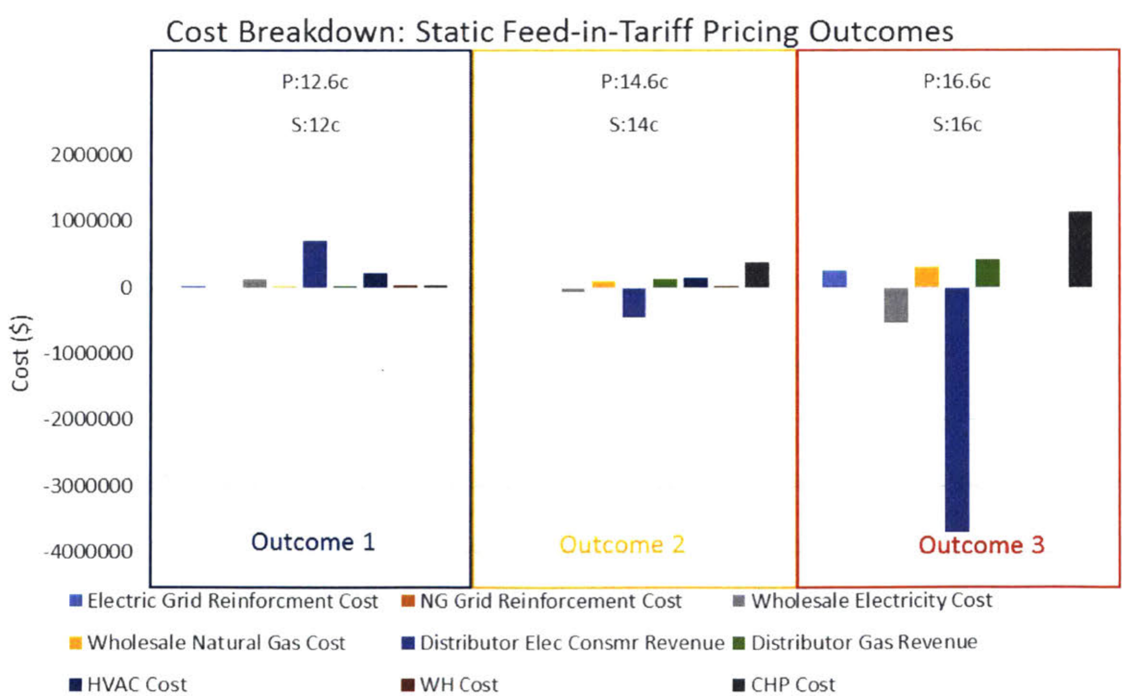


Figure 4-2: Cost Breakdown: Static Feed-in-Tariff Outcomes
P: Retail Purchase Price, S: Feed-in-tariff

voltage grid. Since the households install the same equipment as the Base Case, the reinforcement costs are the exact same as the Base Case (the power flows are the same). For 14 cent/kWh, I note that the distributor-retailer's electricity consumer revenue is negative since CHPs are beginning to be installed and a net amount of electricity is exported to the grid. However, electricity costs are also negative since the distributor-retailer receives a market rate for this electricity (albeit it is insufficient to cover this loss). For scenarios feed-in-tariffs that are greater than 14 cent/kWh, the electricity consumer revenues become highly negative as CHP installations skyrocket.

As discussed in the base case, equipment installation decisions are piecewise functions of demand and price. Figure 4-2 shows the same data as Figure 4-1 but only contains those three outcomes. The reason that there is such a stark change is that the feed-in-tariff is static; with a singular gas price and a singular electricity price, the parameters that decide whether or not to run a CHP are time-independent. Under these scenarios, a CHP will either always be economic to run (and therefore be run all the time) or never be economic. Under the parameters I used in this context, I found that when a consumer is getting paid more than 14c/kWh, they will purchase a CHP and run it all the time. Due to the significant backward flow of electricity, the electricity grid reinforcement costs will balloon in order to ensure that no power flow violations occur. The electricity consumer revenue for a distributor-retailer is negative in Outcome 2 and Outcome 3 due to the need to pay all of the consumers the feed-in-tariff for the electricity that they are selling. The distributor-retailer gets a small amount from the market by injecting electricity back into the high voltage grid and being paid the wholesale rate for that injected amount. However since the feed-in-tariff is multiple times larger than the wholesale rate, the distributor-retailer operates at a loss by buying high and selling low.

The results of Outcome 1, captured in Table 4.2, are identical to the base case since the investment decisions are the same. This means that feed-in-tariffs between 0 cents/kWh to 12 cents/kWh (and tariffs between 10.6 cents/kWh to 12.6 cents/kWh)

more than it is selling it back to the grid. I ignore transmission network charges, but they would further increase the costs if they accounted for are a part of the same piecewise regime of the function of demand and price.

The results of Outcome 2 (Table 4.3) are interesting since they represent a middle ground between consumers being entirely buyers (Outcome 1) or sellers (Outcome 3). In the case where the price is 14 cent/kWh, it only makes sense for HIGH demand consumers to purchase CHPs to mitigate their local electricity use. It is at this feed-in-tariff price point that the piecewise equipment selection function is sensitive to the variations of demand. On the one hand, LOW and Base demand customers choose the same equipment as customers in Outcome 1 whereas HIGH demand customers have sufficient demand for avoided costs to justify purchasing a CHP like the customers in Outcome 3.[12] In this situation, about a third of the population are sellers and the rest are buyers. This is the only case where the grid no longer needs reinforcement due to a significant amount of power is sourced within the grid itself.

