Analysis of Engineering, Socio-Political and Market Aspects of Energy Policies Using Examples from Carbon Tax, Market Diffusion of Combined Heat and Power and Vehicle-to-Grid Services

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DEDICATION

I want to dedicate this dissertation to my family - especially to my wife Dipti and my daughter Divisa. They have always shared my highs and supported me through my lows. Additionally, I would like to dedicate it to my parents for teaching and encouraging me to dream high.

ABSTRACT

Excelling at formulating, analyzing and implementing effective energy policies requires a holistic understanding of its economic, socio-political and engineering aspects. However, both in academia and in practice, one (or more) of these perspectives is often neglected or understudied.

Considering this, this dissertation studies three examples of energy policies focusing on a lesser known, and often-neglected aspect. The examples are compiled as three independent, self-contained essays. The first essay analyses the power engineering aspect of a carbon tax. Using U.S. market practices and policies as an example, a carbon tax is operationalized in a wholesale electricity market. Its effect is examined on the Institute of Electrical and Electronics Engineers (IEEE) Reliability Test System 28-bus model examining both transmission congestion and other energy policies. The results show how a carbon tax affects emission savings, and revenue streams for generators, loads and the government. They indicate that such interactions could lead to ineffective emissions reduction.

The second essay analyzes the socio-political aspect of Combined Heat and Power (CHP). By using expert elicitation and document analysis, the non-financial barriers for CHP are analyzed. The results show three significant barriers a) the business model of the electrical utility b) negative subjective impressions and c) challenges in allocating the risks and benefits.

The third essay analyzes the economic/market aspect of Vehicle-to-Grid (V2G). Model of a centralized V2G system is developed and applied to the 2015 wholesale electricity market in Texas (Houston Hub). Three scenarios are examined. In the first scenario, electric vehicles are paid based on a fixed retail market price; in the second, they are paid a time-varying retail market price; in the third, the virtual power plant shares 50% of its total reward with the participating vehicles. The results demonstrate that, while this system is always financially profitable to the virtual power plant and the system operator gets grid services, the electric vehicles could lose money. Further, results show that these vehicles with lower per unit output-battery cost could lose more money because of extensive battery over-use and insufficient reward at current market prices.

The results have several important policy implications. Study of a power-engineering aspect of a carbon tax reveals that due to operational interactions, in the short term, a carbon tax might not reduce emissions. Study of the socio-political issue of CHP reveals that economically viable technologies may sometimes not gain traction in the market because of internal business models and negative subjective impressions. Similarly, the study of the economic/market aspect of a V2G reveals that lower battery costs, subsidies for participation, and more rewarding market products could all make V2G more economically viable to the vehicle owners. More importantly, these results also imply thorough analysis would reveal the intricacies and allow the policymaker to understand the impacts of such a policy holistically.

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List of Abbreviations

CO_{2e}	Carbon dioxide equivalent
CUSP	Consortium for Sustainable Power
ED	Economic Dispatch
EPA	Environmental Protection Agency
FIT	Feed-in Tariff
GHG	Greenhouse Gases
GDP	Gross Domestic Product
GNP	Gross National Product
H	Hour
IEEE	Institute of Electrical and Electronic Engineers
LP	Linear Programming
LMPs	Locational Marginal Price
MPC	Marginal Private Cost
MSC	Marginal Social Cost
MWh	Mega Watt-Hour
MW	Megawatt
MMBTU	Million British Thermal Units (or mBTU)
NREL	National Renewable Energy Lab
ΔNB	Change in Net Benefits
NB	Net Benefits
OPF	Optimal Power Flow
PTC	Production Tax Credit
RTO	Regional Transmission Organization
RTS	Reliability Test System
RPS	Renewable Portfolio Standard
R&D	Research and Development
AEC	Alternative Energy Certificates
APS	Alternative Portfolio Standard
CHP	Combined Heat and Power
DOE	Department of Energy
EPA	Environment Protection Agency
GHG	Greenhouse Gases
GW	Giga Watt
IOU	Investor Owned Utility
kW	kilo Watt
MN-DOC	Minnesota Department of Commerce
PUC	Public Utility Commission
BAU	Business as Usual
BESS	Battery Energy Storage System
CAISO	California Independent System Operator

DA	Day Ahead
EV	Electric Vehicle
ERCOT	Electricity Reliability Council of Texas
ISO	Independent System Operator
LMP	Locational Marginal Price
MISO	Mid-Continent Independent System Operator
RT	Real Time
RRP	Responsive Reserve Price
SOC	State of Charge
VPP	Virtual Power Plant
V2G	Vehicle to Grid
ZEV	Zero Emission Vehicle

1. INTRODUCTION

In today's world, energy policies play a vital role in shaping sustainable economic development. Excelling at formulating, analyzing and implementing effective energy policies is an essential aspiration for many countries. Such excellence is only possible through reconciliation of trade-offs between different (and sometimes divergent) agendas. For such an agreement, the policy process (see Figure 1-1 for a simplified view) needs to be thoroughly understood using holistic insights from engineering, socio-political, economic/ market perspectives. However, both in academia and in practice, one or more of these aspects are often neglected. This dissertation uses engineering tools with insights from social science to study three examples of energy policies focusing on the understudied and often overlooked issues. The next section describes a few other prominent theories and frameworks that explain the policy process. Readers familiar with this topic can skip directly to section 1.2.

Figure 1-1: The policy stages framework

1.1 Theories on the policy analysis

Figure 1-1 shows a simplified view of an extremely complicated process. It is also referred to as the "Policy Stages" framework. According to this framework, the policy process begins with problem identification such as such as how increasing Carbon dioxide (CO_2) emissions from fossil-fired power plants is deteriorating human life in

New York. The policy analysis (note that these stages can be name differently in different subfields. Example of Stanford *et. al* [1] is described in footnote [1]) stage follows this stage. The policy analysis stage focuses on evaluating policy options in the political context. For example, to lower CO_2 emissions, a Carbon tax or Cap and Trade are two viable options. What are their costs? What are their benefits? This stage is then followed by policy development, e.g., a carbon tax is chosen over cap and trade. Then its consequences are thoroughly studied, and an enactment plan is developed. After the policy is established, it is enacted. For example, the carbon tax becomes a law and is brought into practice. After enactment, the policy needs to be monitored, analyzed, criticized and assessed during the post-implementation evaluation stage.

The policy process occurs over several decades, involves hundreds of actors who are ready to give their own "spin" and includes interactions with other existing policies and sub-fields. Therefore, the stages, as described in the Policy Stages framework, might not always follow a linear, top-down progression. They are just "moments" in the policymaking process, and they can occur linearly (as described above), simultaneously or even in inverse order. Further, they can also be influenced by another policy process. For example, in the CO_2 case above, vehicular emission policy in New York or a federal emissions policy might affect the carbon tax policy of New York. Therefore, Policy

[1] The naming convention of these stages could be different in different policy subfields. E.g., in Implementation literature, the first two stages are generally named as Understanding the policy problem stage and understanding the existing system stage (Stephanie Moulton, Jodi R Sandfort, The Strategic Action Field Framework for Policy Implementation Research. Policy Studies Journal Vol, 2016.) The interview guide for the second essay (see chapter 3) is based on the implementation literature.

Stages framework falls flat while trying to describe this process sequentially. Hence, several newer theories and frameworks have emerged. Some of these are described below.

Institutional Rational Choice: This framework is the most widely used and thoroughly studied. It is represented in the figure below. In this framework, the "action-arena" is a social space where individuals (or corporate actors) interact, exchange goods and services, and solve problems. This arena is responsible for the policy outcomes like a carbon tax policy. These outcomes can be evaluated, and they inform the a) rules used by participants to order their relationships b) states of the community and world where they live. For example, for a carbon tax policy, this framework could help understand the logic behind selecting this policy. For instance Qi [2] uses this model to illustrate that the carbon tax policy in China is the product of interactions between several decision makers who are governed by their own community rules and values, and also by country's economy and international influence.

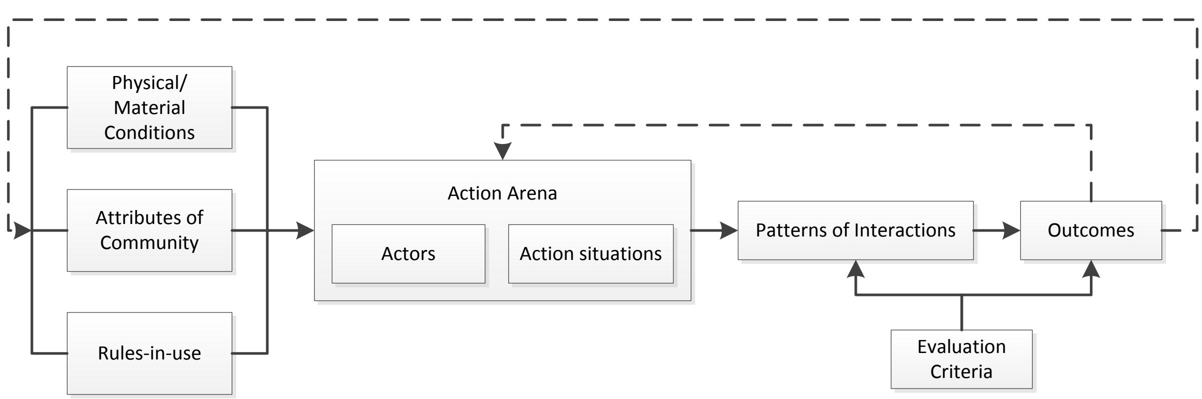

Figure 1-2: Framework for institutional rational choice analysis

The Multiple-Steams Approach: This approach helps in the understanding of the policy process under the conditions of ambiguity in temporal order. "Ambiguity," for this framework, is defined as many ways (that are often not-reconcilable) of thinking about the same problem, and "temporal order" describes the nature of the policy process where adoption of goals, ideas, and alternatives depend on when the policies are being made. For example, Heinmiller *et. al* [3] has used this framework to identify why some governments are early adopters of carbon policy, while others are not. They find that the most critical factor in rapid adoption of such a plan was the presence of a committed champion at the center of the government during that time.

Punctuated-Equilibrium Theory: This theory suggests that the logic of stability and incrementalism drives the policy process; however, occasionally there are significant departures from the past. On the contrary to most of the other theories, it helps to explain both stability and change. For example, using this theory, Speth [4] discusses the details about the dynamics of US environmental policy changes and factors that lead to this change.

The Advocacy Coalition Framework: In this framework, the filtered sets of two exogenous sets of variables affect the policy subsystem (see figure below). The first set is relatively stable like basic constitutional structure, sociocultural values, and natural resources related to the system. The second set is relatively dynamic like significant socioeconomic changes like social movements, or influence from policy decisions from other subsystems. The policy subsystem consists of actors who often group to form "advocacy coalitions." They have a set of core beliefs, and then they use different methods to influence policy change that suits their beliefs. Like other theories and frameworks above, this can also be used to answer climate-related questions. For example, Villagra [5] uses this framework to describe why Canada was falling behind in the climate race in the 2000s.

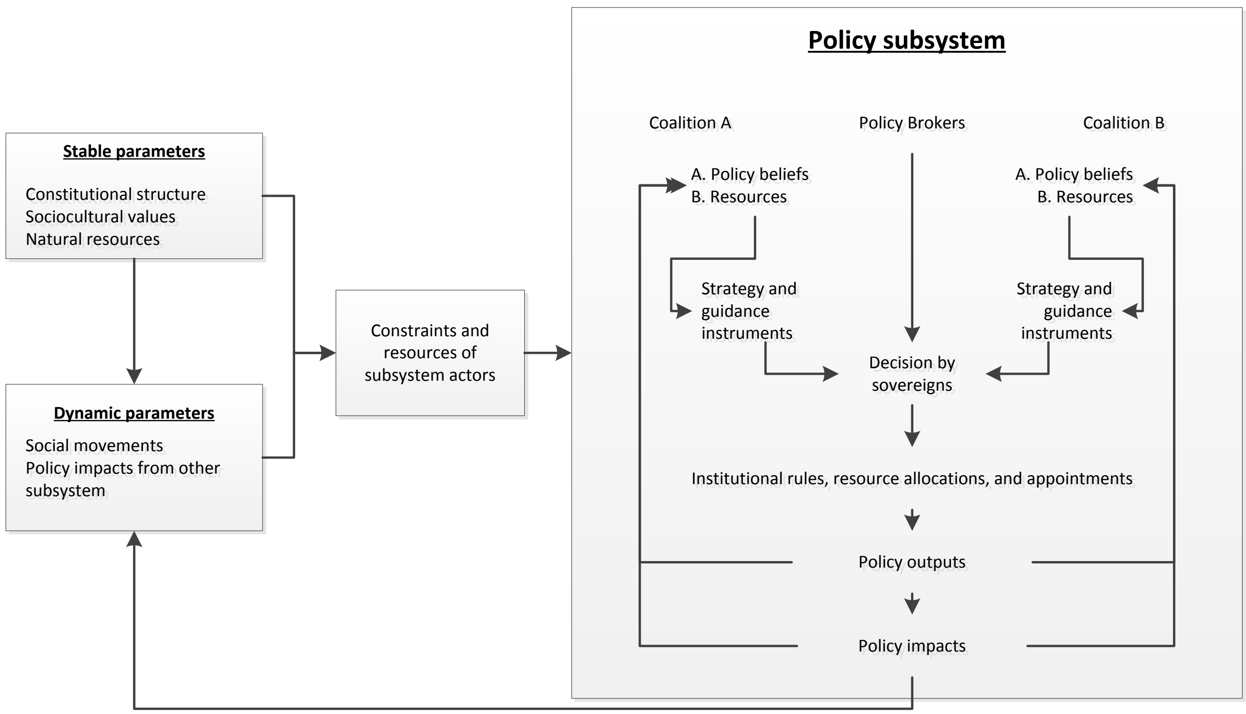

Figure 1-3: Advocacy coalition framework

Like the ones described above, several other models, approaches, frameworks, and theories have emerged in the past decades. Several of them are elaborated in detail in Sabatier et. *al* and Kingdon *et. al* [6; 7]. These theories and frameworks could provide different perspectives on the same policy process; that would make the analysis more holistic and the policy outcome more effective.

The choice of the model should depend on framing of the research questions that is in turn guided by the question ***what is at stake?*** The essays in this dissertation discuss energy policy issues related to the U.S. electricity industry. First, the electricity industry is one of the most significant contributors of Green House Gases (GHG). GHGs can be linked to environment, health, and economy. This brings citizen's right to live in a healthy environment and the structure of the current economy at risk. In a longer term, it also brings the lives of our future generation at risk. Second, innovative technologies like Combined Heat and Power (CHP) or concepts like Vehicle to Grid (V2G), despite having broader benefits, are facing deployment barriers. This is because of limitedness in state policies, the complex interplay between different stakeholders and negative subjective connotations. Such an inability to deploy the right technology brings our democratic values, deliberation process and stakeholder process into stake. The U.S. electricity industry has close interrelationship between socio-political structure (including human values), economic/market structure, and technical structure. Thus, it puts all of these at stake and therefore the lives of our future generation at risk.

Let's see some examples. To understand the deployment barriers faced by CHP, rational institutional choice framework or its derivative would be the best fit. Similarly, to understand why some countries make and enact better carbon reduction policies than others, an approach on the multiple-steams would be the best fit. Therefore, the researcher or the practitioner should not be biased towards one framework or the other. Instead, they should embrace the frames that would best fit their situation.

Since my focus in more on highlighting the importance of missing pillars in the holistic-triad (see section 1.2), I will not dive deep into any of these frameworks. I will, however, use several them and their derivatives to inform both my methods and conclusions; will and mention them if (and when) they are needed.

1.2 Holistic insights

Holistic insight into the policy process requires a thorough understanding of its socio-political, engineering, and economic/market aspects. Understanding this triad is a necessary condition to prevent enacting ineffective energy policies. Additionally, on a case by case basis, other elements like the environmental or the legal aspects could also be analyzed. But the triad of socio-political, engineering and economic/market should not be neglected.

The socio-political aspects play a significant role in influencing the rules, laws, norms and the state of the community (see 1.1 Institutional Rational Choice) that influences (and is influenced by) the policy process. Power and the relationship dynamics at the global, national, subnational and organizational level have a substantial influence on the energy policy. Therefore, a thorough understanding of this aspect is essential for enacting an effective energy policy. Take the example of CHP. CHP is efficient, cash positive and supports future energy transition. Therefore, it is widely adopted in Europe (see essay 2). So, why has not it gained enough traction in the U.S.? Socio-political analysis (understanding of the social construct and power play) would help in understanding this issue. In general, under analysis of (or sometimes even missing to analyze) the socio-political aspects will inaccurately portray the impact of power and relationship dynamics that could ultimately also lead to policy failure.

Like the socio-political aspect, the economic/market element is another important factor. It encompasses the study of the ways societies and individuals organize activities such as production and distribution of goods and services that are related to the energy system. Economic/market aspect would reveal insights on the profitability, utility, and scarcity of the resources in question. For example, Vehicle to Grid (V2G) is a technically viable concept (see essay 3). However, in the past two decades, it has not gained any commercial traction. So, is V2G profitable for all the participating actors? Do the present market rules support this? These are some questions that could not be answered without a thorough understanding of the economic/market aspect. In general, underanalysis of (or sometimes even missing to analyze) the economic/market aspects will inaccurately estimate the profitability, utility, and scarcity of the goods and services that are produced and distributed. Such an inaccurate estimation would lead to ineffective energy policy that could ultimately be set to failure.

Similarly, the engineering aspect (could also be referred to as the technical aspect) is also equally important. Technical elements relate to the technicalities and operational issues of an energy policy. Policies that involve generation, transmission, the distribution of energy would interact with the power system operation. For example, transmission congestion can influence the effectiveness of a carbon tax when the flow of electricity on a transmission line is restricted below its optimal level by either physical conditions or operational restrictions (essay 1). For example, if a transmission line rated at 60 MW is carrying 60 MW, it is 100% congested and cannot carry any additional power. Operationally, such transmission congestion could alter generator dispatch/load demand or change equilibrium prices in a power system with a carbon tax, potentially by altering its effectiveness. Depending on the location of congestion, it could inadvertently force the market to dispatch more power from a coal generator and shutdown lower carbon generators, undermining emission reductions. Such insights would not be revealed without a thorough analysis of the engineering aspect of a carbon tax. In general, under analysis of (or sometimes even missing to analyze) the engineering aspects will inaccurately estimate the operational interaction.

However, for several energy policies, analysis of some of these aspects are often neglected. Such negligence makes the policy ambiguous and less effective. It could even lead to policy failure. Take the example of a Distributed Energy Management System (DEMS). It is a technically sound concept that facilitates incorporation of renewables at the distribution system by utilizing the “smartness” of the smart meters. However, it has not moved beyond a few pilot projects. The study of politics, governance and relationship dynamics of DEMS are often neglected. This study would reveal (future research) the actors are not actively pursuing this concept.

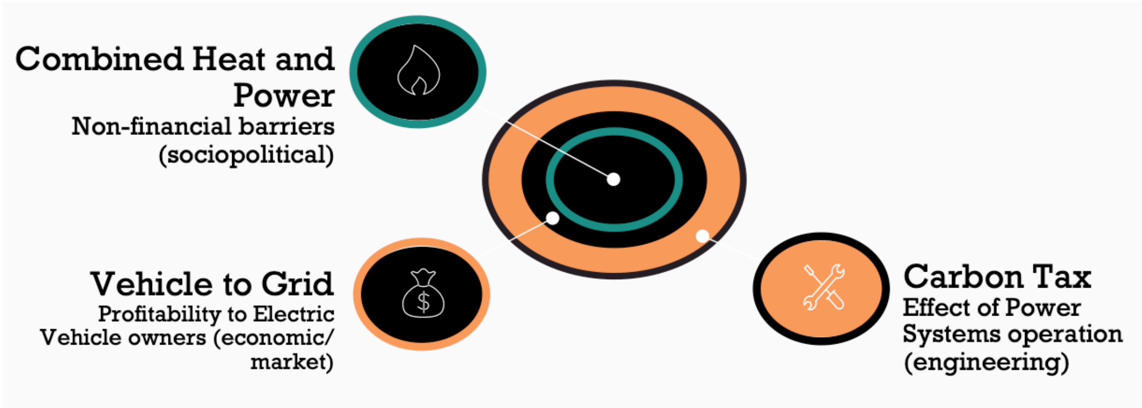

Figure 1-4: Examples of energy policies that will be studied in this dissertation

A thorough understanding will help in discovering a phenomenon that sometimes counteracts and at other times, enhances the effectiveness of any energy policy. For, example, an economist generally studies tax-related issue. Therefore, the economic aspects of a carbon tax are thoroughly investigated. As mentioned before, interaction with power systems operation is often neglected. And, power system operations could significantly change the effectiveness of a carbon tax. Therefore, missing to analyze this aspect will make the policy less effective. However, if such elements are timely and thoroughly studied, the plan can carefully be crafted to alleviate the negative operational interactions and to boost the positive functional interactions.

Unfortunately, both in academia and in practice, one (or more) of these aspects is often neglected. Considering this, this dissertation studies three examples of energy policies focusing on a lesser known, and often-neglected aspect (see Figure 1-4).

Using U.S. market practices and policies as an example, the first essay analyses the power engineering aspect of a carbon tax. A carbon tax is operationalized in a wholesale electricity market. A one-stage forward market is simulated, and its effect is examined on the Institute of Electrical and Electronics Engineers (IEEE) Reliability Test System 28-bus model examining both transmission congestion and other energy policies. Results show how the carbon tax affects emission savings, and revenue streams for generators, loads, transmission right holders and government. They indicate that such interactions could lead to ineffective emissions reduction.

The second essay analyzes the socio-political aspect of highly efficient engineering technology – Combined Heat and Power (CHP). It examines the non-financial barriers that are faced by CHP projects in the United States. It uses expert (developers, owners and operators, regulators, and other stakeholders) elicitation and document analysis to infer the results. The results show three significant barriers a) the business model of the electrical utility b) negative subjective impressions and c) challenges in allocating the risks and benefits.

The third essay analyzes the economic/market aspect of Vehicle-to-Grid (V2G). The model of a centralized V2G system is developed and applied to the 2015 wholesale electricity market in Texas (Houston Hub). Using Dynamic Programming/Unit-Commitment program, three scenarios are examined. In the first scenario, electric vehicles owners are paid based on a fixed retail market price; in the second, they are paid a time-varying retail market price; in the third, the virtual power plant shares 50% of its total reward with the participating vehicle owners. The results demonstrate that, while this system is always financially profitable to the virtual power plant and the system operator gets grid services, the electric vehicles could lose money. Further, results show that these vehicles with lower per unit output-battery cost could lose more money because of extensive battery over-use and insufficient reward at current market prices.

The results have several important policy implications. Study of the power-engineering aspect (understanding how a carbon tax interacts with the power system operations using an optimal power flow) of a carbon tax reveals that due to operational interactions, in the short term, a carbon tax might not reduce emissions. These interactions emerge when the physical and material conditions of the U.S. electricity system interact with the existing rules of the market (see section 1.1 on Institutional Rational Choice Framework) or with the existing renewable promotion policies (see section 1.1 on Advocacy Coalition Framework). Therefore, underanalysis of the engineering aspect would not reveal the impacts of such interactions. Thus, it could make the policy analysis incomplete.

