LONG-TERM INFRASTRUCTURE INVESTMENT PLANNING AND POLICY ANALYSIS FOR THE ELECTRICITY SECTOR IN SMALL ISLAND DEVELOPING STATES: CASE FOR JAMAICA

by

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This dissertation is dedicated to my parents, Donovan and Pearline Atkinson, whose sacrifice has made my academic dreams a reality. This would not be possible without you.

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Abbreviations	Meaning
ACOPF	Alternating current optimal power flow
ADO	Automotive diesel oil
BAU	Business as usual
CO2	Carbon dioxide
CTAX	Carbon tax
DCOPF	Direct current optimal power flow
EIA	Energy Information Agency
EPA	Environmental Planning Agency
FIT	Feed-in tariff
GAMS	General Algebraic Modeling System
GDP	Gross domestic product
GEP	Generation expansion planning
GHG	Greenhouse gas
GoJ	Goivernment of Jamaica
GTEP	Generation and transmission expansion planning
HFO	Heavy fuel oil
HIC	High income countries
JIS	Jamaica Information Service
JLP	Jamaica Labour Party
JPSCo	Jamaica Public Service Company
KL	Kirchhoff's laws
kWh	Kilowatt-hour
LCOE	Levelized cost of energy
LDC	Less Developed Countries
LIIP	Long-term infrastructure investment planning
MILP	Mixed integer linear program
MOJ	Meteorological Office of Jamaica

MPEC	math program with equilibrium constraints
MSET	Ministry of Science, Energy and Technology
NDCs	Nationally determined contributions
NG	Natural Gas
NPV	Net present value
OUR	Office of Utilities Regulation
PCJ	Petroleum Corporation of Jamaica
PNP	People's National Party
PTC	Production tax credit
RETs	Renewable energy technologies
RPS	Renewable portfolio standard
SIDS	Small Island Developing States
UNDP	United Nations Development Program

ABSTRACT

Energy sector transformation is of interest to policy makers and energy researchers. Critical to this transformation is efficient (i.e. least-cost) infrastructure investment planning for new generation and transmission infrastructure investments. Similarly, energy policies designed to encourage low carbon electricity generation have fueled much of the transformation globally over the past two decades. However, knowledge gaps remain with respect to the unique economic and geographic features of Small Island Developing States (SIDS); recommendations from previous studies often have limited applicability to the SIDS context. This dissertation addresses these concerns, contributing to our understanding of least-cost planning methods for new infrastructure investments as well as energy policies appropriate for small, isolated and often heavily indebted nations. The island of Jamaica is used as a case study to gain insights more applicable to the broader SIDS context.

The first problem this dissertation addresses is the impact of *simultaneously* planning for generation and transmission infrastructure instead of *sequentially* optimizing these decisions, as is commonly done. Energy infrastructure planning in SIDS treats transmission infrastructure as an afterthought once generation investments have been determined, potentially leading to sub-optimal investments. Using a dynamic optimization model of generation and transmission infrastructure, we find that it is more cost effective to co-optimize generation and transmission investments. The substitutability between local generation and remote generation, facilitated by transmission infrastructure, underpins this result.

The second empirical problem we address is the impact of loop flow on optimal infrastructure investment decisions. The Energy Information Agency (EIA) defines loop flow as "the movement of electric power from generator to load by dividing along multiple parallel paths; it especially refers to power flow along an unintended path that loops away from the most direct geographic path or contract path" (EIA, n.d.). We find no evidence that loop flow affects optimal investment decisions in Jamaica. We attribute this to an abundance of transmission capacity and the relative simplicity of Jamaica's network design. Results may differ for other SIDS with different starting configurations.

The third problem this dissertation addresses centers on energy policy. We quantify the cost to the Jamaican society under four different policy scenarios: a renewable portfolio standard

(RPS) of 30% by year 2030, a carbon tax, a production tax credit and an investment subsidy for specific renewable energy resources (solar and wind). We find that if the decision makers' primary concern is reducing carbon emissions, a carbon tax is the economically efficient choice (of the four options); an RPS has the second-lowest cost to society. Assessing the tradeoffs associated with each option, a carbon tax is efficient but increases the average annual cost of electricity. If, however, the decision makers' primary objective is energy independence and not carbon emissions reduction, then the RPS may be a better alternative than a carbon tax.

Collectively, this dissertation demonstrates a method for improving long-term planning in the electricity sector in SIDS. It also quantifies the cost to society of implementing a menu of carbon mitigating policies, removing the ambiguity that persists in energy policy setting. Not only does this dissertation advance the energy economic literature by specifically addressing the economic and geographic features of SIDS, but we make our data and program files freely accessible. This is one measure that helps to overcome the data limitation hurdle that is a main contributor to the dearth of energy economics research more applicable to SIDS.

CHAPTER 1. INTRODUCTION

Small Island Developing States (SIDS) possess unique features that cumulatively distinguish them from non-island territories. This includes their small, isolated geographies; comparatively higher levels of dependence on international trade, and vulnerability to global shocks and the impact of climate change. One aspect that warrants special attention is infrastructure planning relating to electricity access and use. This has been observed to be highly correlated with economic growth and development. Hence, this dissertation examines long-term infrastructure investment planning and policy analysis for the electricity sector in a SIDS context.

This chapter introduces the practical problems motivating this dissertation and links them to broader conceptual problems. These conceptual problems include efficient (i.e. least cost) planning for new electricity infrastructure investments. Specifically, this dissertation addresses the scope of the planning effort, the attention to details relating to the laws of physics governing electricity flow, and the economic implications thereof. Additionally, this dissertation assesses the impact of renewable energy policies on the electricity sector in Small Island Developing States. Finally, given the multi-disciplinary nature of this work, this chapter defines some technical concepts to facilitate both the economics and engineering audience.

1.1 Long-term infrastructure investment planning

Long-term infrastructure investment planning (LIIP) is crucial to the electricity sector due to historical trends for electricity demand growth, the need to replace older generation units, and the increasing penetration of renewable energy resources. This is particularly so for Small Island Developing States (SIDS). Over the last four decades, per capita growth in electricity consumption in SIDS (3.93%) almost doubled the world average (2.28%), outpacing Less Developed Countries (3.21%) and High Income Countries (1.82%) (World Bank, 1971-2019). Note that growth rates for SIDS are based on calculations for 43 (of 48) SIDS for which data was available. By 2014, average per capita consumption in SIDS stood at 5,185 kWh, over half of the 9,042 kWh per capita consumption in high income countries and roughly two thirds greater than the world average of 3,132 kWh (Figure 1.1). This trend is accelerated by the growth in electricity access in SIDS (Figure 1.2). As electricity demand increases over time, utilities need additional capacity to generate electricity and replace aging generators to ensure reliable and efficient supply. Additionally, as countries seek to generate more electricity from renewable sources in order to mitigate the impact of climate change, the intermittent nature of resources (such as solar and wind) increases the complexity of maintaining reliable electricity supply. However, building new capacity entails high capital and sunk costs, as well as long construction lead times. So, utilities must anticipate demand far into the future (usually around 20 years) at the time of making their capacity decisions. With significant sums of money at stake, long-term infrastructure investment planning is critical for these countries.

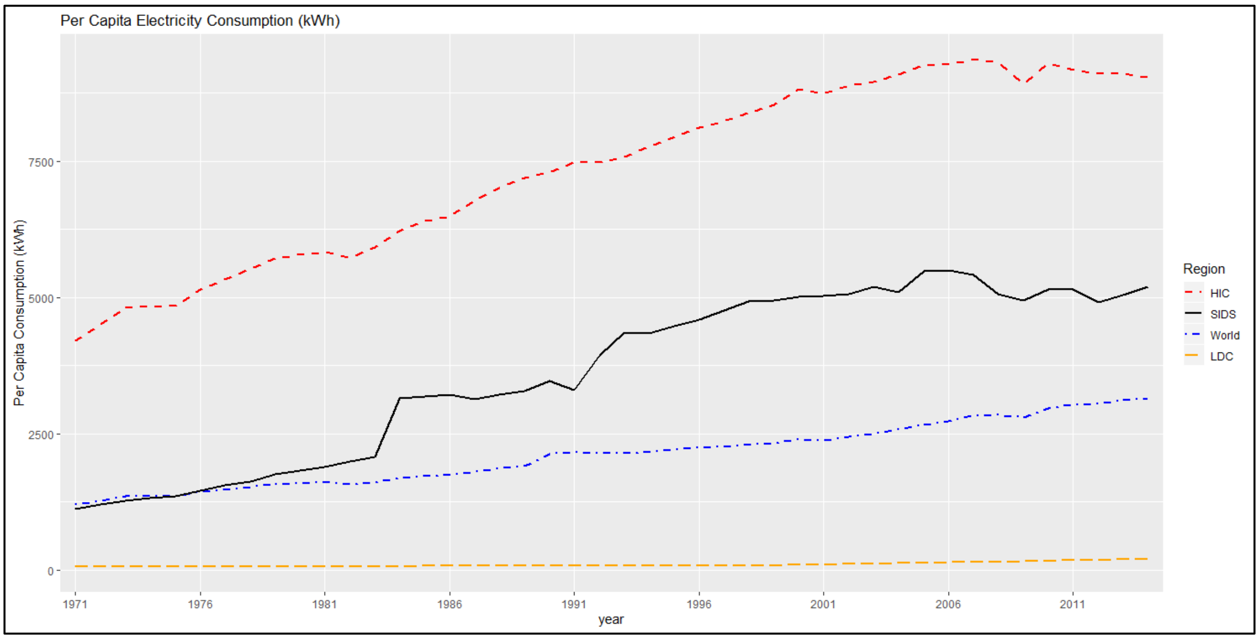

Figure 1.1: Per capita electricity consumption (kWh/year) (World Bank, 1971-2017) *

* HIC = High Income Countries, SIDS = Small Island Developing, World = World, LDC = Less Developed Countries

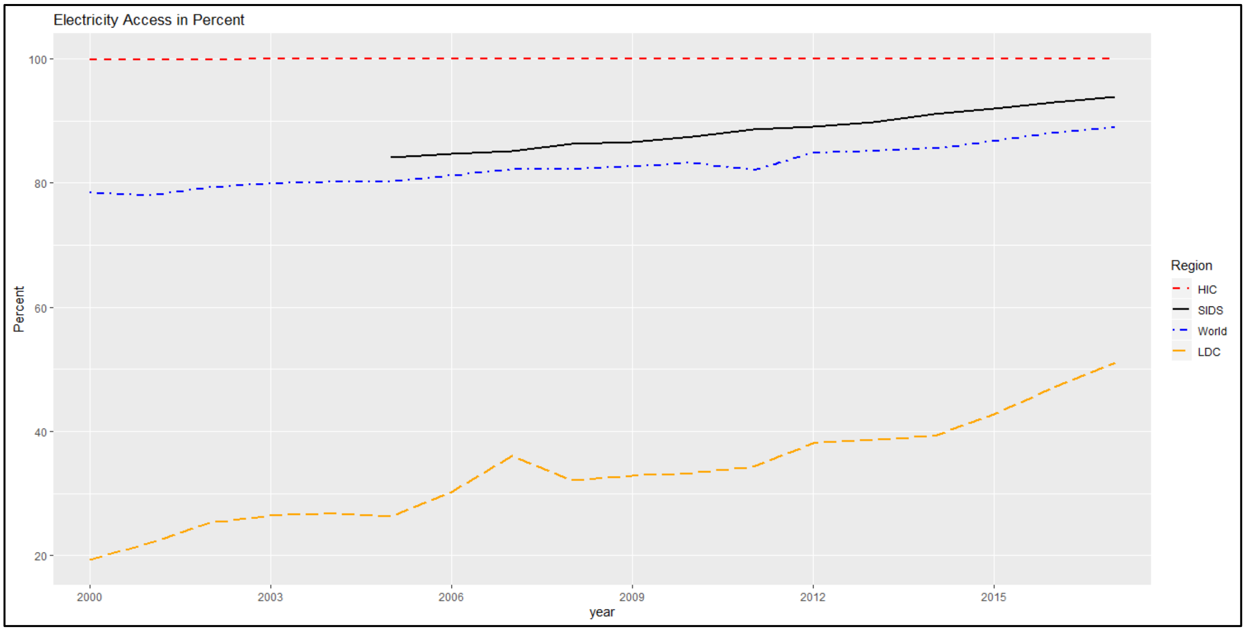

Figure 1.2: Electricity access in percent of population (World Bank, 1993-2017) *

* HIC = High Income Countries, SIDS = Small Island Developing, World = World, LDC = Less Developed Countries

The economic characteristics (e.g., low per capita gross domestic product (GDP), economic openness and high debt) of SIDS coupled with the fact that utilities in SIDS are typically government-owned, gives efficient capital investments greater import for SIDS. These governments generally have limited fiscal room to offset external shocks or compensate for inefficient planning. For instance, over 50% of all SIDS fall between the World Bank's "low income" and "upper-middle income" country classification. While economic growth in these islands is low and sometimes stagnant, their debt to GDP (gross domestic product) ratio has averaged 51% since 1990 (World Bank, 1990). For islands like Barbados and Jamaica, average debt to GDP since 1990 is 95% and 119%, respectively, while their economies grew on average only by 0.62% and 1.28% over the last three decades (World Bank). Low income, low economic growth and high debt, in a context where electric utilities in SIDS are predominantly government-owned, make efficient, capital-intensive, long-term infrastructure investment planning even more important; there is little room for error.

Yet, long-term infrastructure investment planning in SIDS generally focuses on generation expansion planning (GEP). GEP involves optimizing generation capacity to satisfy future expected demand, ignoring transmission constraints. It ignores transmission capacity that may be required to complement new generation capacity. In Jamaica, for instance, the only publicly accessible long-term infrastructure investment plan was a 2010 GEP (OUR, 2010). Despite acknowledging that the GEP would need to be complemented by a transmission expansion plan, this GEP presented no transmission analysis. Figure 1.3 illustrates this. "G" represents generation capacity and "D" represents demand/load. While node 1 can generate 100 MW, its load is only 25 MW. On the other hand, node 2 generates no electricity but has a load of 75 MW. A total of 50 MW can be transferred from node 1 to node 2, but node 2 would still have unserved demand of 25 MW. The solution to a GEP would be to construct a 25 MW power plant at node 2.

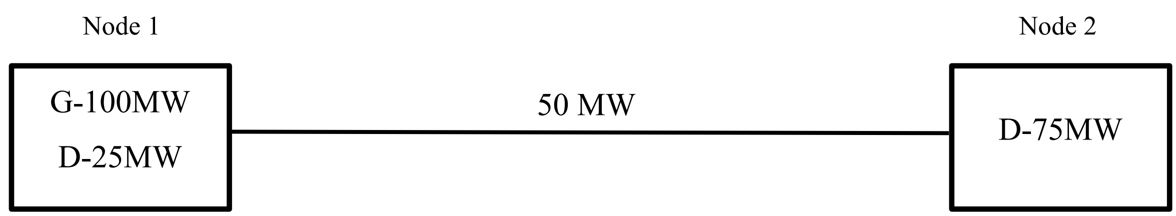

Figure 1.3: Two node transmission network

On the other hand, a generation and transmission expansion planning (GTEP) model includes potential transmission investments and constraints in the optimization process. Referring again to Figure 1.3, if transmission infrastructure is cheaper than a new generator, a GTEP solution might be to expand the transmission capacity from node 1 to node 2 by at least 25 MW. A total of 75 MW could then be transferred to node 2, satisfying demand, while still costing less than it would to build a new generator at node 2.

GTEP models can also explicitly account for Kirchhoff's Laws (KL). Kirchhoff's Laws are physical laws governing the flow of electricity in a network that reflect a phenomenon known as loop flow. Loop flow refers to the movement of electricity from generator to load by dividing along multiple parallel paths. These parallel flows cannot be modified except by changing the pattern of network injections, and these may lead to higher costs than would occur if flow could be directed only along intended paths.

Kirchhoff's Voltage Law states that the sum of voltages in a closed loop (i.e. a closed path in a circuit) equals zero. Kirchhoff's Current Law states that the sum of current entering a node equals the sum of the current exiting a node. (Note that in this dissertation, electricity demand already accounts for line losses. Hence, there are no explicit transmission losses in our network as further discussed in CHAPTER 3.) The implication of KL is that electricity flows along all lines connecting an injection (generation) node and a withdrawal node, following the path of least resistance. Consequently, an injection or withdrawal of electricity from any point in the network affects the system at ever other point.

Figure 1.4 illustrates this concept assuming symmetric reactance on each line. Load at node 3 is 300 MW. In panel (a), node 1 is the only generation node, generating electricity at \$10/MWh. In abstract terms, we denote this as "+G_1" (the plus sign indicates an injection). Satisfying the demand of 300 MW at node 3, Kirchhoff's Laws (resulting in loop flow) dictate that an injection of 300 MW at node 1 flows along all paths between the generation at node 1 to the withdrawal at node 3. Here, there are only two paths. The shorter path is through line 1.3. The longer path is through line 1.2 then through line 2.3. With symmetric line reactance and no restrictions on the flow of electricity (e.g., line congestion), the resulting flow of electricity is such that 2/3 of the 300 MW (i.e. 200 MW or $2G_1/3$) flows through line 1.3 while the remaining 1/3 (i.e. 100 MW or $1G_1/3$) flows through line 1.2 and then passed through line 2.3. These flows are a result of the pattern of network injections, withdrawals, and reactance of the individual transmission lines. In panel (b) however, the capacity of line 1.2 is restricted to only 50 MW (imagine that this is a physical limitation of the line), necessitating electricity generation at node 2 (+G_2) at \$20/MWh to help compensate for this loss in transmission capacity. Again, applying Kirchhoff's Laws, power flow through line 2.3 is defined by $(G_1 + 2G_2)/3$. Power flow across line 1.3 is defined by $(2G_1 + 1G_2)/3$. Power flow across line 1.2 is defined by $(G_1 - G_2)/3$ but is restricted to being at most 50 MW. Hence, $(2G_1 + 1G_2)/3 \leq 50$. Finally, injections at nodes 1 and 2 must be equal to the withdrawal at node 3, that is: $-(G_1 + 1G_2) = -300$ (the minus sign indicates withdrawal). Solving these equations simultaneously, generation at node 1 is 225 MW while 75 MW of electricity is generated at node 2. Of the 225 MW generated at node 1, 175 MW flows through line 1.3. The remaining 50 MW flows through line 1.2; line 1.2 thus hits its (restricted) capacity limit. The 75 MW generated at node 2 together with the 50 MW flowing through line 1.2 results in a total of 125 MW flowing through line 2.3. The 300 MW demand at node 3 is satisfied. Consequently, total system cost in without flow restriction on line 1.2 (i.e. panel (a)) is \$3,000 while with the restriction (panel (b)), the total system cost increases to \$3,750 – an increase in cost of 25%. The important feature in this example is that an injection or withdrawal of electricity from any point in the network affects the system at ever other point. This in turn, can have significant market implications. GEP models typically ignore this feature.