Table 4.2: Static Feed-in-Tariff Results: Outcome 1

Z-DRE (Individual)	**Demand Type**	**Equipment Selected**	**Net Electricity Injected (kWh)**	**Total Electricity Consumed (kWh)**	**Natural Gas Consumed (kWh)**
	LOW	Air-Source Heat Pump	0	4,790	2.26
	BASE	Electric Water Heater	0	8,670	2.26
	HIGH	Condensing Boiler	0	11,368	2.26
Networks	**Grid**	**Reinforcement Cost ($/year)**		**Network Violations (/672 hours)**	
	Electricity		29,400		0
	Natural Gas		0		0

Outcome 3 (Table 4.3) occurs when feed-in-tariffs are sufficiently high enough that all customers will purchase a CHP to reduce costly electricity purchases from the grid and take advantage of the ability to sell back electricity at such a high price. As the feed-in-tariff grows beyond 14 cent/kWh, so do the financial losses that the distributor-retailer is forced to take. The market prices are too low to match the static feed-in-tariff so the distributor-retailer will be buying high cost electricity from

[12]The fact that only one of three demand scenarios chooses the CHP further reinforces the hypothesis that the threshold to buy a CHP is an affine function. It shows that the decision is determined by the investment cost, electricity demand and price. This step change occurs across the demand dimension and the price dimension.

Table 4.3: Static Feed-in-Tariff Results: Outcome 2

<table>
<tr><td rowspan="4">Z-DRE (Individual)</td><td>Demand Type</td><td>Equipment Selected</td><td>Net Electricity Injected (kWh)</td><td>Total Electricity Consumed (kWh)</td><td>Natural Gas Consumed (kWh)</td></tr>
<tr><td>LOW</td><td rowspan="2">Air-Source Heat Pump
Electric Water Heater
Condensing Boiler</td><td>0</td><td>4,790</td><td>2.26</td></tr>
<tr><td>BASE</td><td>0</td><td>8,670</td><td>2.26</td></tr>
<tr><td>HIGH</td><td>CHP</td><td>31,700</td><td>0</td><td>202</td></tr>
<tr><td rowspan="3">Networks</td><td>Grid</td><td colspan="2">Reinforcement Cost ($/year)</td><td colspan="2">Network Violations (/672 hours)</td></tr>
<tr><td>Electricity</td><td colspan="2">0</td><td colspan="2">4</td></tr>
<tr><td>Natural Gas</td><td colspan="2">0</td><td colspan="2">0</td></tr>
</table>

Table 4.4: Static Feed-in-Tariff Results: Outcome 3

<table>
<tr><td rowspan="4">Z-DRE (Individual)</td><td>Demand Type</td><td>Equipment Selected</td><td>Net Electricity Injected* (kWh)</td><td>Total Electricity Consumed (kWh)</td><td>Natural Gas Consumed (kWh)</td></tr>
<tr><td>LOW</td><td rowspan="3">CHP</td><td>38,300</td><td>0</td><td>202</td></tr>
<tr><td>BASE</td><td>34,400</td><td>0</td><td>202</td></tr>
<tr><td>HIGH</td><td>31,700</td><td>0</td><td>202</td></tr>
<tr><td rowspan="3">Networks</td><td>Grid</td><td colspan="2">Reinforcement Cost ($/year)</td><td colspan="2">Network Violations (/672 hours)</td></tr>
<tr><td>Electricity</td><td colspan="2">248,000</td><td colspan="2">0</td></tr>
<tr><td>Natural Gas</td><td colspan="2">0</td><td colspan="2">0</td></tr>
</table>

*The electricity generated is different for LOW, BASE and HIGH since the available amount of electricity that they can sell to the grid is effected by their consumption. The LOW scenario has more spare power to sell to the grid than the BASE or HIGH scenario.

the customer and selling it to the wholesale market at a loss.[13] Furthermore, these distributors will also need to reinforce the lines substantially at significant costs. The annualized capital costs of the grid expansion in Outcome 3 ($248,000/year) is an order of magnitude larger than what it was in the base case($29,400/year). As a stand-alone mechanism, static feed-in-tariffs can cause a distributor-retailer to become insolvent due to the direct costs of forced purchases at an artificially high rate as well as the indirect cost of additional reinforcement.

If static feed-in-tariffs are applied aggressively, distributors must be remunerated through an external mechanism (i.e. a transfer payment that is funded through a tax or an additional network charge) to support this program and maintain its rate base. Ideally, the cost of electricity reinforcement should be borne by the parties that cause such costs; in the case of Outcome 3, a connection charge could be levied against those with CHPs on a per-kW peak basis. However if the same charge were levied in Outcome 2 (where there was no need for grid reinforcement), it would discourage investment in CHP that would actually be beneficial to the grid. It is difficult to allocate costs ex ante in a manner that takes into account cost causation since they are both intertwined. Put simply, this is a chicken-and-egg problem where the policies of cost allocation affect the decisions that are made at the consumer level. These consumer decisions drive the costs in the network ex post of the allocation decisions. However, in order to properly allocate costs to their causes, one must know the decisions of the consumers ahead of setting the cost allocation policies.

Instituting the ideal pricing policy on one's first try is not achievable in reality without perfect foresight. However, discovering the ideal pricing policy through iteratively changing the pricing policy may be possible. In an iterative process, one would institute an initial pricing policy and then observe consumer reaction to this pricing policy. These observation would inform the formulation of the next pricing policy and this would continue until the pricing policies converge on the lowest cost solution.

[13] For the purposes of this thesis, we assume that any net aggregated generation of a distribution system will be bought back at the market rate.

In general, using a static feed-in-tariff is very challenging. On the one hand, it necessitates finding a price that is high enough to merit the purchase of distributed energy resources. However, finding a price that is too high could cause over-adoption of DERs which will require strengthening the grid and selling electricity at a loss which will put the electricity distributor-retailer in significant financial peril. However if a middle ground is reached, where the feed-in-tariff is sufficient for a portion of the consumer base to adopt DERs, then benefits to the system can be achieved through reductions in reinforcement costs.

4.4 Dynamic Feed-in-Tariffs and Dynamic Retail Purchase Rates

4.4.1 Premium Retail Rates and Discounted Feed-in-Tariffs

Next, I considered a more dynamic approach to feed-in-tariffs; I exposed consumers to wholesale market prices with a premium (or discount) applied to retail purchase rates and feed-in-tariffs. Under these circumstances, both prices are pegged against the market. I denoted scenarios in this section as a/b where a is the premium applied to residential purchase tariffs on top of wholesale rates and b is the premium (or discount if negative) to feed-in-tariffs. Table 4.5 shows 4 scenarios below and how the distributor-retailer's electricity consumer revenue (or loss) is guaranteed on a per-kWh basis for the first two cases, but not guaranteed in the last two rows (these are used in Section where the feed-in-tariff is paid a premium over the market rate).