In the United States, due to the current political quagmire, a federal carbon tax is not an immediately plausible option. However, states like Washington, New York, Oregon, Massachusetts, and Rhode Island are independently pursuing it. At all these places, the carbon tax policy is at the policy analysis stage (see section 1.1 for Policy Stages framework). Therefore, the methods and the insights presented in this dissertation would be helpful in analyzing, developing the carbon tax policy and enacting it effectively.

The study of the socio-political aspect (understanding the power play and role of opinion leadership using expert elicitation based on the Strategic Action Framework) of CHP reveals that economically viable matured technologies may sometimes not gain traction in the market mostly because of the business model of the utility, negative subjective impressions and complications in allocating risks and benefit.

The CHP policy context in the U.S. has gone through massive shifts: before the late 1970s, there were no U.S. federal or state policies encouraging CHP deployment but the 1978 Public Utilities Regulatory Policies Act (PURPA), incentivized CHP by forcing utilities to buy electricity from cost-competitive independent generators. Many CHP power plants—especially in the industrial sector—were cost-competitive and installed CHP capacity increased from 12GW in 1980 to 74 GW in 2004 (see essay 2). While CHP facilities can still benefit from a 10% investment tax credit, the Energy Policy Act of 2005 removed the requirement that utilities purchase electricity from CHP facilities and instead directed the Utilities to sell their power through competitive markets and coupled with high natural gas prices (69% of US CHP plants) resulting in only 5.4GW of CHP installed from 2005-2015. Several states have policies to support CHP. However, support from the federal government is evidently lacking. Therefore, insights and recommendations from this dissertation (see policy implication section of essay 2) should be used to improve the existing policies or to formulate the next generation of CHP policies that will ensure evident support at the federal level.

The study of the economic/market aspect (understanding the profitability using dynamic programming and unit commitment) of a V2G reveals that with the present market rules, V2G may not be economically viable for the vehicle owners. In the U.S., the V2G policy has also not moved beyond the policy analysis stage (see section 1.1 for Policy Stages framework), Therefore, the methods and recommendations from this dissertation should be explored to analyze, develop and enact an effective V2G policy. Such an effective system is only possible by significantly departing from the past (see section 1.1 for punctuated equilibrium) e.g., by creating renewable consumption product (see policy implication section of essay 3 for additional examples).

All these results indicate that thorough analysis of the holistic-triad would reveal the hidden intricacies and allow the policymaker to understand the impacts of the policy holistically. Thus, the policymaker could make proper trade-offs and reconcile any conflicting agendas to formulate, analyze and implement energy policy effectively. In all, this dissertation combines engineering tools with insights from social science to study three examples of energy policies that are at the intersection of science, technology, environment, and society.

The three cases from above are the three upcoming chapters of this dissertation. Chapter 2 presents the power engineering aspects of a carbon tax. Chapter 3 shows the socio-political elements of market diffusion of economically viable CHPs and Chapter 4 explains the economic/market aspects of the V2G in regards to the profitability of the electric vehicle owners.

2. Interacting Policies In Power Systems – Renewable Subsidies And A Carbon Tax

2.1 Introduction

Understanding how any new energy or environmental policy will work in practice includes the detailed analysis of existing and future technological, economic, and operational contexts. Implementing a carbon tax is no different. A carbon tax will interact with the legacy electricity system and existing energy policies, and its implementation has important operational components. Its emission savings that are proportional to the power output and tax-related revenue streams, measure the effectiveness of a carbon tax. Many studies have examined socioeconomic, socio-environmental and socio-political perspectives and prior research mostly focuses on calculating/predicting emissions saving from a carbon tax [8-13], identifying broader economic impacts, and mitigating its negative consequences [14-33]. However, how a carbon tax interacts with power system operations is critical but remains understudied [34; 35].

Of the few existing studies that focus on the impact of alternative policies to manage carbon on power systems, like a carbon tax or cap and trade program, most study transmission congestion from an economic perspective. For example, Limpaitoon et al. [34] studied how transmission congestion affects a cap and trade mechanism. They found that such interactions might lead to the abuse of market power in the procurement of clean energy. Similarly, Sauma [36] studied the effects of transmission congestion on carbon leakage for a cap and trade program. For a carbon tax, Downward [37] and Contreas et al. [35] demonstrated some unanticipated impacts of transmission congestion, highlighting in [37] that transmission congestion could cause total emissions to increase and in [35] demonstrating that transmission congestion may benefit less efficient generators. Similarly, Adam et al. [38] found that taxing emissions would change the generator dispatch order and alter a carbon tax's effectiveness [39].

This essay falls in the critical gap area of operational interactions of a carbon tax with power systems with other similar energy policies. It highlights that the energy policies are non-linear in practice. Among other things, such policies could alter system operations (e.g., a carbon tax could change market dispatch) and be affected by it (e.g., a market dispatch could alter the effectiveness of a carbon tax). Operational interactions could result from power system operating conditions like transmission congestion and plant outages and interacting energy policies or operational rules like energy policies to promote renewables such as the Production Tax Credits (PTCs) or Feed-in Tariffs (FITs). In the short term, which ranges from years to decades in the capital-intensive electricity system, such operational interactions could undermine the effectiveness of a carbon tax and examining these impacts has important value for policy creation and implementation.

2.1.1 Key Academic Questions

This essay examines the combined effects of 1) ***the short-term impacts of transmission congestion and 2) price spreads due to other energy policies to promote renewables like Production Tax Credits (PTCs)***. The operation of a power system is simulated using a one-stage forward market, and the critical operational intricacies shaping carbon tax implementation in the electric sector are highlighted.

1. Transmission congestion can influence the effectiveness of a carbon tax when the flow of electricity on a transmission line is restricted below its optimal level by either physical conditions or operational restrictions. For example, if a transmission line rated at 60 MW is carrying 60 MW, it is 100% congested and cannot carry any additional power. Transmission line congestion can also alter power system operations and change the generator dispatch order. For example, according to the U.S. National Renewable Energy Laboratory (NREL) [40], from the years 2009 to 2013, 1-4% of total electricity produced from wind generation was curtailed mostly due to transmission constraints like transmission congestion and lack of transmission access.

   Economists typically study congestion as it relates to the behavior of participants [39; 41; 42], and engineers typically study congestion and congestion management from a reliability perspective [39; 43-50]. However, from a system-wide operational perspective, the interactions of congestion and a carbon tax provide important insights into policy implementation. Operationally, congestion could alter generator dispatch/load demand or change equilibrium prices in a power system with a carbon tax, potentially altering its effectiveness. Depending on the location of congestion, it could inadvertently force the market to dispatch more power from a coal generator and shutdown lower carbon generators, undermining emission reductions.

2. A carbon tax may also interact with other energy policies like a Production Tax Credit (PTC) in the United States or a Feed-in Tariff (FIT) in Germany/United Kingdom (UK) /China or some Canadian provinces, which subsidizes electricity production from renewable resources to incentivize increased deployment. While PTCs have been extremely successful in increasing the profitability and deployment of wind generation [51], they also affect electricity market operations. Rausch et al. and Philibert et al. [52; 53] find that a carbon tax will positively interact with Renewable Portfolio Standard (RPS) by incentivizing early investments in renewables and reducing their long-term cost, which makes renewables readily available. However, in electric power system operations, a PTC may counteract the effects of a carbon tax [9]. A carbon tax increases the overall system price while PTCs decrease it. Presently, electricity generation from the wind in the United States gets a $23 PTC [54] for every MWh generated. As a result, wind generators expect PTCs and often offer negative bids into the wholesale electricity market (see Section 2.2.2). Theoretically, they could bid as low as negative $23 and still break even for every MWh generated. Practically, they may or may not always bid this low, but they will bid at a lower price than other conventional generators. For example, anticipating increasing renewables, in 2014 the California Independent System Operator (CAISO) changed the lower bound of the negative bid from -$30/MWh to -$150/MWh [55]. Such prices create a difference in the bids among the renewable and conventional generators. Throughout this essay, **the difference in bids is referred to as a large price spread[2]**.

[2] A carbon tax can further increase this price spread. It can change the relative price (alternatively

These operational interactions could undermine the effective implementation of a carbon tax in practice. In both cases, such interactions could alter the emissions savings from a carbon tax and alter the revenue collected from loads and paid to generators and the government. Analyzing and understanding these interactions will help to estimate the impacts of a carbon tax accurately, identify critical issues, and help improve its design.

Therefore, for a system with large price spreads (due to with PTCs and a carbon tax), I study the effectiveness of a carbon tax for both congested and uncongested power systems and present the findings in terms of emission savings (proportional to power output) and revenue streams for the generators, loads, government and transmission right holders. In this essay, I focus on standard U.S. electricity market practices, but this work can easily be translated to any electricity market that uses Economic Dispatch (ED) and has congestion and a price spread. The contributions of this essay are the demonstration and study of two critical examples of operational interactions in power systems with a carbon tax, 1) transmission congestion and 2) PTCs and the importance of studying new energy policy implementation in the context of operational considerations and existing energy policies.

This essay is organized as follows: Section 2.2 describes the background and literature review on a carbon tax, U.S. electricity markets, Optimal Power Flow (OPF) and Locational Marginal Prices (LMPs). It also describes the measures for evaluating the effectiveness of a carbon tax. Section 2.4 describes the methods for operationally modeling a carbon tax in power systems. Section 2.5 presents the simulation results and discusses the findings in terms of emissions savings (proportional to power output) and

reflected in their bids) of CO_2 emitting and non-emitting generators.

revenue streams. Section 2.6 discusses some conclusions and identifies policy implications.

2.2 Background

To operationalize, apply and test the effectiveness of a carbon tax on a power system, a discussion on the background of a carbon tax and its interaction with electricity markets is critical. This Section will briefly cover each of these topics. Readers who are familiar with these topics can skip directly to Section 2.4.

2.2.1 Carbon Tax

Many economists argue that a carbon tax is the best approach [56-61] to abate greenhouse gases (GHG). A carbon tax can abate GHG and generate government revenues that can be used as instruments for fiscal reform.

According to the World Bank [62], (see Table 2-1), 12 countries and one Canadian province have implemented a carbon tax and two countries (marked with an asterisk *) have plans to implement one. The situation in the United States is slightly different. Due to the current political quagmire, a federal carbon tax is not an immediately plausible option. However, states like Washington, New York, Oregon, Massachusetts, and Rhode Island are independently pushing for one [63].

Table 2-1: Carbon tax

Country/Province	Tax Rate[3]	Adoption Year
British Columbia (BC)	$\$_{2012}$ 30/tonCO_{2e}	2008
Chile*	$\$_{2018}$ 5/tonCO_{2e}	2018
Costa Rica	3.5% tax on hydrocarbon-based fossil fuel	1997
Denmark	$\$_{2014}$ 31/tonCO_{2e}	1992
Finland	$\$_{2014}$ 35/tonCO_{2e}	1990
France	$\$_{2014}$ 10/tonCO_{2e}	2014
Iceland	$\$_{2014}$ 10/tonCO_{2e}	2010
Ireland	$\$_{2014}$ 27.8/tonCO_{2e}	2010
Japan	$\$_{2014}$ 2/tonCO_{2e}	2012
Mexico	$\$_{2014}$ 10-50/tonCO_{2e}	2012
Norway	$\$_{2014}$ 4-69/tonCO_{2e}	1991
South Africa*	$\$_{2016}$ 7/tonCO_{2e}	2016
Sweden	$\$_{2014}$ 168/tonCO_{2e}	1991
Switzerland	$\$_{2014}$ 68/tonCO_{2e}	2008
United Kingdom	$\$_{2014}$ 16/tonCO_{2e}	2013

According to Ref [62; 64; 65], 12 countries and one Canadian province are currently implementing a carbon tax.

Theoretically, a carbon tax has its roots linked to the Pigouvian tax [66], which internalizes the effects of externalities. For example, consider a fossil-fuel-based power plant. To internalize its negative externalities, this power plant can be taxed. This will shift the equilibrium price and quantity from (ΔC (P*) $/MWh, P* MW) to (ΔC1 (P*) $/MWh, P1* MW) which is a decrease in supply and an increase in price [58; 66; 67] (see Figure 2-1).

[3] A carbon tax, which was not expressed in United States Dollars (USD) by the World Bank, was converted to USD using the average yearly exchange rates from the US Forex.

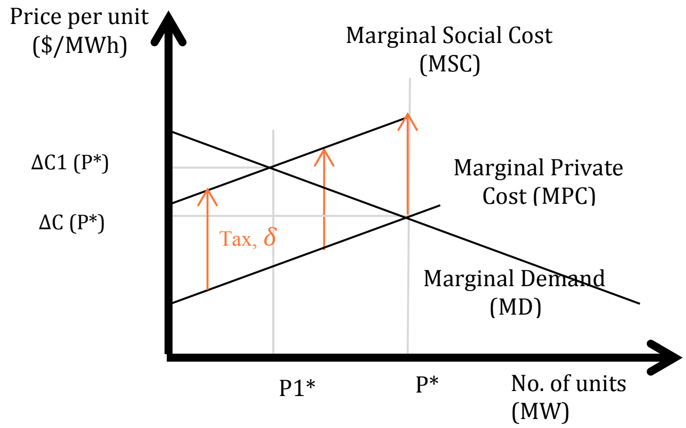

Figure 2-1: Marginal supply and demand including a tax.

A carbon tax is added to the marginal private costs of the supplier to internalize its externalities.

As mentioned previously, a carbon tax is generally expressed in terms of \$/tonCO_{2e} (or \$/tonC or \$/tonCO_2) and is applied to the carbon content of the fuel. It is generally considered as a cost-effective and easy to apply the method to abate emissions. Once applied, it has two dividends [68]. The first dividend is reducing emissions. For example, a carbon tax contributed to a 2% emissions reduction in Norway for a period of 9 years (1990-1999), a 1.69% emissions reduction in Finland for a period of 11 years (1997 – 2008) and a 13% emissions reduction in British Columbia for a period of 6 years (average of 2000-2007 pre-tax emissions vs. average of 2008-2013 post-tax emissions) [8; 10; 12; 69]. The second dividend is increased government revenues. For example, Milne et al. [67] show that the total revenue from environmental taxes (taxes on carbon and other pollutants) for Organization for Economic Co-operation and Development countries for a period of 8 years (2000-2009) was around 2% to 2.5% of their Gross Domestic Product (GDP). According to the New York Times [70], Ireland collected over a billion Euros in three years from 2010-2012 from its carbon tax. And projections of carbon tax performance are rosy: Poterba [71] predicts that a carbon tax could increase Japan's Gross National Product (GNP) by 1.6%, and Rausch et al. [52] predict that a gradually increasing carbon tax of \$20/tonCO_2 in the United States could raise around \$1.5 trillion in revenue in 10 years. I recognize that discussions of revenue distribution are fundamentally important; otherwise, a carbon tax could have negative distributional impacts (i.e., the poor will end up paying more than the rich pay), as are interactions with other taxes and carbon leakage. However, they are not the focus of this essay [12; 27; 72; 73], which concentrates on operational and policy interactions.

2.2.2 Basics of U.S. Electricity Markets

Presently, over 66% [74] of the electricity load in the United States is served by wholesale electricity markets[4]. As shown in Figure 2-2, generally, the resellers buy electricity in the wholesale markets and resell it in the retail markets. Utilities generally act as the resellers, and the end users (residential, industrial and commercial customers) are the ones who consume the electricity. The end users or load generally purchase electricity through retail markets; however, a discussion on retail markets is beyond the scope of this essay.

[4] The remaining population is served by over-the-counter and bilateral trading agreements.

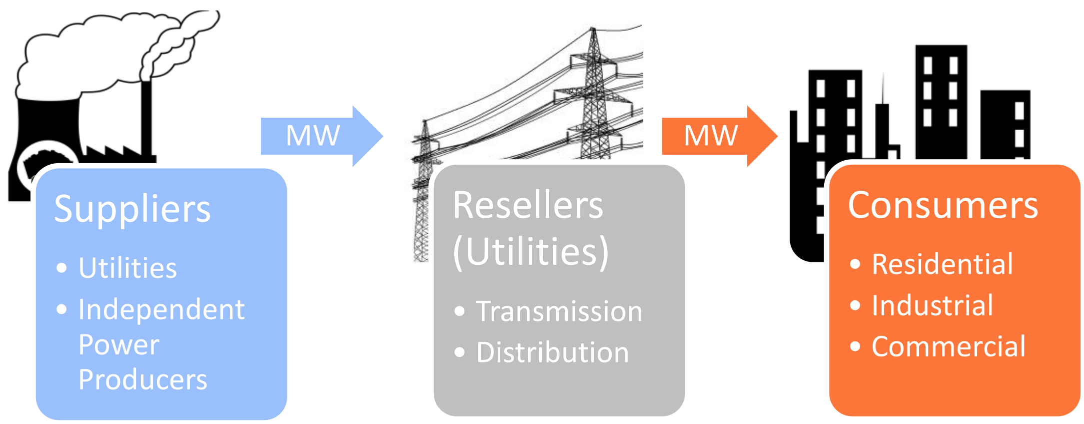

Figure 2-2: Electricity markets in the United States.

Such markets can broadly be divided into the wholesale and retail market. Discussion on the retail markets is outside the scope of this essay.

At the wholesale level, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) are voluntary organizations authorized by the Federal Energy Regulatory Commission (FERC) with the responsibilities of running the wholesale markets and maintaining the day-to-day reliability of the power grid. In this essay, I will refer them as market operators. At present, there are seven RTOs/ISOs in the United States. Figure 2-3 shows the ISO/RTO controlled regions of the United States and Canada.

In the U.S., the markets are settled using a two-settlement system with a day-ahead market and a real-time or spot market. In both markets, the prices are determined by matching supply and demand. However, the key difference lies in the fact that the day-ahead market settles in anticipation of future events and the real-time market settles in real-time. The real-time market reconciles the difference between the day-ahead cleared demand and the real-time load. In both markets, the market operator collects supply bids from the generators and matches them with demand. These bids are in the form of price/MW pairs (see Section 2.4.2) and are used to construct a supply curve for each generator along with their maximum and minimum power values. The market operator then runs some form of Unit Commitment (UC) followed by security constrained economic dispatch (or Optimal Power Flow (OPF)) to dispatch the least-cost generation to meet demand and determine prices. This illustrates the operational complexities in running a market. If a carbon tax were applied in such a market, the operational complications would alter the anticipated impacts of this tax

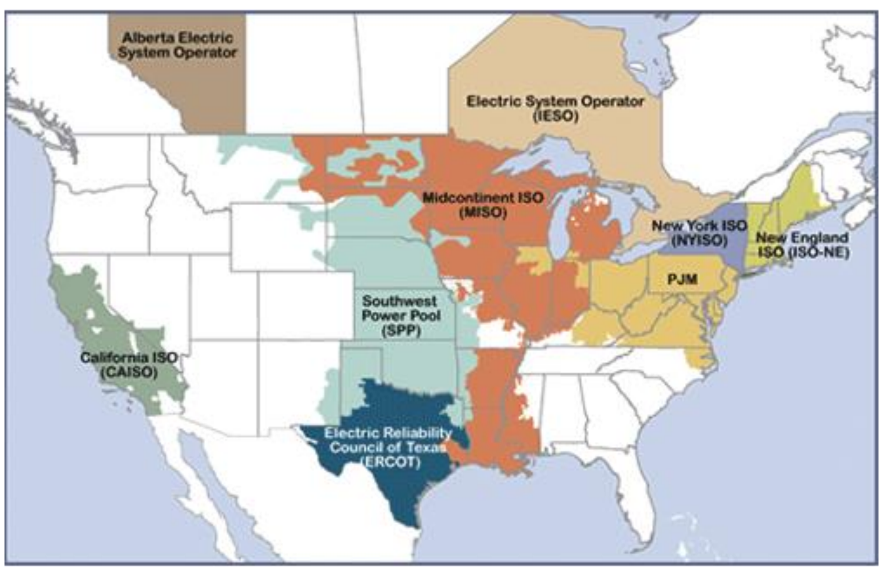

Figure 2-3: RTOs/ISOs in the United States and Canada

Electricity in the United States is generally traded through state of the art wholesale electricity markets run by these ISOs/RTOs [74]

This essay assumes a real-time spot market and simulates the market dispatch. Prices in such markets are more dynamic and interesting. Moreover, they include real-time contingencies. However, the results can easily be extended to day-ahead markets with some minor changes.

As mentioned earlier, in the real-time market the market operator runs an OPF and dispatches generators economically. OPF combines the power flow with the economic dispatch problem. In other words, OPF aims to dispatch the least-cost portfolio of generators when subjected to power-system constraints. The ISO/RTO "generally" solves this OPF problem using a linearized version known as a Direct Current Optimal Power Flow (DCOPF), in which the reactive power and branch resistances are neglected, and all voltage magnitudes are assumed to be one per unit (p.u.).

The solution to this optimization problem results in the dispatch of the least-cost generators, and the solution to the dual problem determines the prices, called LMPs, at each node. LMP is defined as the least-cost of supplying the next increment or decrement of demand at a location when all power systems constraints are met. For example, using a linear marginal supply and demand curve for a given location and assuming no tax, as shown in Figure 2-1, ΔC (P^*) is the LMP and P^* is the optimal amount of power generation if all power system constraints are met.

2.3 Key Policy Questions

As mentioned in the previous sections, during the actual implementation of a Carbon tax, operational/engineering and existing policy interactions could become significant. Therefore, this essay seeks answers to the following policy questions

A) Do we need to thoroughly evaluate energy policies in the context of their engineering aspects like existing power systems operation and the policy environment?

B) Could such aspects undermine or overshoot the effectiveness of the energy policy in question?

2.4 Methods

Though the behavioral interactions among generators and loads, modeled using a Cournot game [39; 75; 76], and long-term capacity planning [77; 78] are also interesting interactions to explore, this essay is limited to the operational interactions between a carbon tax and both transmission congestion and PTCs. First, a carbon tax is operationalized, and four scenarios are created. These scenarios use various combinations of carbon tax and transmission congestion. After that, OPF is solved for each scenario.

Since modeling information for actual systems is critical infrastructure information and not publicly available, the one area 28-bus IEEE Reliability Test System (RTS) was used. Some modifications were made to the IEEE RTS model to mimic actual system conditions in the United States and balance its simplicity with the needs. These modifications are described below.

2.4.1 The IEEE RTS Model

In the IEEE RTS model (see Figure 2-4), there are 33 generators (hydro, oil, coal and nuclear), 17 loads and 28 buses (nodes). However, this is an old test system with an old generation mix, and without modification, it would fail to mimic a present-day power system. The generation mix in the original IEEE RTS system does not have enough renewables, and it does not have any natural gas generators. To address the first problem, the oil generators at bus seven were converted into wind generators. This added 300 MW of renewables to the total system capacity. The cost coefficients of these new renewable generators were set like those of existing hydro generators (see Table 2-2).