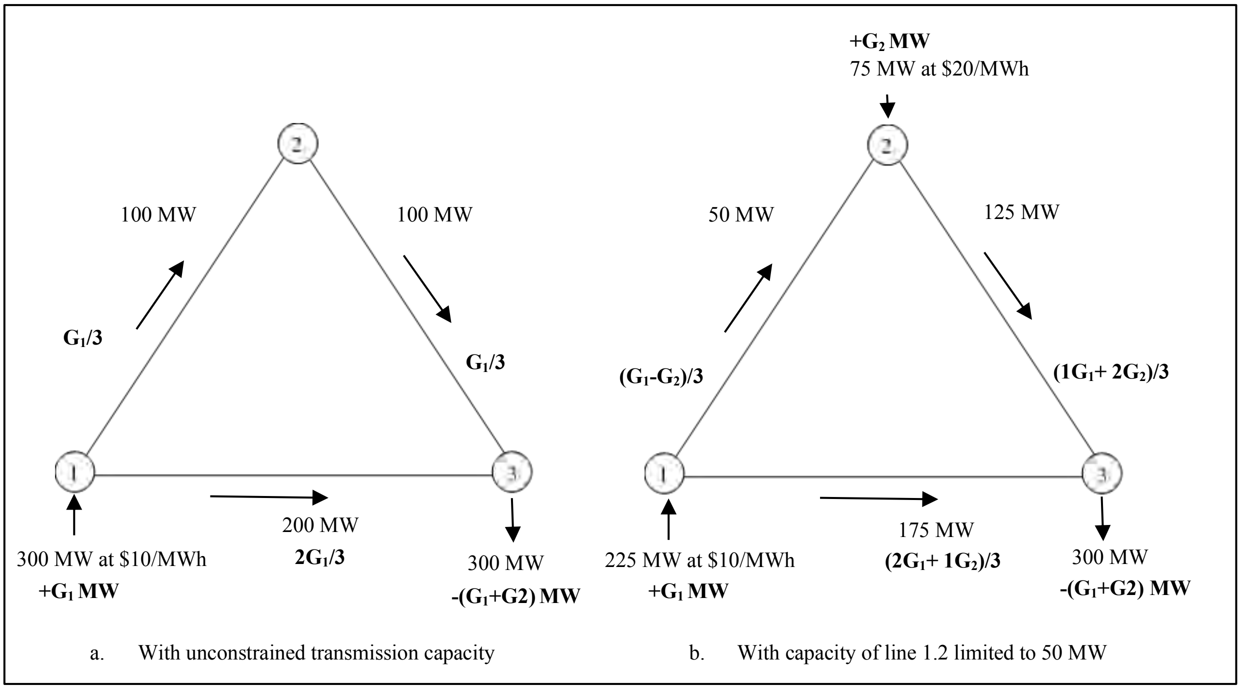

Figure 1.4: Numerical example of the influence of Kirchhoff's Voltage Laws

While there is an extensive literature on long-term infrastructure investment planning (discussed in CHAPTER 2), we have two concerns. First, the literature is dominated either by theoretical Institute of Electrical and Electronics Engineers (IEEE) network designs or on larger, more developed territories (e.g. the United States or Europe). These lack the economic (e.g. high debt and limited fiscal flexibility) and geographic (e.g. small size, diseconomies of scale and isolation of electricity networks) features of SIDS. Studies on larger territories also aggregate nodes and interconnections for computational tractability. Conclusions of these studies often have limited applicability to the SIDS context. Second, SIDS tend to focus on the generation expansion planning, giving potential transmission investments only second order priority. As illustrated in Figure 1.3, this may call into question the efficiency of these long-term plans. Similarly, ignoring the impact of loop flow, as is often done, may lead to inefficiencies in expansion plans.

We therefore ask the following questions:

1. Does simultaneously planning for generation and transmission investments result in lower cost investment plans compared to a sequential planning method?
2. What is the impact of loop flow on long-term investment planning?

Answering these questions can help to improve long-term infrastructure investment planning in SIDS. We also contribute to the literature on infrastructure investment planning for the electricity sector by explicitly accounting for the economic and geographic idiosyncrasies of Small Island Developing States, which have been ignored in the extant literature.

Figure 1.5 summarizes this discussion. Booth et al. (2016) articulate a research process that begins with a practical problem which motivates a research question. In turn, this defines a conceptual/research problem. When answered, this helps to solve the practical problem we began with. The practical problem here is the sequential treatment (or total omission) of transmission constraints in publicly accessible long-term plans for the electricity sector in SIDS. The research questions therefore query the impact of a *simultaneous* vs *sequential* approach to GTEP and the impact of loop flow on long-term infrastructure investment planning. Our conceptual problem is therefore one of efficient (i.e. lowest cost) long-term planning in SIDS. Finally, answering these questions can potentially improve the long-term infrastructure investment planning for the electricity sector in SIDS.

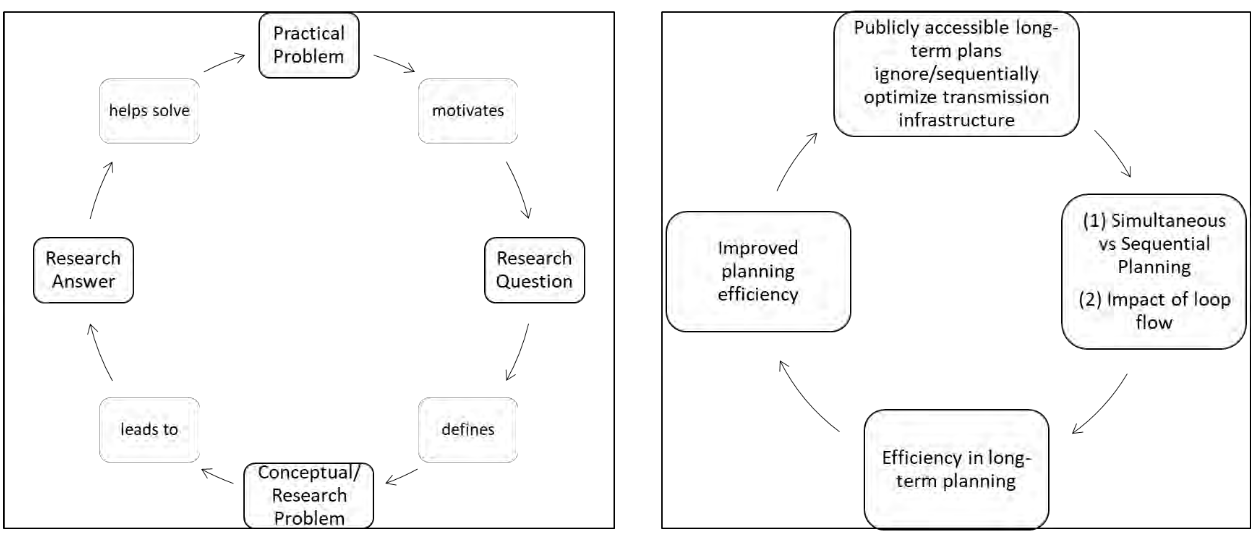

Figure 1.5: Research process and efficient long-term planning

The figures above illustrate the research process. The chart on the left is taken from Booth et al. (2016, pp. 51). The chart on the right corresponds with the practical problem, research question, conceptual/research problem and research answer for this sub-section of the dissertation.

1.2 Energy Policy in Small Island Developing States

Energy policy is another critical element relevant to the electricity sector in Small Island Developing States (SIDS). In particular, the impact of climate change, negative trade balances and vulnerabilities to fuel price shocks have made renewable energy generation a priority for these islands. Sea level rise threatens to erode much of the land in these islands and frequent natural disasters (e.g. hurricanes and droughts) reverse gains in economic growth. Additionally, dependence on imported fuel for over 90% of electricity generation contributes to negative trade balances and exposes SIDS to fuel price shocks. SIDS have therefore implemented a range of policies to reduce greenhouse gas (GHG) emissions and encourage investments in renewable energy technologies. However, these very specific policies appear ambiguous and their empirical foundations are uncertain.

The power sector is ultimately of critical concern; electricity generation is the single largest contributor to climate change, responsible for 25% of greenhouse gas (GHG) emissions globally (EPA, 2010). To address these challenges, countries have set renewable energy targets (RETs) to ensure that a set percentage of electricity is generated from renewable resources (such as hydro, wind and solar) by a given date. Moreover, a total of 196 countries reaffirmed nationally determined contributions (NDCs) to the mitigation of climate change by signing the 2015 Paris Agreement. These NDCs set specific carbon emission reduction targets.

However, achieving these RETs/NDCs often requires government intervention through regulation or financial incentives (e.g. renewable portfolio standards and carbon taxes). In fact, according to the National Conference of State Legislatures and Barbose (2018), about half of the growth in U.S renewable energy generation since 2000 can be attributed to renewable energy requirements in various states. There is therefore overwhelming evidence that market forces, left alone, are insufficient to drive the levels of renewable energy generation required to mitigate the impact of climate change.

While SIDS are the most vulnerable group of countries to the impact of climate change (UNDP, 2018), it is no surprise that developed countries like the United States and countries in Europe, dominate the empirical literature on energy policy. They contribute significantly to global greenhouse gas emissions. Compared to SIDS, they have stronger economies and superior fiscal positions from which to support renewable energy investments. They also have larger areas of land and more diverse natural resource endowments. This allows them greater latitude to ramp up renewable energy generation without compromising reliability of electricity generation or government account balances. However, these economic and geographic features may make some policy recommendations common in the literature infeasible for a SIDS context.

We also observe that the underlying research informing these RETs/NDCs in SIDS is rarely available, casting doubt on the empirical foundation for these very specific goals. These goals also change frequently without clear explanation (see Section 1.3). Furthermore, we have found no empirical work on carbon mitigation policies in SIDS; the existing literature provides only descriptive/anecdotal discussions about broad issues and challenges SIDS face (Timilsina and Shah, 2016). This dissertation helps to address this gap in the empirical literature.

Carbon mitigation policies are promoted on the basis of reducing air pollution and increasing resilience to fuel price shocks. However, they may also require substantial capital investments to counter the intermittency of renewable resources. This could potentially increase costs consumers pay for electricity. Ultimately, what is left unanswered is our third research question:

3. What are the trade-offs associated with achieving carbon mitigation/renewable energy targets in SIDS?

An assessment of the impact of carbon mitigation policies on investment decisions, system cost, the generation portfolio, and carbon emissions would clarify the trade-offs associated with these policies. This would provide an empirical basis for these renewable energy policies and provide a foundation upon which they can be changed. If we cannot quantify and understand these trade-offs, then policymakers are hampered in their ability to set specific carbon mitigation policies premised on evidence-based research. In turn, this impedes our ability to sustainably mitigate the impact of climate change, increase energy security, and reduce external vulnerabilities.

In summary, Figure 1.6 illustrates the analogue of Booth et al.'s (2016) research process. Here, the practical problem is the ambiguous nature of carbon-mitigation policies in SIDS. The objective is therefore to quantify the trade-offs associated with a menu of carbon mitigation polices to tackle this ambiguity. This ties into the broader conceptual problems of environmental protection, carbon mitigation and energy security. Ultimately, an answer to the third research question in this dissertation provides an evidence-based framework for setting effective and efficient carbon mitigation policies in Small Island Developing States.

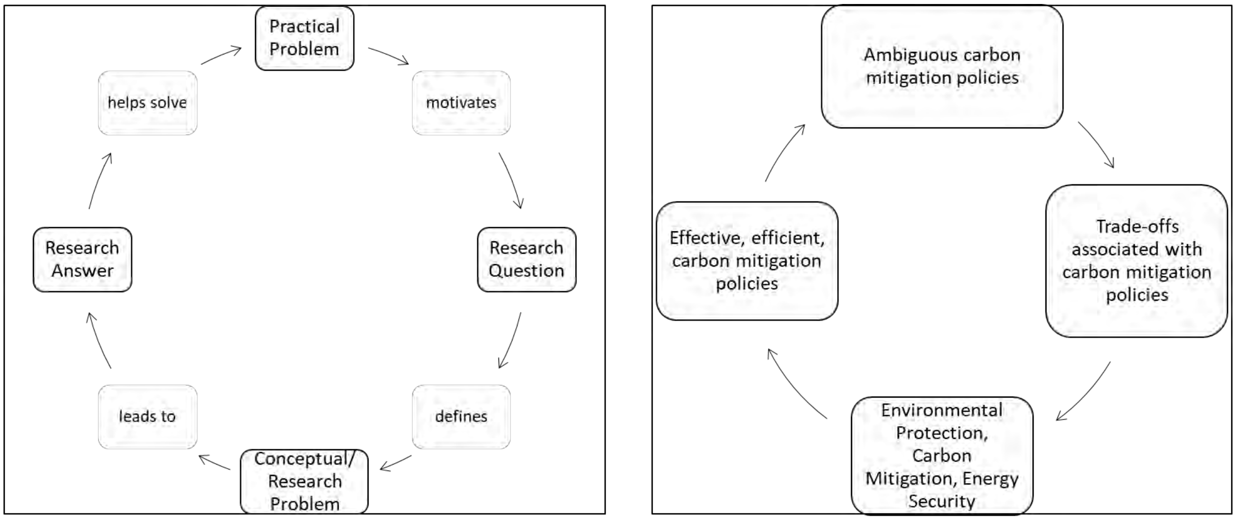

Figure 1.6: Research process and energy policy

The figures above illustrate the research process for this sub-section. The chart on the left is taken from Booth et al. (2016, pp. 51). The chart on the right corresponds with the practical problem, research question, conceptual/research problem and research answer associated with the carbon mitigation subsection of this dissertation.

1.3 Jamaica as a case study

Given the knowledge gaps identified in Sections 1.1 and 1.2, an empirical case study is an effective way to address our research questions. Roughly one-third of the world's SIDS are found in the Caribbean. Jamaica is the third largest island in this region with a population of 2.7 million people. The island's size, market structure and ongoing developments within the electricity sector makes it an excellent case study.

Jamaica has a vertically integrated market structure. The Jamaica Public Service Company (JPSCo) is a vertically integrated, regulated utility with monopoly rights to transmission and distribution. The government of Jamaica (GoJ) retains a 20% stake in JPSCo. Unlike many larger countries, Jamaica does not have competition *in* the market. Instead, Jamaica has competition *for* the market, i.e. competition for generation capacity. Following an official request from the government, interested firms submit bids to build and operate a power plant. The government evaluates each proposal and chooses a winner. The projected marginal cost of electricity heavily influences contract award. The winning firm then builds the power plant and signs a bilateral power purchase agreement with JPSCo. (Jamaica now has 4 independent power producers.) JPSCo retains monopoly rights to transmission and distribution and is therefore the only "wholesale" buyer of electricity. Based on reported costs and transmission constraints, JPSCo determines economic dispatch under the supervision of the regulator. The Office of Utilities Regulation (OUR) is the regulating body that oversees the sector and sets downstream prices for all rate classes of consumers.

Rapid developments in Jamaica's electricity sector also make answering the research questions herein especially timely and relevant. JPSCo owns 75% of total generation capacity and supplies 56% of net generation (JPSCo annual reports; OUR, 2017). The fact that JPSCo assets are older (and in some cases less efficient), as well as the fact that JPSCo assets make up the bulk of reserve capacity, explain this disparity. Total island-wide installed capacity is 952 MW, 70% of which utilizes heavy fuel oil (HFO) or automotive diesel oil (ADO). Renewable resources account for under 20% of capacity (and under 12% of net generation). However, liquefied natural gas (LNG) is fundamentally changing the energy landscape since its introduction in 2016. It now accounts for 120 MW of total installed capacity. Furthermore, three of the nation's four largest power plants were set to be replaced by LNG plants by the end of 2019. This would make LNG the primary fuel source within a few years.

From a public policy perspective, Jamaica's National Energy Policy (MSET, 2009) articulates the government's vision for modernizing and diversifying the electricity sector by year 2030, making the choices of technology, timing and location of great interest. These developments are not unique to Jamaica, but have been observed across several SIDS (Timilsina and Shah, 2016). Improving the planning framework for these countries will therefore make planning more efficient and potentially reduce costs. Understandably, long-term planning will need to be complemented by operational studies with shorter time-scales, particularly as countries integrate more renewable resources into their networks. However, long-term investment planning has strategic relevance for shaping the energy future for SIDS in the coming decades.

Like some other SIDS, Jamaica's renewable energy target also appears to shift consistently without any obvious reason or explanation. This casts doubt on these very specific targets. For instance, Jamaica's National Energy Policy (MSET, 2009) set a renewable energy target of 20% by 2030 under the stewardship of the Jamaica Labour Party (JLP) government. Under the leadership of the People's National Party (PNP), the government made public declarations of a 30% target by year 2030. This 30% target became so common that it has also been used in published research (Timilsina and Shah, 2016). Yet, in April 2017, Jamaica's Finance Minister (JLP) declared a target of 50% by 2020 (JIS, April 14, 2017). The underlying factors driving these moving targets are uncertain. Empirically evaluating a menu of policies, presented in this dissertation, therefore removes the ambiguity from this decision-making process.

This dissertation can also complement the integrated resource plan (IRP) currently under development by Jamaica's Ministry of Science, Energy and Technology (MSET). Additionally, it addresses gaps in Jamaica's previous expansion plan released in 2010 (OUR, 2010). In reviewing Jamaica's 2010 GEP we found that: (1) despite Jamaica's official renewable energy target (originally set at 20% renewable generation by 2030), the 2010 GEP did not evaluate renewable energy options; and (2) despite acknowledging that transmission expansion planning should accompany generation expansion planning, the GEP focused only on generation. It therefore does not explicitly account for investment in the transmission network.

When queried about this in personal communication, OUR officials stated that while the 2010 GEP report did not include transmission planning, they routinely evaluate transmission plans when doing their analyses using tools like Plexos®, DigSilent® and WASP®. We therefore infer that the proprietary nature of these planning tools may contribute to the lack of public research in this area. This absence of published studies may also reflect attempts to balance the right to public information with protecting firms' proprietary information. Nevertheless, the presence of a stand-alone GEP suggests that the OUR employs a *sequential* GTEP planning process. The first research question herein evaluates the benefit of a *simultaneous* GTEP process.

Given the planning process in Jamaica and the fact that a finalized IRP is yet to be published, this dissertation can add value in three ways. It (1) quantifies the benefits of a *simultaneous* planning framework in a SIDS context, (2) provides an open-source tool for academic purposes that may be useful for cross-checking results from these proprietary models, and (3) broadens the scope for further energy economics research in SIDS by making program codes and (anonymized) data freely available.