In the first set of scenarios, I investigated what would happen if feed-in-tariffs were pegged below market rates and retail purchase rates were pegged above market rates. This voids the possibility of distributor-retailer financial losses that I showed in the previous section since the distributor-retailer will always earn the spread (the premium or discount) between the price paid by/to the customer and the grid price. For simplicity, the premium I applied to retail rates was the same discount I applied to the feed-in-tariff or $a = -b$.

Table 4.5: Example Scenarios for Dynamic Feed-in-Tariffs and Dynamic Retail Purchase Rates

(a/b)	Retail Price (cent/kWh)	Distributor's Revenue from Retail Purchases (cent/kWh)	Feed-in-Tariff (cent/kWh)	Distributor's Revenue (Loss) from Feed-in-tariff purchases* (cent/kWh)
+1/-1	LMP+1	1	LMP-1	1
+2/-2	LMP+2	2	LMP-2	2
+2/0	LMP+2	2	LMP	0
+12/+10	LMP+12	12	LMP+10	(-10)

*I assumed that the value of electricity to the distributor-retailer is the LMP (and specifically that the distributor-retailer can sell the electricity at the LMP back to the grid)

With only a small spread of 1 cent/kWh between the prices sold/bought by the consumer, the electric rate is sufficiently small that the distributor-retailer is only making a fraction of what it made in the base case. However, the consumer reaction here is to completely forgo the gas network and rely entirely on the electricity grid since the wholesale rates are sufficiently small. In Table 4.6, I saw that the equipment setup is similar to the base case, but the consumer elects to not install a condensing boiler and instead relies on the air source heat pump to provide heating. Relative to the base case, this increases the electricity demand since heating must be fulfilled with electricity. This has the added effect of increasing electricity reinforcement (up to \$ 123,000 in annualized capital costs compared to \$29,400 in the base case) needs. The gas network is entirely unused by the residential customers in this case.

Figure 4-3 shows that as the spread increases, so does the distributor-retailer's electricity consumer revenue. The distributor-retailer's profit[14] is restored to a level similar to the base case when spread between the retail purchase price and wholesale reaches 8 cent/kWh (not shown in Figure 4-3) which is unsurprising since the base case's retail rate was about 8 cents/kWh higher than the mean market price (which is 2.3 c/kWh in the 672 hours surveyed [38]). Figure 4-3 also shows that there is a step change in equipment selection between the +1/-1 scenario to the +2/-2 where a

[14]The word 'profit' is used very loosely. It considers the variable revenues less the variable costs, but does not consider fixed operational, maintenance and administrative costs. A more apt description would be 'electricity revenue less electricity cost'

boiler is installed in the latter scenario.[15]

With a spread of 2 cent/kWh or greater, I saw that the purchasing behaviour in Table 4.7 is identical to the base case shown back in Table 4.1. This is indicative that the wholesale market rate (and any rate that is pegged *below* that rate) is insufficient to incentivize DER investment in the context of New England. It took a static rate of 14 c/kWh to get any response from consumers so the market rate is unlikely to create any impetus to invest in local generation.

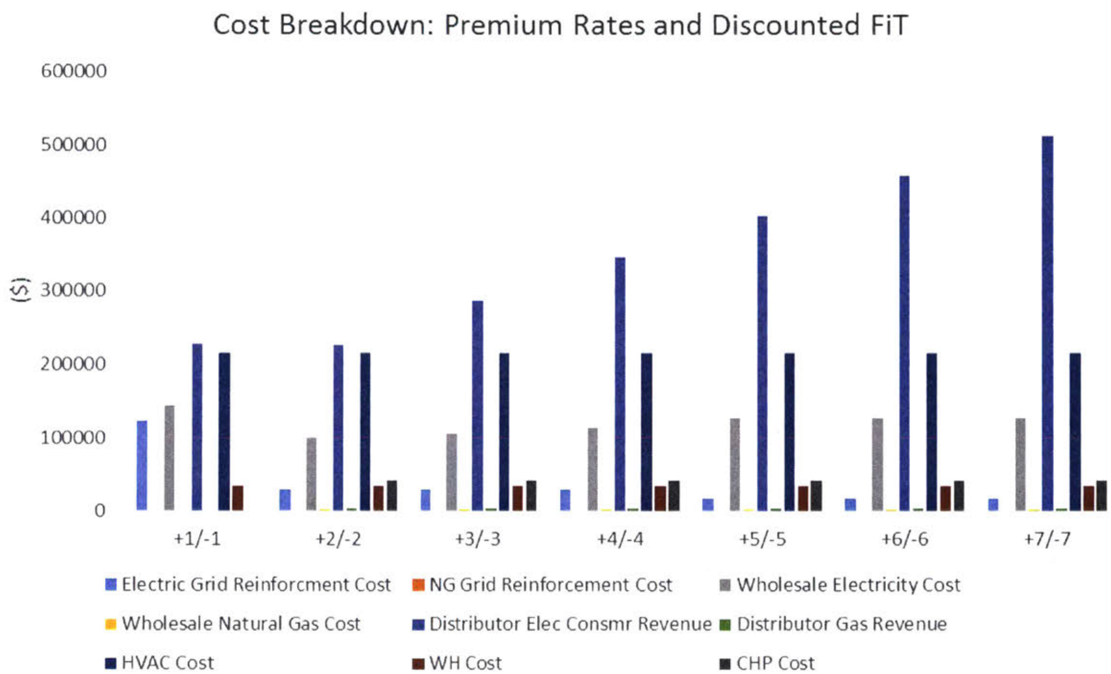


Figure 4-3: Cost Breakdown: Premium Retail Rates and Discounted Feed-in-Tariffs
P: Retail Purchase Price, S: Sellback Price, W:Wholesale Price

4.4.2 Premium Retail Rates and Premium Feed-in-Tariffs

Next, I considered a set of scenarios where the feed-in-tariffs are pegged above market rates (i.e. given a premium). I pegged the retail rates at a premium that is 2 cents/kWh higher than the premium awarded to feed-in-tariffs or $a = b + 2$.