To address the second problem, generators U197 (bus 13) and U12 (bus 15) were converted into natural gas generators. It was assumed that natural gas generators cost 1/5th that of the U12 oil generator. Given natural gas and oil prices over the last couple of years, this was a reasonable assumption.

Apart from adding renewable and natural gas generators, to make the dispatch more economical only 27 of the 33 generators were committed, and the loads were set at 110% of their rated capacity. Derating the transmission lines 14-16 to 40-50% of their rated values created real-time transmission congestion in the spot market.

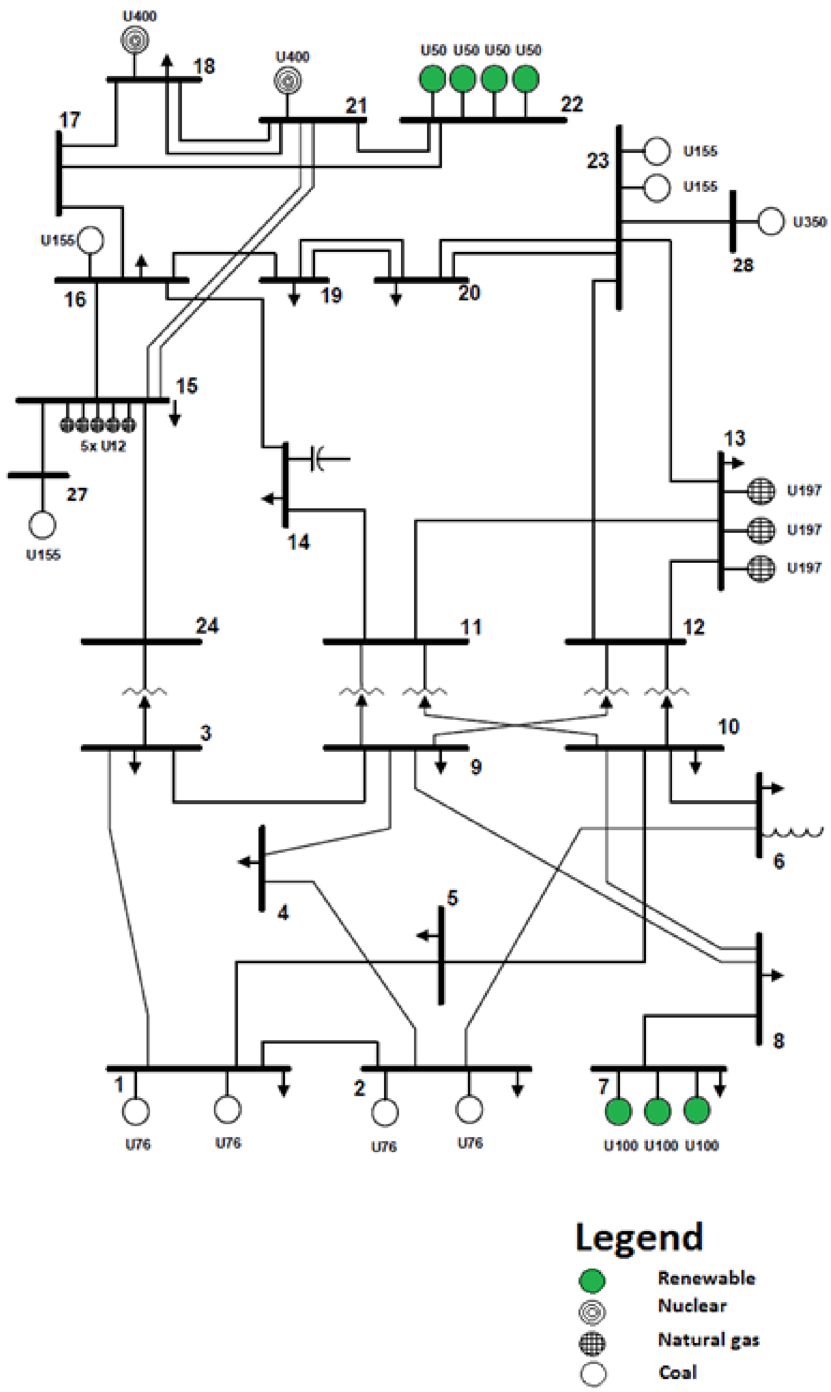

Figure 2-4: 28 bus IEEE Reliability Test System (with modifications).

This system is widely used for conducting reliability studies. This model is expanded in this essay and is used to illustrate interactions of a carbon tax with existing policies and with the power systems.

Table 2-2: Generation mix in a modified IEEE RTS model.

Generator Name	Generator Type	Power (MW)		Bidding coefficients			Status
		Min	Max	a ($/h)	b ($/MWh)	c ($/MW²h)	
U12	Natural gas	2.4	12.0	17.27	11.31	0.06	Online
U20	Oil	0.0	20.0	400.68	130.00	0.00	Offline
U50	Renewable	0.0	50.0	0.00	27.00	0.00	Online
U76	Coal	15.2	76.0	212.30	16.08	0.01	Online
U100	Renewable	0.0	100.0	0.00	0.00	0.00	Online
U155	Coal	54.3	155.0	382.23	12.38	0.01	Online
U197	Natural gas	68.9	197.0	17.27	11.31	0.06	Online
U350	Coal	140.0	350.0	665.10	11.84	0.01	Online
U400	Nuclear	100.0	400.0	395.11	4.41	0.00	Online

2.4.2 Operationalizing a Carbon Tax

As mentioned earlier, Pigouvian taxes [66], which are equal to marginal damages, are imposed on top of a supplier's Marginal Private Cost (MPC) (see Section 2.2.1). The MPC of a supplier is defined in equation (1).

$$\boldsymbol{MPC = \Delta C(P) = \frac{\delta C(P)}{\delta P} = 2cP + b} \tag{1}$$

\$22/tonCO_{2e} is chosen to be the value for marginal damage. This value is on par with the Environmental Protection Agency's (EPA's) estimate, which assumed a 5% discount level [79]. Since the CO_{2e} emissions per MWh for each power plant are different, a carbon tax in \$/tonCO_{2e} is converted into a carbon tax[5] in \$/MWh using equation (2).

$$\boldsymbol{\delta\left(\frac{\$}{MWh}\right) = carbon\_tax\left(\frac{\$}{tonCO_{2e}}\right) * marginal\_emission\_factor\left(\frac{tonCO_{2e}}{MWh}\right)} \tag{2}$$

[5] Generally, a tax in \$/MWh is referred to as an energy tax. Such a tax does not differentiate between clean and unclean generators. However, the carbon tax used in this dissertation, though expressed in \$/MWh, is selectively applied to generators based on their carbon intensity. Thus, it allows for substitution and encourages competition.

The sensitivity of the value of carbon tax is illustrated by varying it from \$0/tonCO_{2e} to \$22/tonCO_{2e} in five discrete steps as shown in Table 2-3.

Table 2-3: Operating parameters of the simulation model

Power Plant Type	Emissions Factor $(\frac{lbCO_{2e}}{MWh})$	Tax $(\frac{\$}{tonCO_{2e}})$	Tax $(\frac{\$}{MWh})$
Coal	2,000	[0, 5, 11, 16, 22]	[0, 5, 10, 15, 20] ➔ coal
Natural gas	1,200		[0, 3, 6, 9, 12] ➔ natural gas
Renewable	N/A		
Hydro	N/A		
Nuclear	N/A		
		The above columns illustrate the translation of a carbon tax expressed in \$/tonCO_{2e} into a carbon tax expressed in \$/MWh for coal and natural gas plants (i.e., a carbon tax of \$22/tonCO_{2e} was translated to a \$20/MWh carbon tax for coal plants and a \$12/MWh carbon tax for natural gas plants.	

Power plant type, emission factor, and tax [62; 79-82]

With a carbon tax ($\boldsymbol{\delta}$), the Marginal Social Cost (MSC) of the supplier is given by equations (3) and (4).

$$\boldsymbol{MSC = MPC + \delta} \tag{3}$$

$$\Rightarrow \quad MSC = 2cP + b + \delta \tag{4}$$

Therefore, from equations (2) and (4), the total cost curve of a generator with a carbon tax is shown in equation (5).

$$\boldsymbol{C1(P) = cP^2 + (b + \delta)P + a}$$

$$\Rightarrow \quad \boldsymbol{C1(P) = cP^2 + (b + carbon\_tax * marginal\_emission\_factor)P + a} \tag{5}$$

2.4.3 Simulation

The following simulation methodology was used to perform the simulations as shown in Figure 2-5:

1. A large price spread (or equivalently a large wind production subsidy) was created to mimic the difference in costs between renewable and conventional generators.

2. Transmission lines were derated to create transmission congestion, and a carbon tax value was chosen and used to create four scenarios. Scenarios 1 and 2 represented an uncongested system, and Scenarios 3 and 4 represented a congested system.

    Scenario 1 (base case): An uncongested system without a carbon tax.

    Scenario 2: An uncongested system with a carbon tax.

    Scenario 3: A congested system without a carbon tax.

    Scenario 4: A congested system with a carbon tax.

3. Solve the DCOPF.

4. To illustrate the sensitivity of the results to the value of the carbon tax, the carbon tax was varied in five discrete steps. The carbon tax for coal generators was increased from \$0/MWh to \$20/MWh, and for natural gas generators was increased from \$0/MWh to \$12/MWh (see Table 2-3).

5. To illustrate the sensitivity of the results to the amount of transmission congestion, its intensity was varied. Transmission lines 14-16 and 7-8 were derated to 40% and 50% of their rated MW capacity.

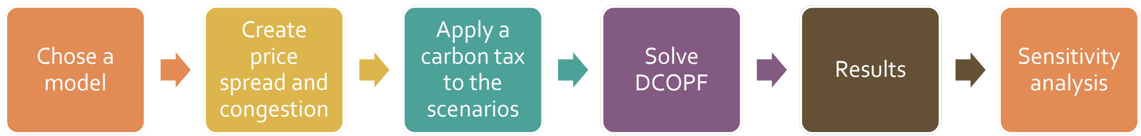

Figure 2-5: Simulation Methodology.

IEEE-RTS model is modified, after that, a carbon tax is applied and then power flow is solved to analyze the results.

2.4.4 Effectiveness Measures

The effectiveness of a carbon tax is evaluated in terms of emission savings (proportional to power output) and revenue streams for the generators, loads, transmission right holders and government. All the measures of effectiveness are the direct result of the market dispatch order.

2.4.4.1 Emission Savings and Power Output

Power output and emission savings are interrelated. The power output of each generator is determined by the OPF solution. Once the OPF solution is known, emissions for each generator can be calculated by multiplying its output by its marginal emissions factor. If there are N generators, total system emission can be calculated using equation (6).

$$\boldsymbol{Total\_emissions} = \sum_{gen_i=1}^{N} \boldsymbol{Power\_output}_{gen_i} * \boldsymbol{Marginal\_emission\_factor}_{gen_i} \qquad (6)$$

2.4.4.2 Revenue Streams

In electricity market settlements, payments flow from the loads to the generators, transmission right holders and government. In this essay, I express the revenue streams in terms of Net Benefits (NB) and change in Net Benefits (ΔNB). For a generator, its net benefit, or profit, is the difference between its revenues and costs as shown in equation (7). For load, its net benefit is the difference between its willingness to pay and its costs as shown in equation (8),

$$\boldsymbol{Net\ Benefit\ (NB_G) = LMP_G * P_G - \left(c * P_G{}^2 + b * P_G + a\right) - tax * P_G} \tag{7}$$

$$\boldsymbol{Net\ Benefit\ (NB_L) = \left(c * P_L{}^2 + b * P_L + a\right) - LMP_L * P_L} \tag{8}$$

Where,

P is the amount of power generated/consumed, LMP is the Locational Marginal Price, and a, b and c are the cost/benefit coefficients of the generators and loads.

Net benefits for the government are its tax revenues, and for Financial Transmission Rights (FTR) holders are its congestion rents as shown in equation (9),

$$\boldsymbol{Net\ Benefit\ (NB_{Gov}) = \textstyle\sum_{gen_i=1}^{N} tax_{gen_i} * P_{gen_i}.} \tag{9}$$

$$\boldsymbol{Net\ Benefit\ (NB_{FTR}) = Cong_{rent}}$$

Where,

$Cong_{rent}$ is the total congestion revenue on the system.

To understand the sensitivity of the net benefits to the amount of the carbon tax, the change in the net benefits is calculated for each entity. Letting *at* represent after tax and *bt* represent before tax, the change in the net benefits (ΔNB) is shown in equation (10).

$$\Delta \boldsymbol{NB} = \boldsymbol{NB}_{\boldsymbol{at}} - \boldsymbol{NB}_{\boldsymbol{bt}} \tag{10}$$

2.5 Results and Discussion

For each scenario, the MW output, emission savings, and revenue streams are shown in Table 2-4

Table 2-4: Summary of Results

		Scenario 1	**Scenario 2**		**Scenario 3**				**Scenario 4**			
					40% transmission derating		**50% transmission derating**		**40% transmission derating**		**50% transmission derating**	
			Act.	**Chg.**	**Act.**	**Chg.**	**Act.**	**Chg.**	**Act.**	**Chg.**	**Act.**	**Chg.**
Output (MW)	Coal	1,274	1,274	0	1,153	-9	1,173	-8	1,152	-10	1,173	-8
	Natural gas	461	461	0	582	26	651	41	583	26	651	41
	Nuclear	800	800	0	800	0	681	-15	800	0	681	-15
	Renewables	600	600	0	600	0	600	0	600	0	600	0
	Total	3,135	3,135	0	3,135	0	3,105	-1	3,135	0	3,105	-1
Emissions (tons of CO_{2e})	Coal	1,156	1,156	0	1,046	-9	1,064	-8	1,045	-10	1,064	-8
	Natural gas	251	251	0	317	26	354	41	317	26	354	41
	Total	1,407	1,407	0	1,363	-3	1,418	1	1,362	-3	1,418	1
Generator Net Benefits ($)	Coal	15,292	5,100	-67	8,996	-41	1,329,205	8,592	4,010	-74	1,282,273	8,285
	Natural gas	4,391	4,392	0	5,975	36	1,259,586	28,588	6,458	47	1,243,962	28,232
	Nuclear	18,699	28,299	51	6,871	-63	7,430	-60	22,827	22	7,430	-60
	Renewables	10,722	17,922	67	8,109	-24	667,374	6,124	17,613	64	667,374	6,124
Other Revenues ($)	Load	-90,507	-128,127	-42	-88,907	2	-4,678,337	-5,069	-133,824	-48	-4,678,337	-5,069
	Government + FTR holders	0	31,017	N/A	15,460	N/A	1,369,200	N/A	39,412	N/A	1,400,478	N/A

In the table, *Act.* refers actual value and *Chg.* refers to percentage change from the base case. Scenario 1 is the base case. Scenario 2 is a case without congestion and 22\$/tonCO_{2e}. Scenario 3 is the case with congestion and without a carbon tax. Scenario 4 is a case with congestion and 22 \$/tonCO_{2e}. The results indicate that a carbon tax would improve the net benefits of renewables but would not effectively reduce emissions. Additionally, depending on the location, transmission congestion could improve or diminish the impact of a carbon tax.

2.5.1 No Emission Savings with Large Price Spread

Scenario 2: As shown in Table 2-4, a carbon tax had no impact on total emissions without congestion because the price spread among generators was large. When renewables are significantly cheaper than other generators, they are always dispatched at their maximum rated capacity. A carbon tax is applied to decrease the output from the coal and natural gas generators and increase the output from the renewables. However, since the renewables are already generating at their maximum rated capacity, they cannot increase their output. Therefore, the output from the coal and natural gas generators will remain unchanged, and their emissions will not be reduced. In this case, only decreasing demand could reduce emissions.

Scenario 3: Transmission congestion, irrespective of any carbon tax or subsidies, could significantly alter the generator dispatch and therefore total emissions. For example, when a transmission line connecting a renewable is congested, a coal generator could replace its output. Therefore, total system emissions would increase. Conversely, when a transmission line connecting a coal generator is congested, its output could be replaced by a renewable. Therefore, total system emissions would decrease. As shown in Table 2-4, when lines were derated to 50% of rated capacity, total system emissions increased by about 1% from the base case, and when lines were derated to 40% of rated capacity, total system emissions decreased by 3% from the base case. For the 50% transmission derating case, both coal and natural gas generators were dispatched to replace the curtailed output of the nuclear generators. Thus, total system emissions increased.

Whereas, for the 40% transmission derating case, the natural gas generators were dispatched to replace the curtailed output of the coal generators. Thus, total system emissions decreased.

Scenario 4: A carbon tax again did not reduce total emissions because the price spread among generators was large. However, irrespective of the carbon tax, congestion had a significant impact on emissions reductions like Scenario 3.

In summary, in the short run:

- ***Large price spreads*** result in renewables being dispatched at their maximum rated capacity. Therefore, a carbon tax would be ineffective in reducing emissions.
- ***Congestion*** in a power system can significantly alter the generator dispatch, and thus change the magnitude and direction of the anticipated emissions savings.

2.5.2 Revenue Streams – Who Earns and Who Pays

2.5.2.1 Renewables – Benefit from a Carbon Tax

Scenario 2: Taxing emissions in an uncongested system will increase total system costs and increase LMPs. Therefore; the net benefits to renewable generators will increase. As shown in Table 2-4, the addition of a \$22/tonCO_{2e} tax increased the net benefits of the renewables by 67% from the base case. If $P_{bt} = P_{at} = P_{max}$, the change in the net benefits of the renewables is $P_{max}\,(LMP_{at} - LMP_{bt})$. Since $LMP_{at} > LMP_{bt}$ and $P_{max}>0$, the change in the net benefits is positive. This result illustrates that renewables would become the beneficiaries of a carbon tax and would reap additional benefits at no extra cost.

Scenario 3: Depending on the location and intensity of the congestion, the net benefits of the renewables could change significantly. For example, when transmission lines were derated to 50% of rated capacity, the net benefits of the renewables increased by approximately 6,000%, and when transmission lines were derated to 40% of rated capacity, the net benefits of the renewables increased by only approximately 24%. Had the transmission capacity reductions been on different lines, the dispatch order of the generators would have changed, and the revenue streams for the renewables would also have changed.

Scenario 4: The net benefits of the renewables for Scenario 4 were like those of Scenario 3, except when the transmission lines were derated to 40% of rated capacity. Again, depending on the location and intensity of the congestion, the net benefits of the renewables could change significantly.

2.5.2.2 Coal and Natural Gas Carbon Tax Payment Depends on Congestion

Scenario 2: In an uncongested power system, unless compensated by an increase in LMPs, coal and natural gas generators will lose revenue due to a carbon tax, and their change in net benefits will be either zero or negative. It will be zero for marginal generators, and it will be negative for inframarginal generators. For a marginal generator[6], $LMP_{at} = LMP_{bt}$ + tax and if $P_{at} = P_{bt}$, then the change in the net benefits will be zero. For others, if (LMP_{at} -LMP_{bt}) < tax (i.e., the change in LMP does not compensate for the tax) and if $P_{at} = P_{bt}$, then the change in the net benefits will be negative.

Scenario 3: Depending on the location and intensity of the congestion, the net benefits of the coal and natural gas generators could change significantly. As shown in Table 2-4, when transmission lines were derated to 50% of rated capacity, the net benefits of the coal generators increased by over 8,000% from the base case, and the net benefits of the natural gas generators increased by over 28,000% from the base case. Similarly, when transmission lines were derated to 40% of rated capacity, the net benefits of the coal generators decreased by 41% from the base case, and the net benefits of the natural gas generators increased by 36% from the base case.

Scenario 4: Like Scenario 3, the net-benefits of the coal and natural gas generators are heavily influenced by the location and intensity of the transmission congestion as shown in Table 2-4.

In summary, in the short run,

- ***Irrespective of the price spreads***, the change in the net benefits of the coal and natural gas generators would be either zero (for marginal generators) or negative (for inframarginal generators - unless compensated by an increase in LMP).

[6]In Scenario 2, the natural gas generator U197 is the marginal generator.

- ***Congestion***, depending on its location and intensity, could significantly change the magnitude and direction of the revenue streams of the coal and natural gas generators.

2.5.2.3 Load and Government

Scenarios 1, 2, 3 and 4: As shown in Table 2-4, for all scenarios, at the end of the day load pays all costs. A carbon tax would increase system costs and LMPs and thus decrease the net benefits of the load. If load remains constant ($P_{L_{bt}} = P_{L_{at}} = P_L$), the change in the net benefits, $\Delta NB_L = P_L\,(LMP_{L_{bt}} - LMP_{L_{at}})$, is negative since $LMP_{L_{bt}} < LMP_{L_{at}}$. The change in the net benefits is positive when $LMP_{L_{bt}} > LMP_{L_{at}}$ and this can only happen if congestion is present. For example, in Scenario 4 when transmission lines were derated to 50% of rated capacity, the load at bus 16 consumed 110 MW and received \$7.22 thousand ($110\ MWh \times -\$65.64/MWh$). The change in the net benefits for the load was thus positive (since $LMP_{L_{bt}} > LMP_{L_{at}}$). Negative LMPs are not rare in U.S. electricity markets [83-88]. Areas with high wind often have negative wholesale prices [83], and loads who purchase energy in these regions can make money by consuming power and thus increase their net benefits.

Like congestion, a large price spread could alter load revenues. The total system cost of a power system with both a large price spread, and a carbon tax is less than with just a carbon tax. This is because, with a large price spread, renewables are less expensive. A carbon tax would increase the amount paid by the load, and the price spread would decrease it. The net change in payment depends on the tax rate and price spread. A large price spread would offset the effect of a carbon tax and change the amount paid by the load.

In summary, in the short run:

- ***A Large price spread*** would lower the total system cost and would lower the amount paid by the load, which would offset the effects of a carbon tax.
- ***Congestion*** could interact with a carbon tax and change the amount paid by the load. Thus, both revenues (congestion rents and carbon taxes) should be carefully recycled to minimize any negative distributional impacts.

2.5.3 Sensitivity of the Results

To test the sensitivity of the results to different assumptions I varied the value of the carbon tax and the amount of congestion; the carbon tax was varied from \$0/tonCO_{2e} to \$22/tonCO_{2e} in five steps and the transmission lines 14-16 and 7-8 were derated to 40% and 50% of their rated values (over 90% of actual carbon taxes are less than \$22/tonCO_{2e} [89]. For the changes in the carbon tax, the results show that in a system with a large price spread, all else being equal, the emission savings may be insensitive to the changes in the carbon tax, but the revenue streams may be sensitive to them. For example, contrary to popular belief [8; 10; 11; 90-94], in a system with large price spreads and fixed transmission congestion, increasing the carbon tax did not decrease emissions, but it did increase the benefits to the renewables and the monetary burden to load.

Besides, the results suggest that in a system with large price spreads, all else being equal, both emission savings and revenue streams would be sensitive to the location and intensity of the congestion. If transmission congestion curtails the output of a coal generator, then total emissions would be reduced. However, if it curtails the output of renewable generators, then emissions would increase. For example, derating line 7-8 would curtail the output of the U100 renewable generators. Thus, total system emissions would increase.