Jamaica can therefore be taken as a representative SIDS. It's economic and geographic characteristics are uncommon in the empirical energy literature. Recent developments with natural gas and planned infrastructural developments make this research timely and relevant. Finally, the ambiguity in energy policy-setting in Jamaica presents an opportunity to generate policy insights more applicable to a SIDS context.

1.4 Conclusion

This dissertation is broadly focused on the areas of energy planning, energy security and climate change. Specifically, long-term infrastructure investment planning for the electricity sector in Small Island Developing States (SIDS) may have room for greater efficiency. There is also a gap in the empirical foundation for energy policies in SIDS. This dissertation's contribution therefore lies in improving infrastructure planning in the electricity sector in SIDS and providing energy policy guidance more sensitive to the economic and geographic idiosyncrasies of SIDS.

CHAPTER 2. RELEVANT LITERATURE

A review of the existing literature reveals important gaps in long-term infrastructure investment planning and energy policy analysis in Small Island Developing States. This chapter discusses these knowledge gaps and highlights more specifically the contributions of this dissertation.

2.1 On long-term infrastructure investment modelling

Optimization models are a staple of decision analysis and long-term planning within the electricity sector the world over. Utilities use optimization models to inform decisions about electricity generation and transmission investments while government agencies use optimization models to assess policy options. Overviews of the development of generation and transmission expansion planning over time are presented in Wu, Zheng and Wen (2006) and Hemmati et al. (2013). Prior to the wave of market liberalization in global electricity markets starting in the early 1980's, traditional expansion planning focused on vertically integrated, regulated monopolies in generation, transmission and distribution. Since then, GEPs now account for competition among utilities within a given region. However, SIDS continue to adopt a central planning perspective in developing expansion plans due to their small size and regulatory structures, which constrain market liberalization. As shown in Figure 2.1 (Wu et al., 2006) the planner typically chooses the least cost generation expansion, and then develops a transmission expansion plan that will support the existing and new generation infrastructure. This *sequential* and iterative form of analysis is done because the cost of generation infrastructure usually exceeds the cost of transmission significantly. Additionally, planning sequentially is less computationally challenging. Furthermore, in most connected networks (i.e., in the absence of isolated sub-networks), any generation expansion plan could be made feasible by sufficient transmission expansion.

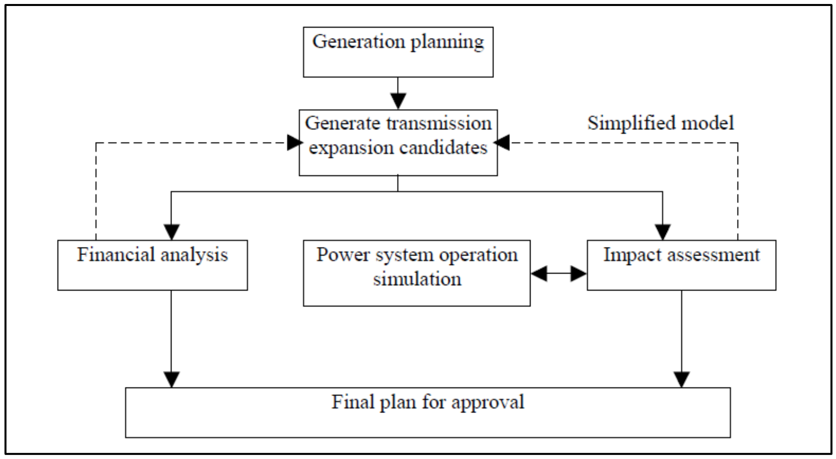

Figure 2.1: Sequential transmission expansion planning (Wu et al., 2006)

This chart illustrates the optimization of transmission infrastructure after generation decisions have been made.

Variants of GEP models reflect different market structures, analytical frameworks and objectives. These include decentralized markets (Botterud et al., 2005), game theoretical frameworks (Budi and Hadi, 2019) and balancing multiple objectives such as minimizing: total investment and operating costs, the environmental impact attributable to installed capacity and the environmental impact driven by output (Antunes et al., 2004). Extensions of this strand of the literature aim to account for increasing penetration of renewable generation resources at utility scale (Gitizadeh et al., 2013) or as distributed generation resources (Barati et al., 2019). However, given the small size of SIDS, significant levels of distributed electricity resources may lead to negative externalities. In Jamaica's case, for instance, if large customers leave the grid in favor of distributed generation, customers remaining on the grid could face higher prices (Jones, 2017). This would be as a result of a narrowing of the base of customers contributing to the recovery of capital investments.

Despite this extensive literature, one weakness of GEP-only models is that they ignore the role of new transmission infrastructure. Depending on the starting configuration, it may be more economical to build new transmission lines instead of new power plants (see discussion on Figure 1.3). Krishnan et al. (2016) give two primary reasons for this. First, to some degree, generation and transmission can be considered substitutes in that demand for electricity can be met either with local generation or by transmission from remote generation. Second, the existing transmission network influences the placement of generation infrastructure. Consequently, transmission decisions will impact future generation investments and vice versa. Unlike GEP, GTEP co-optimizes both generation and transmission investments. In SIDS, where both generation and transmission investments are considered, these two investment decisions are typically optimized sequentially. That is, generation investments are first optimized, and once decisions are made about where and when to build new power plants, transmission investments are optimized to accommodate the added generation capacity. However, this approach can potentially lead to unnecessary costs by failing to account for the substitutability of local generation and remote generation plus transmission.

Another weakness of GEP-only models is that they may fail to account for loop flow, which may have important implications for electricity markets in terms of competition and the exercise of market power (Cardell et al., 1997; Chao et al., 2000; Chao and Peck, 1996). This phenomenon can also misalign private and social costs and can potentially misallocate resources leading to inefficiencies within the sector (Chao and Peck, 1996). These externalities are magnified by the complexity and scale of the network (Chao and Peck, 1996). Here, we examine whether Jamaica, as a representative SIDS, is large enough and its network topology sufficiently complex, that loop flow has an impact on the generation and transmission expansion plan.

Recent advancements have allowed for simultaneous optimization of generation and transmission investments as shown in Figure 2.2 (Wu et al., 2006). This strand of literature suggests that *simultaneously* optimizing generation and transmission investments, may yield better solutions. A combination of theoretical network simulations (Roh et al., 2007; Sauma and Oren, 2006) and real-world applications (Hemmati et al., 2013; Krishnan et al., 2016; Zhang et al., 2015) have added credibility to this conclusion. Extending the scope of planning even further, researchers like Nunes et al. (2018) explore integrating natural gas networks within a simultaneous GTEP framework.

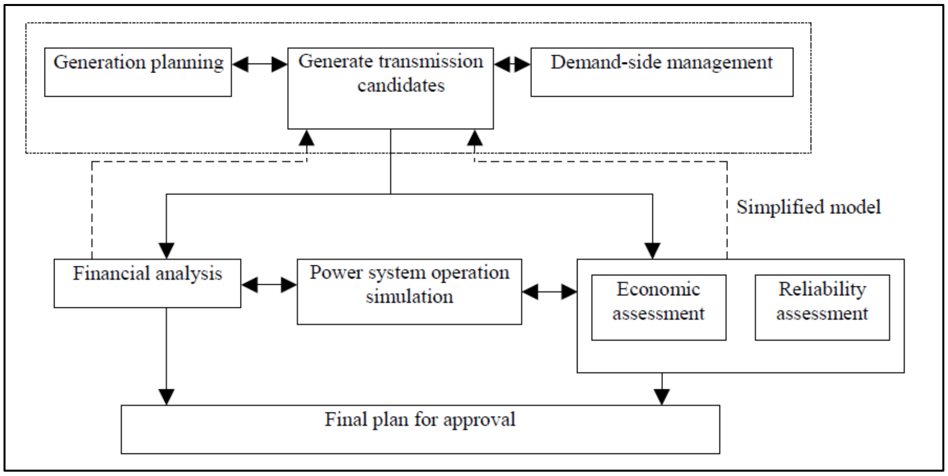

Figure 2.2: Simultaneous generation and transmission planning (Wu et al., 2006)

This chart illustrates the simultaneous planning approach to generation and transmission expansion planning.

However, much of the literature utilizes hypothetical IEEE network topologies. While empirical studies based on more realistic networks can be found, they often focus on larger geographic territories such as the United States or European nations. These networks typically include transmission lines with significantly higher voltage levels when compared to SIDS, cover a significantly longer distance, and embody complex network topologies, often containing many loops. They are also sometimes substantially aggregated in terms of nodes and/or transmission interconnections. These territories may also comprise power pools or network topologies that differ from the network designs in SIDS (characterized by isolated electricity generation and relatively sparse internode connectivity). We therefore extend the existing literature on long-term infrastructure investment planning for the electricity sector by focusing on the economic and geographic idiosyncrasies of Small Island Developing States.

2.2 On Energy Policy

SIDS do not only need investment plans that efficiently allocate scarce resources, but effective and efficient carbon mitigation policies are crucial for encouraging renewable energy investments. Levin, Kwon and Botterud (2019) describe four broad categories of incentive mechanisms for encouraging renewable energy development:

1) **Investment Support**. These schemes provide financial support that subsidizes the capital cost of specific renewable energy technologies, e.g. a solar investment tax credit.

2) **Generation Support**. Offers financial support for each unit of electricity generated by a given technology, e.g. feed-in-tariffs (FITs) and production tax credits (PTC).
3) **Quantity Targets**. Support selected technologies through mandates, e.g. a renewable portfolio standard (RPS).
4) **Carbon Policies**. Support de-carbonization by charging a price or curtailing carbon emissions in the electricity system, e.g. a carbon tax (CTAX).

This dissertation evaluates a policy option associated with each of these four categories. Specifically, we evaluate a renewable portfolio standard of 30% by year 2030, a carbon tax (CTAX) of $63/Ton of carbon dioxide (CO_2), an investment subsidy of 35% and a production tax credit (PTC) of $29/MWh. An RPS is a mandate to generate a set percentage of total generation from renewable resources. A carbon tax imposes a price on carbon emissions - a negative externality of fossil fuel electricity generation. An investment subsidy offsets the investment costs of renewable energy assets by a fixed percent. A production tax credit subsidizes the per unit generation of electricity from renewable resources. We use an RPS of 30% as referenced in Timilsina and Shah (2016). Observing total discounted emissions of 13.97 megatons of CO_2 over the planning horizon, we peg the other three policies to this level of emissions to establish a basis for comparison. This is how we determine the nominal values of $63/Ton of CO_2, 35% and $29/MWh for the carbon tax, investment subsidy and production tax credit respectively. Furthermore, except for the RPS, we simulate each of these policy scenarios for solar and wind generation only, not for run-of-river hydro. This is because run-of-river hydro resources are generally reliable, often used in baseload generation and are not characterized by intra-day intermittency characteristic of solar and wind resources. Instead, run-of river hydro resources are limited by rainfall conditions which tend to be more predictable. Hence, we do not incentivize run-of-river hydro resources.

2.2.1 Top-down approach to energy policy analysis

The empirical literature on energy policy is quite expansive but may be broadly classified as top down or bottom-up. “Top-down” studies begin with a broad/general, macro perspective and attempt to work towards specific outcomes. These studies typically use regression techniques that yield helpful strategic insights (i.e. capture the “big picture”) but lack detail and specificity. For instance, Nicolini and Tavoni (2017) examine the effectiveness of renewable energy policies in the five largest European countries. Using a pooled ordinary least squares, they conclude that incentive policies positively contribute to the production of energy from targeted renewable energy technologies as well as the installation of additional renewable energy capacity. Other top-down methods include Eyraud, Clements and Wane (2013), who use a fixed-effects regression model to assess the macro-economic determinants of green investments. Similarly, Jenner, Groba and Indvik (2013) examine the effectiveness of feed-in tariff (FIT) policies in promoting solar photovoltaic and onshore wind power development in 26 European countries, taking into account differences in policy design. In general, these top-down approaches provide valuable strategic insight on the effectiveness of energy polices on renewable energy use and investments. However, they lack detailed analysis of the energy supply/demand system.

2.2.2 Bottom-up approaches to energy policy analysis

Deterministic Methods

To this end, "bottom-up" models are commonly used in power sector analysis since they account for both the technical and economic features of the power sector. They have the benefit of yielding more detailed descriptions of the impact of energy policies on the power sector, and have the added flexibility of accommodating various renewable energy policies within the analysis. Because the actual electricity system is embedded into the design of these models, co-optimization models are best poised to give insights into policy options relevant to a particular electricity sector. The drawback, however, is that these energy system models tend to be highly data-intensive.

Levin et al. (2019) demonstrate the utility of bottom-up approaches for evaluating energy policies in the Texas power market. Using a mixed-integer linear programming (MILP) optimization model they conclude that a carbon tax is more efficient for reducing GHG emissions while production investment tax credits are more efficient for increasing renewable energy investments. Interestingly, electricity prices vary under different incentive mechanisms even when similar generation portfolios result. However, one limitation of this study is that it accounts for only a single year of operation. Transmission and distribution networks are also ignored.

Bottom-up methods are also useful for long-term planning, directly measuring policy impacts on the electricity system. Knopf, Nahmmacher and Schmid (2015), in evaluating renewable energy policies in the European Union, find that increasing the share of renewable energy in the system by 43%-56% increases total system cost by under 1%. Similarly, these methods can be used to compare various policies. Ritzenhofen et al. (2016) find that FITs and market premia can increase renewable energy penetration at a lower cost than a renewable portfolio standard (RPS); however, the RPS yields results that are more robust with respect to changes in initial conditions. A review of Lund and Mathiesen (2009) indicates the kinds of trade-offs associated with carbon mitigation policies. They find that renewable energy targets of 50% by 2030 and 100% by 2050 are technically feasible in Denmark, but that the country will have to determine to what extent it will depend on biomass for fuel. This would have implications for the agricultural sector. Alternatively, the country will need to decide to what extent it will depend on wind power, which requires a large share of energy carriers like hydrogen. This, in turn, can lead to inefficiencies in system design. Liu et al. (2016) model Chinese FIT policies and evaluate their impact on renewable energy investments in the electricity sector within a game theoretic framework. Accounting for agent interactions, they conclude that the Chinese FIT by cross control (CFCC) is the best performing FIT policy structure they examine. Importantly, they argue that FIT policies benefit investors but place a heavy burden on the government. Each of these studies gives some measure of the effectiveness of carbon mitigation polices and the trade-offs associated with each option.

While much of this literature focuses on the supply-side of the market, utilities may also want to influence consumption patterns (demand response). Fais et al. (2014), for instance, combine various incentive support mechanisms for renewable energy investments on the supply side of the market, but also aim to accounts for demand side responses.

Another distinguishing feature in the literature is the nature of the policy options evaluated. While the previously cited papers assess policy options individually, Zhou, Wang and McCalley (2011), with reference to the United States, find that a *combination* of taxes and subsidies is more efficient than either policy option on its own. Lu et. al. (2016) perform similar analysis for the State of Indiana. However, an interesting implication of this study is that the objective of the decision-maker is important when considering the "best" policy option. They conclude that an RPS is the most effective tool for reducing greenhouse gas (GHG) emissions if the primary concern is the cost to the electricity system. However, if the entire Indiana energy system is considered, then a cap on carbon or a carbon tax is more effective. This illustrates another example of trade-offs policy-makers contend with: system cost (and ultimately cost to rate payers) vs GHG emissions. For SIDS, as small contributors to GHG emissions, the balance may tip in favor of costs.

A critical consideration for policy makers is the actual dollar figure or specific policy target to set. Top-down methods do not generally answer this question. This is another advantage of bottom-up methods. Lu et. al. (2016), using a bottom-up optimization method, determine that a carbon tax of $49/metric ton in 2022, increasing to $109/metric ton in 2034, is required to achieve emissions targets set out in their carbon tax scenarios.

Risk and Uncertainty

While many studies adopt a deterministic framework, there have been studies that account for risk and uncertainty within the energy planning and policy-making process (Gitizadeh et al., 2013). Nunes et. al. (2018) identify gas prices, load growth and variability in renewable energy resources as important sources of risk and uncertainty. Their approach utilizes a stochastic, mixed integer linear program. They examine the impacts of high renewable energy penetration and different environmental constraints on long-term electricity and gas integrated planning in Queensland, Australia. Unlike some studies which focus only on generation expansion planning (GEP) (Gitizadeh et al., 2013; Levin et al., 2019), Nunes et al. (2018) integrate generation and transportation (natural gas) resources in a generation and natural gas expansion planning framework. They find that integrating both segments leads to cost savings. Importantly, the environmental constraints increase costs due to higher investments in renewable energy and natural gas power capacity.

Similarly, Pineda, Boomsma and Wogrin (2018) adopt a stochastic approach in their assessment of renewable generation expansion under various incentive policies. They model their feed-in policy as a math program with equilibrium constraints (MPEC) and the green certificate market as a non-linear complementarity problem (NCP). Their conclusions highlight an important implication: the risk aversion of the investor is the main driver in selecting an appropriate policy mechanism. Market power and the specific renewable energy target are also important factors in determining the optimal incentive policy. Boomsma and Linnerud (2015) and Reuter et al. (2012) employ a real options approach to assess how investors in the electricity sector respond to market and policy risks. Their overarching conclusion is that policy uncertainty introduces significant risk to the investor.

Bottom-up optimization models ultimately have the advantage of presenting a more detailed representation of the power sector on a techno-economic level relative to top-down approaches. While top-down approaches are helpful in providing macro-economic and strategic insight into policy outcomes, direct assessments of energy policies on the electricity sector typically require bottom-up analyses. Bottom-up approaches, such as the optimization models that typify energy sector planning, also have the benefit of testing, *a priori*, the likely impact of various policy measures on the electricity sector. This is the approach we take in this study in order to assess the trade-offs associated with a menu of carbon mitigating and renewable energy policies

2.2.3 Sparse empirical literature relevant to SIDS

Despite a large body of research on energy policy implications, there is a noticeable gap in policy-relevant research for SIDS, whose economic and geographic idiosyncrasies distinguish them from larger, more developed and land-locked countries. For instance, the United States (Levin et al., 2019; Lu et al., 2016; van Benthem et al., 2008; Vedenov & Wetzstein, 2008) and European countries (Fais et al., 2014; Knopf et al., 2015; Nicolini and Tavoni, 2017; Ritzenhofen et al., 2016) feature prominently in the literature. However, these nations tend to have more robust economies, allowing their governments greater fiscal latitude to finance and enforce renewable energy incentive policies. Conversely, SIDS often have depressed economies coupled with significant public debt. This limits their ability to finance incentive schemes for renewable energy technologies. SIDS are also among the most open economies on the planet, increasing their vulnerabilities to external price shocks, e.g. for fossil fuels. High transportation costs associated with importing fuel, low domestic demand for fuel and diseconomies of scale due to their size result in extremely expensive fuel production and significant long term financial risks (Weisser, 2004). Hence, if SIDS are considering policies to incentivize investments in renewable energy generation or disincentivize air pollution, it is critical for them to understand the implications and trade-offs associated with these decisions. This would allow decision-makers to make the best decisions for their context. This emphasis on cost and risk also makes bottom-up approaches to energy policy in SIDS particularly attractive.