[15]Gas boiler costs fall under the 'CHP cost' due to the way the model was structured. As gas-consuming heating equipment, CHPs and Boilers used the same equations and thus their costs were lumped together.

Table 4.6: Market + Premium Sellback Pricing: +1/-1c

Z-DRE (Individual)	**Demand Type**	**Equipment Selected**	**Net Electricity Injected (kWh)**	**Total Electricity Consumed (kWh)**	**Natural Gas Consumed (kWh)**
	LOW	Air-Source Heat Pump Electric Water Heater	0	9,170	0
	BASE		0	13,100	0
	HIGH		0	15,800	0
Networks	**Grid**	**Reinforcement Cost (\$/year)**		**Network Violations (/672 hours)**	
	Electricity		123,000		5
	Natural Gas		0		0

Table 4.7: Market + Premium: +2/-2c

Z-DRE (Individual)	**Demand Type**	**Equipment Selected**	**Net Electricity Injected (kWh)**	**Total Electricity Consumed (kWh)**	**Natural Gas Consumed (kWh)**
	LOW	Air-Source Heat Pump	0	4,790	2.26
	BASE	Electric Water Heater	0	8,670	2.26
	HIGH	Condensing Boiler	0	11,368	2.26
Networks	**Grid**	**Reinforcement Cost (\$/year)**		**Network Violations (/672 hours)**	
	Electricity		29,400		0
	Natural Gas		0		0

Once again I saw a step change in equipment installations in Figure 4-4 as a result of changing prices. For feed-in-tariff premiums less than or equal 12 cent/kWh but greater than 2 cent/kWh on top of the wholesale rate, I found that consumers mimic the equipment installation decisions of the base case (namely, by buying an air source heat pump, an electric water heater and a condensing boiler). This demonstrates that the premium of 12 cent/kWh on top of the wholesale rate is insufficient to justify the purchase of a CHP since it cannot operate profitably and recoup its capital costs at those premiums. I denoted these scenario results as Outcome 4. At a premium of 14 cent/kWh and above, the CHP becomes economic and I denoted these scenarios as Outcome 5.

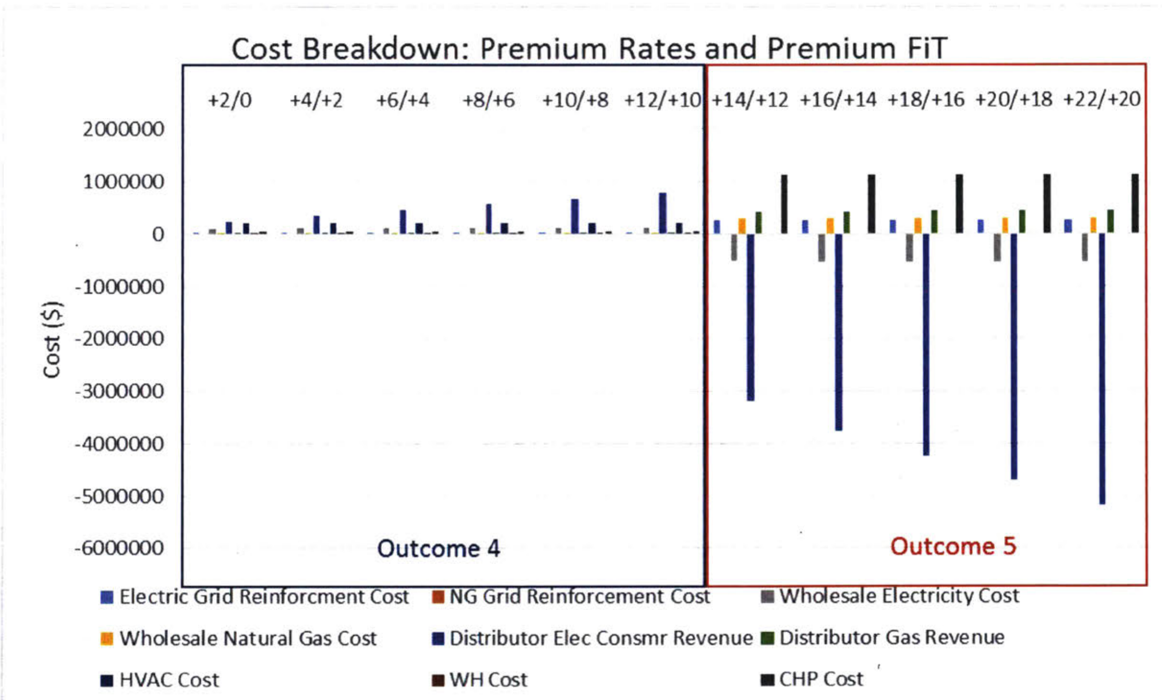


Figure 4-4: Cost Breakdown: Premium Retail Rates and Premium Feed-in-Tariffs

Figure 4-5 shows a juxtaposition of the results of Outcomes 4 and 5 which is reminiscent of Figure 4-2. Specifically, when is widespread adoption, consumers run their CHPs whenever they are economic[16] with these feed-in-tariffs and sell the excess electricity back to the grid. This requires significant reinforcements to the grid to

[16]CHP capacities are static and based on real world data.

accommodate the backwards power flow to the primary feeder. This is uneconomic for distributors on two levels as it increases their capital costs as well as reduces their revenue.