2.6 Conclusion

Power plants are the largest stationary sources of GHG around the world; in many countries, a carbon tax may be an effective method to mitigate these emissions. Successful implementation of a carbon tax requires understanding how a carbon tax will change power system operations and be shaped by the existing policy and operational context of the electric power system. While a carbon tax has significant theoretical advantages, power systems operating conditions, like transmission congestion and large price spreads (due to subsidies created by other energy policies), can alter carbon-tax effectiveness, especially in the short run. I examined the impact of a carbon tax in a wholesale electricity market with and without congestion and with large price spreads and using a modified IEEE RTS 28-bus model. I then evaluated the effectiveness of this tax in terms of emission savings and revenue streams for generators, loads and the government. I focused on standard U.S. electricity market practices, but the results are equally applicable to any electricity market that uses Economic Dispatch (ED) and has congestion and legacy energy policies that create price spreads.

The results show that **a large price spread could change the generator dispatch, reduce average prices, and diminish the carbon tax effectiveness**. For a system with a large price spread and without the proper mechanisms for recycling tax revenues, a carbon tax may not reduce emissions, and it could increase the revenues for renewables at the expense of electricity consumers. However, in the longer term, a carbon tax could provide important incentives for the construction of low-carbon generation resources. If power system operational aspects were not studied, these interactions would never be highlighted, and the predicted effectiveness of a carbon tax would be significantly different from the actual effectiveness.

2.7 Policy Implications

This essay answers the key policy questions raised in section 2.3. The major policy implications from this research are twofold. First, any new energy policy needs to be evaluated in the context of the existing power system operations and energy policy environment. Second, implementation of a carbon tax could be undermined—in the short term—by existing power system operating conditions and existing policies.

A carbon tax remains a popular policy instrument to abate GHG, and the power sector is a prime candidate for a carbon tax because power plants are stationary, their emissions are accurately monitored and recorded, and they are owned and operated by a small number of companies. Abating emissions from this sector could provide significant GHG reductions cost-effectively. Several countries are considering implementing a price on carbon. For example, the liberal party in Canada just announced its carbon tax plan for 2018 [95]. This plan encourages the remaining Canadian provinces to levy a carbon tax that increases from a minimum of \$10/tonCO_{2e} in 2018 to \$50/tonCO_{2e} in 2022. Another example is China. Starting in 2017, China is launching a full-fledged emission trading scheme, with an auction price ranging from ~\$2/tonCO_{2e} to ~\$16/tonCO_{2e}[7] [96], for curbing its CO_{2e} emissions. Similarly, several U.S. states like Massachusetts, Washington, Vermont, Oregon, and Rhode Island are also considering a carbon tax [97-99]. When these countries or its provinces/states tax the emissions from power plants, the tax will be implemented on legacy energy systems with a suite of existing policies (e.g., FIT in China/Germany/UK or parts of Canada, PTCs in the United States, Renewable Portfolio Standards in the United States or Canadian provinces) that could influence the effectiveness of a tax. Policymakers would need to decide on a carbon tax rate and predict its effectiveness both in terms of emissions savings and the revenues generated from the tax. Until now, it has been a common trend to study only the economic, environmental and political interactions of a carbon tax. During actual implementation, operational and existing policy interactions become significant. In the short term, power system operating conditions, like transmission congestion and interacting energy policies to promote renewables, could undermine the effectiveness of a carbon tax – each of these is described below.

[7] These numbers are based on the pilot emission trading schemes in China.

1. In Sections 2.2.1 and 2.5.1, I show how a large price spread, like that created by a PTC, can undermine emissions reductions. While a carbon tax should penalize the polluter (not incentivize a non-polluter) and reduce emissions, existing energy policies could interact with the tax implementation. Many regions in the United States currently have a large price spread due to subsidies like PTCs, which incentivizes renewable deployment. Therefore, examining policy interactions is particularly important in these regions before a carbon tax is adopted. Otherwise, a carbon tax may not effectively reduce emissions.
2. Sections 2.5.1 and 2.5.2 (Scenarios 3 & 4) showed how power system operational issues, like transmission congestion, could change the generator dispatch and completely alter the anticipated emission savings and revenue streams from a carbon tax. Ensuring that policymakers understand the interactions between wholesale electricity markets and a new tax is critical.

These policy and operational contexts can interact with one another. For example, the Mid-Continent Independent System Operator (MISO) region of the United States is facing significant transmission congestion due to increasing levels of wind that cannot be delivered to load, capacity reserves that are concentrated in the west and central regions, and administrative and institutional difference at the borders with other system operators [100]. Therefore, if the emission savings and revenue streams from a carbon tax were calculated for this region, without taking congestion and price spread into account, their ex-ante values would be significantly different from their ex-post values.

Power system operations and the existing policy environment will shape the implementation of new energy policy initiatives in important ways. As I have shown in this work, traditional economic models fail to highlight these important interactions between a carbon tax, congestion and price spread. While the specific numbers presented in this essay cannot be extrapolated to a real system, **the results demonstrate that power system conditions and legacy policies influence the price spread, which affects both the *magnitude and the sign* of system-wide GHG and the flow of revenue streams caused by a carbon tax**. The results show that in a system with a large price spread, without proper recycling mechanisms for both tax and congestion revenues, a carbon tax may be ineffective in reducing emissions and may increase the revenue of renewables at the expense of electricity consumers. Therefore, understanding these interactions will help improve the design of a carbon tax or any new energy policy initiative and ensure its effectiveness.

2.8 Limitations and Further Research

While a lot of effort was put into improving the model and methods, this research used basic market principles to simulate using an IEEE test model. Therefore, an interesting avenue for further research would be to use real data to conduct a similar experiment.

2.9 My Contributions

The work presented in this essay is a part of a collaborative effort with Professor Bruce F. Wollenberg (University of Minnesota), Professor Elizabeth J. Wilson (Dartmouth

College) and Dr. Anthony Giacomoni (Pennsylvania Jersey Maryland Interconnection LLC). I was the primary researcher, and my contributions are concept creation, literature review, gap-identification, mathematical formulation, analysis, result inference, and the content write-up. Prof. Elizabeth J. Wilson and Dr. Anthony Giacomoni were responsible for editorial advice and concept refinement. Being the author of the Unit Commitment program that was used in this essay, Prof. Bruce F. Wollenberg was responsible for technical guidance. A shorter version of this essay is published in Elsevier Energy, [101] DOI: https://doi.org/10.1016/j.tej.2017.06.004

2.10 Acknowledgement

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3. Non-Financial Barriers to Combined Heat and Power In The United States – A Qualitative Study

3.1 Introduction

Imperatives to create reliable and resilient energy systems in the face of shifting climate and weather risks while reducing energy sector Greenhouse Gases (GHG) and other environmental emissions from electricity, heat, and transportation are driving countries to support the deployment of low-carbon energy systems, including large and small-scale renewable generation and by improving end-use energy efficiency. While many research projects focus on electricity or transportation sectors, fewer explore the integration of heat into future energy mixes. Combined Heat and Power (CHP) systems can fill several interesting niches; the technology can reduce GHG by utilizing heat that would be otherwise wasted in generating electricity [102], they can provide low-carbon heating and cooling depending on the fuel source (biomass, natural or renewable gas, waste, or coal); and if designed for operational flexibility, they can enhance system resilience and help integrate variable renewable resources into energy systems [103].

CHP is a low-risk and mature technology, widely used around the world for industrial processes and heating and cooling residential and commercial buildings. While CHP plants were initially developed to fulfill electricity and heating needs, newer CHP plants are being deployed that can rapidly start-up and ramp their power output can, with associated water storage tanks, also provide "flexibility" to the electrical grid to aid in integrating variable energy sources like wind and solar [104]. Local energy and heat generated by CHP plants can also enhance local energy system reliability in the face of storms or large-scale power loss [105].

Over 50% of the electricity generated in Denmark and over 30% of electricity generated in Russia comes from CHP; in the United States, only eight percent of electricity is produced from CHP [106]. While the U.S. Department of Energy estimates a technical potential of 240 GW [105], the U.S. has installed 83 GW. Lower energy costs in the United States make some projects un-economic, but non-financial barriers also stand in the way of CHP projects.

There has been a significant amount of work in understanding the low rates of adoption of energy efficiency technologies, compared to their technical potential. This discrepancy is often described as the "energy paradox" or "energy-efficiency gap" [107], which implies consumers behave irrationally [108] as the economic calculations are favorable. However, there are has been very little work on the "gap" in CHP adoption. Previous studies on CHP have generally focused on financial barriers. For example, the state-by-state study of CHP in the United States [109] identify financial barriers like "spark spread," standby rates, and project financing as the primary barriers. Only very rarely non-economic barriers are highlighted. For example, Stowe [110] identifies the utility business model and lack of education as significant barriers for CHP in the data centers. Similarly, Hampson [105] identifies unclear value proposition, market and nonmarket uncertainties, awareness among the decision makers and local siting/permitting as major barriers and Stowe [110] identify lack of existing policies as a major barrier.

Similarly, one study in the United States studies and one in the United Kingdom (U.K.) [111] include organizational barriers that make financially viable CHP projects unattractive. The U.K. study is the only one that identifies barriers related to the influence of individual agency, i.e., the beliefs and actions of different people; independent of the social structure they work within. Keeping everything else constant (profitability of CHP, its ownership structure and the knowledge about CHP within the organization), an econometric study by [112] finds complex regulatory requirements to be a barrier for CHP adoption. A handful of other studies from the European Union talk about the non-financial barriers. For example, Vietor et al. [113] finds the most prominent barriers to diffusion of CHP in Germany Ruhr Valley are the lack of CHP installation and service companies, lack of knowledge among potential users, poor match with user preferences, and lobbying against pro-CHP policies by the coal and gas industries. Veen van der et al. [114] find that the main barrier to the diffusion of CHP in Denmark is a rule that prevents companies from selling CHP-generated electricity, and Wright et al. [115] use a case study in the United Kingdom to identify site-specific needs like capital structuring and contractual details, and non-site-specific needs like price uncertainty as the prominent barriers for diffusion of CHP.

3.1.1 Key Academic Questions

The existing literature has understudied the non-financial barriers for CHP in the United States. For these non-financial barriers, they are unable to explain how the individual agency and opinion leadership (socio-political aspects) can affect the implementation decision and how different policies can address them. This essay addresses this gap in the literature by exploring the barriers that prevent financially viable CHP plants from being built. For these non-financial barriers, it investigates the following questions by using qualitative analysis (see Section 3.3 for details on methods).

1. What kinds of non-financial obstacles were faced during the CHP implementation process?

2. How can an individual agency; opinion leadership and larger policies affect the implementation decision to construct the CHP plant/facility?

The rest of this essay is organized as follows: Section 3.2 presents the background, Section 3.3 shows the methods, Section 3.5 presents the results and discusses them, Section 3.6 concludes and Section 3.7 presents the policy implications. Readers, who are familiar with the policy context of CHP in the United States, can directly skip to Section 3.3 and continue after that.

3.2 Background

The CHP policy context has gone through massive shifts: before the late 1970s, there were no U.S. federal or state policies encouraging CHP deployment but the 1978 Public Utilities Regulatory Policies Act (PURPA), incentivized CHP by forcing utilities to buy electricity from cost-competitive independent generators. Many CHP power plants—especially in the industrial sector—were cost-competitive and installed CHP capacity increased from 12GW in 1980 to 74 GW in 2004, (Figure 3-1). While CHP facilities can still benefit from a 10% investment tax credit, the Energy Policy Act of 2005 removed the requirement that utilities purchase electricity from CHP facilities and instead directed the Utilities to sell their power through competitive markets, and coupled with high natural gas prices (69% of US CHP plants) resulting in only 5.4GW of CHP installed from 2005-2015 [116].

Currently, 66% of U.S. CHPs facilities have capacities greater than 100MW, and 80% (65.6GW) of CHP capacity is concentrated in the industrial sector (146 GW), especially petrochemicals and pulp and paper, as well as in the commercial area (76GW), district heating (11GW) and waste-to-energy (7GW). (See Figure 3-1) [116]. Policies that explicitly support and facilitate CHP installations are lacking at the federal level. However, some states have adopted policies to encourage CHP plant development (see Figure 3-2) through climate and energy plans.

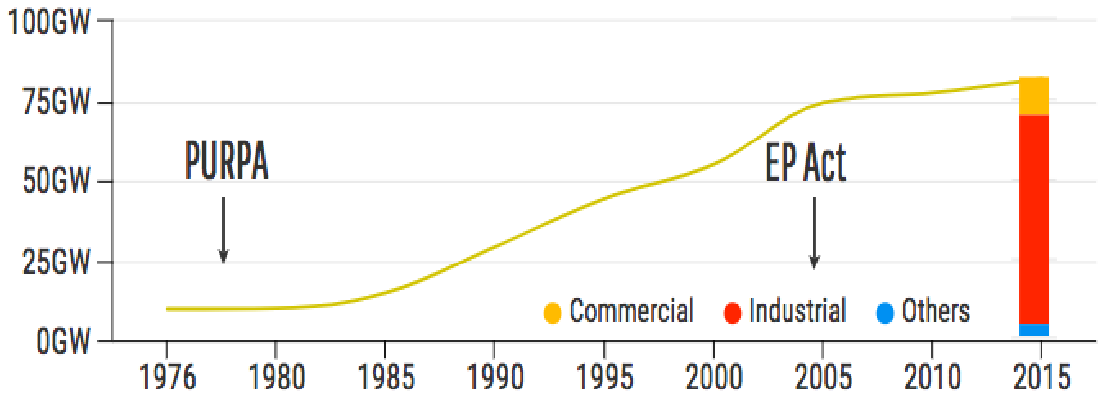

Figure 3-1: Cumulative CHP installations

In this figure, PURPA refers to Public Utility Regulatory Policies Act and EP Act refers to Energy Policy Act. The data for this figure were collected from US DOE CHP Installation Database [116].

For example, the Massachusetts Alternative Portfolio Standard (APS) requires retail electricity suppliers to acquire Alternative Energy Certificates (AEC) from qualifying technologies like CHP and the state Utility Energy Efficiency program provides incentives of up to $750/kW and 50% of feasibility cost for improving efficiency using technologies like CHP.

CHP is a mature technology with promising future capabilities. The installed CHP capacity is only one-third of the 240GW of the technical potential estimated by the United States Department of Energy [105]. However, technological viability is different than economic viability. Assuming companies can compare CHP with other alternatives if it has a payback of fewer than ten years, this time frame is considered for calculating economic viability. A report prepared for the Minnesota Department of Commerce [117] finds that 33% of Minnesota's technical CHP potential (~12.5GW) has a payback of fewer than ten years. Similarly, a different study estimates a lower total United States technical potential of 123 GW and predicts 33% of that has a payback of fewer than ten years [118]. This massive, unexploited potential for financially viable projects suggests that CHP faces significant non-financial barriers. This essay investigates those non-financial barriers through multiple methods and expert elicitations.

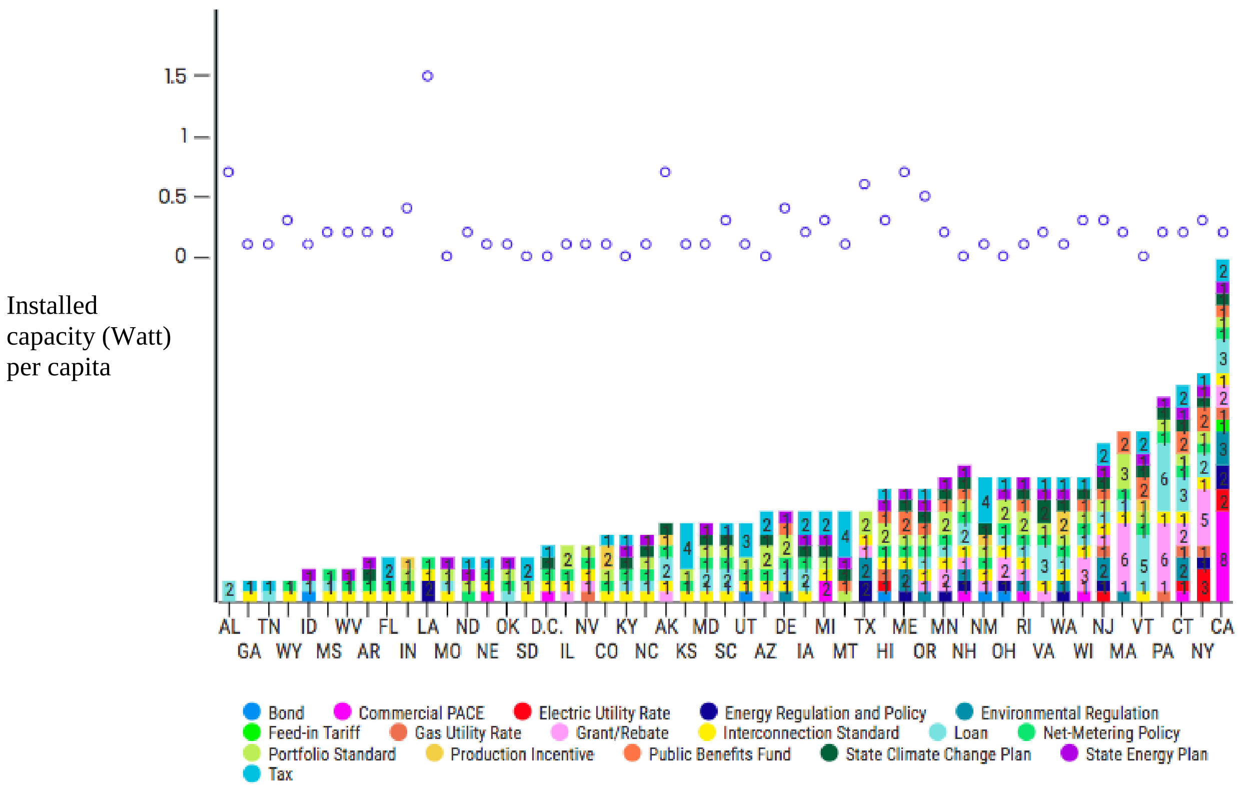

Figure 3-2: CHP installations (Watt) per capital and the policy count for each 50 states

The right-hand Y-axis shows the installed CHP capacity per capita in watts. It illustrates that more CHP policies do not necessarily translate into more CHP installations. Instead, the existing ones should rather be effective. Section 3.7 presents policy recommendations. The data for this figure were collected from US DOE CHP Installation Database [116] and CHP Policies and Incentives Database [119].

3.3 Key Policy Questions

Considering the crippled market diffusion of a matured engineering technology that has immense future potential, this essay seeks answers to the following policy questions

a) Do we need to evaluate the market diffusion of CHP from a socio-political context? Is the market stagnant only because of the financial barriers?

b) What are the non-financial barriers, if any? How can they be alleviated?

3.4 Methods

This essay focuses on the barriers that prevent financially viable CHP plants from being built. It uses a combination of document analysis and semi-structured interviews to answer these questions. First, document analysis was conducted. Documents are a vital source of information [120]. They can be affected by regulatory and institutional settings surrounding them. For states like Minnesota, that are actively exploring options to increase the total GW of CHP installations, such documents can act as an active agent of interactions that are happening in the state. Therefore, the existing policies, that are relevant to CHP, throughout various states in the United States [119] were analyzed.

Figure 3-2 summarizes the CHP installations per capita and the different policies for all the 50 states and District of Columbia. The stacked bar chart, policy count, is the count of policies that are categorized for every state based on the colored legend given in this figure by the United States Environmental Protection Agency. After analyzing these policies, for states like Minnesota, working documents like from Minnesota Department of Commerce (MN-DOC) stakeholder process documents [121]were analyzed. Reports from MN-DOC stakeholder process illustrated the legitimate social means that were used in Minnesota to create and change policies to increase penetration of CHP. For each of these documents, three things a) author b) relevant policies and c) barriers/opportunities - if any were identified. The authors of these documents were the candidate interviewees[8].

Table 3-1: Expert Breakdown

Affiliation	Number of experts
Independent developers (2) and users (9)	11
Utilities	6
Government agencies (regulatory, legislative)	9
Advocates and consultants	6

After document analysis, semi-structured interviews were conducted with 32 experts (Table 3-1 contains the categorical breakdown of the experts) who were working in various roles related to CHP. Interviews were conducted to get the first-hand account from the people who have lived through the process of installing CHPs and rejecting them. The meetings were either conducted in-person or by telephone. Each of these

[8] Details pertaining to interview subjects and the recruitment process are described in appendix.

interviews lasted between 45-75 minutes. The interviews were transcribed, coded, reconciled and triangulated to obtain a final set of codes. From the final set of code, three themes, as described in results emerged.

3.4.1 Interview Protocol

The interviews were focused on the chronology of CHP project development and the dynamics of the social order around it. Experts were interviewed about individual CHP projects in which they had been involved, focusing on these areas: formulating the problem and understanding the policy, business, and organizational environment, integrating into this environment and evaluating the implementation (actual interview guide is attached in the supplementary information). Problem-formulation questions were asked to understand what problem the interviewee was trying to solve by building a CHP plant, why he or she chose CHP, and what other options he or she considered. The existing-system questions sought to understand the organizational structure and cultural characteristics that facilitated implementation. The integration questions focused on barriers when implementing a CHP project in the existing system as well as the factors that influenced designing the plan for that system. The post-implementation evaluation questions examined how successful a CHP project was. Besides, the interviewees were also asked open-ended questions about barriers to improving diffusion of CHP and questions about how they would facilitate or block a hypothetical CHP plant if they were a supporter or an adversary.

Table 3-2: Code and themes

Theme number	Final codes	Codes from document analysis
The business model of the utility	Utility rate, energy regulation, environmental regulation, tariff, interconnection, net-metering, revenue-erosion	Utility contracts, standby rates, utility business model
Negative subjective impressions	Not-alluring, education, training, knowledge, business priority, organization culture	Education, lack of knowledge, organizational culture
Allocation of risks and benefits	Complicated, multiple, output, benefit sharing, price risk, hedge risk.	

3.4.2 Data Analysis

The interviews were analyzed through qualitative coding and triangulation of themes. The interviews were segmented for each phase of the implementation process in implementation - understanding the problem and the existing system, actual implementation and post-implementation evaluation. Initially, 10-random transcripts were coded based on the codes from the document analysis. During this coding process, expert statements and broader themes were consistently triangulated to refine the codes. Therefore, after coding these ten interviews, some codes from the document analysis were dropped, others were reconciled, and yet other newer codes emerged. The codes from the first ten interviews were used to code another set of ten random interviews. This process was repeated until all the transcripts were coded and a final agreeable set of codes was obtained. Finally, these last codes were sorted into three themes (results). The codes from document analysis, the final agreeable-set of codes and the themes (results) are listed in Table 3-2. Intercoder agreement technique [122] was used to reconcile the codes. It is particularly useful in this essay because one of the researchers (who conducted the interviews and transcribed them) is more knowledgeable on the subject matter than others. After several iterations of reconciliation, triangulation, and revision, the Intercoder agreement was over 97% (100 $*$ agreement/(agreement + disagreement)).