Geographically, SIDS are, by definition, small islands, and consequently must rely on their own capacity to generate electricity. Conversely, the geographic landmasses of the USA, China and Europe facilitate cross-border generation and transmission of electricity among states/provinces (within the USA/China) and among countries (within Europe). This reduces the reserve margins required by these energy systems, and consequently, also reduces their relative costs. Additionally, through strategic (or even fortuitous) investments, these large territories can diversify across renewable generation technologies (e.g. wind and solar), and across regions, to achieve a "portfolio effect" on renewable generation. This is because peak output of wind and solar typically occur at different times of day. Additionally, while it may not be windy/sunny in one location, it is rare that winds are calm and lack of sunshine prevails over a large area. This mitigates, to some degree, the reliability concerns typically associated with intermittent renewable energy resources. The large endowments of inversely correlated renewable energy resources allows for greater integration of renewable energy technology in the electricity network as they offset some of the intermittency associated with higher renewable energy penetration. On the other hand, SIDS like Jamaica lack the combination of inversely correlated renewable energy output and large areas of land in order to benefit from this "portfolio effect" that the United States can. The economic openness, fiscal distress and geographic isolation that characterize SIDS necessitate advancements in research with targeted policy focus more aligned with these nations' realities. Indeed, as de Leon Barido et al. (2015) note, few studies provide country-specific insights into electricity systems integration that can help developing countries with making informed policy decisions.

Unfortunately, in our review of the literature, we have encountered only a few papers that seek to inform targeted energy policies in SIDS/developing countries, and the majority of these tend to be only descriptive. Timilsina and Shah (2016) provide a descriptive assessment of SIDS, their renewable energy policies and implementation challenges they face. The primary challenges they identify are: 1) strengthening energy information systems, 2) financing mechanisms for renewable energy projects, 3) improving the regulatory framework and 4) building technical capacity among participants in the renewable energy field. Dornan and Shah (2016) note that international aid helps to shape the renewable energy prospects of SIDS. Jacobs et al. (2013) present an overview of FITs in Latin America and the Caribbean, noting that a high degree of investment security is important for the success of FIT policies in encouraging renewable energy investments. Wright (2001) observes that oil prices above $20/barrel; use of larger, more efficient wind turbines; appropriate land area with sufficient wind availability; fiscal tax credits; and financial incentives such as low interest rate loans and subsidies contribute to the adoption of renewable energy resources in the Caribbean region. Weisser (2004) stresses the importance of policy design for renewable energy development, but even with this acknowledgment, he notes that future studies should integrate policy recommendations with a model that accurately captures the technological details associate with renewable energy technologies, and particularly over a longer time horizon.

Understandably, a significant barrier to empirical energy policy research in SIDS is a lack of high quality data (Timilsina and Shah, 2016). Where the data exists, institutional barriers significantly hinder access to it. Nevertheless, researchers, over time, make gradual inroads towards reducing this barrier. For example, in explaining renewable energy diffusion in developing countries, Pfeiffer and Mulder (2013), using panel regression techniques, conclude that the adoption of non-hydro renewable energy (NHRE) in developing countries is accelerated by strong regulatory instruments, higher per capita income, higher levels of education and stable democratic governments. In contrast, a more open economy, foreign direct investment and overseas development assistance, increased electricity consumption, and significant levels of fossil fuel generation delay NHRE adoption. Interestingly, they conclude that policy support programs also delay NHRE. It is of note however, that while Pfeiffer and Mulder (2013) evaluate the determinants of NHRE adoption in developing countries, we did not find SIDS among the list of countries evaluated.

Another quantitative attempt at informing renewable energy policy setting in SIDS is provided by Shirley and Kammen (2013). The authors conduct a cost-benefit analysis of four Caribbean renewable energy projects. They assert that several benefits can be obtained from early, innovative energy projects.

Ultimately, we find a scarcity of empirical research on energy policy analysis relevant to the SIDS context; the literature is primarily descriptive. For the most vulnerable group of countries on the planet to the impact of climate change, and with some of the most ambitious renewable energy targets among the signatories to the Paris Climate Agreement, energy planning and policy analysis relevant to SIDS can benefit from further empirical research. We fill this gap using a techno-economic framework with a richer data quality than previously explored.

2.3 Conclusion

This dissertation fills empirical gaps in infrastructure investment planning and energy policy analysis in Small Island Developing States (SIDS). We evaluate modelling methodologies to improve least-cost infrastructure investment planning, specifically accounting for the geographic and economic idiosyncrasies of a representative SIDS. From an energy policy perspective, we directly address the concerns raised by Weisser (2004) by capturing technological details associated with renewable energy technologies within a long-term electricity generation and transmission planning framework. Hence, energy policy no longer needs to be ambiguous in Jamaica or in any other Small Island Developing State. We also lay the groundwork for future empirical energy economic research in SIDS by making available a richer dataset and optimization codes to the academic community.

CHAPTER 3. METHODOLOGY

This chapter presents the conceptual framework and mathematical details of the empirical methods employed in this dissertation. For ease of interpretation, models are presented graphically to illustrate general intuition. The models are also represented by equations which provide greater detail.

3.1 Conceptual Framework

Conceptually, we face a cost minimization problem. The government/utility wants to satisfy present and future demand for electricity at the least cost, while maintaining system reliability. This means minimizing the net present value (NPV) of investment and operating costs over our planning horizon (2017-2040), constrained by economic and engineering principles. It is within this context that we answer the three research questions posed in this dissertation.

3.2 Generation and Transmission Planning

To compare *simultaneous* and *sequential* investment planning methods, and to evaluate the impact of loop flow on investment decisions and cost, our conceptual model is focused on cost-minimization. The central planner minimizes the investment and operating cost of satisfying future demand for electricity. The central planner is also constrained by economic limitations due to finite budget resources and physical limitations on potential new generation and transmission assets by land area and topography. Figure 3.1 illustrates the model: we input supply (i.e. capacity and generation), demand and price (of fuel, operation and investment) parameters into a cost minimization framework subject to economic and engineering constraints. Outputs include total costs (investment and operating), investment decisions (location and timing of the construction and deployment of new assets), generation by technology and transmission flows.

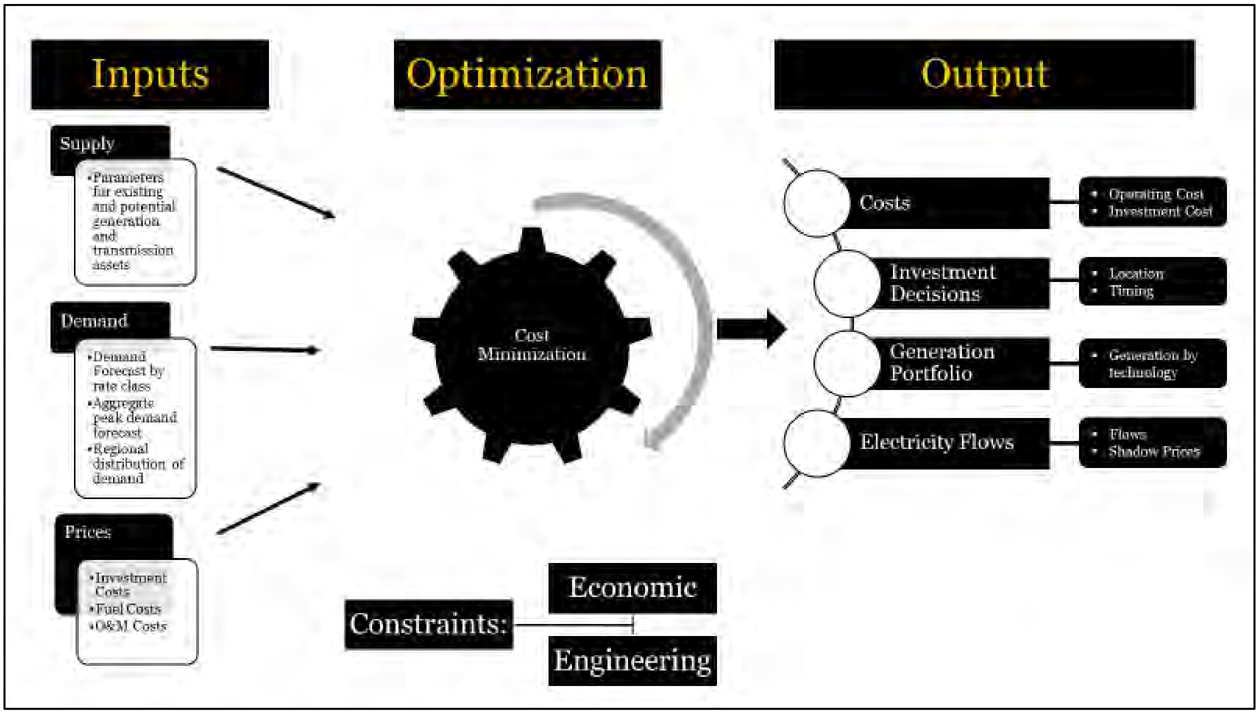

Figure 3.1: Graphical description of simultaneous and sequential planning model

To solve this model, we use the Direct Current Optimal Power Flow (DCOPF) model described in Krishnan et al. (2016). We make minor modifications inspired by the Long-term Investment Planning model designed by Purdue University's Power Pool Development Group (Sparrow et al., 1998). We solve this model as a Mixed Integer Linear Program (MILP) in the General Algebraic Modeling System (GAMS), using the IBM/CPLEX solver.

An alternative to the DCOPF model is the Alternating Current Optimal Power Flow (ACOPF) model. While the ACOPF model more accurately captures the operational details of an electrical system, the non-convexity of the problem, including nonlinear constraints, combined with indivisibilities, makes the ACOPF a difficult model to solve. It is therefore common practice in both academia and industry to use the DCOPF linear approximation of the ACOPF for planning purposes. The DCOPF model balances the tradeoff between model fidelity and computational tractability. We present the equations for this model below:

Notation

Sets

l	Transmission lines (directed by definition)
g	Generation plants
n, z	Nodes in network
h	Hour types
t, τ	Year or time-period index

Subsets

e	Existing generator (subset of g)
c	Candidate generator (subset of g)
j	Existing transmission line (subset of l)
k	Candidate transmission line (subset of l)

Parameters

Parameters	Units	Definition
B_l	Siemens	Susceptance of transmission line l
r	Fraction	Discount rate $\in (0,1)$
$y_{e,t}$	Indicator	0 if existing generator is retired in period t, 1 otherwise
$I_{e,t}$	$ Millions	Annualized investment cost of candidate generation plant
$I_{k,t}$	$ Millions	Annualized investment cost of candidate transmission lines
F_g	$ per year	Fixed operating and maintenance (O&M) cost of generator g
V_g	$ per MWh	Variable operating and maintenance (O&M) cost of generator g
ϕ_h	Hours	Number of hours of hour type h
P_g^{MAX}	MW	Maximum generation capacity of generator g
λ_g	Fraction	Forced outage rate of generator $g \in [0,1]$
$\psi_{g,h}$	Fraction	Unforced outage rate of generator g for hour type $h \in (0,1)$
S_l^{MAX}	MW	Maximum power flow across line l
$D_{n,h,t}$	MW	Demand at node n for hour type h in year t
K_t	$ Millions	Infrastructure investment budget in USD millions in year t
$q_{g,h}$	Fraction	Availability factor of generator g in hour type $h \in (0,1]$
$q_{g,h}^{peak}$	Fraction	Availability factor of generator during peak hours $\in (0,1]$
α_t	MW	Peak demand in year t
R	Fraction	Reserve margin $\in (0,1)$, i.e. share of installed capacity that must be available above peak demand

Binary Variables

$x_{c,t}$	1 if candidate generator is built
$w_{k,t}$	1 if candidate transmission line is built

Variables

Variables	Units	Definition
$P_{g,h,t}$	MW	Real power produced by generator g for hour type h in year t
$S_{l,n,z,h,t}$	MW	Power flow across line l from node n to node z, for hour type h in year t. (This will be negative if flows is from z to n).
$\theta_{l,n,h,t}$	Radians	Bus voltage angle for line l at node n for hour type h in year t
U_{t,l^c}	MW	Slack variable for use with big "M" method

The objective is to minimize the net present value (NPV) of the total investment and operation costs of the electricity system and is given by

$$\min \sum_{t}^{T} \left\{ \left[TOC_t + \sum_{c} \left(I_{c,t} \times \sum_{\tau \le t} x_{c,\tau} \right) + \sum_{k} \left(I_{k,t} \times \sum_{\tau \le t} w_{k,\tau} \right) \right] \right\} \div (1+r)^t \tag{1}$$

where TOC_t denotes the total operating and maintenance (O&M) cost of power plants in year *t* as defined by

$$TOC_t = \left[\sum_{e} (F_e \times y_{e,t}) + \sum_{c} \left(F_c \times \sum_{\tau \le t} x_{c,\tau} \right) + \sum_{g,n,h} (V_g \times P_{g,h,t} \times \phi_h) \right] \div 1{,}000{,}000 \tag{2}$$

where F_e and F_c denote the fixed O&M cost for existing and candidate generators respectively, measured in \$ per year; and $y_{e,t}$ is a binary parameter that captures whether or not an existing generator is available (=1) or has been retired (=0). This is an exogenous representation of plans already committed and approved by Jamaican market participants. The binary variable $x_{c,t}$ takes a value of 1 if a candidate generator c is built in year *t*. Hence, $\sum_{\tau \le t} x_{c,\tau}$ accounts for whether a candidate power plant was built during or prior to year *t*. Variable O&M cost of a generator *g* is denoted by V_g, and is measured in \$/MWh. Real power generation by generator *g* for hour type *h* in year *t*, is denoted by $P_{g,h,t}$, and is measured in MW. The number of hours of type *h* is denoted by ϕ_h. We convert total O&M costs to millions of dollars to make the units of measurement consistent with the units for capital investments.

Continuing with the objective function, $I_{c,t}$ and $I_{k,t}$ are the investment costs corresponding with prospective power plants and transmission lines, measured in millions of dollars. The binary variable $w_{k,t}$ is takes a value of 1 if a candidate transmission line is built in year *t*. Hence,

$\sum_{\tau \le t} w_{k,\tau}$ has a value of unity if the candidate transmission line is available in year *t*. Finally, r denotes the discount rate for calculating the NPV. We use a discount rate of 11.95 % as used by the OUR (2010).

Candidate generators c can be built no more than once ((3)-(4)).

$$x_{c,t} \in \{0,1\} \quad \forall \ c, t \tag{3}$$

$$\sum_t x_{c,t} \le 1 \quad \forall \ c, t \tag{4}$$

Similarly, candidate transmission lines are built no more than once ((5)-(6)).

$$w_{k,t} \in \{0,1\} \qquad \forall \, k, \mathrm{t} \tag{5}$$

$$\sum_t w_{k,t} \le 1 \qquad \forall \, k, t \tag{6}$$

These restrictions represent constraints on the physical land available for the development of electricity infrastructure.

In (7), power generated by a power plant $P_{g,h,t}$ cannot exceed the generator's capacity P_g^{MAX} adjusted by the generator's forced and unforced outage rates λ_g and $\psi_{g,h}$, and by the generator's availability factor $q_{g,h}$.

$$0 \le P_{g,h,t} \le P_g^{MAX} \times (1 - \lambda_g) \times (1 - \psi_{g,h}) \times q_{g,h} \ \times Availability_{g,t} \quad \forall \ g, h, t \tag{7}$$

where $Availability_{g,t}$ represents $y_{e,t}$ for existing plants (in which case all parameters are indexed by e) or $\sum_{\tau \le t} x_{c,\tau}$ for candidate generators (in which case all parameters are indexed by c). Note that the unforced outage rate for peak hours is set to zero because preventative maintenance can be scheduled during times of relatively low demand.

Equation (8) is the reserve margin constraint. The reserve margin is a metric used in long-term planning models to ensure resource adequacy, and is defined as some capacity level above expected peak demand. Here, $q_{g,h}^{peak}$ is the availability factor of generator g during peak hours and is bounded by 0 and 1, α_t is the peak demand for year t, and R is the reserve requirement. For Jamaica, this reserve requirement is 25%, more than double the typical reserve margin for US planning areas. This results in comparatively higher capacity costs. This is another example of the impact of the small size of SIDS on the operations of the electricity sector. The high reserve margin reflects the fact that the largest generating unit comprises a substantial fraction of the generating capacity, and physical isolation results in a lack of possibilities for imports satisfying peak demand in an emergency.

$$\sum_{g} P_g^{MAX} \times q_{g,h}^{peak} \times Availability_{g,t} \geq \alpha_t \times (1+R) \quad \forall\, g,t \tag{8}$$

Equations (9)-(19) represent transmission line constraints and our implementation of Kirchhoff's Laws (KL). Power flow across existing lines at all points in time $S_{j,n,z,h,t}$ is limited by the capacity of that line, S_j^{MAX}. Because line j is directed from node n to node z, flow can be either positive or negative depending on its direction.

$$-S_j^{MAX} \leq S_{j,n,z,h,t} \leq S_j^{MAX} \qquad \forall\, j,n,z,h,t \tag{9}$$

Power flow across candidate lines at any point in time $S_{k,n,z,h,t}$ is also constrained by that line's capacity S_k^{MAX} once that line has been constructed as indicated by $\sum_{\tau \leq t} w_{k,\tau}$.

$$-\sum_{\tau \leq t} w_{k,\tau} \times S_k^{MAX} \leq S_{k,n,z,h,t} \leq \sum_{\tau \leq t} w_{k,\tau} \times S_k^{MAX} \qquad \forall\, k,n,z,h,t \tag{10}$$

Because bus voltage angles $\theta_{l,n,h,t}$ are measured in radians, they are restricted to be within the $[-\pi, \pi]$ interval

$$-\pi \leq \theta_{l,n,h,t} \leq \pi \qquad \forall\, l,n,h,t \tag{11}$$

The model is implemented in terms of voltage angles rather than directly in power flows to allow for transmission investments. This is because a power flow-based formulation would require pre-calculation of the matrix of power transfer distribution factors (PTDFs), which change when new transmission lines are added. Formulating the problem in terms of voltage angles eliminates the PTDFs from the formulation, and facilitates the incorporation of binary variables for adding candidate transmission lines over time (Hedman et al., 2011).