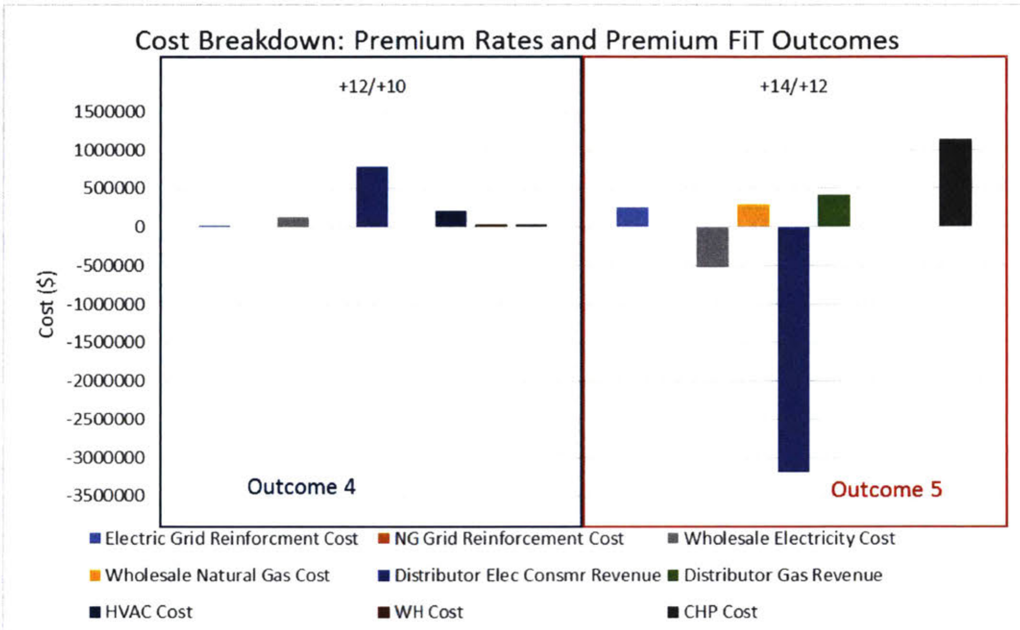


Figure 4-5: Cost Breakdown: Premium Retail Rates and Premium Feed-in-Tariffs Outcomes

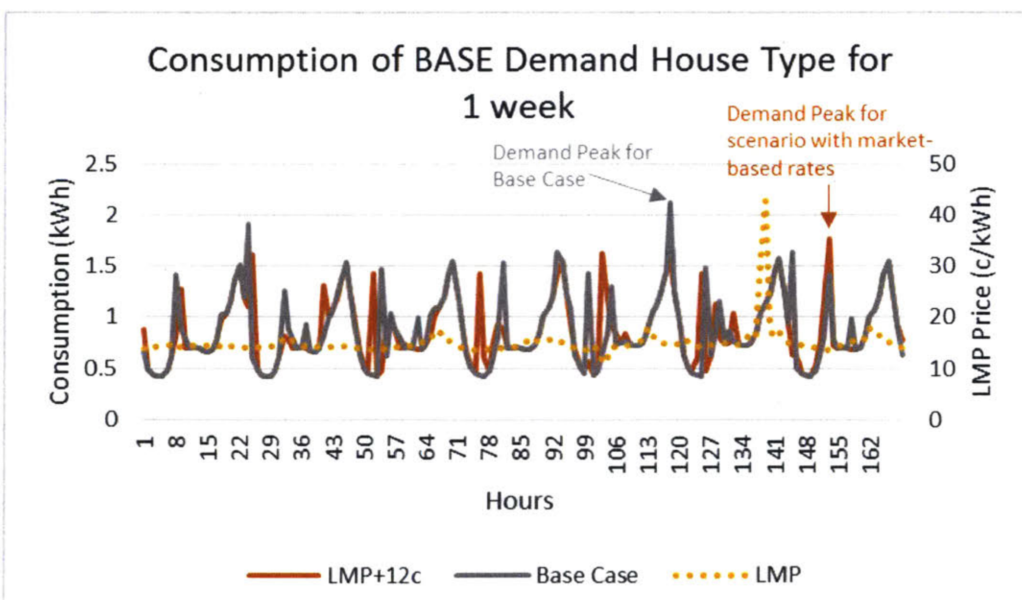


Figure 4-6: Consumption of BASE Demand House Type for 1 week: Market based-rate vs Base Case

Table 4.8: Market + Premium : +12/+10, Outcome 4

Z-DRE (Individual)	**Demand Type**	**Equipment Selected**	**Net Electricity Injected (kWh)**	**Total Electricity Consumed (kWh)**	**Natural Gas Consumed (kWh)**
	LOW	Air-Source Heat Pump	0	4,790	2.26
	BASE	Electric Water Heater	0	8,670	2.26
	HIGH	Condensing Boiler	0	11,368	2.26
Networks	**Grid**	**Reinforcement Cost ($/year)**		**Network Violations (/672 hours)**	
	Electricity	17,600		2	
	Natural Gas	0		0	

Table 4.8 shows that Outcome 4 (feed-in-tariffs below 12 cent/kWh) has identical metrics to the base case in all but one: the electrical reinforcement costs. There is a 40% reduction in annualized capital costs from $29,400 to $17,600. This is due to consumers scheduling their hot water and cooling electrical consumption to lower cost hours which coincide less with the peak prices. The hours of peak prices also tend to be the hours that their non-heating and non-cooling electrical loads occur. In effect, using the market rate with a premium causes consumers to reduce their electrical demand peaks thereby reducing the strain to the grid in peak hours as shown in Figure 4-6. Outcome 4 scenarios only required 3 network reinforcements relative to the 5 needed in the base case.

As Outcome 4 mirrored Outcome 1 (where the feed-in-tariffs were insufficient), Outcome 5 is also very similar to Outcome 3 (the case static feed-in-tariffs were sufficient). In both Outcome 3 and Outcome 5, I saw that all the consumers purchase CHPs and continually sell electricity back so that the feeder is often exporting electricity rather than importing. The main difference in Table 4.9 when compared to Table 4.4 is the amount of electricity sold back to the grid. The pegging of the feed-in-tariff to market rates caused a small fraction of hours to be uneconomic for energy generated by CHP whereas in the static case of Outcome 3, the CHP was economic all the time leading to more electricity generated.