3.5 Result and Discussion

Three categories of non-financial barriers to CHP projects emerge from the data: a) the business model of the electrical utility b) negative subjective impressions and c) allocation of the risks and benefits. The following Section describes them in greater detail. Different groups of interviewees emphasize different barriers: utilities don't consider their business model a barrier; government agencies don't think that there are negative subjective impressions for CHP, and independent installers consider the allocation of risks and benefits to be less critical than others. Figure 3-3 illustrates these differences between the groups by plotting the frequency with which different categories of interviewees discuss each type of barriers.

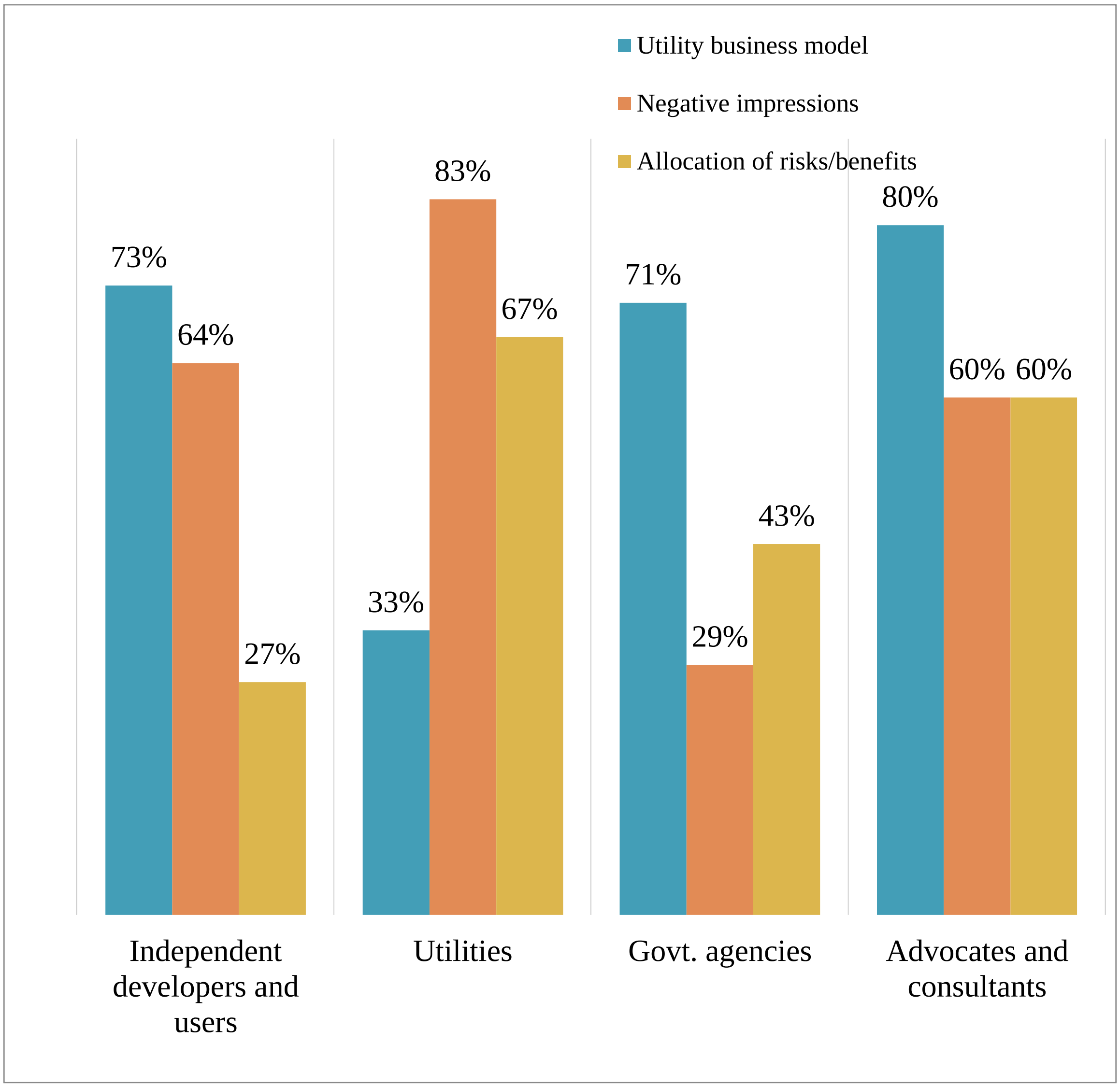

Figure 3-3: Non-financial barriers broken down for each subclass of interviewees.

The X-axis is the percentage of interviewees and Y-axis is their category. Everyone but the utilities consider the business model of the utility to be a significant barrier.

3.5.1 The Business Model of the Electricity Provider

Many interviewees describe building CHP plants in the territory of investor-owned utilities (IOU), especially in electricity-only utilities, is difficult because of their business model. Over 70% of the independent developers, users, government agencies, advocates and consultants who were interviewed feel this was one of the most substantial non-financial barriers, but only 33% of the utilities had such an impression. The regulatory system gives powerful incentives for utilities to increase electricity sales. With the present business model, their profits are proportional to the volume of electricity sold. Customer-owned CHP would reduce electricity sales and thus their profits. One interviewee explains that customer-owned CHP can look like “revenue erosion” to a utility, and another stated that a “utility has the strong reason to oppose the loss of electricity sales.” One of the owners mentions that after a CHP project was announced, the utility “actually sent their president over to talk to [our president], encouraging him [not to do the project].” Another interviewee adds that unless we are successful in pivoting IOUs to “a different revenue model in which [they] become agnostic as to how much electricity they sell or how much natural gas they sell,” increasing the market penetration of CHP is difficult.

In contrast, interviewees describe municipal and cooperative utilities as less opposed to CHP. Those types of utilities have a nonprofit business model and are focused more on selling energy at a reasonable cost, so they are less worried about revenue erosion and return on investment. For example, an interviewee from a municipal utility says “[selling]

energy at the most reasonable price possible [is our aim] and if CHP [helps to] drive those customer needs, [we`ll] be pursuing in that direction.” Municipal and cooperative utilities can also be more flexible and make decisions more quickly than IOUs because they are governed more directly by their customers and do not require approval from the regulators.

IOUs hamper customer-owned CHP by imposing technical requirements like interconnection standards and financial barriers like high standby rates. One developer said, “we were watching [the utility] pretty carefully to see what it [was] up to because they could suddenly drive [to] increase the standby charges so badly that this project would [be stalled].” As customer-owned CHP is “revenue erosion” for the utilities, they sometimes oppose already-operating projects. For example, the owner of a biomass-fueled plant says, “We have 4 years left on our PPA [Power Purchase Agreement]. [If] they don't tend to purchase biomass produced electricity as before, that would impact on our finances.”

IOUs generally do not build their CHP plants because they are a complicated solution for providing power (as CHP typically operate to generate heat first and electricity second). A CHP generator is typically smaller than a conventional generator, and it straddles different policy boxes because separate regulations and incentive programs cover them differently. Instead, utilities prefer to build a sizeable thermal generator that benefits from economies of scale and has only an electricity customer or a renewable generator that benefit from government incentives. IOUs also face the risk that the Public Utilities Commission (PUC) might not approve their cost recovery.

If IOUs oppose CHP development, how do CHP plants get built at all? In general, either the PUC that regulates the IOU is pro-CHP or the customer building the CHP plant is a high-value customer to the utility. One interviewee compares IOU's and PUC's relationship as that of a sunflower and the sun. He says, “Sunflowers will track the sun across the sky. Utilities will find and track what their regulators want and will follow them.” For example, utilities in states where the PUC supports a CHP (e.g., biomass) are much more likely to build these projects. In Minnesota, 24MW of biomass-based CHP was installed from 2009-2014 because, as a regulator from Minnesota explained, “[statue] directs us that we approve [biomass-based CHPs] regardless of prices.” Another interviewee, when asked about how their CHP was financed, says, “We are a regulated utility. So, the cost that it takes for us to provide service to our customers [is] covered under the [rate structures that] our [stateX] regulators set.” Large or high-value electrical customers can often persuade the utility to accept a CHP project. An interviewee said, “The only reason that a utility wants a CHP unit is that the customer is [significant] to the utility and they want the customer to be happy.” He further adds an example, “[Customer X] is largest [regarding] total load that they serve. [This customer] wanted to build a co-generation facility.” Because this customer was “such a large and important customer,” the utility worked with them to overcome the barriers.

3.5.2 Negative Subjective Impressions Based on Anecdotal Evidence

Personal, psychological and contextual factors combine to shape decision-makers' opinion of CHP. Many current CHP plant owners and operators describe having negative impressions of CHP before they evaluated it for their facility, like one who had the impression that installing CHP was "a never-ending process." Most of our non-governmental interviewees (over 60% of them) describe negative subjective impressions as a major impediment. Many decision-makers' negative perceptions seem to stem from their lack of knowledge and experience. An interviewee from the malting industry describes struggling in “trying to pull other [knowledgeable] people” to help them fill the knowledge gap before and during the initial stages of their CHP installation. Negative perceptions are most common in industries where CHP plants are uncommon. Opportunities to install a CHP plant are rare; they usually come when a heating system needs to be upgraded or replaced, which happens only once every few decades. Therefore, prospective owners/operators must rely on anecdotal evidence from others.

Their attitudes towards competing technologies also shape Decision-makers’ attitudes towards CHP. A CHP plant owner describes it as not being “as alluring technology [like] solar and wind,” and another says “It is not a flashy, sexy thing. It is not solar. It is not wind.” A third owner admits CHP is “frankly [p]retty boring.”

When CHP (or energy) is not part of their core business, they are afraid that CHP would be too big of a distraction [123] for them to handle. For example, an interviewee explains that allocating money to install a CHP plant must compete with "research, teaching, and outreach. And, so if academic health department comes along and says that we must put up a brand-new hospital, our CFO will say wait a minute, I have a bulk of money here. Am I going to build a CHP or am I going to build a hospital?"

An opinion leader who advocates for CHP can help overcome initial negative perceptions of the decision-maker. A CHP user says, "Somebody has to champion these things. Somebody has got to say. This is what we are going to do." An opinion leader can align CHP with their other organizational goals. Opinion leaders have a variety of motivations. One interviewee explains "We decided to put the CHP because it [would] be able to eliminate our boiler system; [it] serves the entire plant's need." Another interviewee adds, "I knew that putting in a package boiler just to make steam was not a very smart thing to do from [the] sustainability point of view, from a cost point of view, etc." Another developer decided to install a CHP plant, despite a payback period of 20 years, because their institution wanted to achieve "zero carbon by 2050." Similarly, for another facility, "the efficiency of the arrangement" and "the waste reduction" was the prominent driver. They do not look for the immediate return on investments but value their broader organizational goals (e.g., going green or minimizing waste).

Many interviewees, except those from government agencies, believe these negative subjective impressions are a significant barrier. One independent developer explained that working together with the client and educating them is a significant aspect for cashing this rare window of opportunity. Another user explains "education is the main tool" when the decision makers "do not understand [and] know [what] co-generation is." Another consultant explained how he envisions of having "CEO only" meetings to create positive impressions of CHP among the opinion leaders. Another developer explained that they often find that "the boundaries of the projects are very limiting, [so they] talk about what's on edge, what is beyond the bounds" and convince the decision makes to consider CHP.

3.5.3 The Risks and Benefits of Multiple Cost and Revenue Steams

Allocating "who pays and where do the benefits accrue" can be a major barrier to CHP projects with separate customers for the heat and electrical outputs. Most non-government interviewees (over 60% of them) think this is an important barrier, but it is mentioned less than the other two barriers described above. One interviewee said the "holy grail of CHP is some kind of deal structure that captures all the value streams and returns them to the parties that are bearing the risk." Those deal structures and business agreements are complicated. First, a project is exposed to both electricity price and fuel price risks. Second, some of the benefits accrue to both the electricity and heat customers, while other benefits are mutually exclusive, i.e., one customer loses when the other benefits. Third, owners and investors face 'off-take' risks, i.e., the likelihood that the customer for electricity or heat will shut down or otherwise exit the agreement.

A CHP project faces both fuel- and electricity-price risks. An interviewee from a state energy office says, "The more substantial risk is the risk on the commodity side of the natural gas [and] electricity." Most CHP plants are fueled by natural gas, which in the U.S. has historically more volatile prices than other fossil fuels. An owner/operator says, "Most of our risk and uncertainty is just based on natural gas prices. [...] We have been hedging that risk well with natural gas future purchasing positions. [...] It [provides] stable prices for our thermal BTUs." Some plants are designed to switch between fuel sources, such as natural and oil, depending on their relative price. For example, it is common for dual-fuel CHP plants to have "an interruptible gas contract" that allows supply to be cut off during peak demand times in exchange for a lower price the rest of the time. Several interviewees discussed biomass-fueled plants, but none described burning biomass to reduce fuel price risk.

The interdependence between the outputs of a CHP plant makes it more difficult to allocate fuel price and electricity price risks than a typical power plant or heating project that only provides one output. Comparatively lower percent of the interviewees (27% for independent developers to 67% for utilities) talked about the complications for CHP that arise due to interdependent outputs. For example, many CHP plants are operated to follow the heat load, which means that they may not be able to take advantage of high electricity prices or avoid low electricity prices. The same allocation problem also applies to other revenue sources. For example, the electricity produced by a CHP plant that burns biomass may receive renewable credits, but the heat generated does not. An interviewee says, "I have been beating the drums for a couple of years that if thermal energy is valued the same as electrical energy - from a renewable source - I think there should be a level playing field and the investment dollars will follow the best technology and best efficiency." At least one state addresses this problem with an Alternative Portfolio Standard that "specifically supports CHP and it provides a credit, an electronic certificate, for each MW [electric generation and useful thermal load] of CHP generation." Availability of such benefits has a direct impact on their finances. For example, an interviewee explains, "[The utilities] get some revenue by selling the APS credits, which is a meaningful amount." For example, a 1.8 MWe CHP plant with absorption chiller in Massachusetts could receive almost $600,000 per year from Alternative Energy Credits (AECs) [124]. At places where such credits don't exist, the developers and operators must rely on the Power Purchase Agreements (PPAs). An operator explains, "We have four years left on our [Power Purchase Agreement] for [a] renewable energy purchase agreement with the utility. [If] they don't tend to purchase biomass produced electricity in the same extent than that would impact on our finances."

In addition to fuel and electricity price risks, plants with separate heat and electricity customers face 'off-take' risk, i.e., the risk that the customer for electricity or heat will shut down or otherwise exit the agreement. If this happens, the remaining partner could lose money or service. An environmental advocate says building a CHP plant is "like getting married. If they're putting in with this company, they have to feel pretty sure that this company is going to stay there." Large companies are particularly averse to being locked into a long-term relationship. An interviewee explains, "one of the big barriers for these [...] potentially multinational companies that have a lot of little operations all over the place [is that] they're not going to invest in capital costs and operation if they're not certain about how long it's going to be around." A utility writes "many potential projects have not been implemented, due to the risk of stranded assets if the host customers were to go out of business or experience a significant reduction in operational demand [125]."

Much of the existing CHP capacity in the U.S. (over 60%) does not face this barrier because it is installed at industrial facilities that use both the heat and electricity outputs, such as petroleum refining, chemical manufacturing, and pulp-paper manufacturing. However, there is little opportunity for growth of CHP in those industries; so many new CHP systems will be installed in facilities that do not consume the entire heat and power outputs. One interviewee suggests doing smaller projects to reduce the risk or building movable CHP plants. She speculates about a movable project– "instead of going full in on the marriage, doing a smaller project that you could move, like a boiler or system that, if that energy user was gone, you could pick it up and put it somewhere else. That is probably less efficient, but that reduces some of that risk if that energy user's going to remain." Therefore, unless the "holy grail" of properly valuing and allocating risks and benefits is sorted out, the diffusion of financially viable CHP will remain stagnant.

3.5.4 Discussion

With changing energy system landscape, future of the energy system is shifting towards energy efficiency, resiliency, and flexibility. The United States is no different. Producing electricity and useful heat at the same time using CHP can help in achieving resiliency and flexibility services with huge efficiency improvements. However, despite a substantial unexploited potential (110-150 GW) [106], the United States generates less power and heat from CHP plants than other parts of the world (see Section 3.2). While the financial barriers like spark-spread, need for substantial capital investment, and long-term return on investment is necessary, many financially viable CHP projects in the United States are blocked by non-financial barriers. This essay finds the business model of electric utilities, especially IOUs, to be a barrier to market diffusion of CHP. The majority of the non-utility experts (over 70% of them) believe utilities impose fees, rate structures, and technical requirements to make distributed generation financially unattractive. This finding is consistent with the findings of other studies of CHP adoption [126] and innovation in the electric power industry [127]. It is also consistent with an Environmental Protection Agency (EPA) survey of 41 United States utility companies, which finds only two electric-only IOUs that provide support for CHP that is not state-mandated, compared to ten public utilities and six gas related IOUs [128]. However, this and previous studies do not objectively examine the requirements utilities impose on CHP projects to conditions imposed on other types of projects because the terms of the contracts are confidential. The interviewees describe for-profit IOUs as more opposed to CHP than nonprofit (i.e., municipal and cooperative) utilities. A statistical analysis of a larger sample of projects could quantitatively test the effect of utility business models on CHP adoption. Finally, some interviewees describe some IOUs as being less opposed to CHP than others. Future research could interview utility decision-makers further to try to understand the source of this heterogeneity. Over 60% of the non-governmental interviewees talk about negative subjective impressions as a barrier to CHP. Decision-makers' personal opinions (subjective impressions) based on anecdotal evidence are a barrier to many other technologies that are rare and don't have supportive policies. In this situation, business decisions must be made, without adequately analyzing risks and opportunities, by making trade-offs based on anecdotes. Previous research shows that both peer networks and change agents influence the diffusion of innovations[129]. Future research could test the peer network effect on CHP diffusion by more closely examining industries with significantly different penetrations of CHP and test the "change agent" effect by interviewing additional people within each company to better understand the internal decision-making process. Although fewer interviewees (27% developers/users to 67% utilities) identify the allocation of revenue and cost streams as a major barrier than the other two described above, I anticipate it will become more important as the variability of electricity prices increases. Grid operators need "flexible" generators that can rapidly adjust their output to balance variable wind and solar power, but these requirements limit CHP to meet their heating demand. Some CHP plants in countries with high penetration of renewables, such as Germany, Denmark, and Sweden[130], are increasing their flexibility by installing thermal storage [131] to reduce the coupling between heat and power output. The cost of such a technical solution must still be allocated between the heat and electricity customers, though that may be less complicated than a contract that compensates the heating customer for unmet heating demand. Lessons can be learnt from the use of Alternative Energy Certificates. These certificates value both renewable heat and electricity equally. AECs are needed for IOUs to meet their portfolio standards. In Massachusetts one AEC is equal to 3.4 MMBTU or 1 MWh [132]. So, the IOUs can buy these certificates instead of developing their renewable projects. Therefore, the concept of AEC can be extended to include resiliency and flexibility services. Further, research is required in developing methods to conduct a thorough assessment, extend the concepts of AECs, and allocate capital costs that value the benefits like resiliency and flexibility services from CHP.

3.6 Conclusion

CHP is a mature technology that already plays a critical role in the energy systems of many countries. It is well known for improving energy efficiency, and its newest fleet can provide “flexibility services” to increase renewable penetration. In the United States, CHP remains an under-exploited technology and many projects with payback periods of less than ten years have not been built. This essay assessed the non-financial barriers to CHP in the United States through interviews with energy experts and found that financial viability is a necessary but not enough condition for developing a CHP project. The most critical non-financial barriers are a) the business model of the electrical utility b) negative subjective impressions based on anecdotal evidence and c) allocating the risks and benefits of many costs and revenue streams. Overcoming these barriers would help to exploit CHP potential, improve energy efficiency, and, in the case of the newest CHP systems, provide flexibility services to the grid. To overcome these barriers, clear policies are necessary.

3.7 Policy Implications

This essay seeks answers to the policy questions as described in section 3.3 considering the existing government policies with recommended improvements. As shown in Figure 3-2, every state in the United States has some policies related to CHP. Generous financial incentives could make CHP projects profitable enough to overcome the non-financial barriers that are identified in this essay. However, the International Energy Agency finds, "The evidence from many countries is clear. CHP does not need substantial financial incentives to make it happen. Rather, it requires the effective use of often modest, targeted policies to systematically address barriers and allow for full realization of the potential" [133]. The PURPA law in the United States is a targeted, non-financial policy that addresses the utility business model barrier by forcing utilities to accept cost-competitive power from CHP plants. That law was largely responsible for increasing the penetration of CHP from 12GW in 1980 to 74 GW in 2004 (see Section 3.2).

Another example is the United States federal CHP Technical Assistance Partnerships (CHP-TAPs), which address the lack of knowledge by providing information and technical assistance to energy end-users and policymakers. I recommend the CHP-TAPs should go beyond identifying market opportunities for CHP by directly contacting potential users well suited to CHP. I also recommend expanding forums and workshops for CHP operators to share experiences and lessons learned with each other and with prospective operators. These policies can be supplemented with policies that address the electric utility business models (especially rate-related) barrier like the standby rate waiver for distributed generation in Connecticut or optional standby rates in Hawaii. CHP plants have efficiency and emissions advantage over fossil-fuel-burning heating and power plants, but it can be difficult for them to take advantage from policies that focus individually on electricity or heat. To address the barrier of multiple outputs and revenue streams, policies that encourage energy efficiency or restrict pollution (especially greenhouse gasses) should either encourage CHP explicitly or take a holistic view of all types of energy consumed by a building or collection of buildings. For example, industry performance standards in Massachusetts give CHP owners credits for "avoided emissions." Texas Utility Code that allows CHP facilities to sell electricity and heat to any customer. Proper allocation of risks and benefits is crucial for CHP implementation. Each CHP project and its financing are unique. Whether a project is self-financed or financed through an external lender/investor, funding for CHP project largely depends on the capital available from its host or owner and their creditworthiness. As CHP projects generally involve multiple partners, availability of such capital depends on the proper allocation of risks and benefits among them (i.e., the partners need to decide on who gets what and who invests what). CHP projects must first navigate through an intricate landscape of streamlining allocation of risks and benefits and then look for project financing options. CHP projects are likely to be financed, with reasonable terms, if the developers come with a detailed plan (where risks and benefits are appropriately allocated) and build a strong relationship with their lenders.

CHP is a proven engineering concept that utilizes waste heat to get substantial efficiency gains (see section 3.1). It has been in existence for over a century and is widely used for reducing GHG and increasing energy efficiency. The newest plants can provide “flexibility services” to help manage the intermittency of renewable generators. However, without adopting the measures described above, the market diffusion of CHP in the United States shall remain stagnant, and the projects will not be able to secure financing.