Power flow from node n to node z at all points in time $S_{l,n,z,h,t}$ is the product of suseptance, B_l, and the difference between the bus voltage angle at the sending node, $\theta_{l,n,h,t}$, and the bus voltage angle of the receiving node, $\theta_{l,z,h,t}$. For existing transmission lines:

$$S_{j,n,z,h,t} = B_j \times \left(\theta_{j,n,h,t} - \theta_{j,z,h,t}\right) \qquad \forall\, j,n,z,h,t \tag{12}$$

For candidate transmission lines, we would need to multiply an analogue of the right-hand side of (12) by the build variable $\sum_{\tau \leq t} w_{j,\tau}$ to account for whether or not that transmission line is available (13).

$$S_{k,n,z,h,t} = B_k \times \left(\theta_{k,n,h,t} - \theta_{k,z,h,t}\right) \times \sum_{\tau \le t} w_{k,\tau} \qquad \forall\, k, n, z, h, t \tag{13}$$

However, this would result in a non-linear problem due to the product of two sets of variables: the difference in voltage angles and the binary variable $w_{k,\tau}$. Since we are using a linear approximation of the ACOPF model, we employ the "Big M" method to constrain power flow across candidate lines as in Krishnan et al. (2016). That is:

$$S_{k,n,z,h,t} = B_k \times \left(\theta_{k,n,h,t} - \theta_{k,z,h,t}\right) + \left(\sum_{\tau \le t} w_{k,\tau} - 1\right) M + U_{k,t} \tag{14}$$

$$\ldots \forall\, k, n, z, h, t$$

where M is a large constant and $U_{k,t}$ is a slack variable. This slack variable is non-negative (15) and constrained by (16) below.

$$U_{k,t} \ge 0 \qquad \forall\ k, t \tag{15}$$

$$U_{k,t} \le 2 \times \left(1 - \sum_{\tau \le t} w_{k,\tau}\right) \times M \qquad \forall\ t, k \tag{16}$$

Hence, if a candidate line has not been built by year t (i.e. $\sum_{\tau \le t} w_{k,\tau} = 0$), then (14) is non-binding. This is because in this case (14) - (16) are equivalent to (17) - (18),

$$S_{k,n,z,h,t} = B_k \times \left(\theta_{k,n,h,t} - \theta_{k,z,h,t}\right) - M + U_{k,t} \qquad \forall\, k, n, z, h, t \tag{17}$$

$$0 \le U_{k,t} \le 2 \times M \qquad \forall\ k, t \tag{18}$$

which results in no restriction between the voltage angle and susceptance in power flow for a sufficiently large M. Alternatively, if the candidate line has been built by year *t* (i.e. $\sum_{\tau \le t} w_{k,\tau} = 1$), then $U_{t,k} = 0$, and (14) is binding, and analogous to (12). In our model, we do not explicitly delineate line losses since rate class demand forecasts (OUR, 2017) already includes line losses.

Equation (19) is our power balance equation; total generation $\sum_g P_{g,h,t}$ and net inflows $\sum_n \left(S_{l,n,z,h,t} - S_{l,z,n,h,t}\right)$ sum to load (i.e. demand) $D_{n,h,t}$ for each time period. (Note that there is a direct mapping of each generator to each node already embedded in the indexing scheme.)

$$\sum_g P_{g,h,t} + \sum_n \left(S_{l,n,z,h,t} - S_{l,z,n,h,t}\right) = D_{n,h,t} \quad \forall\, n, h, t \tag{19}$$

We adopt a social planning perspective, reflecting the market structure that typifies a SIDS and the standard perspective adopted by Jamaica. We represent the infrastructure investment budget constraint by (20), which limits investments in new generation capacity and transmission assets to an annual maximum budget. In our base model, we consider first a non-binding budget constraint to allow for maximum investment in order to guarantee that supply limits demand, and merely demonstrate the flexibility of our model to incorporate this feature.

$$\sum_{c} I_{c,t} \times x_{c,t} + \sum_{k} I_{k,t} \times w_{k,t} \leq K_t \quad \forall \ t \tag{20}$$

Equations (1)-(20) capture the physical, economic and operational features of the electricity network in mathematical formulations in such a way as to accommodate the co-optimization of investments in generation and transmission infrastructure.

3.3 Evaluating Energy Policy Options

To evaluate the impact of a renewable portfolio standard (RPS), carbon tax (CTAX), production tax credit (PTC) and investment subsidy, we simulate a policy shock either to the objective function or constraints presented in Equations (1)-(20). Figure 3.2 illustrates this process. While CTAX, the PTC and an investment subsidy are price shocks in the model, the RPS is a technical constraint. Energy system cost, the generation portfolio, carbon dioxide emissions and the government cost/revenue associated with the respective policy are observed.

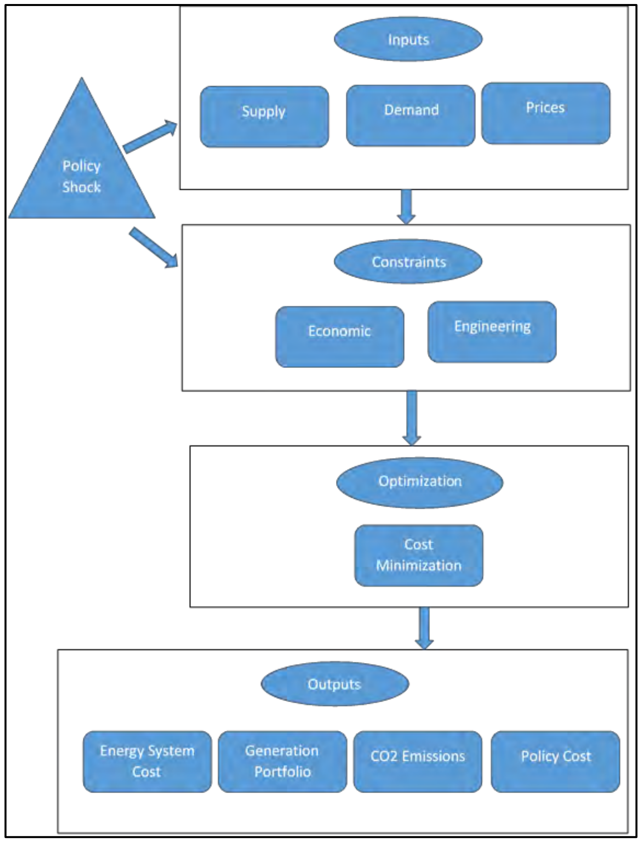

Figure 3.2: Flow chart describing implementation of policy simulations

Here, we introduce additional notation:

Notation

<u>Sets</u>

f	Fossil fuel generator (subset of g)
i	Renewable energy generator (subset of g)

<u>Parameters</u>

Parameters	**Units**	**Definition**
φ_g	Ton/MWh	Ton of carbon dioxide (CO_2) emitted by generator g per MWh computed using generator heat rates and carbon emission by fuel type.
X	\$/Ton	Carbon tax in dollars per ton of carbon dioxide
ρ	\$/MWh	Production tax credit for renewable resources in dollars per MWh
m	Fraction	Investment subsidy for potential renewable resources $\in (0,1)$

b	Megatons	Total discounted megatons (1 million tons) of CO_2 emitted over planning horizon

3.3.1 Renewable Portfolio Standard (RPS)

Since Jamaica's National Energy Policy (MSET, 2009) sets an explicit renewable energy target, an RPS is an obvious starting point for analysis. While the policy as written set a target of 20% renewable energy generation by 2030, the continued increase in policy targets is a demonstration that the government wishes to be even more ambitious. Additionally, a decade has passed since the policy was written. During this time, the cost of renewable energy infrastructure has fallen. For these reasons, we implement an RPS of 30% by 2030 as noted in Timilsina and Shah (2016). Using notation defined in Chapter 3.2, we insert an additional constraint (21). Total renewable energy generation $\sum_{i,n,h} P_{i,n,h,t}$ must be at least 30% of total demand $\sum_{n,h} D_{n,h,t}$ for each year starting in year 2030. (Recall that (19) ensures that demand equals supply.)

$$\sum_{i,n,h} P_{i,n,h,t} \geq 0.3 \times \sum_{n,h} D_{n,h,t} \qquad \forall\, t \geq 2030 \tag{21}$$

Equation (22) defines the total discounted sum of carbon dioxide (CO_2) emissions b, measured in megatons, produced over the entire planning horizon based on total generation in MWh $\sum_{f,n,h,t} P_{f,n,h,t} \times \phi_h$ and the CO_2 factor φ_f for each fossil fuel generator.

$$\left(\sum_{f,n,h,t} P_{f,n,h,t} \times \phi_h \times \varphi_f \times 1/(1+r)^t\right) \div 1{,}000{,}000 = b \tag{22}$$

Total period-wise emissions are discounted using the same discount rate r used in the rest of the model and set equal across all policy scenarios. This is to ensure that the different time paths for the different policies are comparable on a value basis where the real value of emissions is taken to be equal across all periods. For example, let v denote the value of emissions in real first period dollars. Consider two different time paths for emissions d_t and s_t (we implement the RPS in year 2030 while all other policies are take effect in year 2019). The total real value of emissions over the planning horizon $\hat{d}$ and $\hat{s}$ are:

$$\hat{d} = \sum_{t} v \times d_t \times 1/(1+r)^t \tag{23}$$

$$\hat{s} = \sum_{t} v \times s_t \times 1/(1+r)^t \tag{24}$$

So to compare which time path is better (i.e. lowest cost to society), we would consider:

$$\begin{aligned} \hat{d}/\hat{s} &= \left[\sum_{t} v \times d_t \times 1/(1+r)^t\right] \Big/ \left[\sum_{t} v \times s_t \times 1/(1+r)^t\right] \\ &= \left[\sum_{t} d_t \times 1/(1+r)^t\right] \Big/ \left[\sum_{t} s_t \times 1/(1+r)^t\right] \end{aligned} \tag{25}$$

Note that, v does not affect this ratio so long as the value is held constant over time; the discounted emission paths are what remain. In our model, our policy rates are held constant over time but are implemented in two different years (2019 and 2030). By discounting total emissions, we establish a basis for comparison among all four policy scenarios.

3.3.2 Carbon Tax (CTAX)

The carbon tax, X, measured in \$/Ton of CO_2, is implemented as a price shock by modifying (2) to yield (26).

$$\begin{aligned} TOC_t = \Bigg[&\sum_{e} \left(F_e \times y_{e,t}\right) + \sum_{c} \left(F_c \times \sum_{\tau \le t} x_{c,\tau}\right) + \sum_{i,n,h} \left(V_i \times P_{i,h,t} \times \phi_h\right) \\ &+ \sum_{f,n,h} \left(P_{f,h,t} \times \phi_f \times \left(V_f + \varphi_f \times X\right)\right) \Bigg] \div 1{,}000{,}000 \end{aligned} \tag{26}$$

3.3.3 Investment Subsidy

For potential renewable generation assets (except hydro resources), we implement the investment subsidy m as a modification to the objective function (27). This offsets the capital cost associated with these potential assets. For potential, non-renewable assets, investment costs remain as in (1).

$$\min \sum_{t}^{T} \left\{ \left[TOC_t + \sum_{c} \left(I_{c,t} \times \sum_{\tau \le t} x_{c,\tau} \times (1 - m) \right) + \sum_{k} \left(I_{k,t} \times \sum_{\tau \le t} w_{k,\tau} \right) \right] \div (1 + r)^t \right\} \tag{27}$$

3.3.4 Production Tax Credit (PTC)

We implement the production tax credit (PTC) as a modification of (2). For renewable generation assets (except hydro), the variable cost of generation V_i is offset by a PTC, ρ, measured in \$/MWh.

$$TOC_t = \left[\sum_{e} (F_e \times y_{e,t}) + \sum_{c} \left(F_c \times \sum_{\tau \le t} x_{c,\tau} \right) + \sum_{i,n,h} \left((V_i - \rho) \times P_{i,h,t} \times \phi_h \right) + \sum_{f,n,h} \left(V_f \times P_{f,h,t} \times \phi_f \right) \right] \div 1{,}000{,}000 \tag{28}$$

Equations (21) - (28) implement the policy shocks to the electricity system. While the RPS influences hydro, wind and solar resources, the CTAX, PTC and investment subsidy target only wind and solar resources.

CHAPTER 4. DATA

In this section, we discuss the data used in this study, their sources and our approach to addressing some data gaps we encountered. Table 4.1 summarizes the data. Most of the data were collected in person from the Office of Utilities Regulation in June-July 2018.

4.1 Generation Capacity, Emission Factors, Demand and Costs

Data on the supply side of the energy system includes a technical inventory of Jamaica's generation and transmission infrastructure. For generators, this includes: a complete list of generators, their locations, heat rates, capacity factors, name-plate capacities, etc. We model candidate hydro resources using a list of potential sources identified by the Petroleum Corporation of Jamaica (PCJ, n.d.). We construct seasonal availability factors for run-of-river hydroelectric resources using rainfall data (1991-2016) from the Meteorological Office of Jamaica (MOJ) and capacity factors from the Office of Utilities Regulation (OUR). In the absence of wind output data, we use wind speed data from the MOJ to calibrate availability factors for wind resources throughout an average 24-hour period. For solar generation, we obtain actual hourly output data for each day of the year 2018 for Jamaica's sole solar plant. Since Jamaica is at latitude 18° north (close to the equator), there is little seasonal variation in average solar radiation. Using average hourly output as a fraction of the maximum of average hourly output, we create hourly availability factors and adjust downward until the model is calibrated to actual capacity factors provided by the OUR. We then apply these availability factors to all candidate solar generators.

We obtain technical features of candidate generators from the U.S. Energy Information Agency including estimates of costs (EIA, 2016). For transmission infrastructure, technical details include length and type of wires, susceptance, reactance, and node-to-node connections. While the locations of candidate sites to build hydroelectric generators were determined based on PCJ information, other renewable energy generators were subjectively assigned to specific sites absent actual data on possible locations for future solar power and wind plants. We obtain carbon emission factors from the US Environmental Protection Agency (EPA, 2018).

Demand-side data focuses on temporal, sectoral and regional load diversity. OUR demand forecasts, produced in 2015 (OUR, 2017), under-estimated actual demand in 2017. For this reason, we utilize the forecasted growth rates starting at the actual 2017 values. An alternative would be to generate our own forecasts. However, this is beyond the scope our study.

Finally, while we obtained temporally distributed demand for Jamaica in 2017, as well as a demand forecast for different sectors of the Jamaican economy, the data lacks regional distribution. To overcome this challenge, we multiply hourly demand for 2017 by the known share of total demand by rate class. This gives us a distribution of demand across rate classes for each hour. To obtain a regional distribution of demand, we multiply hourly demand for each rate class by the share of population (for streetlights, residential and small commercial customers) or the share of hotel rooms per parish (for large commercial, industrial and "other" customers). (Note: a parish is a geographic sub-division of the island. "Other customers" refers to two customers with a total of 25 GWh given a special designation by the utility. The OUR does not reveal who these two customers are. A total of 25 GWh suggests these customers area at least commercial in size. An educated guess would list Jamaica's two largest universities, which receive various government concessions, as the likely designated customers.) We do this because of the heterogenous growth rates of each rate class and the fact that the concentration of economic activities differs across parishes. We use these variables (number of hotel rooms and population) because the OUR (2017) identifies them as explanatory variables for rate class electricity demand. Intuitively, these variables correspond with tourism (Jamaica's primary service sector) and the fact that residential consumers make up one-third of electricity sales. Other predictor variables such as gross domestic product (GDP) are not available in a spatially disaggregated format and therefore could not be used. We project forward using demand growth rates (OUR, 2017).

For financial parameters, we use fixed and variable O&M costs for each generator from the OUR. We obtain investment costs for candidate generators from the EIA (EIA, 2016) and adjust to 2017 dollars. To convert to discrete capacity choices, we adjust investment cost by generator capacity relative to the capacity sizes listed in the EIA tables. We use annual fuel costs in real 2017 dollars based on EIA price projection (EIA, 2018).

Table 4.1: Summary and status of required data

Required Data	Status	Source	Gaps in data
Supply side			
Inventory of generators in Jamaica	Obtained	OUR, JPS	Availability factors and unforced outage rates not temporally disaggregated
Technical features of candidate generators	Obtained	EIA (2016)	
Location of candidate generators	Partially obtained	PCJ	Locations subjectively assigned (except for hydro generators)
Technical features of transmission lines in Jamaica	Obtained	OUR, JPSCo	
Emission Factors	Obtained	EPA (2018)	
Demand side			
Historical annual demand	Obtained only at aggregate level (2009-2016)	OUR (2017)	Disaggregated by customer type but not location
Annual demand forecast	Obtained only at aggregate level (2016-2040)	OUR (2017)	Disaggregated by customer type but not location; also includes line losses
Annual peak demand	Obtained only at aggregate level (2001-2016)	OUR (2017)	Not disaggregated by customer type or location
Annual peak demand forecast	Obtained only at aggregate level (2016-2040)	OUR (2017)	Disaggregated by customer type but not location
Historical hourly demand and peak demand	Obtained only at national level (Jan. 1, 2017 – Dec. 31, 2017 in half-hour intervals)	OUR (2017)	Not disaggregated by customer type or location
Hourly demand forecast	Computed	Authors' Calculations	Computed using hourly demand for 2017, demand shares per rate class and regional distribution of rate classes.
Costs			
Fixed and variable operating and maintenance (O&M) costs	Obtained	OUR	
Investment costs	Obtained	EIA (2016)	
Fuel price projections	Obtained	EIA (2018)	

CHAPTER 5. RESULTS AND DISCUSSION

The results of the empirical investigations are presented in this section. We answer the research questions within the context of Jamaica's electricity sector, presenting our main findings and discussing their underlying drivers and implications. Each subsection is summarized by a conclusion which reconciles our results with the broader conceptual problems this dissertation sets out to address.

5.1 Least-cost Investment Planning

Here, we compare investment decisions, costs and the generation portfolio across model specifications. First, our reference case *simultaneously* optimizes generation and transmission decisions. The second specification *sequentially* optimizes generation and then optimizes transmission decisions, given the generation plan optimized in the first stage. This simulates the planning process we believe to be most common among SIDS. Both models account for loop flow. The impact of simultaneous versus sequential planning is obtained by observing the differences in costs, investment plans and generation portfolio between these two specifications. The third model simultaneously optimizes generation and transmission decisions but excludes loop flow constraints. We first present the results of the baseline scenario and then discuss the differences in results across model specifications. We also perform sensitivity analysis relative to fuel prices and the discount rate to assess the robustness of our results.

5.1.1 Reference Case

In our reference case, the NPV cost of investment and operations over the 2017-2040 time-horizon is estimated at US $2.159 billion (see Table 5.1). This includes the construction of 944 MW of additional capacity. Large capacity power plants are primarily located in the south-eastern region and the north-west region. Respectively, these regions correspond to areas with the highest population density (and manufacturing center of Jamaica) and Jamaica's primary tourism destination (Figure 5.1). These investments represent the replacement of 11 power plants (631 MW) within the planning horizon. They also suggest that our approach to generating a regional distribution of demand is consistent with what one would expect given the distribution of economic activity across the island.