Table 4.9: Market + Premium : +14/+12, Outcome 5

Z-DRE (Individual)	Demand Type	Equipment Selected	Net Electricity Injected (kWh)	Total Electricity Consumed (kWh)	Natural Gas Consumed (kWh)
	LOW	CHP	36,700	1	194
	BASE		32,900	7	195
	HIGH		30,000	14	195
Networks	**Grid**	**Reinforcement Cost ($/year)**		**Network Violations (/672 hours)**	
	Electricity	248,000		0	
	Natural Gas	0		0	

4.5 DERs in the New England Context

In all of the scenarios analyzed, only CHPs were ever installed of the entire menu of DERs available and only under extremely generous conditions. This seems to indicate that the geographical and market parameters in New England make it difficult to justify DER purchases without external wealth transfers. The moderate insolation make photovoltaic installations difficult to justify while the arbitrage opportunities[17] in the ISO-NE market are insufficient for energy storage to run profitably and cover their capital costs. However with low gas prices, CHPs can be made competitive if given a sufficient premium. With falling capital costs due to technological and manufacturing advances, these results may need to be revisited in the coming years. Specifically, rises in efficiency and decreases in capital costs will be key factors that could drive future investment. Furthermore, the exogenous trends in the grid-sourced electricity and natural gas prices will also play a role

[17]Arbitrage opportunities arise when electricity can be bought at a low price, stored and then sold at a later time at a higher price.

4.6 The Coupling of the Natural Gas and Electric Network

The results presented show that the natural gas and electric network are unlikely to be strongly coupled in the New England system at the distribution level. However, the results also provide clues as to what factors that would cause a strong coupling in the two networks at the distribution level. Combined Heat and Power units are the nexus which connect these two networks and therefore a high penetration of combined heat power would be necessary for a strong coupling. There are a number of factors which would favour CHP adoptions. Specifically, a relatively high heat load is required in addition to having favourable electricity prices to sell excess electricity at as well as relatively low gas prices (a high feed-in-tariff to gas price ratio is needed). A high electrical load combined with high retail electrical prices could obviate the need for favourable electricity sell back prices as a CHP owner would benefit from avoided electricity costs. Some European nations such as Denmark meet these criteria and have much higher CHP penetration at the distribution level than North American nations.[39]

A tightly coupled system could see a reduced reliance on the external electricity grid. In the case of Outcome 2 in the Static Feed-in-Tariff scheme, I showed that partial adoption of CHP was sufficient to avoid network reinforcement on the distribution grid. On the other hand, outcome 3 also showed a worse case where aggressive pricing caused over-adoption which in turn required several reinforcements to the electrical grid. One remedy would be to introduce distributed locational marginal pricing which would allow prices to more appropriately signal scarcity of distribution capacity to potential CHP owners.

Of course, another caveat to this potential decreased reliance on the electrical grid is an increased reliance on the natural gas grid. However in the simulations, I found the gas grid was sufficiently robust such that it did not directly contribute to any failure hours. However, this does not mean that any natural gas grid is infallible. Instead I only conclude that the topology of the gas grid is resilient to failures due to increased gas flows. The reliability of the natural gas grid is still dependent on factors that are exogenous to the natural gas network topology (e.g. supply issues) whereas electrical grids are more likely to fail due to endogenous features (e.g. violation of power flow limits).

Chapter 5

Conclusion

In this chapter, I summarize the work performed in this thesis, consider the implications, envision what further research endeavours one could pursue and comment on the larger trends in our energy systems.

5.1 Summary of Work

At the outset, I established that the interconnection between the natural gas system and the electrical system must be a critical concern to planning in both systems. There has been research into the interdependence of both system, especially at the high voltage grid. I reviewed the literature to show that there is potential for this level of interdependence to spill over to the distribution level if a large number of gas-based DERs are adopted. I examined the CHP as the nexus of these two systems at the distribution level. I considered how electricity and natural gas pricing could affect CHP adoption and investigate the effect that such adoption would have at the distribution network level, for electricity and gas.

In order to perform this research, I developed a long-term planning tool that is able to consider the interaction between the integrated natural gas-electric energy system. I developed a mixed integer linear program, Z-DRE, as a proxy for a rational economic consumer. Given commodity prices, investment costs and demand profiles, Z-DRE decides which DER equipment or conventional equipment to invest in as well as when to run the set of chosen equipment to meet demand. The results of the decisions at the consumer level would determine the demand profile (or supply profile) that the electrical and natural gas grids would need to meet. An electrical grid model and a natural gas grid model were simulated with these demands to determine if any reinforcement was needed. If the system was not operating in a reliable operating state for 99% of the time, I reinforced the grid at the points of failure. The simulation was then rerun to determine if any more reinforcements were needed. This process was iteratively continued until a 99% reliability was achieved. I considered two ways to price feed-in-tariffs to determine their effects on individual consumers and effects on the overall grid. The two pricing strategies were (1) a static feed-in-tariff combined with a static residential consumption tariff and (2) a dynamic feed-in-tariff and a dynamic residential consumption rate, both pegged to the market price of electricity.

In the context of New England, my analysis showed that it is difficult to economically justify investment in DERs. This was primarily due to the wholesale and retail electricity prices relative to the investment costs of the DERs and natural gas prices. When I introduced extraordinary measures to increase DER adoption, I found a quick shift to mass CHP adoption and a proclivity to sell excess electricity to the grid at every opportunity. However, I also found a small middle ground where a fraction of the population adopted CHPs and were able to sell their excess electricity to the grid, but this power flow generally remained within the electricity grid. The electricity went to meet the electrical needs of those who had not adopted CHPs. This partial CHP adoption reduced the overall reliance on the external grid by sourcing their needs locally.