3.8 Limitations and Further Research

This research took years to complete, and the methods were rigorous. However, there are a few avenues and biases that can be further explored. Some of these, being more relevant to the discussion of the results, are described in the last paragraph of section 3.5 whereas others are mentioned here. For example, this research is based on the subjective perceptions of the interviewees. Opinions are important because they influence decision-making, but it is hard to know whether those perceptions are accurate independently. For example, advocates perceive that IOUs impose onerous conditions to block CHP projects, but I do not assess whether the requirements they impose are the unreasonable or unusual. Therefore, an interesting topic would be to explore the detailed barriers imposed just by the IOUs by questioning their intentions and motivations. Another limitation of this research is that none of the interviewees was a decision-maker who did not install CHP. The essay includes early impressions of people who eventually installed a CHP system, and that's interesting and important. However, it does not necessarily tell if the people who haven't invested in CHP think the same way. Therefore, research focusing on decision makers who did not install CHP would be an interesting avenue. Finally, quantitative analysis to either support or criticize my findings would also help to take this quest into another level.

3.9 My Contributions

The work presented in this essay is a part of a collaborative effort with Prof Elizabeth J. Wilson (Dartmouth College) and Dr. Stephen Rose (Mid Continent ISO). My contributions are concept creation, scheduling and conducting interviews, transcribing and coding them, inferring results, writing and presenting the findings. Prof. Elizabeth J. Wilson was responsible for editorial guidance. Dr. Stephen Rose was responsible for theme creation, triangulation, and editorial support. This content of this chapter is published in The Electricity Journal, Elsevier [134] DOI: https://doi.org/10.1016/j.tej.2019.02.011

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4. DISPATCHING EVS AS MICRO -GENERATORS OF A VIRTUAL POWER PLANT IN A WHOLESALE ELECTRICITY MARKET

4.1 Introduction

Countries around the world are encouraging reductions in greenhouse gas emissions with strategies such as decreasing dependency on fossil fuel, improving energy efficiency, and switching to renewable and nuclear generators [135]. Electric Vehicles (EVs), both fully electric and their hybrid counterparts (Plug-in Hybrid EVs) are energy efficient and are thus responsible for direct reductions in greenhouse gases (GHG) emissions relative to emissions from conventional vehicles. Nealer *et. al* [136] finds that, with a clean grid mix, cradle-to-grave[9] GHG for EVs are ~50% lower than for conventional vehicles. Clean-grid-mix is important here. One of the ways to achieve a clean grid is by carefully implementing a carbon tax[101]; otherwise there may not be sufficient emission reduction. For example, Babcan et al. [137]find that decentralized residential energy storages could only reduce emissions if it is coupled with carbon-related tariff reforms that precede it.

EVs also have the potential for indirect benefits by improving the operation of power systems that rely on renewable energy sources. Increasing renewable penetration can

[9] Cradle-to-grave emissions include all the emissions that occur during manufacturing, transportation, actual operation and end-of-life.

cause intermittency issues like uncertainty in power generation, lack of capacity reserves and reduction in ramping capabilities. If connected to the grid, EVs could compensate for renewable intermittency, reduce feeder losses through volt/VAR optimization, and improve load factor and load variance. For example, Kempton et al. [138] find that Vehicle-to-Grid (V2G) systems can be used to provide both backup and storage for compensating for renewable intermittency. Manbachi et al. [139] introduce smart-meter based optimization for EVs that minimizes distribution system losses by using volt/VAR control techniques. Similarly, Sortomme *et. al* [140] argues that EVs could be used to minimize load variance and thus minimize the feeder losses. Some argue that EVs could facilitate the development of power systems that are not reliant on fossil fuels [141] and decreasing renewable curtailments [142; 143].

Further, as EVs are parked for most of their lifetimes, with advances in power electronics and time-dependent control [144], EVs can also help in reducing renewable curtailments. For example, wind generally peaks at night when the load is at a minimum and is therefore often curtailed. Parked EVs can be used to consume extra electricity generated by wind, store it, and return it to the grid when it is needed during the day. The effect on curtailment can be substantial: in one study based in Hawaii[10], it was demonstrated that EVs could reduce wind and solar curtailment by 30-47% (220GWh to 346GWh) [145].

It should be noted that there are many energy storage system ideas, most of which have the potential for improving power system reliability. Paine et al.[146], For example,

[10] This is the one study of its kind. The amount of curtailment may not be realized in locations that are less sunny or less windy than Hawaii.

studies how market rules affect the profitability of pumped hydroelectric storage facilities. One significant advantage of EVs relative to these other storage options is their ubiquity.

The number of EVs has significantly grown in the past decade. For example, according to the International Energy Agency [147], globally, the number of EVs has increased from 1.67k in 2005 to 1257k in 2015. This increase has been facilitated by a mixture of technology-push and demand-pull policies that are targeted at global, national and regional levels (see Section 4.5) However, irrespective of these numbers, all the benefits from these EVs have not yet been fully realized. A key to realizing all these benefits is an actively functioning V2G system [148]. In a V2G system, the EVs can both charge and discharge, as needed, and also provide grid services like frequency regulation, phase regulation, and voltage balance without impairing driving patterns [149]. For example, Wang *et. al* [150] find that EVs can provide grid services in a decentralized V2G system, confer significant cost savings and still allow for sufficient battery energy levels for driving.

The concept of V2G was first introduced in the late 1990s [151]. Since then, engineers have focused on technical factors like improving optimization, controlling V2G operation or improving battery life [152]. For example, Ansari *et. al* [153]propose an optimal bidding strategy of coordinated ancillary services (regulation and spinning reserve). While the technical side of integrating EVs into V2G systems is highly important, economic aspects cannot be neglected. Economic feasibility is key to the adoption of EVs in the marketplace [154]. Most of such work on the economics and finance of EVs finds V2G to be profitable[11]. For example, Kempton *et. al* [155] find that V2G systems are profitable for providing peak demand, spinning reserve, and regulation services. Pelzer *et. al* [156], using a price responsive approach, find that V2G systems are profitable in Singapore. Guo *et. al* [157], using an optimal charging scenario, also finds V2G systems to be useful.

However, despite such claims, in the past two decades, most V2G projects have not moved beyond the pilot phase. It is likely that one barrier to commercial viability is that, despite the findings in the literature, V2G systems would not be profitable to all participants given current market conditions and rules. For example, Peterson *et. al* [158] find V2G systems are not profitable to the EVs, mostly because of battery costs.

4.1.1 Key Academic Questions

The goal of this essay is to examine the economics of a V2G system and to assess the impact of alternative sets of market rules governing compensation for electricity products. Estimation of rewards depends on the revenue system and battery costs, both of which are dependent on market rules and policies.

This essay builds a detailed model for a centralized V2G system in which a single entity (like a Virtual Power Plant (VPP)) schedules the EVs to minimize its total generation cost. This essay builds on prior work on EVs and V2G systems in several ways. First, this

[11] This refers to share of profit that is a result of a market transaction and not how the perception of this profit might influence the demand for EVs.

research captures more of the real market features by using actual market prices and rules from the Electricity Reliability Council of Texas (ERCOT) that is an Independent System Operator (ISO). It uses the battery and EV price data from EV manufacturers. Data on Nissan vehicles were acquired from Nissan's website [159]. Data on Tesla were acquired from Tesla's website [160]. It also uses data on subsidies from both federal and state repositories. Data on federal incentives were acquired from [161]. Data on state subsidies were acquired from the Legislature of the State of Texas [162]. Second, it assumes that aggregated-EVs can offer both ancillary services (as a capacity resource) and energy. Third, building on [163], it formulates a Dynamic Programming-Unit Commitment (DP-UC) bi-layer algorithm to capture the tiered decision-making that would occur in a V2G: the first stage evaluates the reward for each of the possible control actions (charge/discharge/idle) using DP, and the second stage dispatches the least-cost EVs from the set of all the available EVs using a UC.

Three pricing scenarios are modeled. In all the scenarios, the VPP is the wholesale electricity market participant, i.e., it receives a nodal price signal ($/MWhr) from the market and dispatches the available EVs to deliver electricity. Since the VPP is only transacting very small amount of energy - around 1MW [164] at a given point of time - it cannot influence the prices in the wholesale market. Therefore, it is an infra-marginal generator and thus a price taker. Table 4-2 lists ERCOT's generating capacity and peak demand. According to the Federal Energy Regulatory Commission (FERC) [165], ERCOT's summer generating capacity is 75GW with a peak demand of 69GW (in 2015) and has 46.5K miles of transmission lines. Its average energy price for 2015 is 24.70$/MWh and average regulation price for the same year is 7.8$/MWh [166]. The VPP cannot influence prices in the wholesale electricity market. It owns the parking lot and the Battery Energy Storage System (a control system) that sends the actual control signals to the EVs (see Figure 4-1 for a typical V2G setup). The EVs choose whether to participate in the provision of grid services (see Section 4.2 for details). Further, a typical centralized V2G require a collection of complete information from each EV, control power demand, price from the grid-operator and heavy bi-directional communication. Since the purpose of the model is to learn whether a V2G system would be profitable for EVs under alternative assumptions about how EVs are compensated, it is assumed that all these barriers for a centralized V2G system are overcome and that it is functional.

Table 4-1: Scenario description.

Scenario	Description
Business as Usual (BAU)	The EVs charge (but do not discharge) at the VPP's premises, at a fixed retail price.
Fixed retail price	The VPP transacts with the market or system operator using the wholesale market price and EVs charge and discharge at a fixed retail price.
Dynamic retail price	EVs charge/discharge at a dynamic retail price, which means that the retail price changes with time to reflect the changes in the wholesale electricity market.
Wholesale price with 50% profit sharing	The VPP transacts with the system operator at the wholesale price and shares 50% of its total reward from the wholesale market with the participating EVs.

I use ERCOT data and market rules. Therefore, the results apply to markets like ERCOT: those with a centralized V2G system that both *a*) use nodal energy and ancillary service prices and *b*) have prices like those in ERCOT. Table 4-2, lists some of the comparable system operators and their attributes (see Section 4.4.4 for details on market trends for ERCOT).

Table 4-2: Comparing electricity markets in the United States.

ERCOT, the case study in this paper, manages the electricity market in Texas

	LMP ($/MWh)	**Regulation Prices ($/MWh)**	**Generating Capacity (GW)**	**Peak Demand (GW)**	**Annual Billing (Billion $)**
ERCOT	24.70	10.25 (up) 5.35(down)	75	69	34
California ISO	31.01	5.66 (up) 3.13 (down)	60	50	11
Mid Continent ISO	25.05	7.49	174	118	25

Section 4.2 describes the methods, Section 4.5 shows the results and discusses the

findings, and Section 4.6 presents the conclusion. The main conclusion of this essay is that V2G could be profitable to all the participants with reduced battery costs and well-designed market rules. V2G systems could thus become sustainable (i.e., EVs join and remain) in the long-term. Such insights are useful for decision makers who are concerned about developing newer market products, investing in Research and Development and weighing policy alternatives.

4.2 Background

V2G is a concept where EVs can both charge and discharge, as needed, and also provide grid services like frequency regulation, phase regulation, and voltage balance to the market or system operator, without impairing driving patterns [149]. EVs, aggregators and market operators are critical players in any V2G system.

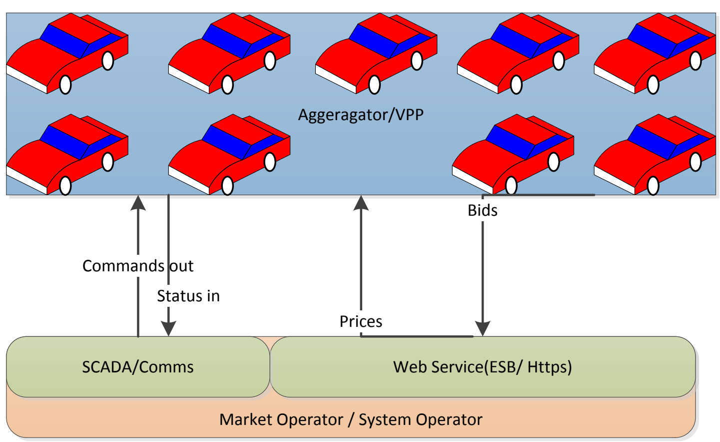

Figure 4-1: Typical V2G setup

In this setup, typically the Market Operator communicates with the Aggregator using web services and Supervisory Control and Data Acquisition (SCADA)/communication channels. SCADA and communication channels are used to send signals like set points and receiving statuses, whereas web services (like Enterprise Service Bus (ESB)) are used to send and receive price signals as XML payloads.

This essay uses a centralized architecture based V2G. In a centralized architecture [140; 167], the control decision and data exchanges are based on the aggregator's central computers; whereas, in a decentralized architecture [142; 168], the control decisions and data exchanges are both distributed. In a centralized architecture, VPP transacts with both EVs and the system operator. Generally, a VPP can partner with a local parking owner and act as an aggregator. The centralized architecture may a) require redundant systems to provide backup during failures b) be computationally intense and c) may value itself over the EV owners. However, it better utilizes network capacity, and optimization problem is more straightforward and more practical. Therefore, it is chosen as a V2G architecture for this essay.

4.3 Key Policy Questions

Since the 1990s, the concept of V2G is burgeoning among academics. There have also been a few pilot projects. However, in practice, this concept shows no signs of commercial takeoff. Therefore, this essay seeks to answer the following key policy questions

- Do we need to thoroughly evaluate the V2G concept/policy in the context of the present market rules?

- Are the market rules/rewards enough to compensate EV owners for V2G services? How can they be improved?

4.4 Methods

In the model, the VPP receives data from both EVs and the system operator and, for each period, evaluates the best rewards from the set of available rewards for performing three different control actions (charge, discharge and idle). Upon entry into the VPP (that owns the parking lot and Battery Storage System), EV owners indicate their willingness to participate, their minimum State of Charge (SOC_{min}) and their cost/battery parameters. Availability and willingness flags indicate the presence of EVs in the parking lot and their willingness to participate in the market for the next 15 minutes[12]. Since the real-time elasticity of electricity supply/demand is small, it is assumed that the EV's willingness to participate remains unaffected by the market price (except in sensitivity case 3 - see Section 4.5.3). If they are unavailable or unwilling, they will not be considered for market participation. Based on this information, the VPP bids capacity and energy into the ERCOT market. For simplicity, it is assumed that the bids are always accepted without any changes. The bids offered by the market participant and actual schedules dispatched orders from the market can be slightly different.

SOC_{min} represents the minimum SOC that each EV wants to have by the time it exits the

[12] The time increment is 15 minutes. As an example, consider the present time to be 13:00 PM. At 12:45 PM, 15-minutes prior to dispatch, the VPP has obtained all the necessary flags from the EVs. This 15-minute window also provides enough cushions to cover for delays that can happen during the flow of information to and from the VPP.

VPP. 100% SOC corresponds to the rated load capacity of the EV (please see Section 4.4.5). Similarly, VPP's load capacity is the sum of load capacities of the available and willing EVs (~1MW). The VPP guarantees this SOC unless the EVs leave the premises before reaching this level. To illustrate, suppose EV1 wants to achieve 60% SOC and EV2 wants to achieve 20% SOC by the time they exit the VPP's premises. Assume the initial SOC of EV1 is 20% and EV2 is 10%. EV2 stays within the VPP for 5 hours and EV1 stays there only for 15 minutes. Assume that the VPP can only increase SOC by at most 15% every 15 minutes. When both EVs enter the VPP, they will immediately be considered for charging during the next dispatch (next 15 minutes). However, since EV1 leaves immediately after the next dispatch, its SOC will only be 35%. However, since EV2 stays there for 5 hours, it will participate in the market after charging and will also ensure that it's $SOC=SOC_{min}$.

The VPP will first charge any EV with $SOC< SOC_{min}$ and will not consider this EV for providing energy or ancillary services. Along with their preferences, EV owners also submit cost functions, and these are linear in the charge and discharge space as described below. This approach is like that employed by other market participants (e.g., steam power plants use heat rate curves) to derive and submit their cost functions to the market operator. Analogously, it is assumed that the EV owners come up with their cost functions based on information at their disposal as described in Section 4.4.5 and submit them to the VPP.

Unlike EVs' preferences, the system operator's preferences are in the form of market signals like Real Time-Locational Marginal Prices (RT-LMPs) and Real Time-Regulating Reserve Prices (RT-RRPs). RT-LMPs are paid to market participants for providing energy and RT-RRPs are paid for providing reserve services.

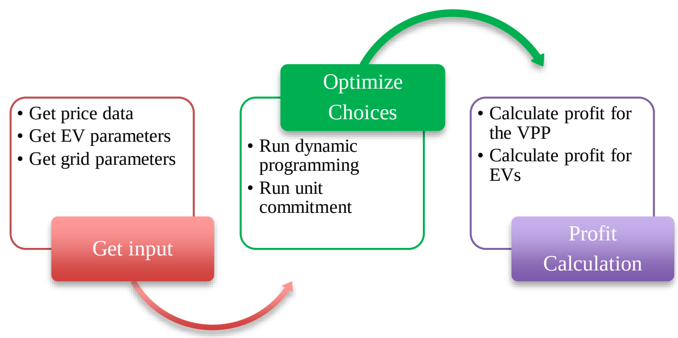

Figure 4-2: Simulation Method – EVs in a wholesale electricity market

To decide on the control action, the VPP runs a two-level optimization as shown in Figure 4-2. In the first level, it performs dynamic programming (Section 4.4.1and in the second level, it performs unit commitment (Section 4.4.2).

The DP layer gives a desired MW value to the UC layer. The UC layer then solves for the least-cost dispatch order with respect to this MW value. The DP problem is solved using forward search as in Paine et al. [146] and UC is solved using Lagrange relaxation as described by Wood et al. [169]. Forward search is used, instead of a backward recursive search, because the starting point and the future objective are known for the DP problem. Lagrange relaxation is used, instead of Mixed Integer Programming, because is easy to implement and is well proven to work with scheduling problems. For each 15-minute interval, the VPP decides on the control action (discharge, charge, idle) to maximize its returns and sends corresponding binding signals to the EVs. The solution to the DP-UC problem is computationally intensive. For a laptop computer with Intel-I3-4030 at 1.9GHZ, it took 44.21 hours to solve a scenario for one year. Note: This is the time taken after selecting representative hours - as described in Section 4.4.3 and threading the program into the available 2-cores.

4.4.1 Dynamic Programming

Dynamic programming provides a way to solve for the optimal control action necessary to maximize a VPP’s present value. The VPP sells energy and ancillary services (capacity) on the wholesale market. I assume that this VPP is an inframarginal generator and thus a price taker in this market.

Given states $S_t$and time t_1, the VPP seeks to maximize the sum of its current and future rewards. The VPP observes $S_t$and takes the control action $x_t$to maximize its total reward. The state variable vector S_t includes both the capacity of the VPP and market prices. The control variablex_t represents discharge, charge or idle mode x_t= (1, 2, 3). If the EVs are unavailable or unwilling or if $SOC<SOC_{min}$, they will not be considered for market participation and will only be charged until $SOC=SOC_{min}$. Therefore, the reward function is given by$f(S_t, x_t)$ when$availability = 1$,$willingness = 1$and $SOC \geq SOC_{min}$. The total capacity Q_{total}^t of the VPP, given as a part of S_t, is calculated as the sum of the

available capacity of n EVs, i.e.,

$$Q_{total}^{t} = Q_1^t + Q_2^t + Q_3^t + \cdots + Q_i^t + \cdots + Q_n^t \quad (11)$$

Where, Q_i^t is the available battery capacity of the ith EV in kWh.

The UC problem selects the least-cost EVs from the set of all available and willing EVs in the parking lot (see Section 4.4.2 for details about UC). The control decisions are made every $T_0 = 15$ minutes and the Bellman equation for this optimization is given by

$$V_t(s_t) = \mathbf{max}\, x_t \{f(s_t, x_t) + V_{t+1}(s_{t+1}|x_t)\} \quad (12)$$

where $V_t(s_t)$ represents the value of present and future rewards; $V_{t+1}(s_{t+1}|x_t)$ represents the future reward given state s_{t+1}; and $f(s_t, x_t)$ is the reward which is given by

$$f(s_t, x_t) = \begin{cases} -P_{EV}^t \sum_{i=1}^{N} Q_i^t + P_{Rt}^t Q_{total}^t, & x_t = 1 \\ P_{EV}^t \sum_{i=1}^{N} Q_i^t + P_{Rt}^t Q_{total}^t, & x_t = 2 \\ 0, & x_t = 3 \end{cases} \quad (13)$$

Where, P_{EV}^t, a part of s_t, is the price paid to the EV in \$/MWh; P_{Rt}^t , also part of s_t, is the wholesale market real-time price in \$/MWh. P_{EV} could be the same for all periods e.g., retail price or could change with time e.g., dynamic retail price. Further, P_{EV}^t and P_{Rt}^t at time t and t+1 are independent of each other and Q_{total}^t is the total power

Superscripted t or subscripted t represents time interval t. The next time interval is t+1.

consumed/generated by all the available and willing EVs. The state transition function shows how the state variable Q_i^t is related toQ_i^{t+1}:

$$Q_i^{t+1} = Q_i^t + \Delta Q_i^t \tag{14}$$

$$\Delta Q_i^t = \begin{cases} \min(r_{d,i} * T_0,\ Q_i^t - Q_{rated,i} * SOC_{min}),\ x_t = 1 \\ \min(r_{c,i} * T_0,\ Q_{rated,i} - Q_i^t), x_t = 2 \\ 0, x_t = 3 \end{cases} \tag{15}$$

Where, ΔQ_i^t is the change in battery capacity under the three control actions; $r_{d,i}$ is the discharge rate of the ith EV; $r_{c,i}$ is the charge rate of the ith EV; $Q_{rated,i}$ is the maximum battery capacity of the ith EV; $Q_i^t$is the current battery capacity of the ith EV; $T_0$is the control decision interval.

4.4.2 Unit Commitment

In the second level, the parking lot owner uses UC to schedule the least-cost EVs who are available, willing and have SOC>SOC_{min}. UC guarantees the optimal schedule for a VPP with varying numbers of EVs. Mathematically, the UC problem can be represented as:

$$\boldsymbol{f}(PW_i^t, U_i^t) = \min \sum_{t=1}^{T} \sum_{i=1}^{N} [C_i(PW_i^t) + Startup_{cost}]U_i^t \tag{16}$$

subject to:

$$h_{UC}(\underline{x}) = 0\ and, g_{UC}(\underline{x}) \leq 0$$

• Where $C_i(PW_i^t)$ is the cost of each EV, given as a function of Power ($PW_i^t = Q_i^t/t$), is expressed in \$/hr. Each $C(PW)$ is given by (9). $Startup_{cost}$ $Startup_{cost}$is the start-up cost of the EVs (I assume that the startup costs for all the EVs are the same); U_i^t = 0 if the i^th unit is unavailable or unwilling or 1 otherwise $h_{UC}(\underline{x})$ is the set of equality constraints. It comes from balancing the load, i.e., $Q_{totaload}^t - \sum_{i=1}^{N}(Q_i^t U_i^t) = 0$ for t=1 to T ; $g_{UC}(\underline{x})$ is the set of inequality constraints. And it is limited byQ_i^t, i.e. $0 \leq Q_i^t \leq Q_{rated,i}^t U_i^t$ for t=1 to T and i=1 to N.

4.4.3 Data, Assumptions and Case study

This model is implemented for Electricity Reliability Council of Texas (ERCOT). The choices of electricity prices, EV cost function, and other parameters are described below.