Table 5.1: Total discounted annual cost for 2017-2040 by model specification

	Units	Simultaneous Model with Loop Flow	Sequential Model with Loop Flow	Simultaneous Model without Loop Flow
Total Cost	US$ million	2,159	2,170	2,159
Difference*	US$ million		11	0.0
Difference*	%		0.5%	0.0%

* Relative to simultaneous model with loop flow

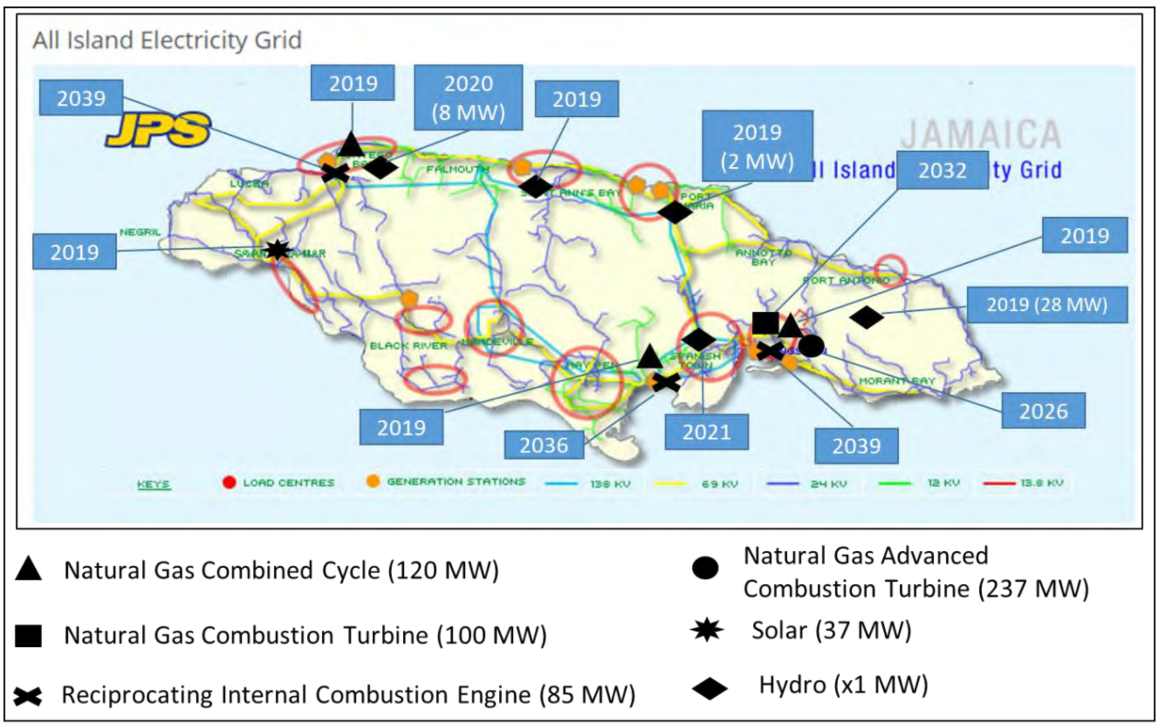

Figure 5.1: Map of Jamaica with optimal investments by year of installation (reference case)*

* We overlay JPSCo's map (JPSCo, n.d.-a) with black shapes to represent new generation investments; years of the investment are indicated in boxes. For hydro resources, capacities are listed in parenthesis given resource capacity available at that location. Red circles indicate load centers/nodes in the network, and orange pentagons indicate existing generators.

In our reference case, natural gas (NG) dominates new generation investments and the generation portfolio (Figure 5.2). The precipitous fall in the use of heavy fuel oil (HFO) in 2019 represents the scheduled decommissioning of HFO plants. The variability associated with renewable energy (RE) makes RE resources least attractive among new capacity investment alternatives; only 75 MW of new RE capacity is added (37 MW solar and 40 MW run-of river hydro). Of note, the 37 MW solar plant was exogenously imposed on the model to reflect plans already made by Eight Rivers Energy Company (an independent power producer) to construct that solar plant. The exhaustion of most of Jamaica's hydro generation potential and worsening drought conditions are also likely to dampen the construction of new hydro plants in Jamaica. Combined with the fact that model results do not recommend new wind plants to be built, we find that natural gas is the most cost-effective generation technology to meet future electricity demand.

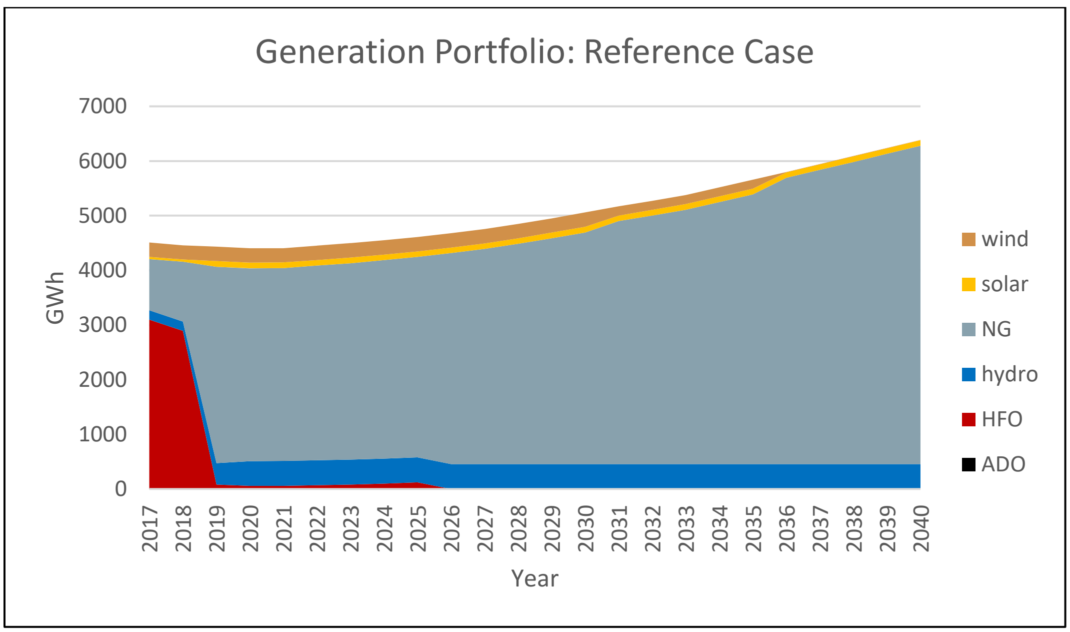

Figure 5.2: Generation Portfolio (reference case)

ADO = Automotive Diesel Oil; HFO = Heavy Fuel Oil; NG = Natural gas

Finally, to accommodate the additional generation capacity, our model recommends expanding one transmission corridor (10 km in length) between Spanish Town and St. Andrew in the south-east (Figure 5.3).

Figure 5.3: Optimal Transmission line investments by year of installation (reference case)*

* We overlay JPSCo's map (JPSCo, n.d.-a) with a black line to represent the optimal new transmission line investment, and the year of investment indicated in the box.

5.1.2 Sequential Model

As expected, a sequential planning approach results in a higher cost than our reference case (Table 5.1); total system cost increases by about US$ 11 million (in NPV terms). Natural gas remains the dominant fuel source (see Figure 5.2). However, an additional 16.1 MW in generation capacity (Figure 5.4) and an additional 5 transmission corridors with 87 km of transmission lines (Figure 5.5), are constructed in this scenario. These differences are driven by the treatment of transmission constraints. Recall that in the first stage of the sequential model, transmission constraints are ignored, and the power balance equation needs only satisfy aggregate demand. In the second stage, regional demand (as opposed to aggregate demand) needs to be satisfied, and generation capacity investments are taken from the results of the first stage model. This necessitates the expansion of 5 transmission corridors to satisfy demand at each node in the network.

However, the cost differential of US$ 11 million is smaller than anticipated, representing less than a 1% difference in costs relative to our reference case. We conjecture that these results are driven by the fact that transmission capacity is not a scarce resource in Jamaica. However, when one considers a set of vulnerabilities (e.g. exchange rate volatility and fuel price uncertainty) the cost differential of these models is likely biased downward.

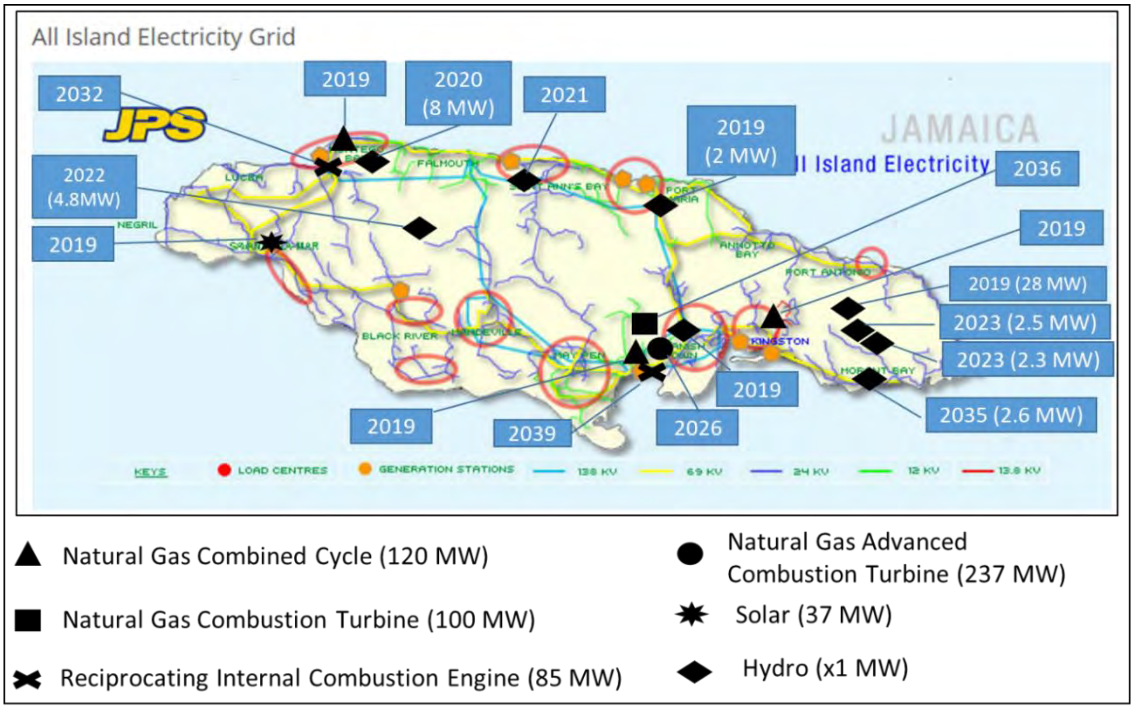

Figure 5.4: Map of Jamaica with optimal investments by year of installation (sequential model)*

* We overlay JPSCo's map (JPSCo, n.d.-a) with black shapes to represent new generation investments and indicate years of investments in boxes. For hydro resources, capacities are listed in parentheses given resource capacity available at that location. Red circles are load centers/nodes in the network and orange pentagons are existing generators

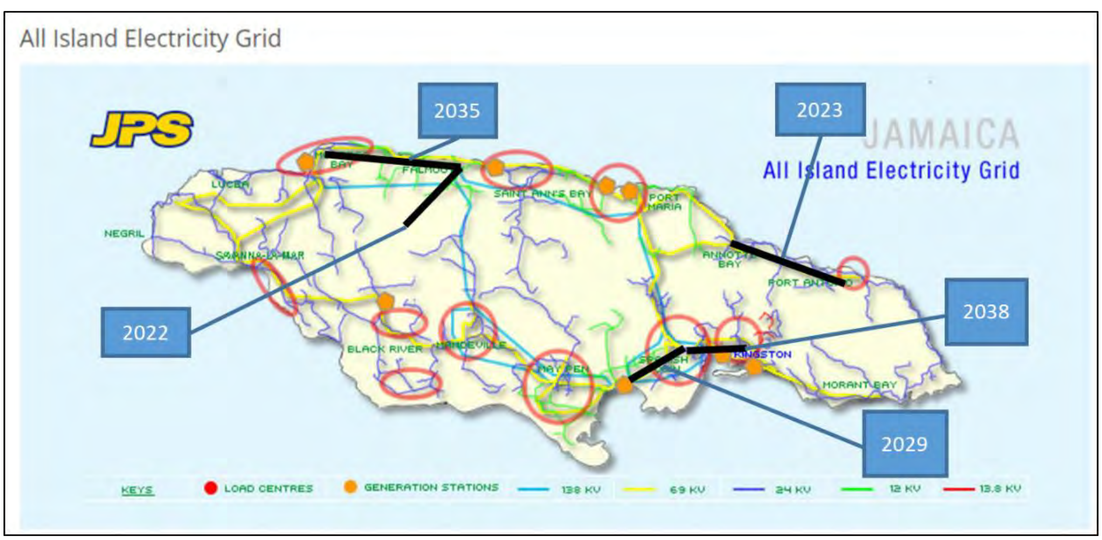

Figure 5.5: Map of Jamaica with transmission line investments by year of installation (sequential model) *

* We overlay JPSCo's map (JPSCo, n.d.-a) with black lines to represent new transmission line investments; year of investment in call-out boxes.

5.1.3 Impact of Loop Flow

Contrary to our expectation, we find no evidence that loop flow affects long-term investment planning in Jamaica. There is no difference in total system cost between models with and without loop flow constraints (Table 5.1) and investment patterns between the two are near identical. This suggests that Jamaica's network topology may lack the complexity, size and scarcity of transmission capacity to make loop flow a significant economic consideration, at least from a long-term planning perspective. Results may differ in an operational plan that considers much smaller time-scales and additional transmission details such as ancillary services of voltage support.

5.1.4 Sensitivity Analysis

We use sensitivity analysis to address an important source of uncertainty in our model - fuel prices. Since fuel prices drive the bulk of operating costs, we re-evaluate our models using high and low fuel price projections for HFO, ADO and natural gas (EIA, 2018). As Table 5.2 summarizes, total cost is higher under a high fuel price scenario and lower when prices fall.

It is interesting that the difference between the sequential and simultaneous specification is highest in our baseline fuel price scenario, and not the high fuel price scenario. This result is driven by the non-linear interaction between investment costs and operating costs, and the impact of integer variables in our model. In Table 5.3, we decompose these differences by generation investments (driven by hydro power investments), transmission investments, operating cost and total cost (in millions of dollars). Positive numbers indicate a higher cost in the sequential specification relative to the simultaneous. We observe that it is differences in the (hydro) generation and transmission investments (inversely correlated with operating costs) that drives our results.

However, despite these differences across fuel price scenarios, our results are consistent: (1) a sequential planning approach increases costs and results in additional capacity investments (relative to a simultaneous planning approach) and (2) natural gas dominates new capacity investments. There are no investments in onshore wind capacity. Only 1 solar plant (the one already committed) is constructed and there is minor variation in run-of-river hydro investments.

Table 5.2: NPV Total cost given fuel price scenarios

Model Type	**Units**	**Baseline Fuel Cost**	**High Fuel Cost**	**Low Fuel Cost**
Simultaneous model with Loop Flow	Total Cost (US$mil)	2,159	2,274	1,990
Sequential model with Loop Flow	Total Cost (US$mil)	2,170	2,281	1,992
	Difference (US$mil)*	11	7	3
	Difference (%)*	0.52%	0.32%	0.13%
Model excluding Loop Flow constraints	Total Cost (US$mil)	2,159	2,274	1,990
	Difference (US$mil)*	-	-	-
	Difference (%)*	0%	0%	0%

* Relative to simultaneous model of the same fuel price scenario.

Table 5.3: Cost differences (USD millions) between sequential and simultaneous specifications by fuel price scenario

	Baseline Fuel Cost	High Fuel Cost	Low Fuel Cost
Generation Investments	19	9	5
Transmission Investments	5	2	2
Operating Cost	-13	-4	-4
Total Cost	11	7	3

We also evaluate how sensitive our results are to discount rates. The results we have presented are based on an 11.95% discount rate as used by the OUR (2010). However, this seems very high in comparison to discount rates we have found in the academic literature. Following Lu et al. (2016), we re-evaluate our models using a 5% discount rate. As Table 5.4 shows, total discounted costs under each model specification is higher compared to results shown in Table 5.1. Additionally, the difference between the simultaneous model specification and the sequential model specification increases to 1.3%. However, these numeric results are driven only by the discount rate; there is no change in the choice of generation or transmission infrastructure nor is there a difference in the timing of these investment decisions. That is, the timing of investment decisions is insensitive to the discount rate used. Naturally, however, a lower discount rate results in a higher NPV of investment and operating costs over the planning horizon. The higher total NPV costs therefore reflects only the calculation of discounted sums using a lower discount rate and not a change in investment decisions.

The insensitivity of the location and timing of investment decisions to the discount rate is driven by the fact that nearly half of the new capacity investments take place within the first 5 planning years to compensate for the decommission of three of Jamaica's largest power plants. Consequently, the same choice of generator and transmission lines are made irrespective of the discount rate. Nevertheless, our qualitative conclusions are unchanged; a simultaneous planning framework results in a lower discounted sum of investment and operating cost over the planning horizon in comparison to a sequential planning approach, and we detect no impact of loop flow on long-term investment planning in our case.

Table 5.4: Total discounted annual cost using 5% discount rate

	Units	**Simultaneous Model with Loop Flow**	**Sequential Model with Loop Flow**	**Simultaneous Model without Loop Flow**
Total Cost	US$ million	3,672	3,720	3,672
Difference*	US$ million		48	0
Difference*	%		1.3%	0.0%

* Relative to simultaneous model with loop flow

5.1.5 Conclusions Re Model Features

In this section, we extend the literature on long-term infrastructure investment planning in the electricity sector by explicitly accounting for the economic and geographic idiosyncrasies of Jamaica, a representative Small Island Developing State (SIDS), and the role they play in long-term planning. Compared to the existing literature, this paper offers insights into the importance of modeling features in the SIDS context.

We find that co-optimizing generation and transmission investment decisions is less costly than the traditional sequential approach to long-term planning historically practiced in SIDS. In the Jamaican context, the savings are modest; however, in other SIDS instances, the initial conditions may be such that these savings are more substantial. Our qualitative results appear to be robust to varying fuel price scenarios and discount rates. For these reasons, we conclude that the modest additional computational requirements of simultaneous planning are justified in long-term infrastructure investment planning in SIDS.