5.2 Implication

My results show that providing too strong of an incentive via feed-in-tariffs for DERs may result in unintended consequences. Providing special rates through feed-in-tariffs can lead to over-adoption, which incur extra network costs due to grid reinforcement. However, a well conceived rate that reflects the impact on network congestion should allow a balanced adoption of CHPs alongside other DERs and conventional equipment in our energy system, which could mitigate some grid costs by sourcing and consuming electricity locally. This thesis considers feed-in-tariffs as the only mechanism to spur incentives in DERs. Essentially, I investigated the implications of paying a premium rate for local generation in order to offset grid reinforcement costs in both networks. The results show that it is extremely difficult to find a rate that neither creates a scenario of over-adoption of DERs nor creates a scenario of under-adoption. Without finding the ideal rate, feed-in-tariffs are a poor tool for procurement of DERs.

Perez-Arriaga et al.[23] instead propose forward network capacity option auctions at the distribution level to procure DERs. Under capacity auctions, households and/or aggregators would bid for contracts with the distributor-retailer that would be exercised when the system is under stress. The distributor-retailer would be able to contract a specific quantity of relief and the auction would determine the strike price paid out to DER operators. In addition, the distributor-retailer could set a ceiling price that is representative of the costs of simply reinforcing the network. This method allows for tariffs to be established by the market and only paid out when the services of DERs are needed. The forward network capacity option auction is superior to the feed-in-tariff in economic allocative efficiency, but it lacks the simplicity of explanation and implementation of feed-in-tariffs for the layman.

On the topic of using static rates against dynamic market rates for feed-in-tariffs, I found that dynamic market rates generally outperform their static counterparts. Hogan[40] has estimated that even Time-of-Use retail prices[1] only captures 18% of the welfare loss that is incurred when using a fixed rate as opposed to exposing consumers to the real-time market prices. I did not consider neither societal nor behavioural norms in these experiments. In my estimation, the layman would generally disfavour unpredictable market rates over static rates. If society wants to overcome this bias against market rates, policy makers must educate the population that there are market inefficiencies involved with static rates.[2] Whenever possible, a clear price

[1]Time-of-Use prices set different rates for specified time ranges during the day or week. However, these rates remain static day-to-day or week-to-week.

[2]Alternatively, financial derivatives may be used so that a third party bears exposure to market

signal that represents the true cost of electricity or natural gas should be striven for. Although not considered in this research, a distributed locational marginal price (DLMP) - coupled with network and connection charges - would be the clearest signal to the consumer on the value of electricity. This option is also the most politically and socially unpalatable. Pegging the tariffs to the closest feeder's locational marginal price may be the second best option. It still sends a signal on the wholesale value of electricity that a static tariff does not reflect, but I have shown that it still suffers from many pitfalls that plague the static tariff. Specifically, it sends the same price signal to everyone, which makes a CHP at any point in the network equally valuable to the consumers, when in reality the value of CHPs could be highly location-dependent.

5.2.1 Other Considerations

While this thesis has noted several times that over-adoption of CHPs can present real issues, there are some inherent assumptions and limitations in the model that do not consider the additional value that a CHP can bring to a grid. For one, my mixed integer linear problem determines the investment costs ahead of time with perfect foresight of the demand. However this does not recognize the value of controllable DERs, such as CHPs, in the system since it can plan around the uncertain elements in the system such as heat load and demand. In reality, the flexibility of a controlled unit has innate value since it may respond to unexpected or uncertain events in real-time. Having developed a planning tool, this value is missed since the added benefits are only realized in operation. Furthermore, the hourly granularity of my investigation also diminishes the value of CHP units since they can provide services (and generate revenue under the right policies) that only materialize at finer time-scales such as providing automatic generation control, voltage support services and operating reserves.

While this research did not find any issues with the natural gas network due to

rates, while the consumer is hedged and given a static rate. However, this introduces moral hazard or a principal agent problem since the party that is consuming the commodity will no longer be directly exposed to the market rate.

network constraints, system planners should continue to be cognizant of the issues in the increased reliance on the natural gas network. Most importantly, high-adoption of CHP DERs will expose more of my electrical system to upstream supply risks. To ensure reliability, I encourage planners to consider $n-1$ contingencies that include the elements in the natural gas networks. If CHP adoption is moderately high and an issue in the natural gas system (e.g. pipeline failure) were to disable several CHPs, the electricity distribution network must be sufficiently robust to handle a sudden renewed reliance in grid based electricity. In essence, planners cannot become complacent if local CHP generation reduces the need for electrical reinforcement, because a failure in the natural gas network could cascade into a failure in the distribution network.

5.3 Future Work

5.3.1 Next Steps for the Model

There are several research paths that this tool can take and be improved. I outline multiple paths that I could see this tool being developed.

As said in the section above, in its current incarnation this tool plans for demand that is deterministic and known beforehand. A more realistic tool must take into account uncertainty in a variety of variables. Robust optimization presents an option by constructing uncertainty sets for which the solver generates a solution that is feasible for all possibilities contained in those uncertainty sets. In the case of this tool, one would generate uncertainty sets for photovoltaic output, local electrical demand and even prices themselves. Using a robust approach will increase the costs, but will also make my solution more conservative.

Next, the tool in this thesis has only considered 3 different consumer types based on 3 different electricity profiles. Since a concluding remark of this study is that an ideal solution involves partial DER adoption, it would make sense to diversify the pool of consumers into smaller subgroupings. The behaviours of consumers can be differentiated by existing parameters (i.e. demand profile, value of non-served energy), entirely new constraints (e.g. a capital cost budget constraint), introducing new facets of the problem (i.e. bootstrapping some customers with existing equipment) or introducing entirely new customer classes (e.g. commercial, industrial).

Finally, the scope of depth for the power grid and natural grid could be widened. The smallest granularity used in the respective system was a secondary node and a gas distribution withdrawal point. For the electricity grid, one could consider the single line phases that go to each residence (likely leading to unbalanced phases). Likewise, the natural gas grid could consider the small meshed distribution pipes that connect the houses to the gas distribution withdrawal point. The consideration of the more fine elements in each network adds to the possible areas of network failure and this would likely increase network reinforcement costs on either network.