4.4.4 Electricity Prices and Locations

The price data from ERCOT for 2015 are chosen.

- Each month of 2015 is represented by a simulated 24-hour period with LMP (for energy) and RRP (for capacity) prices changing at a 15-minute interval. To estimate these representative 24 hours for each month, three prices series are generated. In the first price series, the price for each 15-minute interval in a day is averaged over the month. In the second series, the minimum price, for each interval, over the month, represents that time of day. The third series uses the maximum price for each time of day. For example, for January 2015, for 1 pm, the average RT-electricity price was 23.94$/MWh, the maximum price was 495.37$/MWh and the minimum price was 0.89$/MWh. Similarly, the average response reserve price for the same daytime was $5.16/MWh; the maximum price was $10.31/MWh and the minimum price was $3.08/MWh. All of these prices are obtained from the ERCOTs database for historic prices [170]. These prices were for Houston hub. Marginal prices vary in space in time. However, for each hour, on average, minimum and maximum prices are similar across space. Therefore, the results for other nodes/hubs would be similar. Please refer to Table 4-3 for comparison with other locations and Table 4-2 for comparison of ERCOT with other ISOs.

Table 4-3: Spatial variation of LMP across different ERCOT hubs for 2015.

Maximum LMP is seen at Houston Hub

	LMP ($/MWh)		
	Minimum	**Average**	**Maximum**
Hub Houston	-11.58	24.83	3118.2
Hub North	-29.61	23.81	1538.7
Hub South	-67.73	24.41	1538.7
Hub West	-13.40	23.82	1538.7

- For the fixed retail price (scenario 1) and BAU: Retail price of 12.58$/MWh [170] was chosen for every time interval in the solution space.

- For the dynamic retail price (scenario 2): Dynamic retail price was created by using (17) and (18) as shown below.

$$DynamicRP_t = \Delta LMP_t + FixedRP \tag{17}$$

$$\Delta \mathrm{LMP}_t = \begin{cases} \min(LMP_t - Avg(LMP), \sigma_{LMP}), & LMP_t > Avg(LMP) \\ \max(LMP_t - Avg(LMP), -\sigma_{LMP}), & LMP_t < Avg(LMP) \end{cases} \tag{18}$$

where, the average LMP, Avg(LMP), for 2015 is 24.83$/MWh; σ_{LMP} is the calculated standard deviation of LMP; the fixed retail price *FixedRP* is 12.58$/MWh.

- For 50% profit sharing (scenario 3): Wholesale LMP and RRP prices are used and it is assumed that the VPP shares 50% of its reward with the participating EVs.

4.4.5 Electric Vehicle Cost Function

EV cost functions are linear in charge/discharge space, i.e.:

$$C(PW) = (b + \Delta b)PW + a \tag{19}$$

Where b is a constant expressed in $/kWh and represents the EV deterioration that happens with every charge/discharge cycle. Since it is impractical to count the charge/discharge cycles for EVs, the detailed representation of *b* was adapted from [171; 172]:

$$b = \gamma \frac{C_{battery}}{Q_{TotalEnergy}} \tag{20}$$

$$Q_{TotalEnergy} = 2 * L_{cycle} * Cap * DoD \tag{21}$$

Where $C_{battery}$ is the capital cost of a battery in $ and $Q_{TotalEnergy}$ is the total energy transferred during the lifetime of a battery. γ represents the reduction in battery cost due to EV subsidies. γ is assumed to be 30% . This was because in Texas the EVs get $7500 [161] in federal and $2500 [162]in state subsidies. I assume that these subsidies are reflected in their battery costs. As a comparison, according to Hardman *et. al* [173], EV incentives range from $2500 to $20000 per vehicle. *Cap* is the battery capacity in kWh. Battery prices are taken from manufacturers web pages. The retail price of Nissan Leaf 24kWh battery pack is $5,500 before tax [159]. The battery pack of the Tesla Model S is $12,000 for its 85kWh pack [160]. L_{cycle} is the battery life in cycles and DoD is the depth of discharge. These values are from figure 3 of Han and Han's paper [172].

All these parameters are used to get the $Q_{TotalEnergy}$ range for Nissan Leaf and Tesla-S as shown in the table below. This information is used to calculate the range of *b* for these vehicles**.** It is assumed that vehicles in the parking lot are characterized by different values of *b,* and that the heterogeneity of vehicles regarding *b* can be represented by a uniform distribution. An equal number of Nissan and Tesla vehicles are selected to equalize their probability of being used. Further, a fleet of 20 cars is assumed to be available at any given period. This also ensures that there is enough capacity for the VPP to participate in the ERCOT's market.

Table 4-4: EV battery characteristics and coefficients

	Capacity (kWh)	**L_{cycle}**	**%DoD**	**b ($/kWh)**
Tesla-S	85	700	90	0.034
		4500	6	0.078
Nissan Leaf	24	700	90	0.055

	Capacity (kWh)	L_{cycle}	%DoD	b ($/kWh)
		4500	6	0.127

- *b* for each EV does not change over with every charge and discharge cycle.

- a represents the hourly Operation and Maintenance (O&M) costs that are incurred irrespective of the charge and discharge cycles. One example would be battery insurance that the EV owner must pay irrespective of the charge/discharge cycle. It is expressed in $/hr.

4.4.6 Other Parameters

Besides parameters for EV cost functions, there are a few additional assumptions. The first is EVs option to limit the maximum number of charge/discharge cycles that happen every day. It is assumed that, for a given day, each EV can charge/discharge for ten cycles. For comparison, Honarmand et al., [174] assumes that newer EVs can charge/discharge to eight cycles every day. Second, I assume that there are three sets of EVs that enter the VPP a) a group that arrives at 6 am and leaves at 2 pm; b) a group that arrives at 2 pm and leaves at 10 pm; c) a group that arrives at 10 pm and leaves at 6 am. Third, among these sets of EVs, it is assumed that an EV is either a Nissan Leaf or Tesla S - the top two best-selling EVs in the United States in 2015 [175]. Minimum SOCs are randomly assigned between 20% and 80% to each of the available EVs. Further, it is assumed that each EV can be charged to 40% of its capacity in 1 hour using fast chargers [160].

4.5 Results and Discussion

The results illustrate that the total amount of energy drawn from and injected into the ERCOT region each year varied across scenarios. For the fixed retail price scenario, results showed that 808MWh were discharged and 411MWh were charged; in the dynamic retail price scenario, 714MWh were discharged and 273MWh charged; and, in the 50% profit sharing scenario, 885MWh were discharged and 299MWh were charged. More important, with the present market rules, the results illustrate that V2G is not profitable to the EVs and that cheaper EVs are likely to lose more than expensive EVs, as described below.

4.5.1 Profit – VPP Makes Money, EVs Don't

Table 4-5 presents the bounds of VPP and EVs profit for 2015, when using average, minimum and maximum LMP and RRP. In all the scenarios, the VPP would make more profit from BAU (The BAU case for EVs represents their monthly costs of charging batteries) case and the system operator would get energy and ancillary services. With the present market rules, there is an insufficient reward for the EVs to cover their battery deterioration cost. Therefore, they are likely to lose more by participating in a V2G system through a VPP.

Table 4-5: Rewards made by VPP and EVs in different scenarios

		Profit ($)	
	VPP ($)	**EV TypeI**	**EV TypeII**
BAU	NaN	-162	-454

	Profit ($)		
	VPP ($)	EV TypeI	EV TypeII
Fixed retail price scenario	[1952, 18467]	[-351, -324]	[-1182, -1126]
Dynamic retail price scenario	[1913, 16889]	[-353, -295]	[-1166, -1007]
50% profit sharing scenario	[816, 11209]	[-357, -82]	[-1052, -726]

4.5.2 Cheaper EVs Lose More

Another interesting result is illustrated in Figure 4-3. For all the scenarios, EVs with a comparatively lower battery cost ($/kWh) lose more money when compared to EVs with a higher battery cost. This is because the EVs with lower battery costs are cheaper and thus will be used more. None of the scenarios could generate enough revenue for these EVs. Therefore, the EVs with smaller $/kWh is used more and they lose more. This disadvantage for cheaper EVs would exist when EVs are dispatched using least-cost methods like economic dispatch, unit commitment or merit order dispatch. It could, however, be mitigated if battery cost is reduced or if EVs limit how many charge-discharge cycles they allow daily.

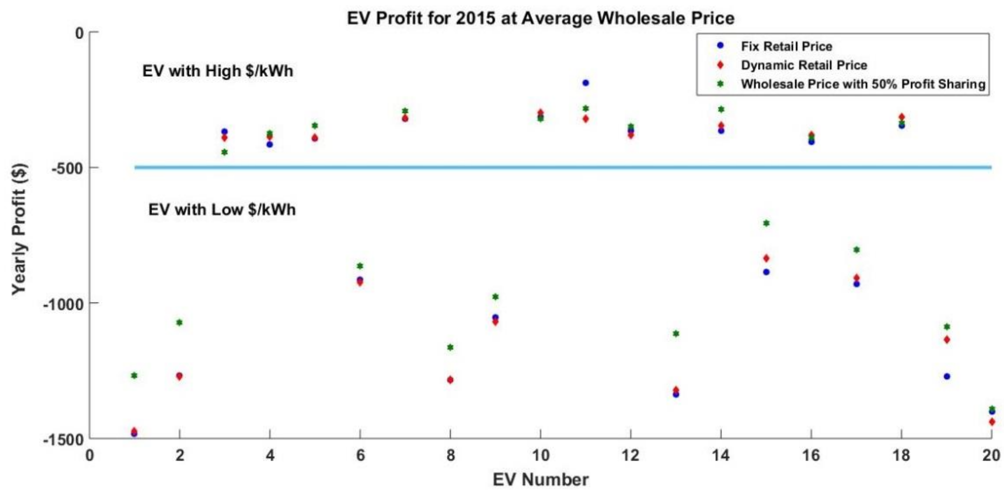

Figure 4-3: Yearly profit in $ for all the EVs,

Per unit cost EV-type2 is lower than that of EV-type1. Therefore, EV-type2 gets extensively used. When extensive use is combined with lower profit (all the scenarios), EV-type2 loses more money

4.5.3 Sensitivity

The specific results are dependent on the assumptions and the data choices that are made. However, the results (that EVs will lose and VPP will make more and EVs with lower $/kWh will lose more money relative to BAU) are robust to changes in electricity costs. To illustrate this, three cases and a few sub-cases are simulated. Sensitivity case 1 illustrates the change in rewards if battery costs are reduced. Sensitivity case 2 illustrates the change in rewards for the choice of average, minimum and maximum LMP vs. using the actual LMP. Sensitivity case 3 illustrates the change in rewards if the EVs participate only when price exceeds a threshold. Sensitivity case 4 illustrates the redistribution of benefits between the VPP and EVs.

To illustrate the change in battery cost, three sub-cases are created: 1-a) where γ is 5%; 1-b) where γ is 100% and an additional benefit is $50/MWh; 1-c) where γ is 30% and the additional benefit is $50/MWh. The additional benefit illustrates a new market product that provides flexibility with an average market price of $50/MWh. Flexibility is the extent to which an electrical system can change its generation or consumption in response to changing power system conditions [176]. Products that provide peak-shaving and renewable consumption, for example, are valued for their ability to increase the flexibility of the power system. This reward is later used to illustrate the significance of market rules.

Table 4-6: Summary of sensitivity cases

Case Name	**Description**	**Reason for case selection**
Case 1a	γ =5%	To illustrate near term (5 years) plausible reduction in cost
Case 1b	γ =100% with extra $50/MWh reward	To illustrate edge case
Case 1c	γ =30% with extra $50/MWh reward	To illustrate far term (5-10 years) reduction in cost
Case 2	RT actual LMP	To illustrate the choice of using representative hours for each month instead of average, minimum and maximum
Case 3	EVs only participate above a threshold price	To illustrate the impact of EVs choice if the price exceeds a threshold
Case 4	Cap VPPs profit and share it with EVs	To illustrate a case where regulatory agencies like a Utility Commission can cap VPPs profit and re-distribute among the EVs.

First, the Fixed Retail Price scenario is examined. Results indicate that, in all these cases, VPP rewards were relatively unaffected. On average, EV reward increases by 79% (-$161 in both cases versus -$766 in the fixed retail price scenario) for sensitivity case 1-a (γ is 5%) and sensitivity case 1-c (γ is 30% and $50/MWh benefit) when compared to the

Fixed Retail Price scenario. This is because the reward in sensitivity cases 1-a and 1-c is more than the battery operating cost. However, in sensitivity case 1-b (γ is 100% and \$50/MWh benefit), when compared to the fixed retail price scenario, EV reward decreases by 144% (-\$1869 in this case vs. -\$766 in fixed retail price scenario). This is because the reward is insufficient to overcome the increase in operating costs.

In sensitivity case 2, real 15 minutes LMP (instead of average, minimum and maximum LMP) are used. The results for this sensitivity case are within the bounds of minimum and maximum values given in Table 4-6. As an example, for the fixed retail price scenario, the EVs on an average lost around \$750. This is well within the bounds of the results from Table 4-5. In this table, for the fixed retail price scenario, the use of maximum LMP yields an average loss of \$766. Similarly, for the dynamic retail price scenario, the EVs lose \$788 and for 50% profit sharing scenario, they lose \$710 while using the real LMP. All of these are well within the bounds of our results.

In sensitivity case 3, a threshold price that would make V2G profitable to the EVs, is identified. For fixed and dynamic retail price scenario, participation at a retail threshold price larger than \$34/MWh would make V2G profitable (when compared to BAU, though the cash flow is still negative) to the EVs. Similarly, for the 50% profit sharing scenario, participation at a threshold price larger than \$30/MWh would allow EVs to break even.

In sensitivity case 4, the VPP's reward is capped such that the EVs, on an average, also make a profit. This is a case where regulatory agencies intervene and re-distribute the wealth or, alternatively, the EVs and VPP come to an agreement on wealth re-distribution among themselves. For EV type I to make \$162 and type II to make \$454 more than BAU, such redistribution is only possible if the VPP makes \$15,330 in the fixed retail price scenario and \$15,190 in the dynamic retail price scenario. Any penny that is made over this amount would go into the profits of the VPP. For example, in the fixed retail price scenario, the VPP is likely to earn between \$1,952 and \$18,467. If the VPP makes the maximum amount, i.e., \$18,467, \$15,330 can be redistributed to the EVs. In such a case, the VPP's profit is \$3137, type I EV's profit is \$162 and type II EV's profit is \$454 more than BAU.

In sum, as shown in Table 4-6, the sensitivity cases indicate that the results are robust to changes in parameters: without enough market reward, V2G is profitable for everyone except the EVs. Sensitivity case 3 makes V2G profitable to the EVs. However, it curbs the grid services unless the grid operator is willing to pay and has abundant ready-to-dispatch reserves. Sensitivity case 4 also shows that participation in a V2G could be profitable to the EVs if the VPP makes around \$15K and redistributes their profits; and this is impractical.

The results and sensitivities around results show interesting findings. Some of these are discussed in the upcoming paragraphs. According to IEA[177], the electricity sector accounts for 42% (13.51 Gton CO_2e) and the transportation sector accounts for 23% (7.4 Gton CO_2e) of global CO_2e emissions. Without reducing emissions from these sectors, it is unlikely that the emissions reduction targets will be achieved. The International Energy Agency [178] estimates that the electricity sector should be completely de-carbonized and annual road energy consumption should decrease by 17% (around 413 mill tons of Oil equivalent) by 2050 to maintain an acceptable level of CO2e. Countries around the world have started to engineer solutions to this problem. In a system with clean grid mix, EVs can become significant contributors to the solution in both sectors. EVs replace traditional gasoline-based modes of propulsion, especially for passenger cars, which leads to increased efficiency and reduced tailpipe emissions. They also help in replacement of traditional fossil fuel-fired power plants with renewables by providing solutions to renewable intermittency problems and improving power system reliability.

At present, EVs represent 0.1% of the total number of passenger cars globally [147]. Though the percent share is small, the stock has increased over the past decade. According to the International Energy Agency [147], globally, the number of EVs have increased from 1.67k in 2005 to 1257k in 2015. The increase has been facilitated by global, national and regional policies: the Electric Vehicle Initiative aims to deploy 20 million EVs globally by 2020; China has implemented an excise incentive of $6000-$10000 for purchasing an EV [147]; the Zero Emission Vehicle (ZEV) program in California calls for having 1.5 million ZEVs in California by 2025 (in 2015, 24 million vehicles were registered in California)[179]. Such policies create markets for EVs, make them commercially viable, and have increased their penetration.

Unfortunately, V2G systems have not been able to catch up with the growing number of

EVs. To fully realize commercially viable V2G systems, several barriers including the following need to be addressed: cost, EV range, optimization, control, charging access and infrastructure, impact to the grid, consumers' lack of awareness of the EV-V2G option, and supportive market rules. The literature is beginning to acknowledge the importance of incentives, including market rules. For example, Sarah Keay-Bright [180] argues that proper design of time-varying dynamic price, demand response and proper value of flexibility would increase the penetration of EVs in the European Union. Similarly, the study done by Paine et al. [146] highlights the importance of market rules. They find that market rules could change the yearly reward of the pumped hydro station by 2.4 times ($4.64k) when installed in Mid Continent ISO (MISO) region than in ISO-New England region. Another pragmatic example that highlights the importance of market rules is the increased penetration of renewables in areas within wholesale electricity markets of the United States that have access to the spot market [181] with transparent and fair rules and improved granularity in pricing and dispatch. ISO/RTO Council [182] highlights the importance of fair market rules. Some examples of market rules that facilitated renewable penetrations are the introduction of the Energy Imbalance Market in the California ISO region and Dispatchable Intermittent Resource in the Mid-Continent ISO region.

Like renewables or pumped hydro, V2G systems (and therefore EVs) would further blossom if there were appropriate market rules and supporting policies that ensured that participants earned enough rewards. This essay highlights the importance of such rules. A two-stage optimization, as described in Section 4.2, is modeled. It is assumed that the VPP participates in the wholesale electricity market for energy and ancillary service (capacity) and the market rules for the EVs are changed. Three scenarios are created. These scenarios represent three market rules for EVs where they interact with the VPP in a) fixed retail price b) dynamic retail price c) 50% reward sharing. This model is applied to ERCOT electricity market, and the results illustrate the following.

- In all the scenarios, a centralized system based V2G is always profitable to the VPP. However, it is different for an EV. For example, in Fixed, dynamic retail price scenario and 50% profit sharing scenario, EVs would lose money when compared to business as usual. However, if the market price is increased or if the battery costs are substantially decreased, or if the EVs chose to participate only if the price exceeded a threshold, V2G could become a profitable option (or at least better than BAU) to an EV.

- For fixed, dynamic retail price scenario and 50% profit sharing scenario, EVs with lower per unit battery costs may actually end up losing more money because of extensive overuse (see Figure 4-3) thereby deteriorating the battery.

The results illustrate that, with high battery costs and existing market rules, V2G would not be profitable to the EVs; therefore, owners are unlikely to participate in this system. V2G can provide numerous additional services than energy, capacity or regulation. A V2G system with EV participation can help accommodate surplus renewable generation or provide storage to compensate for the intermittency of renewables. It can shave peak and can provide quick ramping capabilities. However, the present market rules do not allow these functions of EVs to be properly rewarded. Therefore, newer market products like a peak shaving product; a renewable consuming product or a flexibility product could help in improving the rewards EVs get for participating in a V2G system. For example, provided the battery costs are reduced by 5-30%, the introduction of a new market product (or a subsidy) worth 50$/MWh would significantly (79%) increase the rewards for the EVs (see Section 4.5.3). However, without such products, things could be even worse than the status quo. Since the renewables have low operating costs, they could bring market prices down and can even make these prices go negative [183]. That means, with increasing renewables, the reward that the EVs normally get from the market would further be reduced. A lower reward would make the EVs unwilling to participate in a V2G (see Section 4.8 on limitations).

To avoid these outcomes, EVs would need to be compensated sufficiently. One option to consider would be to use market products like flexibility or renewable support service or a peak shaving product. Alternatively, EVs could choose to participate only above a threshold price that is higher than average LMP. However, this option limits the ability of V2G to provide grid services. Finally, another option would be to use alternate means like Combined Heat and Power (CHP), water heaters and demand response. Some of these like water heaters could be even cheaper than a V2G scheme. Further research should thoroughly analyze all these alternatives.

4.6 Conclusion

On average, a private vehicle is parked for 95% of its lifetime. Parked EVs, both fully electric and their hybrid counterparts can be used to provide grid services and can help in emissions reduction. A key to realizing these benefits is an actively functioning V2G system that depends, in turn, on enough rewards of the system to participants. On top of battery costs, the way in which market rules are established is likely to have an impact on these rewards.

This essay investigates the implications of battery costs and different market rules on the rewards of a V2G to participants by developing a model of a centralized V2G system and applying it to the wholesale electricity market in Texas. In a centralized system, EVs act as micro-generators and participate in the wholesale market through a VPP (e.g., an aggregator or a parking lot). I asses three potential market rule scenarios examining different ways that EV owners are compensated. In Scenario 1, EVs are paid based on a fixed retail market price; in Scenario 2, EVs are paid in time-varying retail prices that change with changing wholesale market conditions; in Scenario 3, the VPP shares 50% of its total reward with the participating EVs. Sensitivity analysis is conducted to assess the impact of subsidies and of enhanced rewards for providing flexibility services.

The results illustrate that, while the V2G system is always financially profitable to the VPP and the system operator gets grid services, the EVs often lose money. Cheaper EVs (lower per unit output-battery cost ($/kWh)) could lose more by participating because of extensive battery over-use and insufficient reward at current market prices.

4.7 Policy Implication

The concept of V2Gs has been in the academic literature since the 1990s. There have also been a few pilot projects, but V2Gs remain commercially unviable. Therefore, this essay addresses the key policy issues for V2G as described in section 4.3.

Analysis of economic/market aspect of V2G illustrated that the current market rewards are not enough for the vehicle owners to participate in a V2G. Therefore, to improve the rewards for EVs and thus to make their participation economically viable, policymakers like the National Science Foundation and the Department of Energy could invest in reducing battery costs or policymakers like FERC could spur the introduction of newer market products such as a peak-shaving product or a renewable consuming/flexibility product. In the peak shaving product, the EVs would get extra revenue for discharging during peak hours and charging during off-peak hours. For the renewable consuming/flexibility product, EVs could get extra revenue to prevent wind or solar curtailment and to compensate for the intermittency of the renewable resources. All these options are pragmatic and would compensate EVs in a V2G system for providing their services. The variety of policymakers listed above, could also work together and introduce additional subsidies, like Production Tax Credits, to the EVs for participating in the V2G, or adopt a mixture of these policies. These changes would help to make V2G systems commercially sustainable. Commercially viable V2G would aid in the reduction of emissions, improvement in power system reliability and a decrease in renewable-curtailments.