We do not find evidence that loop flow impacts least cost investment decisions in the Jamaican case. We therefore reject our initial hypothesis that failing to account for loop flow would under-estimate costs and misallocate resources as indicated by Chao and Peck (1996). Our results are attributable to the small size, the near radial topology of the Jamaican electricity network, and the abundance of existing transmission capacity in the island. Loop flow may be of greater import to short-term operational plans in the SIDS context.

5.2 Energy Policy Analysis

In this section, we discuss the results of our policy simulations. We use total discounted CO_2 emissions to establish a point of comparison among the four policy options. Specifically, we use the discounted cumulative emissions of 13.97 megatons of CO_2, generated by the 30% RPS, as the emissions target for the carbon tax, PTC and investment subsidy (see Appendix C for undiscounted annual emission levels). By simulating a series of values for each of these policy scenarios, a carbon tax of $63/ton of CO_2, a PTC of $29/MWh and an investment subsidy of 35% were found to be the appropriate magnitudes that yielded the desired emissions target. Due to the mixed integer nature of the mathematical program and the different periods in which the policies take effect, the emissions targets do not precisely match 13.97 megatons of CO_2. However, deviations do not exceed 0.19% and are within tolerable bounds for this dissertation.

Ultimately, we find that the magnitudes of the policies we simulate are reasonable and comparable to policy levels in the US and other countries. For instance, Lu et al. (2016) find that a carbon tax of $49/metric ton in 2022, increasing to $109/metric ton in 2034 would be needed to meet Indiana's emission targets. The PTC of $29/MWh (2.9 cents/kWh) is comparable to the 1.2 cent/kWh – 2.5 cents/kWh in the US (Sherlock, 2020). The investment subsidy of 35% is comparable to investment subsidies in the US as high as 30% (DoE, 2020). There are few fiscal policy incentives in the Caribbean for comparison. Existing or planned incentives include net billing, net metering and small loans. However, tax credits in the Caribbean range from a 15% value added tax credit on renewable technologies and a 20% credit on import duties for renewable energy technologies (CaPRI, 2018). Examining the range of policies existing both within the

Caribbean and in larger more develop territories, we conclude that the carbon tax of $63/ton of CO_2, a PTC of $29/MWh and an investment subsidy of 35% are reasonable and comparable to policies in other territories.

5.2.1 Policy Scenarios and Welfare Implications

Our model simulates the electricity system and not the general economy. Due to data limitations, welfare implications are therefore limited to a partial equilibrium framework as opposed to a general equilibrium environment. To assess the welfare impacts of each policy, we extract the total discounted cost associated with each policy from the optimized value of our objective function (the "net system cost") and compare with the total system cost under a business-as-usual scenario.

The net system cost reflects the effect of each policy on the electricity sector, ignoring the distribution of government revenue (carbon tax) and the funding source of government expenditure (investment subsidy and PTC). (Future research can aim to expand our work to a general equilibrium environment.) Implicit in our model, inflows to and outflows from government accounts reflect a transfer of resources from segments of the economy to other segments of the economy, without changing total welfare. By using the net system cost, however, we can ascertain a measure of welfare in a partial equilibrium framework that remains informative due to the treatment of emissions reductions across policy scenarios and the market structure of Jamaica's electricity sector. Specifically, by ensuring the same (or near same) emissions target across policy scenarios, the benefits gained by reducing carbon emissions are equalized across scenarios. An examination of the costs associated with each option is therefore sufficient to establish a comparison among the four policy options. Additionally, our model assumes inelastic demand and a regulated, third-degree price discriminating monopoly with a step supply function. Hence, there is no deadweight loss as one would expect in a competitive market. (See Figure 5.6 for illustration. The chart on the left represents a standard competitive market while the chart on the right represents the electricity market.) Irrespective of how the government redistributes tax revenue or how the government raises revenue to finance the PTC or the investment subsidy, the cost is borne by society. From the net system cost, we can calculate the *added* cost borne by society because of each policy. Ultimately, the equalization of emissions reduction benefits across policy scenarios and the market structure we model allow us to garner useful welfare inferences from net system costs.

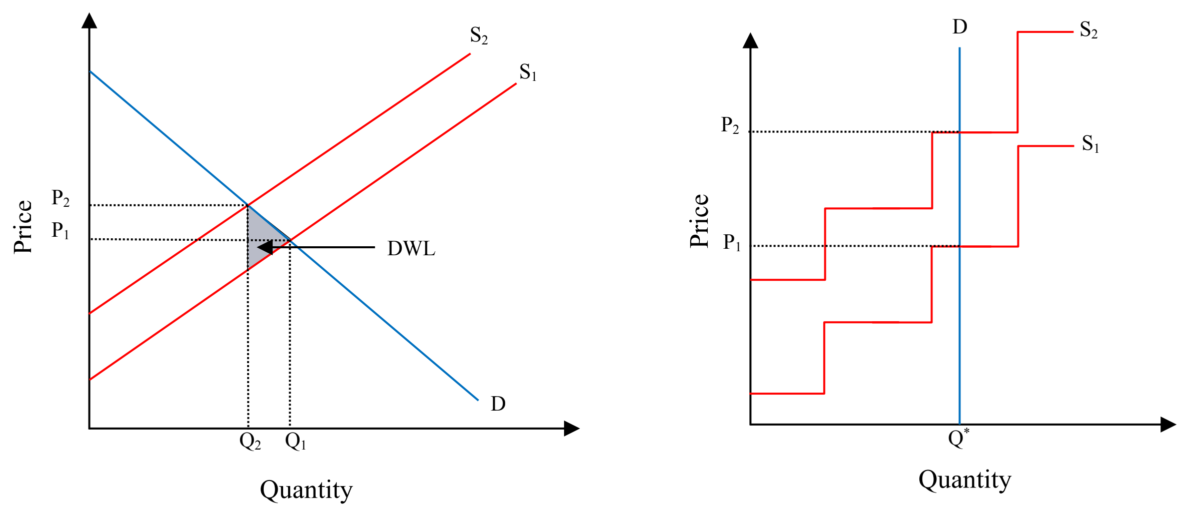

Figure 5.6: Welfare differences between competitive (left) and electricity (right) markets*

* "S" denotes supply curves, "D" denotes demand curve, "P" denotes price, "Q" denotes quantity and the shaded region "DWL" denotes deadweight loss.

Table 5.5: Net system cost by policy scenario*

	Gross System Cost ($ millions)	Impact on Fiscal Account ($ millions)	Net System Cost ($ millions)	Increase in Net System Cost ($ millions)
BAU	2,159	N/A	2,159	N/A
RPS 30%	2,193	0	2,193	34.7
CTAX $63/ton	2,785	602	2,183	24.0
Inv_Sub 35%	2,104	-90	2,194	35.4
PTC $29/MWh	2,077	-117	2,194	35.4

* "BAU" denotes a business as usual scenario, "RPS" denotes a renewable portfolio standard, "CTAX" denotes carbon tax, "Inv_Sub" denotes investment subsidy and "PTC" denotes production tax credit.

Table 5.5 presents the net system costs under each policy scenario and compares them to the business-as-usual case. All numbers are in millions of dollars in NPV terms. Positive numbers in the third column denote inflows to government accounts while negative numbers denote outflows. Since the RPS is not implemented using fiscal policy, its impact on government accounts in our model is zero. From these results, we observe that the carbon tax is the most efficient policy tool to achieve the discounted cumulative carbon reduction target, increasing total net system cost by $24 million. This aligns with economic theory which suggests that a market-based mechanism for addressing negative externalities is more efficient than a command and control policy. These results are driven by the fact that a carbon tax directly penalizes carbon emissions while the remaining three policies indirectly address carbon emissions by enforcing or incentivizing renewable energy investment and generation.

However, notice in Figure 5.7 that a carbon tax significantly increases the annual average cost of electricity relative to all other policies (undiscounted). The annual average cost of electricity is calculated as the sum of operating, maintenance and investment cost each year divided by total output each year. It can therefore be interpreted as the average cost of service inclusive of operating and maintenance cost and the recovery of investment costs per unit of output. When setting the rate of electricity, the regulator would compute a more complex formulation of this cost and include a reasonable rate of return for installed assets. Here, we use an annual average cost of electricity simply to reflect that a carbon tax, transferred to rate payers, would result in higher electricity bills compared to other policies.

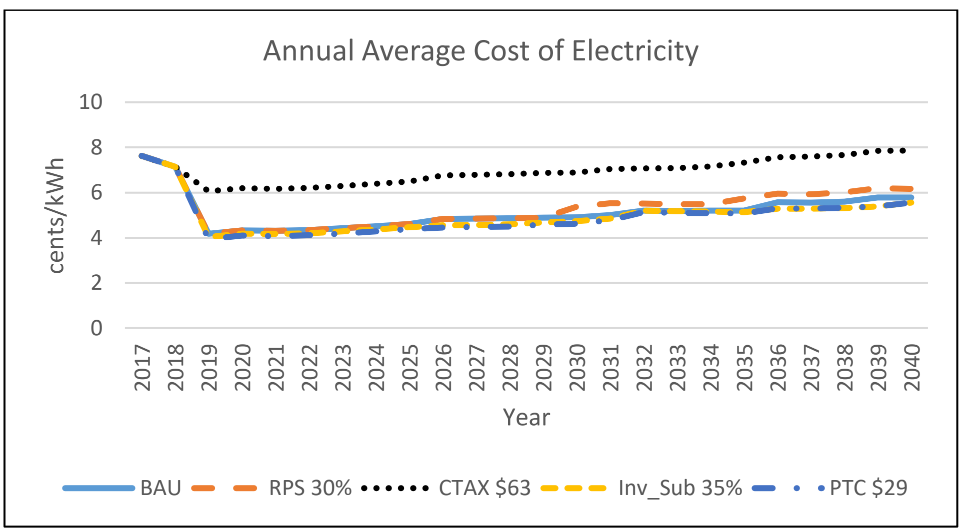

Figure 5.7: Annual average cost of electricity (cents/kWh) (undiscounted) *

* "Inv_Sub 35%" denotes a 35% investment subsidy, "PTC $29" denotes a production tax credit of $29/MWh and "CTAX $63" denotes a carbon tax of $63/ton of CO_2.

The significant fall in the average annual cost of electricity in 2019 (see Figure 5.7) results from the decommissioning of automotive diesel oil (ADO) and heavy fuel oil (HFO) plants. This reduction is however tempered in the carbon tax scenario due to the tax on the use of fossil fuels, including natural gas, which largely replaces the decommissioned ADO and HFO plants. While tax revenues may be redistributed to consumers, higher electricity bills often make carbon taxes politically unfavorable. It is therefore useful to also assess the comparative efficiency of the other policies or to give decision-makers a sense of the trade-offs associated with each option. Our results indicate that second to the carbon tax, a renewable portfolio standard is efficient; it increases net system cost by \$34.7 million (see Table 5.5). The RPS marginally outperforms the production tax credit and the investment subsidy. Interestingly, the PTC and investment subsidy both increase net system cost by \$35.4 million.

5.2.2 Government Revenue and Expenditure

While our model does not account for how the government redistributes tax revenues or raises revenue to finance the PTC or investment subsidy, our results provide dynamic insights that are helpful for long-term planning for budget allocation (Figure 5.8). In real terms, revenue from the carbon tax falls smoothly over time in response to increases in renewable energy generation and the discount factor. Expenditure on the PTC and investment subsidy follow a near parallel trend, fluctuating over time. We observe that increases in expenditure (more negative numbers) follow years in which new RE generators (primarily wind) are constructed, but then fall over time. For instance, between 2028 and 2031, significant investments are made in new wind generation capacity, which logically increase government expenditure. Additionally, we observe that an investment subsidy generally places less demand on government accounts annually when compared to a PTC except in the last five years of the planning horizon. Hence, while Table 5.5 ranks the PTC and the investment subsidy equally in aggregate, if the government is concerned about minimizing its annual expenditure each year, an investment subsidy may be preferred to a PTC.

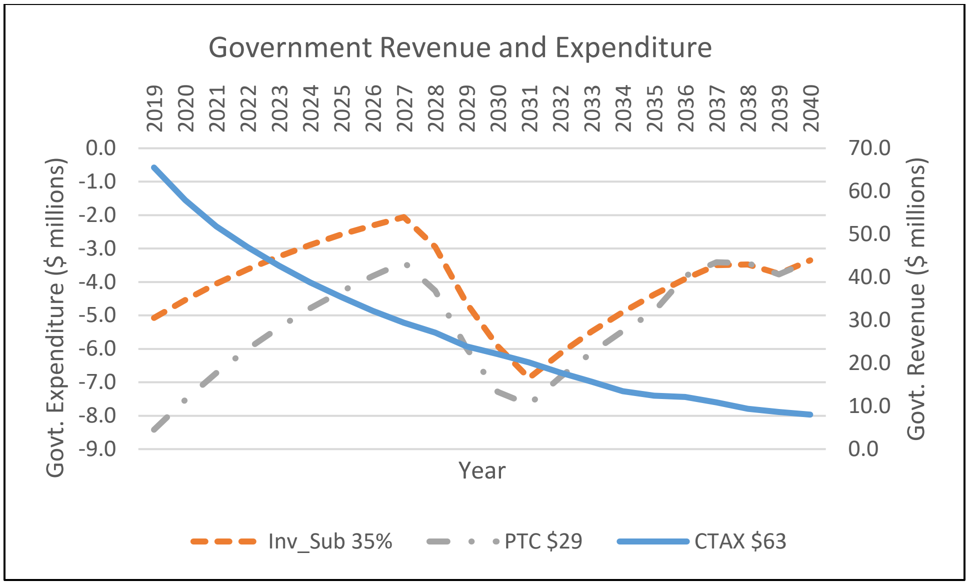

Figure 5.8: Annual government expenditure and revenue (net present value) by policy scenario*

* "Inv_Sub 35%" denotes a 35% investment subsidy, "PTC $29" denotes a production tax credit of $29/MWh and "CTAX $63" denotes a carbon tax of $63/ton of CO_2. The right-hand vertical axis measures government revenue (CTAX) while the left-hand vertical axis measures outflows from government accounts (PTC and Inv_Sub).

5.2.3 Generation Portfolio and Energy Security

One dimension of energy security focuses on stable, reliable supply of energy at prices with little volatility. Natural gas is preferred to fuels such as heavy fuel oil due to historically lower prices and lower comparative volatility. However, another dimension of energy security is energy independence – relying on a country's ability to satisfy its own demand for energy with little dependence on international markets. For small island states like Jamaica, this gives renewable energy generation from local resources added import. As illustrated in Figure 5.9, the RPS is the only policy that ensures renewable energy generation remains at least 30% of total generation post 2030; all other policy scenarios have fluctuating renewable generation levels. (A full breakdown of the generation portfolio by fuel source and policy scenario is presented in Appendix B.) Hence, if energy independence is of major concern to the government, the RPS appears the most attractive policy option.

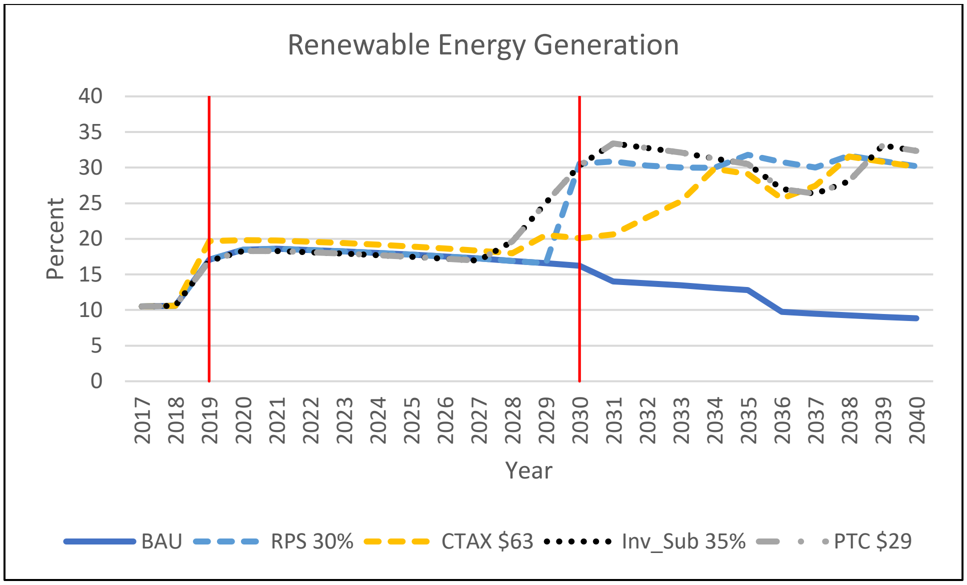

Figure 5.9: Renewable energy generation as a percent of total generation*

* "BAU" denotes "business as usual", "RPS 30%" denotes a renewable portfolio standard of 30%, "CTAX $63" denotes a carbon tax of $63/ton of CO_2, "Inv_Sub 35%" denotes a 35% investment subsidy and "PTC $29" denotes a production tax credit of $29/MWh. The vertical line at year 2030 indicates the effective date of the RPS. The vertical line at year 2019 indicates the effective date of all other policies.

5.2.4 Conclusions on Energy Policy Analysis

As Small Island Developing States (SIDS) seek to balance the delivery of low-cost electricity to satisfy demand while minimizing carbon emissions and improving energy security, it becomes important to quantify the tradeoffs associated with a menu of policy tools available to them. This provides an empirical foundation for setting energy policy, removing the ambiguity from these decisions. Here we present a framework for analyzing these policy options. Specifically, we compare a renewable portfolio standard (RPS), a carbon tax, a production tax credit (PTC) and an investment subsidy. We find that a carbon tax of $63/ton of CO_2 is the most economically efficient of the four policy options. If the primary concern of the government is reducing CO_2 emissions, the carbon tax is the most efficient. However, even if the government can perfectly redistribute tax revenue to consumers, the higher electricity prices often makes a carbon tax politically unfavorable. In this case, an RPS ranks second in terms of lowest increase in cost to society.

If the government's primary concern is not carbon emissions, but instead, energy independence, then an RPS may be the most suitable policy tool of the four policy options we evaluate. This, however, requires an ability to effectively monitor electricity generators. Given that the electricity markets in SIDS are typically characterized by regulated monopolies, it may not be difficult to monitor electricity generation.

If there is insufficient political will to implement a carbon tax or weak institutions inhibit the effective execution of an RPS, a PTC or an investment subsidy may be alternative policy tools worth considering. If the government opts for either of these two options, an investment subsidy of 35% would have the lower annual impact on government accounts than would a PTC of $29/MWh. However, the use of these two tools are predicated on the ability of the government to raise revenue from other segments of the economy.