5.3.2 Future Research

The results of this thesis make it clear that feed-in-tariffs are not an ideal incentive mechanism. In future research work, I will consider alternatives to incentives to the Z-DRE model. For example, an additional module that simulates a forward network capacity option auction could create dynamic incentives to Z-DRE rather than having static price parameters[3]. This would add further nuance to the distributor-consumer dynamic as the consumer must now actively bid their value of electricity into an auction rather than be a passive price taker.[4] Furthermore, this model should be equipped and modified for the consideration of other grid services (e.g. AGC, reactive support, ancillary services) that are valuable but not currently captured.

Finally, an evaluation of the robustness of the networks that result from these models should be done. Specifically, I will investigate the possibility of survival of the networks under $n-1$ contingencies. Since the worst case scenario of $n-1$ will likely be the trunk branch that connects the distribution network to the bulk/transmission network, this research query basically considers whether the networks would be able

[3]Even in the case of residential prices pegged to market rates, the prices were static going into Z-DRE

[4]In this thesis, the role of consumers were limited to DER investors looking for a rate of return. I am proposing here to make them participants in the market.

to survive under electric islanding conditions or complete gas loss.

5.4 Final Remarks

As technology advances and regulatory frameworks evolve, we will continue to see our energy systems adapt to these changing constraints. The trend towards more distributed energy resources in our power systems is a paradigm shift in an industry that has seen and planned for decades of long-lived centralized power generation. Moreover, the penetration of natural gas-fired electricity production into our high voltage energy system has also been a recent stark change. Looking over the horizon, it is very possible, perhaps even probable, that these two trends could amalgamate in the form of natural gas DER adoption. This thesis has tried to anticipate this possible future and equip policy makers and potential DER owners with the tools to understand and manage their integration and risks through proper pricing mechanisms.

Appendix A

Data Sets and Parameters Used

Table A.1: Model Input Data

Model Input	**Data Set**	**Source**
Low Voltage Distribution Network	Based upon IEEE 342-Node Low Voltage Network Test System	IEEE PES[36]
Gas Distribution Network	Based upon a section GasLib-582	GasLib [41]
Real Time Electricity Prices	2016 Historical Prices at Somerville Node	ISO-NE[38]
Real Time Natural Gas Prices	2016 Historical Spot Prices at Henry Hub	EIA[42]
Local Electricity Demand	TMY Residential Load Profile at Boston Logan	DoE[43]
Local Hot Water Demand	TMY Residential Load Profile at Boston Logan	DoE[43]
Solar Insolation	Solar Energy Data in Oxnard,CA	NREL[44]
Outdoor Temperature	2010 Boston Temperatures	NOAA[45]
HVAC Characteristics	Residential and Commercial Building Technologies	EIA[32]
Boiler Characteristics	Residential and Commercial Building Technologies	EIA[32]
CHP Characteristics	Impact of Support Mechanisms on Microgeneration Performance in OECD Countries	ORNL[46]
PV Characteristics	Lazard's Levelized Cost of Energy Analysis	Lazard [47]
Energy Storage Characteristics	Lazard's Levelized Cost of Storage Analysis	Lazard [48]
Electric Grid Reinforcement Cost	Capital Costs for Transmission and Substations	WECC [49]
Natural Gas Reinforcement Cost	Historical data provide low-cost estimating tool	[50]
Baseline Retail Electricity Price	Eastern Massachusetts 2017 Rate	Eversource[51]
Baseline Retail Gas Price	Eastern Massachusetts 2017 Rate	Eversource[51]

Appendix B

Equipment Parameters

Table B.1: CHP Equipment Parameters

CHP Alias	Power output (kW)	Electrical Efficiency	Heat-to-Power Ratio	Water Heater Efficiency	AC Coefficient of Performance	CAPEX ($)	Useful Life (yr)	Boiler
ICE 1 (UK)- Honda MCHP1	1	0.225	2.8	0.9	1.1	4500	20	0
ICE 2 (DE)- Stirling	1	0.2	5	0.9	1.1	5400	20	0
ICE 3 (IT)	5	0.288	1.95	0.9	1.1	19552	20	0
PEM Fuel Cell	1	0.35	1.6	0.85	1.1	24000	20	0
ICE 4 (CAN)	1	0.192	3.2	0.92	1.1	6600	20	0
GSHP+FC	1	0.32	19.1	0.92	1.1	25000	20	0
ICE 5 (KOR)- Stirling	1	0.24	2.67	0.92	1.1	10000	20	0
Condensing Boiler	30.8	1	1	0	0	800	25	1

Table B.2: HVAC Equipment Parameters

Alias	Max Electrical Input- Heating (kWh_e)	Max Electrical Input- Cooling (kWh_e)	Coefficient of Performance (Heating)	Coefficient of Performance (Cooling)	CAPEX ($)	Useful Life (yr)
Air Heat Pump	10.5	10.5	2.26	3.8	3150	15
Ground Heat Pump	10.5	10.5	3.1	3.9	15000	25
Electric Resistance + Central AC	19.9	10.5	1	3.8	3300	25
Central AC	30.8	10.5	0	3.8	2300	25

Table B.3: Energy Storage Parameters

Alias	Capacity (kWh)	Maximum Charge Rate (kW)	Maximum Discharge Rate (kW)	Charging Efficiency	Discharging Efficiency	CAPEX ($)	Useful Life (yr)
Li-Ion Battery	10	5	5	0.94	0.94	15000	10
Lead Battery	10	5	5	0.927	0.927	18000	10
Flow Battery	10	5	5	0.79	0.79	12000	10

Table B.4: PV Equipment Parameters

Alias	Capacity per Module (kW)	Required Area (m^2)	CAPEX ($)	Useful Life (yr)
Solar Panel	5	0.5	22500	15

Table B.5: Water Heater Parameters

Alias	Maximum Electrical Input (kW)	Efficiency	Storage Capacity (kWh$_q$)	CAPEX ($)	Useful Life (yr)
Gas Fired WH	1	0.62	10	1000	20
Electric WH	1	0.9	10	500	15

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