4.8 Limitation and Further Research

The DP-UC method used this essay applies to any VPP-EV-market scenario that uses day ahead or real-time prices. However, the results are only relevant to specific markets that have nodal prices for energy and ancillary services. Moreover, the assumptions impact the results. These assumptions are laid out in the Methods Section, and most of them are analyzed in sensitivity Section. However, a few are open for extended analysis and further research. These include understanding the impact of rewards on a) EV's willingness to participate and b) improving EVs market diffusion. Another exciting avenue would study the effects of EVs length of stay, e.g., three eight-hour shifts (nursing home) or two 12-hour shift (Control center of a power plant) or sporadic entry/exit (parking ramp close to a cafe), on their rewards. Understanding these would help in guiding the creation of policies to improve EV's market penetration and their participation in V2G.

4.9 My Contributions

The work presented in this essay is a part of a collaborative effort with Professor Frances Thomas (University of Minnesota) and Kaiyang Sun (BIOPAC Systems, LLC). My contributions were concept creation, literature review, gap-analysis, mathematical formulation, programming, result inference, and the content write-up. Professor Thomas was responsible for editorial and technical guidance. Kaiyang Sun supported with programming and precise problem formulation. A shorter version of this paper is published in Elsevier Energy, [184] DOI: https://doi.org/10.1016/j.energy.2018.04.038

4.10 Acknowledgement

I want to thank my collaborators for helping me shape this research.

5. CONCLUSION

In today's world, energy policies play a vital role in any country's strives towards sustainable economic development. The effectiveness of any energy policy depends on how it interacts with other engineering, economic and socio-political aspects surrounding it. These are the holistic-triad. However, both in academia and practice, one or more of pillars in this triad are often neglected. Such elements can lead to unsuccessful or ineffective policy formulation, analysis and implementation. This dissertation highlights the importance of such understudied aspects using three examples viz, a) Carbon tax b) CHP and c) EVs providing V2G services.

The essay on Carbon tax reveals that successful implementation of a carbon tax requires an understanding of how a carbon tax will change power system operations and be shaped by the existing policy and operational context of the electric power system. The results show that **a large price spread could change the generator dispatch, reduce average prices, and diminish the carbon tax effectiveness**. If power-engineering aspects were not studied, these interactions would never be highlighted, and the predicted efficacy of a carbon tax would be significantly different from the actual efficacy.

The essay on CHP finds that financial viability is necessary but not an enough condition for developing a CHP project. **The most significant non-financial barriers are a) the business model of the electrical utility b) negative subjective impressions based on anecdotal evidence and c) allocating the risks and benefits of many costs and revenue streams**. Overcoming these barriers would help to exploit CHP potential, improve energy efficiency, and, in the case of the newest CHP systems, provide flexibility services to the grid. To overcome these barriers, clear new policies are necessary. If the sociopolitical aspects were not studied, these non-financial barriers would never be revealed.

The essay on EVs investigates the implications of battery costs and different market rules on the rewards of a V2G to participants by developing a model of a centralized V2G system and applying it to the wholesale electricity market in Texas. The results reveal that, while the V2G system is always financially profitable to the VPP and the system operator gets grid services, **the EVs often lose money**. Further, **cheaper EVs (lower per unit output-battery cost ($/kWh)) could lose more** by participating because of extensive battery over-use and insufficient reward at current market prices. If these economic/market aspects were not studied, the ultimate barrier (profitability) that could prevent EVs from participating in the V2G scheme would never be revealed.

Therefore, for an effective energy policy, holistic insights of the triad are necessary. Such insights help in discovering phenomenon (as illustrated in prior paragraphs) that would sometimes counteract and at other times enhance the effectiveness of the policy in question.

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7. APPENDIX

7.1 Interacting Policies in Power System

7.2 Relevant Network Data

Generator data

Bus	Pg (MW)	Qg (MW)	Q Max (MW)	Q Min (MW)	Vg (p.u)	P Max (MW)	P Min (MW)	Generator Name
1	10	0	10	0	1.035	20	16	U20
1	10	0	10	0	1.035	20	16	U20
1	76	0	30	-25	1.035	76	15.2	U76
1	76	0	30	-25	1.035	76	15.2	U76
2	10	0	10	0	1.035	20	16	U20
2	10	0	10	0	1.035	20	16	U20
2	76	0	30	-25	1.035	76	15.2	U76
2	76	0	30	-25	1.035	76	15.2	U76
7	80	0	60	0	1.025	100	25	U100
7	80	0	60	0	1.025	100	25	U100
7	80	0	60	0	1.025	100	25	U100
13	95.1	0	80	0	1.02	197	69	U197
13	95.1	0	80	0	1.02	197	69	U197
13	95.1	0	80	0	1.02	197	69	U197
14	0	35.3	200	-50	0.98	0	0	Syn Cond
15	12	0	6	0	1.014	12	2.4	U12
15	12	0	6	0	1.014	12	2.4	U12
15	12	0	6	0	1.014	12	2.4	U12
15	12	0	6	0	1.014	12	2.4	U12
15	12	0	6	0	1.014	12	2.4	U12

15	155	0	80	-50	1.014	155	54.3	U155
16	155	0	80	-50	1.017	155	54.3	U155
18	400	0	200	-50	1.05	400	100	U400
21	400	0	200	-50	1.05	400	100	U400
22	50	0	16	-10	1.05	50	10	U50
22	50	0	16	-10	1.05	50	10	U50
22	50	0	16	-10	1.05	50	10	U50
22	50	0	16	-10	1.05	50	10	U50
22	50	0	16	-10	1.05	50	10	U50
22	50	0	16	-10	1.05	50	10	U50
23	155	0	80	-50	1.05	155	54.3	U155
23	155	0	80	-50	1.05	155	54.3	U155
23	350	0	150	-25	1.05	350	140	U350

Generator Cost data

Cost Curve Type	Start Up ($)	Shut Down ($)	Num Coeff	c ($/MW^{2}hr)	b ($/MWhr)	a ($/hr)	Generator Name
2	1500	0	3				U20
2	1500	0	3				U20
2	1500	0	3				U76
2	1500	0	3				U76
2	1500	0	3				U20
2	1500	0	3				U20
2	1500	0	3				U76
2	1500	0	3				U76
2	1500	0	3				U100
2	1500	0	3				U100
2	1500	0	3				U100
2	1500	0	3				U197
2	1500	0	3				U197
2	1500	0	3	It is same as the bidding data of essay 1			U197
2	1500	0	3	0	0	0	SynCond
2	1500	0	3	It is same as the bidding data in essay 1			U12

2	1500	0	3	U12
2	1500	0	3	U12
2	1500	0	3	U12
2	1500	0	3	U12
2	1500	0	3	U155
2	1500	0	3	U155
2	1500	0	3	U400
2	1500	0	3	U400
2	1500	0	3	U50
2	1500	0	3	U50
2	1500	0	3	U50
2	1500	0	3	U50
2	1500	0	3	U50
2	1500	0	3	U50
2	1500	0	3	U155
2	1500	0	3	U155
2	1500	0	3	U350

Bus data

Bus No	Pd (MW)	Qd (MW)	Vm (p.u)	Va (rad)	Base KV	V Max (p.u)	V Min (p.u)
1	108	22	1	0	138	1.05	0.95
2	97	20	1	0	138	1.05	0.95
3	180	37	1	0	138	1.05	0.95
4	74	15	1	0	138	1.05	0.95
5	71	14	1	0	138	1.05	0.95
6	136	28	1	0	138	1.05	0.95
7	125	25	1	0	138	1.05	0.95
8	171	35	1	0	138	1.05	0.95
9	175	36	1	0	138	1.05	0.95
10	195	40	1	0	138	1.05	0.95
11	0	0	1	0	230	1.05	0.95
12	0	0	1	0	230	1.05	0.95
13	265	54	1	0	230	1.05	0.95

14	194	39	1	0	230	1.05	0.95
15	317	64	1	0	230	1.05	0.95
16	100	20	1	0	230	1.05	0.95
17	0	0	1	0	230	1.05	0.95
18	333	68	1	0	230	1.05	0.95
19	181	37	1	0	230	1.05	0.95
20	128	26	1	0	230	1.05	0.95
21	0	0	1	0	230	1.05	0.95
22	0	0	1	0	230	1.05	0.95
23	0	0	1	0	230	1.05	0.95
24	0	0	1	0	230	1.05	0.95

Branch data

Fr	To	r (p.u)	x (p.u)	b (p.u)	Rate A (MW)	Rate B (MW)	Rate C (MW)
1	2	0.0026	0.0139	0.4611	250	250	200
1	3	0.0546	0.2112	0.0572	175	208	220
1	5	0.0218	0.0845	0.0229	175	208	220
2	4	0.0328	0.1267	0.0343	175	208	220
2	6	0.0497	0.192	0.052	175	208	220
3	9	0.0308	0.119	0.0322	250	208	220
3	24	0.0023	0.0839	0	400	510	600
4	9	0.0268	0.1037	0.0281	175	208	220
5	10	0.0228	0.0883	0.0239	175	208	220
6	10	0.0139	0.0605	2.459	400	193	200
7	8	0.0159	0.0614	0.0166	400	208	220
8	9	0.0427	0.1651	0.0447	400	208	220
8	10	0.0427	0.1651	0.0447	400	208	220
9	11	0.0023	0.0839	0	400	510	600
9	12	0.0023	0.0839	0	400	510	600
10	11	0.0023	0.0839	0	400	510	600
10	12	0.0023	0.0839	0	400	510	600
11	13	0.0061	0.0476	0.0999	500	600	625

14	11	0.0054	0.0418	0.0879	500	625	625
12	13	0.0061	0.0476	0.0999	500	625	625
12	23	0.0124	0.0966	0.203	500	625	625
13	23	0.0111	0.0865	0.1818	500	625	625
14	16	0.005	0.0389	0.0818	500	625	625
15	16	0.0022	0.0173	0.0364	500	600	625
15	21	0.0063	0.049	0.103	500	600	625
15	21	0.0063	0.049	0.103	500	600	625
15	24	0.0067	0.0519	0.1091	500	600	625
16	17	0.0033	0.0259	0.0545	500	600	625
16	19	0.003	0.0231	0.0485	500	600	625
17	18	0.0018	0.0144	0.0303	500	600	625
17	22	0.0135	0.1053	0.2212	500	600	625
18	21	0.0033	0.0259	0.0545	500	600	625
18	21	0.0033	0.0259	0.0545	500	600	625
19	20	0.0051	0.0396	0.0833	500	600	625
19	20	0.0051	0.0396	0.0833	500	600	625
20	23	0.0028	0.0216	0.0455	500	600	625
20	23	0.0028	0.0216	0.0455	500	600	625
21	22	0.0087	0.0678	0.1424	500	600	625

7.3 Relavant Bidding Data

S.No	**Name**	**Coefficients**		
		a ($/hr)	**b ($/MWhr)**	**c ($/MW^{2}hr)**
1	L265	-105	-8500	1.05
2	L100	-49.2618	-7500	0.492618
3	L195	-90	-6500	0.9
4	L317	-1.2513	-5557	0.012513
5	L71	-37.5	-5200	0.375
6	L125	-7.9008	-5200	0.079008
7	L175	-60	-5200	0.6

8	L74	-75	-4700	0.75
9	L108	-75	-4200	0.75
10	L194	-0.75	-4200	0.0075
11	L97	-1.8	-3800	0.018
12	L136	-1.875	-3500	0.01875
13	L171	-3	-3500	0.03
14	L180	-48.75	-3200	0.4875
15	L181	-7.5	-3000	0.075
16	L128	-6.75	-2700	0.0675
17	L133	-3.75	-2564	0.0375
18	U50	*0.001*	*0.001*	*0*
19	U50	*0.001*	*0.001*	*0*
20	U50	*0.001*	*0.001*	*0*
21	U50	*0.001*	*0.001*	*0*
22	U50	*0.001*	*0.001*	*0*
23	U50	*0.001*	*0.001*	*0*
24	U400	395.3749	4.4231	0.000213
25	U400	395.3749	4.4231	0.000213
26	U197	17.27704	11.3128 + *tax*	0.065682
27	U197	17.27704	11.3128 + *tax*	0.065682
28	U197	17.27704	11.3128 + *tax*	0.065682
29	U12	17.27704	11.3128 + *tax*	0.065682
30	U12	17.27704	11.3128 + *tax*	0.065682
31	U12	17.27704	11.3128 + *tax*	0.065682
32	U12	17.27704	11.3128 + *tax*	0.065682
33	U12	17.27704	11.3128 + *tax*	0.065682
34	U350	665.11	11.8495 + *tax*	0.004895
35	U155	382.2391	12.3883 + *tax*	0.008342
36	U155	382.2391	12.3883 + *tax*	0.008342
37	U155	382.2391	12.3883 + *tax*	0.008342
38	U155	382.2391	12.3883 + *tax*	0.008342
39	U76	212.3076	16.0811 + *tax*	0.014142
40	U76	212.3076	16.0811 + *tax*	0.014142
41	U76	212.3076	16.0811 + *tax*	0.014142
42	U76	212.3076	16.0811 + *tax*	0.014142

43	U100	0.001	22	0
44	U100	0.001	22	0
45	U100	0.001	22	0

7.4 Non-Financial Barriers to Combined Heat and Power

7.5 Sample Recruitment Email

To: <Name>

Cc: <Name1>

Subject: Request for research interview

Dear Ms./Mr. <Name>

I am a PhD student at the Humphrey School of Public Affairs and contacting you as part of a research study on Combined Heat and Power based at the University of Minnesota. We are studying opportunities and barriers affecting adoption of CHP in Minnesota are particularly interested to understand the technology from your perspective.

I would like to interview you about your work with <Company> and your experiences with CHP projects. Given your background and experience, we believe that your perspective will provide critical insights into the opportunities and challenges facing the deployment of the technology. I anticipate that the interview will take less than one hour.

I am working with <Name 1> at the <Location> as project advisers and I would be happy to provide you with more details about our team, the project, and our learning objectives if you wish.

I know you are busy, but would welcome a time to speak with you in the following weeks. If you would like to email me a few times which would work for you, I would appreciate it, if not, I can follow up with a call to schedule.

Best regards,

Vivek Bhandari

7.6 Sample Consent Form

The purpose of this form is to provide you information that may affect your decision as to whether to participate in this research study. If you decide to participate in this study, this form will also be used to record your consent.

You are invited to participate in a research project about decision-making in Combined Heat and Power. The purpose of this study is to understand your perspective of technology diffusion for Combined Heat and Power.

The research is guided by the following questions: <Research Questions>

You were selected to participate in this project because you are especially knowledgeable about CHP. The study is sponsored by the <DONOR>.

What will I be asked to do?

If you agree to participate in this study, we will ask you to participate in an interview. We may contact you individually later (within 1 year of the interview) to ask to follow up. The interview will last between ½ an hour to 1 hour. We will ask you to discuss a set of questions surrounding *Combined Heat and Power*, with a focus on your experience with it and perceptions of it. You do not need to respond to every question. The interview discussion will be audio recorded to ensure that transcripts of the session are accurate. After sessions are transcribed, recordings will be destroyed.

What are the risks involved in this study?

The risks associated in this study are minimal and are not greater than risks ordinarily encountered in daily life.

What are the possible benefits of this study?

You will receive no direct benefit from participating in this study; however, the study may benefit society by contributing to U.S. energy security and sustainable development.

Do I have to participate?

No. Your participation is voluntary. You may decide not to participate or to withdraw at any time without your current or future relations with the University of Minnesota. If you decide to participate, you are free to refuse to answer any questions that may make you feel uncomfortable. You can withdraw at any time without negative consequences.

Who will know about my participation in this research study?

This study is confidential. We will keep the records of this study private. Other members of your focus group will, however, know about your participation. No identifiers linking you to this study will be included in any sort of report that might be published. Research records will be stored securely and only members of the research team who have an approved report demonstrating successful completion of training in Social and Behavioral

Research Investigations on file with the University of Minnesota will have access to the records.

If you choose to participate in the interview, you will be audio recorded. Any audio recordings will be stored securely and only members of the research team who have an approved report demonstrating successful completion of training in Social and Behavioral Research Investigations on file with the University of Minnesota will have access to the original recordings. Recordings will be kept for up to 2 years from the date of your interview and then erased.

To ensure accuracy, professional transcribers will transcribe interview sessions. Prior to transcription, we will replace participants' names with numbers to protect identities. Following transcription, we will 'clean' the file, removing names used in conversation.

In any reports we might publish, we will not include any information that will make it possible to identify you or your organization, unless you state your preference that we do so. Because we have learned that some individuals prefer their statements attributed to themselves, we have made provision for that option. At the end of this form, you will be asked to indicate your preference regarding attribution.

Whom do I contact with questions about the research?

If you have questions regarding this study, you may contact Name 1 <Email 1> and Name 2 <Email 2>

Whom do I contact about my rights as a research participant?

The Institutional Review Board at University of Minnesota has reviewed this research study. For research-related problems or questions regarding your rights as a research participant, you can contact these offices at <Phone> or <email>.

Preference regarding attribution

<u>Please indicate your choice by circling one statement from the following list</u>:

I prefer that any quotations from me be used in the following way:

- □ Quotes without attribution (research team will use language that does not identify you or your organization)
- □ Quotes attributed to me

Signature

Please be sure you have read the above information, asked questions and received answers to your satisfaction. You will be given a copy of the consent form for your records. By signing this document, you consent to participate in this study.

Signature of Participant: ______________________________ Date: ______________

Printed Name: ____

Signature of Person Obtaining Consent: __________________Date: ______________

Printed Name: ____

7.7 Interview Subjects and The Recruitment Process

Interview subjects/experts were recruited from attendees at a public stakeholder forum on CHP organized by the MN-DOC, commentators on the corresponding docket [185], and authors of/contributors to the documents from document analysis. An example of the recruitment email is given in section 7.5. Not only the authors and participants of the meetings but also people who run a CHP facility but don't have public visibility were approached. List of such people were obtained by calling the facility using the CHP installation database [116]. Initially, only four of the 50 experts initially contacted agreed to be interviewed. This illustrates how the CHP community is closed to outsiders. Therefore, these four experts were used to recruit the remaining interviewees ("snowball sampling") who were more willing to be interviewed after someone they knew and trusted introduced them to us. In this way, I was able to recruit 32 experts over a period of 1.5 years. Each of the experts I interviewed had at least 5 years of experience with CHP and was regarded as an expert by their peer interviewees (since they were generally cross-referenced among one another). Table 3-1 contains the categorical breakdown of the experts. Though I was able to get a broad spectrum of expert interviewees, the recruitment process biases the sample of interviewees in several ways. First, the interviewees are mostly proponents of CHP because I selected experts who have worked on CHP projects. Second, most have experience with natural-gas-based CHP, but very few had experience with biomass-based CHP. Third, the experts are based in a few states

(Iowa, Minnesota, Massachusetts and Washington D.C.), though many them worked in other states and could speak about CHP in the United States more generally.

7.8 Sample Interview Guide

Introduction demographic questions

- Establish that you have done homework, but you are a novice and are open to learn. Also be sure to establish that you will learn ins and outs but will not judge.

- After this gives them the consent form, allow them to read and sign. Then start the recorder.

Prelude: Our goal is to understand the diffusion/implementation process of energy technologies from implementer's perspective. [Your organization] is an implementer (or potential implementer or rejecter)? We have taken CHP as our case technology. We have been reading literature and e-dockets. But, to understand the process, we need to understand perspectives of actual participants. We need to learn from their experiences. That is why we are here. We would love to make this interview conversational. We want to learn about diffusion and implementation of CHP from your experience.

Introduction

1. How long have you been involved in [organization name]?
2. How long have you participated directly in
    2.1. [This program] conceptualization or

2.2. [This program] implementation and promotion

Understanding the market diffusion of CHP (the non-financial barriers)

(1) *Step 1: Understanding the policy problem*. The key policy problem to be addressed.

- Perception of the Problem:
    i. How severe of a problem was/is [this program in this place]? Why?
- Viable Solutions:
    i. What were/are existing strategies (other than this program) to address this problem?
    ii. Why did you make this choice?
- Desired Outcomes:
    i. What would be considered a "successful" outcome of [this program]?

    Probe: What would need to happen for this program to be considered a success?

(2) *Step 2: Understanding the existing system.* Each place has a unique network/system that includes [various institutional actors].

- Structure:
    i. Can you describe the structure of [institutions] working to provide this [program]?

ii. What are the implications of this structure

Probe: What would be different if this structure would be different?

- Power & Authority:

i. Can you describe who has the authority to make different decisions about [this program]?

Probe: Does the staff set have discretion for how they will implement the program? Do they have the authority to change the structure operational steps?

ii. What role do politics and elected (or appointed) officials play in determining [the problem/solution]?

iii. How is ____ [this program] funded?

iv. How would [other agencies involved in service] fund it? How much discretion do they have over deciding [this program]?

- Culture:

i. How things 'really happen' is often a function of culture. Yet, it is often difficult to describe. How would you metaphorically describe your [organization network], for example – factory, family, team, and zoo)? Why?

Probe: What are some of the key values that under-pin the way [this program] is delivered? What are the values now?

ii. To what extent do the [various actors your local system] investigate other models of best practices? Which models?

(3) Step 3: Implementing [the Policy/Program] in the System.

- The integration challenges.
    i. Introducing [new program] into an existing local system takes political will, local leadership, designated capacity, etc. Describe the process by which the [this program] was first introduced? Were there any resistance or support? Who were the biggest supporters? Critics?
    ii. How difficulty (or easy) was it to integrate the [this program] into the existing system? What factors made it easier (or more difficult)? What were the biggest challenges?
    iii. How long did it take?
    iv. What sorts of communication media were used to make effective communications?
- The design challenges.
    i. Describe/review the program process flow and key design elements (e.g., incentives, payment plans) [for this program].
    ii. Which steps in the process was most challenging, and how did you overcome these challenges?

        Probe: [could list ones you know]

    iii. What factors influenced the program elements selected in this place (e.g., incentives, repayment plan structures, want to become greener)? Are these elements the “ideal” elements that should be included in a model? Which elements are most important? What is missing, and why?

iv. How long did it take?

v. What sorts of communication media were used to make effective communications?

(4) *Step 4: Post implementation evaluation* – only for ones who have implemented

i. How do you ‘now’ describe [this program]?

ii. How could you evaluate if your expectations were met?

iii. Describe the existing infrastructure for data collection system [for evaluating this program]. How would you describe the flexibility and capacity of this process?

Probe: Were there any challenges in creating treatment and control? What were those? What made the solution easier/difficult?

iv. How would you characterize risk and uncertainty at this phase? How about in the previous phases?

v. How long do you think will this evaluation take?

vi. What sorts of communication media are/were/should be used to make effective communications?

Conclusion

i. How would you summarize innovation in each stage [in a word or two] (policy perception, actual system, implementation and post implementation)?

ii. How would you summarize the most critical opportunities and barriers, for every stage, [in a word or two]?

iii. If I am a supporter/adversary of this diffusion/implementation process

   a. How can I possibly block the process?
   b. How can I provide levers to unblock it?
   c. Where can I provide these levers?
   d. Who should I interact with?
   e. Can you provide some examples

Extras

i. What most important thing about energy innovation diffusion/implementation that we should know?

ii. That is all for my questions. What else, do you think, that I should ask to know about this process?

iii. Is there anything that you would want from me?

iv. Who else should I speak with?