CHAPTER 6. CONCLUSION

Long-term infrastructure investment planning is critical to ensuring adequate resources to satisfy future electricity demand, which underpins economic activity. As the world grapples with the impact of climate change and energy security, policies which mitigate the impacts of climate change and encourage renewable energy investments and generation are of import. This is particularly true for Small Island Developing States (SIDS), which have been recording rapid increases in per capita electricity consumption and are the countries most at risk of the consequences of climate change. However, publicly accessible information indicates that there may be room to improve least-cost investment planning, reducing costs to society and to rate payers. Energy policies in SIDS change frequently, sometimes miss their targets, and appear to have ambiguous empirical foundations. Furthermore, the extant literature largely ignores the economic and geographic idiosyncrasies that distinguish SIDS from other countries. It is therefore important to investigate methods of improving infrastructure investment planning in the electricity sector and to provide an empirical foundation for energy policy setting in SIDS.

This dissertation advances long term investment planning in the electricity sector by examining the impact of *simultaneously* planning for generation and transmission infrastructure. This contrasts with other approaches that optimize generation investments only, or otherwise, *sequentially* optimize generation and transmission investments. We also examine the impact of loop flow on the least cost investment path for generation and transmission infrastructure. Finally, we quantify the cost to society of a menu of policy options to reduce carbon emissions and bolster energy security. This allows us to assess the trade-offs associated with each policy and provide an empirical foundation for policy makers to determine an appropriate energy policy for their objectives. We explicitly account for the economic and geographic features of Jamaica, making our results more applicable to the SIDS context than much of the existing literature. Finally, we offer an open-source tool for electric energy economics research relevant to SIDS context. This can potentially help to generate more research in this area.

The first problem addressed in this dissertation concerns efficient energy planning. Based on publicly accessible information, SIDS generally optimize investments in generation infrastructure, giving transmission investments second-order priority. We hypothesize that simultaneously planning for generation and transmission investments yields a lower cost solution that sequentially optimizing these investment decisions. Using a mixed integer mathematical program representing Jamaica's electricity network, we find that a simultaneous planning approach is more efficient than a sequential planning strategy. We therefore conclude that the modest additional computational requirements of simultaneous planning are justified in long-term infrastructure investment planning in SIDS. The underlying principle behind this conclusion is the substitutability between local generation and the transmission resources.

While savings are modest in the Jamaican context, savings may be more substantial in other SIDS with different network configurations. For instance, Haiti, the country occupying the western portion of the island of Hispaniola, has an electrification rate of only 25% (NREL, n.d.-a). Furthermore, Haiti does not have a centralized transmission and distribution system; instead, it has 10 isolated regional grids (NREL, n.d.-a). Given the large population of almost 10 million people, a significant lack of grid access, generation capacity and reliable electricity services, we envision that cost savings from a simultaneous planning framework would be substantial in the Haitian context. Similarly, cost savings in the islands of St. Vincent and the Grenadines may be more substantial when compared to Jamaica's case. The electrification rate in St. Vincent and the Grenadines is 73% (NREL, n.d.-b), much lower than Jamaica's 98%. Transmission and generation capacity is therefore likely more scarce than the Jamaican case. This scarcity would likely increase the value of a long-term capacity investment plan that co-optimizes generation and transmission investments.

The second issue we explore is the impact of Kirchhoff's Laws (KL) – important laws governing the flow of electricity in a network – on optimal planning solutions. We find that ignoring KL, particularly Kirchhoff's Voltage Law, does not significantly impact long-term planning solutions. We therefore reject our initial hypothesis that failing to account for loop flow would under-estimate costs and misallocate resources as indicated by Chao and Peck (1996). Our results are attributable to the small size, the near radial topology of the Jamaican electricity network, and the abundance of existing transmission capacity in the island. Loop flow may be of greater import to short-term operational plans in the SIDS context. Again, an alternate network configuration may lead to a significant result. Haiti has one of the most under-developed electricity networks in the Caribbean region. Given that the country does not have a centralized transmission and distribution system, loop flow may have a more significant impact in the Haitian context.

The third problem this dissertation addresses shifts the focus from efficient energy planning to efficient energy policy setting. While SIDS have some of the most ambitious carbon mitigating/renewable energy policies, the empirical foundation justifying these very specific targets is unclear. To dispel this ambiguity, we evaluate four energy policies to achieve a total discounted carbon emission target of 13.97 megatons of CO_2 between years 2017 and 2040. We find that the most efficient policy (i.e. the policy with the lowest additional cost to society) is a carbon tax of $63/ton of CO_2. This increases the cost to society of $24 million over the planning horizon. However, it also increases the cost of electricity. Even in cases where the government can perfectly redistribute tax revenue, higher electricity bills may make this policy tool less politically favorable. In such a case, a renewable portfolio standard (RPS) of 30% by year 2030 ranks second; it increases the cost to society by $34.7 million between 2017 and 2040. An RPS may also be a more suitable policy tool than a carbon tax if the government's primary objective is not carbon mitigation, but energy independence instead. If these two policy tools are infeasible for the government, a production tax credit of $29/MWh and a 35% investment subsidy can achieve the total emissions target. However, the 35% investment subsidy will generally have a lower annual impact on the government's account. Our primary contribution here is our ability to quantify the societal costs of each policy and weigh the tradeoffs associated with each against different government objectives. While we present results for the Jamaican context, the magnitudes of the various policies are comparable to what has been document in other countries. Given the similarities Jamaica shares with other SIDS, we posit that the qualitative results are informative for other SIDS as well. That is, a market-based approach such as a carbon tax has the lowest total cost to society. Additionally, of the four policy scenarios we evaluate, a renewable portfolio standard ranks second from a least-cost perspective.

Taken together, the three questions answered in this dissertation demonstrate the utility of the open-source tool we create. The mathematical program we design in GAMS has the flexibility to conduct efficient-long term investment planning, while explicitly accounting for Jamaica's economic and geographic features. It also enables energy policy research that, in comparison to the existing body of literature, is more applicable to the SIDS context. Critically, data availability has been a significant hindrance to energy economics research in SIDS. By making our data and program publicly available, we are able to help advance empirical work in this area. Importantly, we gain useful insights that can help utilities and energy planners efficiently plan for future generation and transmission investments in SIDS. We also demonstrate that energy policy setting in SIDS do not need to be ambiguous. Subject to the objectives of governments, our model can quantify the costs of a variety of policy options and assess the trade-offs among them. This empowers policy makers with critical insights to inform decisions they take that may have long-term implications for a country.

Nevertheless, this dissertation faces some limitations. First, while we have a richer dataset compared to previous works, the data limits our analysis to only the electricity sector. More data would be needed for a general equilibrium analysis that takes account of other sectors and their interaction with Jamaica's electricity sector. A second limitation is the long-term focus of this work. Given the intermittent nature of renewable resources, complementary operational studies with smaller timescales would be needed to effectively integrate renewable resources in an electricity network. Hence, while our results provide useful strategic insights, it is limited in its ability to provide operational insights on smaller timescales. A third limitation of this dissertation concerns regional patterns in electricity demand growth. Given the lack of regionally disaggregated data, our treatment of regional demand growth was limited to generating a distribution based on population and the tourism sector. A distribution accounting for a greater variety of economic activity would add greater accuracy to our analysis.

These limitations however present opportunities for future research. First, future research could explore the economy-wide impact of various energy policies. This would allow us to not only quantify total social welfare impacts, but we would be in a better position to assess the distributional impact of these policies. That is, we would be able to identify "winners" and "losers" in the economy. Including other sectors of the economy may also allow for not only the co-optimization of generation and electricity transmission investments, but also, potential natural gas transmission as well. Given the novelty of natural gas to Jamaica's energy landscape, there is significant potential for large-scale investments in natural gas infrastructure in the future.

A second area for future research includes keener focus on integrating renewable energy resources into Jamaica's energy portfolio. Specifically, future research can explore integrating renewable resources using finer time-scales for operational accuracy. Additionally, there is significant potential in assessing the extent to which energy storage technology can help make renewable energy more economical. This dissertation indicates that solar energy is not economical. However, given the abundance of sunlight in the Caribbean region, efficient energy storage may alter the economics of solar energy and potentially open new frontiers for the energy security ambitions of Caribbean SIDS.

Third, there is significant research potential in building a more detailed regional forecasting model for electricity demand. There is utility for long-term planning purposes, providing a more accurate distribution of electricity demand and demand growth. This also allows for greater flexibility in potential research on specific sectors of the economy. Building a regional forecasting model for electricity demand would help address a key limitation in this dissertation while opening opportunities for future applications to other research including research on specific sectors of the economy.

In conclusion, this dissertation should help to advance future empirical energy economics research that acknowledge the important economic and geographic features Small Island Developing States. Here, we evaluate empirical methods in long-term electricity infrastructure investments with a view to help reduce costs. We also provide quantitative analysis of a menu of energy policy options to help inform decisions taken by policy makers. We address an important knowledge gap by accounting for the unique economic and geographic features of SIDS in terms of infrastructure investment planning and energy policy setting.

APPENDIX A. MODEL CALIBRATION

In calibrating the model, we compare results with information provided by the OUR as well as data found in JPSCo's 2017 annual report. This was necessary because the two data sources provided two sets of information and neither was all-encompassing. For instance, while we have reported net output from different renewable resources from the OUR, there was no information on the net output from non-renewable resources. This information is however available in the JPSCo's 2017 annual report. Nominal magnitudes also differ somewhat depending on the data source. We therefore examine both nominal figures as reported, as well as electricity generation as a share of total output.

Table A.1 compares our simulation with data available in JPSCo's 2017 annual report. In terms of operating cost, our simulation yielded US$344 million compared to JPSCo's US$549 million. Given that we included only the direct costs associated with generation (which is 61% of total JPSCo costs), excluding administrative costs, we believe the simulated operating costs are within expected bounds. Since our net generation data was obtained from the OUR and not from JPSCo (which differ in nominal values for output), we observe differences in net output from slow speed diesel (SnSSD), hydro plants owned by JPSCo, gas turbine plants (GGT) and combined cycle plants (CCT) when compared to the JPSCo report. This is similarly true for the net output of JPSCo and IPPs in nominal terms. However, when one compares the share of total output by each set of plants (the final two columns), we find the differences to be within tolerable limits.

In Table A.2, we find encouraging results when our simulation is compared with the actual source data from the OUR. The first column represents anonymized plants. Columns 3 and 4 represent the output in GWh from our simulation versus the reported output from the OUR. The final two columns compare our simulated capacity factors with reported OUR capacity factors. The maximum error is 0.01.

Table A.1: Comparing simulation with data from JPSCO's annual reports

Variable	Units	Simulated	Reported	Nominal Difference	Difference (%)	Simulated Share (%)	Reported Share (%)
SnSSD Net. Gen	GWh	1116	1467	-351	-24	25	34
JPSCo Hydro	GWh	172	157	15	10	4	4
JPSCo GGT	GWh	0	92	-92	-100	0	2
JPSCo CCT	GWh	937	820	116	14	21	19
JPSCo Net Output	GWh	2229	2536	-306	-12	49	58
IPPs Net Output	GWh	2278	1827	451	25	51	42
Operating Cost	USD Mil.	344	549	-205	-37		

Table A.2: Comparing simulation with OUR data

		Output		Capacity Factor	
Plant	**Technology**	**Simulated (GWh)**	**Reported (GWh)**	**Simulated**	**Reported**
h1	hydro	39.9	40.0	0.76	0.76
h2	hydro	17.1	17.0	0.78	0.78
h3	hydro	28.2	28.0	0.67	0.67
h4	hydro	23.7	23.6	0.75	0.75
h5	hydro	6.0	6.0	0.62	0.62
h6	hydro	2.5	2.5	0.36	0.36
h7	hydro	29.1	29.0	0.81	0.81
h8	hydro	25.8	26.0	0.46	0.46
W0	wind	5.1	5.3	0.19	0.19
W1_2	wind	95.2	96.5	0.29	0.28
W3	wind	98.7	99.7	0.33	0.32
W4	wind	61.4	63.1	0.29	0.29
S1	solar	40.7	40.9	0.19	0.20

APPENDIX B. GENERATION PORTFOLIO – POLICY ANALYSIS

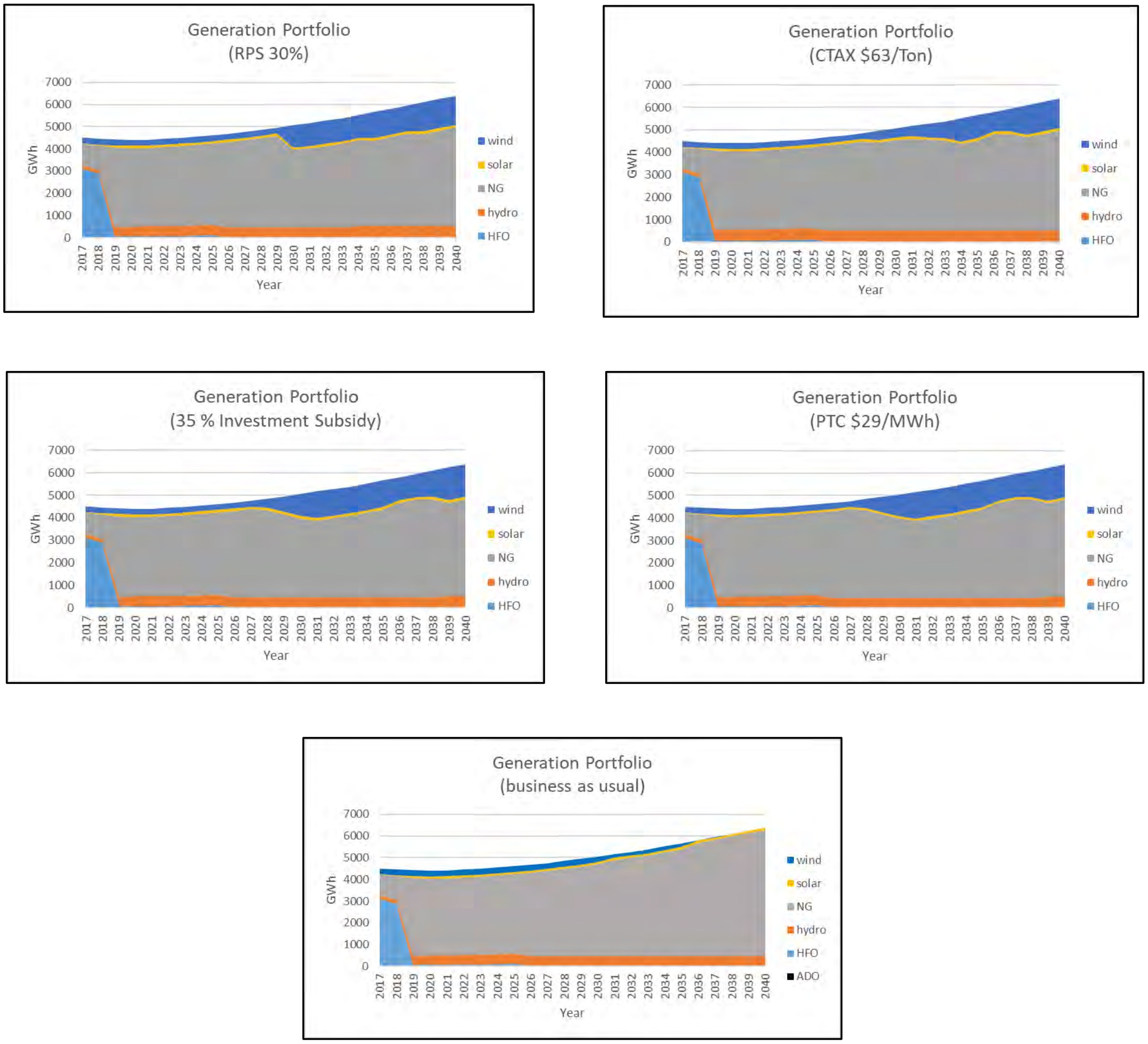

Figure B.1: Generation portfolio by policy scenario

In Figure B.1 , we observe that wind is a more economical option to solar (without storage) as a renewable energy resource in Jamaica. We also observe that the time-varying generation portfolio for the production tax credit (PTC) and the investment subsidy are near identical. In all scenarios, natural gas commands the greatest shear of the generation portfolio, largely replacing automotive diesel oil (ADO) and heavy fuel oil (HFO) after year 2019.

APPENDIX C. EMISSION LEVELS – POLICY ANALYSIS

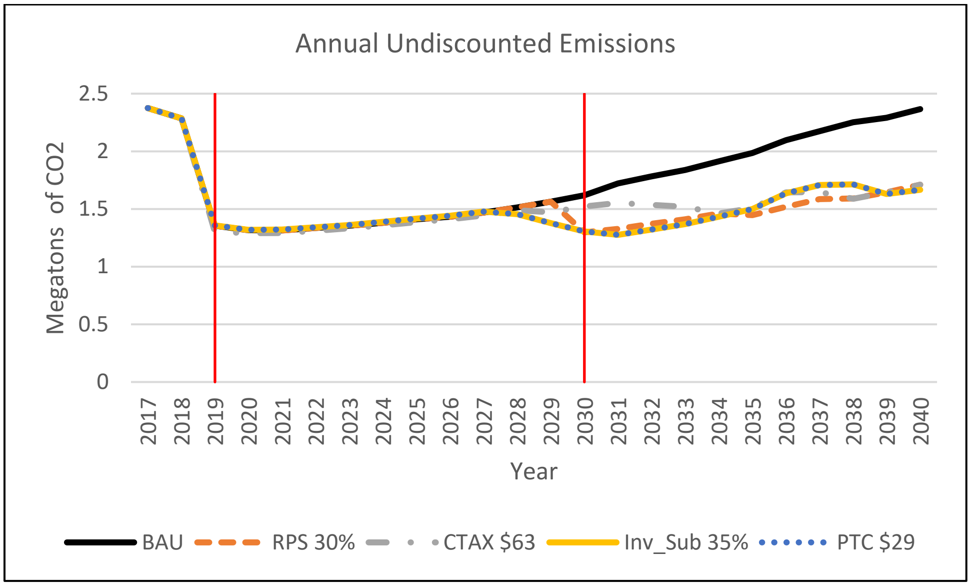

Figure C.1:Annual undiscounted emissions by policy scenario*

* "BAU" denotes "business as usual", "RPS 30%" denotes a renewable portfolio standard of 30%, "CTAX $63" denotes a carbon tax of $63/ton of CO_2, "Inv_Sub 35%" denotes a 35% investment subsidy and "PTC $29" denotes a production tax credit of $29/MWh. The vertical line at year 2030 indicates the effective date of the RPS. The vertical line at year 2019 indicates the effective date of all other policies.

Figure C.1: illustrates the annual undiscounted emissions by policy scenario. While undiscounted emissions fall in 2019 with the decommissioning of some automotive diesel oil (ADO) and heavy fuel oil (HFO) plants, emissions will continue to rise without policy intervention as greater levels of investments are made in natural gas plants.

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